UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Trans Alaska Pipeline System, *et al.*	Docket No. OR89-2-017
Exxon Company, U.S.A. v. Amerada Hess Pipeline Corporation, *et al.*	Docket No. OR96-14-006
Tesoro Alaska Petroleum Company v. Amerada Hess Pipeline Corporation, *et al.*	Docket No. OR98-24-002
BP Pipelines (Alaska), Inc.	Docket No. IS03-137-001
ExxonMobil Pipeline Company	Docket No. IS03-141-001
Phillips Transportation Alaska, Inc.	Docket No. IS03-142-001
Unocal Pipeline Company	Docket No. IS03-143-001
Williams Alaska Pipeline Company, L.L.C.	Docket No. IS03-144-001

INITIAL DECISION

(Issued August 31, 2004)

Appearances

John E. Kennedy, *Louis R. Veerman, Daniel W. Sanborn, Heather H. Grahame, John B. Rudolph, Sara C. Weinberg* and *Andrea M. Halverson* on behalf of the TAPS Carriers

John B. Rudolph, Audrey P. Rasmussen, and *Timothy E. McCoy* on behalf of Williams Alaska Pipeline Company, L.L.C.

John W. Griggs and *Debra B. Adler* on behalf of Union Oil Company Of California and OXY USA, Inc.

Patricia Godley, Richard A. Curtin, and *Jonathan D. Simon* on behalf of Petro Star, Inc.

Jeffrey G. DiSciullo and *Robert H. Benna* on behalf of Tesoro Alaska Petroleum Company

Randolph L. Jones, Jr., Melinda L. Kirk, Alex Goldberg and *Excetral Caldwell* on behalf of Williams Alaska Petroleum, Inc.

Eugene R. Elrod, James F. Bendernagel, Jr., Matthew J. Perry, Ronald S. Flagg, Kurt H.

Jacobs, Robert W. Johnson, Laurie A. Rachford, and *R. Bryant Siddoway* on behalf of Exxon Mobil Corporation

John A. Donovan, Matthew W.S. Estes, Graham Vanhegan, Barbara Fullmer, Tom Cook and *Steven A. Velkei* on behalf of ConocoPhillips Alaska, Inc.

Bradford Keithley, Jason F. Leif, Amy A. Stathos, *Jeanne H. Dickey, John Hagan, Charles William Burton* and *C. Michael Stebbins,* on behalf of BP Exploration and Amoco Production Company

J. Andrew Langan on behalf of BP America, Inc., and Atlantic Richfield Company

Andrew J. Dalton and *Peter D. Lejeune* on behalf of Valero Energy Corporation

Stephen L. Neal, Jr., on behalf of Paramount Petroleum Corporation

James M. Armstrong on behalf of Flint Hills Resource Alaska, LLC

Gregg D. Renkes, Robert E. Mintz, W. Stephen Smith and *Edward Twomey* on behalf of the State of Alaska

Marc Gary Denkinger and *Arnold H. Meltz* on behalf of the Federal Energy Regulatory Commission

EDWARD M. SILVERSTEIN, Presiding Administrative Law Judge

PRELIMINARY STATEMENT

1. This is the next chapter in the continuing saga which began in the 1980s surrounding the Trans Alaska Pipeline System ("TAPS") Quality Bank. TAPS is the sole means for producers of crude oil on Alaska's North Slope (sometimes "ANS") to ship that crude to the Port of Valdez on Alaska's southwest coast for further shipment to other markets. It is owned and operated by the TAPS Carriers.[1] The crude shipped on TAPS

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[1] The TAPS Carriers at the time of the hearing and the briefing in these proceedings were Amerada Hess Corporation, BP Pipelines (Alaska), Inc., ExxonMobil Pipeline Company, Phillips Transportation Alaska, Inc., Unocal Pipeline Company, and Williams Alaska Pipeline Company, L.L.C. Exhibit No. TC-1 at p. 3. It must be noted that, on March 31, 2004, Flint Hill Resources Alaska, LLC, acquired, from Williams Alaska Petroleum, Inc., the refinery which Williams owned at North Pole, Alaska, as well as Williams's refined products terminals in Fairbanks and Anchorage, Alaska. "Motion to Intervene of Flint Hills Resources Alaska, LLC," filed April 2, 2004.

comes from fields owned and operated by several different oil companies. Because the quality of the crude may differ from field to field, because all of the crude shipped on TAPS is commingled into a common stream, and because portions of the common stream are withdrawn in between the North Slope and Valdez,[2] while a shipper may receive the proper volume of crude at Valdez, the quality of what it receives may significantly differ from that which it shipped. As a result, a Quality Bank was created to enable the shippers who received a higher quality crude at Valdez to compensate those who received a lesser quality. *See OXY USA, Inc. v. F.E.R.C.*, 64 F.3d 679, 684 (D.C. Cir. 1995)("*OXY*").

2. The methodology to be used by the Quality Bank has been the subject of litigation before this Commission, as well as before the Alaska Public Utilities Commission ("APUC") and its successor, the Regulatory Commission of Alaska ("RCA"), virtually for all the time that TAPS has existed.[3] In 1984, following the issuance of decisions by an administrative law judge as well as itself, the Commission approved a contested settlement of the Quality Bank issue. *Trans Alaska Pipeline System*, 29 FERC ¶ 61,123 (1984). In that settlement, the parties agreed to, and the Commission approved, a gravity-based methodology:

> The posted gravity differentials of six named companies producing West Texas Sour are averaged using a simple average. The same method is used with respect to the posting of four companies producing California oil. These postings were picked because they have a range of gravity which includes the average [American Petroleum Institute ("API")] gravity of the TAPS common stream at Valdez. Next, the West Texas Sour differential and the average California differential will be weighted by the percentage of Alaskan North Slope crude oil which is distributed east of the Rockies and to the West Coast, respectively. The weighted averages are combined to provide the quality adjustment.

Id. at p. 61,239 (footnotes omitted). Under this methodology, "the higher the API gravity, the higher the quality." *Trans Alaska Pipeline System*, 57 FERC ¶ 63,010 at p. 65,035 (1991).

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[2] The Golden Valley Electrical Association ("Golden Valley") and the Petro Star Valdez Refinery ("Valdez") withdraw a portion of the common stream. They, then, return a modified portion of what they withdrew consisting of the common stream less the products extracted in their refining process. Exhibit No. EMT-1 at p. 9.

[3] *See, e.g*., *Trans Alaska Pipeline System,* 10 FERC ¶ 63,026 (1980); *Trans Alaska Pipeline System,* 23 FERC ¶ 63,048 (1983); and *Trans Alaska Pipeline System,* 26 FERC ¶61,149 (1984).

3. The current chapter in the continuing saga began in 1989 with the filing of a petition by the TAPS Carriers seeking a Commission investigation into the lawfulness of the Quality Bank provisions in their Tariff. *Id.* They also sought the Commission's approval of the then currently used methodology. *Id.* Almost simultaneously, the TAPS Carriers filed a tariff containing a Quality Bank adjustment of 2.57¢ per tenth of a degree of API gravity per barrel. *Id.* After a concurrent hearing with the APUC, the Commission's presiding administrative law judge issued an initial decision on November 19, 1991, in which he found, in pertinent part, that: (1) the Commission previously had determined that the gravity-based methodology was just and reasonable, but that that ruling did not preclude a finding that it was no longer just and reasonable; (2) the TAPS Carriers were not violating their tariff; (3) the TAPS Carriers properly determined the Quality Bank adjustments for the refinery return stream and the common stream with which the return streams have been blended; (4) the TAPS Carriers properly used posted gravity differentials in effect on May 1, 1989, in calculating the Quality Bank adjustments for the six-month period beginning July 1, 1989, and there were no refunds due; and (5) the introduction of natural gas liquid blending into the common stream materially changed the circumstances under which the Quality Bank operated by increasing the API gravity of certain streams and, because of the volume of the natural gas liquids introduced, the API gravity methodology should be modified at Pump Station 1 and at the Golden Valley interconnection, but not at Valdez. *Id.* at pp. 65,036-53. He concluded that the gravity methodology at Pump Station 1 and the Golden Valley interconnection should be modified by a bendover adjustment which imposes a penalty for API gravity exceeding 45°F applicable to natural gas liquids and light refinery products. *Id.* at pp. 65,053-72.

4. The APUC then issued its decision which varied from that of the Commission's presiding administrative law judge. While the APUC judge held that a modification should be made to the gravity methodology then being used, she only applied that modification at Pump Station 1, rather than at Pump Station 1 *and* the Golden Valley interconnection. Moreover, rather than the bendover method described above, the APUC judge "proposed a methodology that values unblended streams and the oil portions of the NGL blended stream as crude oil according to their API gravities, but values the added NGL portion of the blended stream by a distillation method." *See Trans Alaska Pipeline System*, 65 FERC ¶ 61,277 at p. 62,282 (1993), *order on reh'g*, 66 FERC ¶ 61,188 (1994), *further order on reh'g*, 67 FERC ¶ 61,175 (1994). In addition, she ordered refunds, while the Commission's presiding administrative law judge did not.

5. As a result of the conflicting decisions, the Commission referred the proceeding to a Settlement Judge pursuant to 18 C.F. R § 385.603. *See Trans Alaska Pipeline System*, 63 FERC ¶ 61,145 (1993). The APUC, concurrently, also referred the matter for settlement. *In the Matter of Formal Complaint of Tesoro Alaska Petroleum Co.*, P-89-1(61), P-89-2(54). Subsequently, the Commission's Chief Judge referred a settlement to it. The proposed settlement sought to impose a distillation method to

replace the gravity method previously used to equalize the Quality Bank. *Trans Alaska Pipeline System*, 65 FERC at p. 62,283. According to the Commission, the distillation method would operate as follows:

> [A] stream's value is determined by valuing the components, or cuts, derived by the process of distilling (boiling and recondensing) the stream, with each cut separated out of the petroleum at a certain temperature.
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> These cuts and temperature ranges at which they boil out of the petroleum stream are: propane (C3), isobutane (iC4), normal butane (nC4), light straight run, sometimes referred to as natural gasoline (C5-175°F), Naphtha (175-350°F); distillate (350-650°F); gas oil (650-1050°F); and vacuum [Resid] (1050°F). Each cut constitutes a component for which market values are available, or can be derived, from prices reported in Platt's Oilgram Price Report (Platt's), or the Oil Pricing Information Service (OPIS).

Id. at pp. 62,283, 62,285 (footnotes omitted). While adopting the methodology contained in the proposed settlement, the Commission modified it in some regards. As to the Resid cut, the Commission held that, in order to make its treatment fair and impartial, all materials exceeding 1050°F should be treated as Resid without requiring, as did the proposed settlement, that it be blended with Heavy Distillate so as to meet the viscosity standard of No. 6 fuel oil. *Id.* at p. 62,288.

6. In approving the settlement, the Commission further stated that it "believed that market prices, uncomplicated by subjective adjustments, must be used for the Quality Bank adjustments to be non-discriminatory, in appearance as well as in fact. Market prices have the advantage of being objective, non-discriminatory, easily ascertainable, and generally not susceptible to manipulation." *Id.* at p. 62,289. As a consequence, it required the use of unadjusted, quoted market prices to value each of the nine cuts. *Id.* The Commission added:

> [I]f or when market prices for a given market are not posted in one of the two markets [*i.e.*, the West Coast and the Gulf Coast] rather than making the adjustments specified in the settlement, we will require the use of prices quoted in the single market to value the entire cut. . . . Under this approach, the parameters in the proposed settlement will be used, but will be modified to assure that it is objective and fair to all parties.

Id.

7. After establishing these parameters, the Commission substituted the Gulf Coast Naphtha price for the formula set forth in the settlement to establish a West Coast Naphtha price. *Id.* In addition, it required the use of separate prices for Light and Heavy Distillate (Light Distillates were valued at the price of Platts West Coast waterborne jet fuel and Platts Gulf Coast waterborne jet/kerosene 51, and Heavy Distillates were valued at Platts Los Angeles pipeline No. 2 oil spot quote and Platts Gulf Coast waterborne No. 2 fuel oil), rather than the single price contained in the settlement, required the use of the West Coast waterborne gas oil for both coasts since there was no quoted Gulf Coast price for the cut, eliminated the pricing adjustment for sales of low sulfur gas oil on the West Coast because North Slope crude could not meet the California standard for low sulfur gas oil. *Id.* at pp. 62,289-90.

8. In its first rehearing order, addressing the TAPS Carriers's request for clarification of the West Coast Heavy Distillate because Platts ceased publishing a West Coast No. 2 fuel oil price, the Commission stated:

> We would note here that in the future other reference quoted prices for valuing a distillation cut for purposes of the Quality Bank might be discontinued or radically altered. Should this occur, the Administrator of the Quality Bank will be required to do one of two things. If the reference price is discontinued in one market but not in another (as in the instant case), the price for the single market will be used to value the cut in both markets, as provided in the November 30 Order. If both prices (or the price for both markets) for a single cut are discontinued or radically altered, the Administrator will notify the Commission of this fact and all parties entitled to notice of Quality Bank proceedings, and propose an appropriate replacement reference price, with explanation and justification. Comments can be filed with the Commission within 30 days of the filing. If the Commission takes no action within 60 days of the filing, the proposed price will become effective as of the 60th day.

66 FERC at p. 61,418.

9. The Commission ruling was appealed and the United States Court of Appeals for the District of Columbia Circuit, affirming in part and reversing in part, remanded the matter back to the Commission. *See OXY,* 64 F.3d 679. The Court stated:

> We find that the Commission was justified in ordering a change in the Quality Bank valuation methodology and in declining to order certain refunds. We also find, however, that two aspects of the new methodology and the Commission's claim that it lacked jurisdiction to consider one shipper's complaint do not comport with the [Administrative Procedure Act's] requirement of reasoned decisionmaking.

Id. at p. 685.

10. In particular, the Court found fault with the following:

(1) The Commission valued light distillate at the market price of jet fuel and Heavy Distillate at the price of No. 2 oil. According to the Court, the Commission's valuation of these products was arbitrary and capricious. *Id.* at p. 693. The Court held that the Commission had presented no data to support its argument that "the prices of the finished products are close enough to the values of the raw materials to serve as their proxies . . . ." *Id.* The Court further stated that, to achieve the goal of assigning accurate relative values to all of the petroleum delivered to the common stream in TAPS, all cuts must be accurately valued or they must be undervalued or overvalued to approximately the same degree.[4] *Id.*

(2) The Commission's methodology for valuing Resid did not satisfy the Administrative Procedure Act's "basic requirement of reasoned decisionmaking." *Id.* at p. 694.

(a) The proxy used by the Commission to value 1050°+F Resid (FO-380) reflected its most prevalent use rather than its marginal use. This raised the question of whether the 1050°+F Resid was being overvalued. The Court required, on remand, that the Commission address the question of whether the marginal use of 1050°+F Resid should be taken into account in valuing it. *Id.* at p. 695.

(b) No evidence in the record supported the Commission's decision to value lighter Resid at the price of No. 6 fuel oil. *Id.* at p. 696.

(3) The Commission failed to "establish a consistent and reasoned position as to whether it has jurisdiction over the method by which the TAPS Carriers distribute Quality Bank payments among co-owners of streams delivered to TAPS." *Id.* at p. 701.

11. After first attempting to resolve the parties's dispute through alternative dispute resolution procedures,[5] the Commission issued an order in which it determined that there

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[4] The Court indicated that intervenors, who argued that the processing required to manufacture the finished product is minimal, made a stronger argument than the Commission in support of its decision. However, the Court noted that it could not affirm the Commission's decision using a ground on which the Commission did not rely. *See OXY*, 64 F.3d at pp. 693-94.

[5] *See Trans Alaska Pipeline System,* 74 FERC ¶ 61,317 (1996).

was no reason to include the methodology for resolving disputes between co-owners of TAPS in its tariff. *Trans Alaska Pipeline System*, 76 FERC ¶ 61,119 at p. 61,619 (1996).[6] In that order, with regard to distillate (petroleum which boils out of a stream between 350°F and 650°F), the Commission also referred the following issues for hearing:

> 1. What are the costs required to process distillate into jet fuel, and Heavy Distillate into No. 2 fuel oil?
>
> 2. How do such costs compare to the costs required to permit other cuts to meet the specifications assumed by the spot market prices used to value them?
>
> 3. Is it necessary to subtract these processing costs from the reference prices for the No. 2 fuel oil and jet fuel?

Id. at pp. 61,619-20.

12. With regard to Resid (oil with a boiling point above 1050° F.), the Commission stated: "[T]he parties should be allowed to submit their proposals as to Resid valuation with supporting evidence, and the ALJ will make a determination based upon the record. The ALJ should also consider the issues raised by the court regarding resid's marginal use." *Id.* at p. 61,620.

13. A further attempt to resolve this matter through alternative dispute resolution resulted in the filing of three competing offers of settlement. The Chief Administrative Law Judge terminated the settlement judge procedure and appointed me to act as presiding judge on January 16, 1997. On September 30, 1997, after reviewing the parties's submissions and hearing oral argument, I certified the Nine Parties's[7] offer of

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[6] In addition, in that same order, the Commission consolidated the remanded proceedings with *Exxon Company, U.S.A. v. Amerada Hess Pipeline, et al.*, Docket No. OR96-14-000. *See* 76 FERC at p. 61,620. Also, in a separate order, the Commission consolidated the remanded proceedings with the hearing on a tariff filed by Sadlerochit Pipeline Company. *See Sadlerochit Pipeline Co.*, 76 FERC ¶ 61,125 (1996). However, on January 15, 1997, that company filed a notice, pursuant to 18 C.F.R. § 341.13, that it was withdrawing its tariff. Such a notice automatically terminated that proceeding. *See* 18 C.F.R. § 341.13(b)(1) (2004).

[7] Amoco Production Company, ARCO Alaska, Inc., BP Exploration (Alaska), Inc., MAPCO Alaska Petroleum, Inc, OXY USA, Inc., Petro Star, Inc., Phillips Petroleum Company, The State of Alaska, and Union Oil Company of California. *See Trans Alaska Pipeline System*, 80 FERC at p. 65,211.

settlement to the Commission. *See Trans Alaska Pipeline System*, 80 FERC ¶ 63,015 (1997).[8] By order issued December 17, 1997, the Commission approved the Nine Parties's offer of settlement. *See Trans Alaska Pipeline System*, 81 FERC ¶ 61,319 (1997).

14. The Commission's order, once again, was appealed to the United States Circuit Court of Appeals for the District of Columbia Circuit which reversed it in part and remanded it. In its order remanding the matter back to the Commission, the Circuit Court upheld all of the Commission's approval of the Nine Parties's offer of settlement except for the manner in which it valued Resid and the Commission's holding that the methodology set forth in the settlement only have prospective effect. *Exxon Company, U.S.A. v. F.E.R.C.*, 182 F.3d 30 (1999)("*Exxon*"). As to Resid, the Circuit Court concluded that it could not uphold the settlement's use of FO-380 less 4.5¢ on the West Coast and Waterborne 3% sulfur No. 6 fuel oil less 4.5¢ on the Gulf Coast as proxy prices for it because there was "no evidence that the prices of the proxy products [were] more than coincidentally related to the value of resid as a coker feedstock." *Id.* at p. 42. With regard to the effective date issue, the Circuit Court held that the Commission had failed to provide an adequate explanation as to why the new methodology should not have been made retroactive to 1993. *Id.* at p. 50.

15. While that matter was pending before the Commission and the Circuit Court, the parties were also involved in litigating, before me, a complaint filed by Exxon Company, U.S.A. ("Exxon"). That matter resulted in my issuance of a "Ruling on Motion for Summary Disposition and Initial Decision Terminating Proceeding," on May 29, 1998. *See Exxon Company, U.S.A. v. Amerada Hess Pipeline Corp.*, 83 FERC ¶ 63,011 (1998). There, I held that Exxon was not entitled to reparations because, as a matter of law, the Commission could only give prospective relief. *Id.* at p. 65,093. In addition, I held that "November 30, 1993, is the appropriate point of reference for determining whether the opponents of the [then] current methodology have presented sufficient evidence establishing a change in circumstances significant enough to warrant a change in the [then] current methodology." *Id.* at pp. 65,097-98. After reviewing all of the evidence which Exxon claimed supported its position that it showed changed circumstances, I concluded that it had failed to carry its burden of proof and terminated the proceeding. *Id.* at pp. 65,101-02. In addition, I addressed the arguments made by Tesoro Alaska Petroleum Company ("Tesoro") holding that they were moot because it was not a complainant and inviting it to file its own complaint. *Id.* at pp. 65,102-03.

16. Tesoro did, in fact, file its own complaint on August 20, 1998, which the Commission, holding that Tesoro failed to show changed circumstances, dismissed. *See*

[8] The competing offers of settlement are amply described in my certification. *See Trans Alaska Pipeline System*, 80 FERC at pp. 65,212-16.

Tesoro Alaska Petroleum Co., 87 FERC ¶ 61,132 (1999). On the same day on which it acted on the Tesoro complaint, the Commission affirmed my *Exxon* ruling. *See Exxon Company, U.S.A. v. Amerada Hess Pipeline Corp.*, 87 FERC ¶ 61,133 (1999). In doing so, it noted, *inter alia*, that it consistently has refused to base its Quality Bank decisions on the basis of regression analyses. *Id.* at p. 61,528.

17. Needless to say, both of the Commission rulings were appealed to the Circuit Court for the District of Columbia Circuit. *See Tesoro Alaska Petroleum Co. v. F.E.R.C.*, 234 F.3d 1286 (D.C. Cir. 2000)("*Tesoro*"). The Circuit Court once again remanded the matter to the Commission holding that both Exxon and Tesoro had presented evidence which may have indicated changed circumstances. *Id.* at pp. 1291, 1294. In doing so, it criticized the Commission for rejecting, out-of-hand, regression analysis evidence: "The Commission cannot be saying that regression analysis, good enough to be a valuable tool for everyone else interested in quantitative analysis, is never good enough for" it. *Id.* at p. 1291.

18. The Commission addressed these matters in a November 7, 2001, Order. *See Trans Alaska Pipeline System*, 97 FERC ¶ 61,150 (2001). In that order, the Commission consolidated the dockets initiated by the Exxon and Tesoro complaints, as well as that initiated by the Quality Bank Administrator's November 24, 1999, notice to the Commission that Platts will no longer publish a West Coast High Sulfur (0.5%) Waterborne Gasoil, which the Quality Bank used to value West Coast Heavy Distillate. *Id.* at pp. 61,649-50. As to the latter matter, the Commission noted that all parties agreed that the proper proxy for West Coast Heavy Distillate should be Platts West Coast LA Pipeline LS (0.05%) No. 2, but noted that "[t]here was disagreement as to the level of sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the quoted price." *Id.* at p. 61,650. In referring this matter for hearing, the Commission delineated the issues to be heard as follows:

> (1) The valuation of the Resid cut and the retroactive application of the modifications.
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> (2) The valuation of the naphtha and VGO cuts and whether the distillation methodology is no longer just and reasonable.
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> (3) The level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the quoted price.

Id. at p. 61,650.

19. The Chief Administrative Law Judge appointed me to serve as presiding judge by order dated November 9, 2001. I convened a prehearing conference on December 5, 2001. At the prehearing conference the parties agreed to a procedural schedule to be

followed in this matter.

20. Further, the parties agreed that the following nine issues were to be litigated:

1. What is the appropriate method for valuing the Resid cut?

2. What is the level of adjustment necessary to bring the Heavy Distillate cut into line with the specifications for Platt=s West Coast LA Pipeline Low Sulfur No. 2? What should be the effective date of the change in the Heavy Distillate cut price?

3. Whether the current method for valuing the West Coast Naphtha cut is just and reasonable, and if not, what is the appropriate method for valuing the Naphtha cut? What should be the effective date of any change to the West Coast Naphtha cut?

4. Whether the current method for valuing the West Coast VGO cut is just and reasonable, and if not, what is the appropriate method for valuing the VGO cut? What should be the effective date of any change to the West Coast VGO cut?

5. Should the revised values for the cuts subject to the D.C. Circuit remand in *OXY USA v. FERC*, 64 F.3d 679 (D.C. Cir. 1995) (Resid, Heavy Distillate and Light Distillate) be made retroactive to December 1, 1993?

6. Whether the distillation methodology with the cuts valued per issues 1-4 produces unjust and unreasonable results?

7. If the distillation methodology with the cuts valued per issues 1-4 produces unjust and unreasonable results, what other methodology or other changes to the distillation methodology should be implemented?

8. If a methodology (including a distillation methodology) other than the distillation methodologies that previously have been in effect, is adopted, what is the appropriate effective date for that methodology?

9. Are reparations an issue in this proceeding? If so, what reparations, if any, are appropriate? The Parties agree that the following subissues are relevant to a determination of this issue, but reserve their rights to argue that other issues also may be relevant.

a. Whether any acts or omissions by the TAPS Carriers with respect to the Quality Bank violated the Interstate Commerce Act and, if so, which provisions of that Act?

b. If a methodology is implemented that produces just and reasonable results for past periods, how has ExxonMobil been injured by the alleged violations of the Interstate Commerce Act?

c. What damages, if any, have been sustained by ExxonMobil as a consequence of the alleged violations of the Interstate Commerce Act by the TAPS Carriers?

Order Establishing Procedural Schedule, Ruling on Untimely Motion to Intervene, and Setting Forth Preliminary Statement of Issues, issued December 20, 2001.

21. The hearing commenced on October 15, 2002, and lasted (with breaks) until June 13, 2003. By agreement, as much as possible, the witnesses testified on a schedule structured around the above nine issues. For the most part, issues 6, 7 and 8 were left for last. After the examination of the first witness testifying on those issues began, it became clear to Judge Wilson and me, as well as to the parties, that these issues could not be properly addressed until after Judge Wilson and I decided Issues 1 through 5 and 9. Consequently, the parties agreed that those issues would be deferred until after that time. *See* Joint Stipulation Suspending Procedures with Respect to Issues 6, 7 and 8, filed April 25, 2003. In addition, there was testimony from the Quality Bank Administrator regarding issues 1 through 5 and 9, and with regard to his February 23, 2003, proposal (see comment below) for altering the Heavy Naphtha price to which the parties were allowed to respond. To facilitate matters, the evidentiary summary contained herein will follow that order.

22. At the end of the hearing, the parties agreed that the following issues were to be briefed:[9] (Their arguments will be summarized and decided after the summary of the evidence.)

1. What is the appropriate method for valuing the Resid cut?

2. What is the level of adjustment necessary to bring the Heavy Distillate cut into line with the specifications for Platts West Coast LA Pipeline Low Sulfur No. 2? What should be the effective date of the change in the Heavy Distillate cut?

3. Whether the current method for valuing the West Coast naphtha cut is just and reasonable, and if not, what is the appropriate method for

[9] *See* Joint Final List of Issues and Positions of the Parties, filed October 3, 2002.

valuing the naphtha cut? What should be the effective date of any change to the West Coast naphtha cut?

4. Whether the current method for valuing the West VGO cut is just and reasonable, and if not, what is the appropriate method for valuing the VGO cut? What should be the effective date of any change to the West Coast VGO cut?

5. Should the revised values for the cuts subject to the D.C. Circuit remand in *OXY USA v. FERC* (Resid, Heavy Distillate and light distillate) be made retroactive to December 1, 1993?

6. Whether the distillation methodology with the cuts valued per issues 1-4 produces unjust and unreasonable results?

7. If the distillation methodology with the cuts valued per issues 1-4 produces unjust and unreasonable results, what other methodology or other changes to the distillation methodology should be implemented?

8. If a methodology (including distillation methodology) other than the distillation methodologies that have previously been in effect, is adopted, what is the appropriate effective date for that methodology?

9. Are reparations an issue in this proceeding? If so, what reparations, if any, are appropriate? The parties agreed that the following sub issues were included –

a. Whether any acts or missions by the TAPS Carriers with respect to the Quality Bank violated the Interstate Commerce Act and, if so, which provisions of that Act?

b. If a methodology is implemented that produces just and reasonable results for past periods, how has ExxonMobil been injured by the alleged violations of the Interstate Commerce Act?

c. What damages, if any, have been sustained by ExxonMobil as a consequence of the alleged violations of the Interstate Commerce Act by the TAPS Carriers?

23. On February 27, 2003, the TAPS Carriers filed new tariffs relating to the value of West Coast and Gulf Coast Naphtha. They noted that, from initiation of the distillation methodology, both had been valued based on the Platts Gulf Coast Waterborne Naphtha assessment and that Platts, effective on February 3, 2003, began also publishing a Gulf

Coast Waterborne Heavy Naphtha price. According to the TAPS Carriers, this new price assessment, based on API gravity and initial boiling point, is more similar to ANS than the previously used quote. Consequently, they propose substituting it for the former. Answers to that proposal, both in favor and opposed, were filed. On March 28, 2003, the Commission accepted and suspended the tariffs, and consolidated that proceeding with the ones already pending before me. *See BP Pipelines (Alaska), Inc.*, 102 FERC ¶ 61,345 (2003). The evidence on this issue was presented last.

24. The Quality Bank Administrator, on June 18, 2003, filed a "Notice . . . Regarding Proposed Replacement Product Price to Value Naphtha Component on the U.S. Gulf Coast and the U.S. West Coast." On August 13, 2003, the Commission issued an "Order Accepting Replacement Product Price and Consolidating Issues With Hearing Proceedings." *Trans Alaska Pipeline System,* 104 FERC ¶ 61,201 (2003). Pursuant to that Order, I held a prehearing conference on August 19, 2003, at which I set October 28, 2003, for the hearing related to that matter. On October 10, 2003, the parties filed a "Stipulation . . . Regarding Hearing on Proposed Replacement Product Price to Value Naphtha Component on the U.S. Gulf Coast and U.S. West Coast effective August 17, 2003." In that document, the parties agreed that no further hearing was necessary provided I admitted five documents into evidence. Consequently, on October 17, 2003, I issued an order canceling the hearing and admitting Exhibit Nos. TC-19 through TC-23 into evidence.

25. Just prior to the hearing, the parties entered into the following stipulation:[10]

ISSUE NO. 1 - RESID VALUATION

> The Parties agree that Resid shall be valued as a Coker feedstock, but the Parties have not agreed on the date when the new Resid value would become effective. The Coker feedstock value of Resid shall be determined in accordance with the following formula: Resid = Before-Cost Value of Coker Products - (Coking Costs * Nelson Farrar Index)

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[10] Neither the TAPS Carriers nor Commission Staff joined in the Stipulation. However, neither opposed the Stipulation and the TAPS Carriers, but not Staff, agreed not to contest them. In addition, in a footnote, the Parties recognized that there were disputes as to the value to be used for certain Quality Bank cuts, but stipulated that, once these disputes are resolved, "the resulting values should be used for valuing Resid." Joint Stipulation of the Parties, filed October 3, 2002.

WHERE

1. **Before-Cost Value of Coker Products** is calculated in a three step process:

(A) First, the product yields that result from running ANS Resid through a Coker, are The TAPS Carriers take no position with respect to any of the matters stipulated in this Stipulation. Therefore, the TAPS Carriers do not join in any of the stipulations, determined through the use of PIMS, with respect to the following products: (1) Fuel Gas; (2) Propane: (3) Isobutane; (4) Normal Butane; (5) LSR; 6) Naphtha; (7) Heavy Distillate; (8) VGO; and (9) Coke.

(B) Second, values are determined for each of the nine Coker products. For all of the products except Fuel Gas and Coke, the Quality Bank value for that product is to be used. For Fuel Gas, the prices to be used are: (1) on the West Coast, the monthly California Natural Gas spot price quote from *Natural Gas Week* (South, delivered to pipeline) plus 15¢/MMBtu for transportation from the Arizona-California Bother; and (2) on the Gulf Coast, the monthly Gulf Coast (Henry Hub, LA) Natural Gas spot price quote from *Natural Gas Week* As to Coke, the prices to be used are: (1) on the West Coast, the mid-point monthly quote from *Petroleum Coke Quarterly* for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke; and (2) on the Gulf Coast, the mid-point monthly quote from *Petroleum Coke Quarterly* for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke. The Parties disagree as to whether there should be an additional adjustment made to the Coke price.

(C) Third, the Coker product yields for each product determined in Step A are multiplied times the product prices determined in Step B. The resulting values are added together to derive the Before-Cost Value of Coker Products.

2. **Coking Costs** shall be set forth as a single value. The Parties do not agree on what that value should be, or whether it should differ between the West Coast and Gulf Coast.

3. **Nelson Farrar Index** is the ratio of: (a) the Nelson Farrar Index (Operating Indexes Refinery) for the year in which the value is being determined to (b) the Nelson Farrar Index (Operating Indexes Refinery) for the base year. The Eight[11] Parties have proposed a base year of 1996 and

[11] The "Eight Parties" refers to Amoco Production Company, BP Exploration

ExxonMobil Tesoro have proposed a base year of 2000.

ISSUE NO. 2 - WEST COAST HEAVY DISTILLATE VALUATION

1. West Coast Heavy Distillate will be valued at the published Platts West Coast price for Los Angeles Pipeline low sulfur (0.05%) No. 2 Fuel Oil, less appropriate deductions. The Parties agree that deductions should include the cost of desulfurizing ANS Heavy Distillate to meet the 0.05% sulfur specification, but they do not agree as to the cost of desulphurization They also disagree as to whether there should also be a logistics adjustment deduction to the reference price.

2. The Parties agree that the effective date for the new West Coast Heavy Distillate price will be February 1, 2000.

ISSUE NO. 3 - WEST COAST NAPHTHA VALUATION

The Parties disagree as to whether a West Coast Naphtha valuation methodology needs to be developed and substituted for the previously approved and currently used Gulf Coast price. They also disagree as to (1) how to value the West Coast Naphtha cut if the Commissions decide to adopt a new valuation methodology and (2) what the effective date for new methodology would be.

ISSUE NO. 4 - WEST COAST VGO VALUATION

1. West Coast VGO shall be valued based on the published OPIS West Coast High Sulfur VGO weekly price.

2. The Parties disagree as to the effective date of the new West Coast VGO value. However, the Parties agree that if a different West Coast Naphtha valuation methodology is adopted in this proceeding, it and the new West Coast VGO value should have the same effective date.

ISSUE NO. 9 - REPARATIONS

The Parties agree that ExxonMobil/Tesoro's reparations claim shall apply only to the West Coast VGO and West Coast Naphtha cuts.

(Alaska), Inc., Phillips Alaska, Inc., Petro Star, Inc., Williams Alaska Petroleum, Inc., OXY USA, Inc., Union Oil Company of California, and the State of Alaska. *See, e.g.,* Statement of Position of the Eight Parties on Issue Nos. 6-9, filed March 28, 2002.

Joint Stipulation of the Parties, filed on October 3, 2002.

26. During the course of the hearing, which took place on 103 days during the aforementioned period, 19 witnesses appeared, some testifying on more than one issue, and 1474 exhibits were received into evidence.

27. The omission of a discussion of any issue raised by the parties herein, or of a portion of the record, does not indicate that it has not been considered. Rather, such issue and/or portions of the record are found to be irrelevant, immaterial and/or without merit. Moreover, arguments made on brief which were not supported by reference to specific evidence in the record or to specific legal precedent were give no weight.

SUMMARY OF THE EVIDENCE

ISSUE NOS. 1 (RESID) AND 2 (HEAVY DISTILLATE)

A. JOHN B. O'BRIEN

28. John B. O'Brien ("O'Brien") was the first witness to appear at the hearing. O'Brien is the president and co-founder of Baker & O'Brien, Inc., a consulting firm serving the energy, chemical and related industries. Exhibit Nos. PAI-1 at p. 1; PAI-2 at p. 1. He is a registered professional engineer, a member of the American Institute of Chemical Engineers, an associate member of the National Petroleum Refiners Association and a former member of the Australian Institute of Petroleum. Exhibit No. PAI-2 at p. 2.

29. O'Brien's testimony was presented on behalf of ConocoPhillips Alaska, Inc. ("Phillips"),[12] but was supported by BP America Production Company and BP Exploration (Alaska), Inc. ("BP"),[13] OXY U.S.A., Inc. ("OXY"), Petro Star, Inc. ("Petro Star"), the State of Alaska ("Alaska"), Union Oil Company of California ("Unocal"), and Williams Alaska Petroleum Company ("Williams"). Exhibit No. PAI-1 at p. 1.

30. According to O'Brien, the distillation method establishes a market value for crude

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[12] At the outset of this proceeding, ConocoPhillips Alaska, Inc. was known as Phillips Alaska, Inc. Its name was changed after the merger of its parent company with Conoco, Inc. *See* "Joint Stipulation Suspending Procedures with Respect to Issues 6, 7, and 8," filed April 25, 2003.

[13] At the outset of this proceeding, BP America Production Company was named Amoco Production Company. *See* "Joint Stipulation Suspending Procedures With Respect to Issues 6, 7 and 8," filed April 25, 2003.

based on the value of the products into which it can be refined. *Id.* at p. 4. He describes distillation as the process of boiling crude into different cuts based on the various temperatures at which they come to a boil, and notes that "[s]ome of these cuts are sold without further processing, while others are processed and sold as more valuable products."[14] *Id.* O'Brien describes the TAPS Quality Bank distillation method as follows:

> It takes 9 basic cuts commonly produced by refiners in the distillation process,[15] and determines how much of each of these cuts is contained in each of the crude streams transported by TAPS. The methodology then develops a price for each cut, multiplies that price by the percentage of the cut that is contained in the crude stream, and sums the resulting prices to develop a total crude stream value. These values are then used to determine Quality Bank payments. Those streams with total cut values that are higher than the ANS total cut values receive payments from the Quality Bank, while those crudes with total cut values lower than the ANS stream make payments into the Quality Bank.

Id. at p. 5 (footnote added).

31. O'Brien proposes to value Resid, "what is left of the crude oil in the distillation process after all other products have been boiled out," as a Coker[16] feedstock,[17] as it

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[14] For a schematic of Quality Bank cut distillation, *see* Exhibit No. PAI-3.

[15] "The nine cuts, from lightest to heaviest, are: (1) Propane; (2) Isobutane; (3) Normal Butane; (4) Light Straight Run ("LSR"); (5) Naphtha; (6) Light Distillate; (7) Heavy Distillate; (8) Vacuum Gas Oil ("VGO"); and (9) Resid." Exhibit No. PAI-1 at p 6.

[16] On redirect, O'Brien described a coker as:

> a process unit within a refinery that takes the very heaviest portion of the barrel and it subjects that portion of the barrel that's called resid, subjects it to high temperature and to certain conditions of pressure, but most importantly very high temperature, and it effectively cooks the material.
>
> That causes the large molecules to break into smaller molecules and produces a lot more of the kinds of products that we use in our cars and trucks and trains. You would not be able to use the resid for that, unless you put it through this coker first to transform it first into these lighter products.

currently is valued, but suggests some modifications to the current methodology. *Id.* at pp. 9-10. He adds that processing Resid through a Coker converts it into more valuable products, both liquid (e.g. Vacuum Gas Oil (sometimes "VGO") and Heavy Distillate) and solid (petroleum coke).[18] *Id.* at p. 10. Noting that the liquid products of coking need to be further processed, O'Brien asserts that the primary additional processing is catalytic hydrotreating. *Id.*

32. Saying that his primary goal was to value Resid as a Coker feedstock for a "typical existing refiner," O'Brien, using the Process Industry Modeling System, Version 11.0 ("PIMS"),[19] first calculated the value of Resid without adjusting for the costs of coking or other treatment. *Id.* at pp. 10-11. Using PIMS, he determined the amount of each product produced from processing ANS Resid[20] through a Coker. *Id.* at p. 12. O'Brien recommends that the cuts resulting from the coking of Resid be valued at the same prices as the Quality Bank uses for the products derived from the refining process. *Id.* at p. 13. However, he recognizes that there are two cuts for which there are no Quality Bank reference prices, gas and petroleum coke, and as to those he makes the following recommendations: (1) for natural gas, he proposes that the *Natural Gas Week* monthly California natural gas price quote South delivered to pipeline plus 15¢ per million Btus; and (2) for petroleum coke, he recommends the *PACE Petroleum Coke Quarterly* (sometimes *"PCQ")* West Coast Low Sulfur price quote (above 2% sulfur category). *Id.* To determine the before-cost Coker feedstock value of Resid, he would then multiply the PIMS output of each product times the monthly price of that product and add the sum of each. *Id.* at p. 14 and Exhibit No. PAI-8.

33. According to O'Brien, the problem in determining the cost of processing Resid through a Coker is complicated because: (1) the cost of processing Resid varies from refinery to refinery; (2) Cokers do not necessarily produce Quality Bank quality products;

Transcript at p. 967.

[17] "A feedstock is something that has to be further processed." Transcript at p. 9423.

[18] For a schematic of Coker and Coker product processing to Quality Bank specifications, *see* Exhibit No. PAI-4.

[19] "PIMS is a standard, commercially available computer model licensed by Aspen Technology, Inc., that is used to simulate refinery operations." Exhibit No. PAI-1 at p. 11. The PIMS model yield for ANS Resid can be found in Exhibit No. PAI-5.

[20] O'Brien based his estimate of the quality of ANS Resid on assays performed by Caleb Brett in 1996 and 2001. Exhibit No. PAI-1 at p. 12.

and (3) the use of different processes at refineries may result in the production of products of different qualities. Exhibit No. PAI-1 at p. 17. He, therefore, based his calculations on a "typical large West Coast refinery (approximately 200,000 barrels per day (B/D)) with an assumed coking capacity of 40,000 B/D."[21] *Id.* Moreover, he assumed that the processing units within the refinery were "efficiently sized" and were capable of processing all of the material coming from distillation, cracking and coking units. *Id.*

34. For each processing unit, O'Brien divided his coking cost calculation into three categories:

> (1) capital costs; (2) fixed costs; and (3) variable costs. [His] capital cost calculation in turn was divided into a three step-process: (a) estimation of Inside Battery Limits ("ISBL") costs;[22] (b) estimation of "Offsite" or Outside Battery Limits ("OSBL") costs;[23] and (c) estimation of both the

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[21] There are two different barrels per day numbers used in the industry – barrels/calendar day and barrels/stream day:

> Barrels per calendar day is a figure that's derived by a refiner or some other entity that may be doing an accounting of some sort about the refinery's operation, and . . . they take the total barrels that are processed in the refinery or in a specific unit for that year, and then that quantity is divided by 365, and that generates a barrels per calendar day stream.
>
> A barrels per stream day number is typically the barrels that the unit or the refinery can run on a consistently stream day with the variances within the unit itself, but typically, it's greater than . . . the barrels per . . . calendar day number because the calendar day number indicates the times they were down and not able to process.

Transcript at pp. 4270-71. In other words, the barrels per stream day is a figure representing the plant operating under typical conditions while the barrels per calendar day figure takes into account the shut downs which occur over a year. *Id.* at p. 4271. The 40,000 barrels per day figure used in this case is the stream day rate, which is then discounted by an industry agreed upon 87% utilization rate to get the calendar day rate of 34,800 barrels per day. *Id.* at pp. 4271-74.

[22] "ISBL costs are those costs associated only with the coker process unit itself." Exhibit No. PAI-1 at p. 19.

[23] "OSBL costs are those additional costs needed to support the processing operation." Exhibit No. PAI-1 at p. 19.

> capital recovery factor (which includes both return on and return of capital) and the equipment "utilization" rates needed to convert the total ISBL and OSBL capital costs into a capital recovery cost per unit of Resid processed.

Id. at p. 19 (footnotes added). Based on 1996 dollars, and using his firm's cost curves,[24] O'Brien estimates an ISBL capital cost of $107.4 million. *Id.* at pp. 19-20. He claims that his estimate is "well within the range of the publicly available data." *Id.* at p. 20. However, he admits that his company's cost curves are not based on West Coast costs, but rather are national in scope with a Gulf Coast dominance, and that he did not make any adjustment for West Coast costs.[25] *Id.* at p. 22. Admitting that such a bias favors the producers of heavier crude, O'Brien notes that he used the same methodology for both the Naphtha and Heavy Distillate cuts and that this would favor producers of lighter crude. *Id.* at p. 23. In addition to estimating the ISBL costs, O'Brien estimated OSBL costs and assumed that they would be 35% of the ISBL costs. *Id.* at p. 24. All of his capital costs are based on his further assumption that refineries would recover these costs over a five year period. *Id.*

35. In addition to estimating a Coker's capital costs, O'Brien also estimated its Fixed Costs, which he defined as those "costs . . . incurred irrespective of the volume of oil processed through a unit," by reckoning the actual labor costs and then using a percentage of the capital replacement costs to represent the costs of maintenance, taxes and insurance. *Id.* at p. 25.[26] He also computed his guess of the Coker's variable costs, those costs "incurred in direct proportion to the volume of oil processed through the unit," by using data included in the PIMS model. *Id.*

36. According to O'Brien, he also calculated the costs to process the products derived from the Coker by, first, identifying an "efficiently sized capacity for each process unit" commonly used at West Coast refineries "to process intermediate products into finished products." *Id.*[27] He "then assigned to the coking process only that portion of those process unit costs (variable, fixed and capital costs, if appropriate) that are attributable to treating products from the coker." *Id.* O'Brien was careful to only use costs necessary to process Coker products to Quality Bank standards. *Id.* at pp. 25-26.

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[24] The equations for the Baker & O'Brien, Inc., Coker cost curves are in the record as Exhibit No. EMT-210.

[25] On cross-examination, O'Brien asserted that neither he, nor anyone in his firm, ever uses location factor adjustments. Transcript at p. 212.

[26] *See also* Exhibit No. PAI-11.

[27] *See also* Exhibit No. PAI-12.

37. O'Brien asserts that all Heavy Distillate, whether produced from the distillation or the coking processes, must be processed through a high-pressure distillate hydrotreater. *Id.* at p. 27. Assuming a 50,000 barrel/day high-pressure hydrotreater would be necessary to treat all of a refinery's Heavy Distillate, O'Brien estimated the cost of processing "Quality Bank Heavy Distillate (at 0.52% sulfur) to the quality of the West Coast Heavy Distillate reference product (0.05% sulfur)" to be 4.1¢/gallon. *Id.* He also calculated the cost of processing Heavy Distillate derived from a Coker (at 1.9% sulfur) to the West Coast Heavy Distillate reference price to be 5.5¢/gallon. *Id.* According to O'Brien, the 1.4¢/gallon difference between the two represents the incremental cost of processing Coker Heavy Distillate and this cost was allocated to the cost of coking.[28] *Id.* at p. 28.

38. Recognizing that Quality Bank VGO (about 1.3% sulfur) needs no further processing, O'Brien asserts that it still does require further processing through a medium-pressure hyrdrotreater to lower its sulfur content before it can be used in a refinery's catalytic cracker ("cat cracker").[29] *Id.* at pp. 29-30. He claims, however, that Coker VGO requires processing through a high-pressure hydrotreater before it can be used in the cat cracker and that, therefore, most refineries would use an intermediate unit to process both Quality Bank and Coker VGO. *Id.* at p. 30. Claiming that calculating the cost of such a unit is a "challenge," O'Brien nevertheless did make such an estimate. *Id.* He started by, based on his experience, determining that the typical West Coast coking refinery would use a 50,000 barrels/day hydrotreater and then determining the total cost, including both operating and capital costs, of using that hydrotreater to process Quality Bank VGO to cat cracker feed quality which he estimated as being 4.1¢/gallon.[30] *Id.* at pp. 30-31. He then calculated the total cost of processing coker VGO to cat cracker feedstock quality assuming the higher cost of the high-pressure hydrotreater, which he estimated at 6.6¢/gallon. *Id.* at p. 31. In his opinion, O'Brien states, "the 2.5¢/gallon difference provides a reasonable approximation of the incremental cost that would be incurred by a refiner associated with the need to include a volume of 11,536 [barrels/day] of coker VGO in a 50,000 [barrels/day] VGO hydrotreater, and to process this VGO to a Quality Bank VGO quality level." *Id.*

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[28] *See also* Exhibit No. PAI-13.

[29] "A cat cracker [sometimes referred to as an FCC unit] is a refinery machine that takes a heavier portion of the output from the crude unit or intermediate portion – heavy portion and cracks or breaks the molecules to make lighter molecules out of heavier molecules." Transcript at p. 419. It is used to process VGO. *Id*. at p. 420.

[30] O'Brien's methodology is displayed on Exhibit No. PAI-14.

39. Using the same method as he used for Coker VGO, O'Brien also calculated the total cost of Coker Naphtha. He states:

> [T]he calculated total cost, including both operating and capital, to process Coker Naphtha is 5.2¢/gallon versus 1.9¢/gallon to process Quality Bank Naphtha. The difference, 3.3¢/gallon, represents a reasonable approximation of the incremental cost of an intermediate pressure hydrotreater to process both Coker Naphtha and Quality Bank Naphtha quality and to process Coker Naphtha to Quality Bank Naphtha quality.

Id. at p. 32.[31]

40. Stating that Coker Light Straight Run (sometimes "LSR") must be hydrotreated to meet Quality Bank LSR standards, O'Brien assumed that a refiner would process it through the same medium hydrotreater as was used for processing Quality Bank Naphtha. *Id.* at p. 33. He estimated the cost to process the Coker LSR at 2.0¢/gallon.[32] *Id.*

41. In addition to the above costs, O'Brien also suggests that a Coker refinery would have additional costs for a sulfur plant. *Id.* at p. 33. He estimated that processing 40,000 barrels/day of ANS Resid would produce 47 long tons of sulfur from the coking unit and 38 long tons from the hydrotreater. *Id.* With regard to the latter, as sulfur has a value and as introducing hydrogen during hydrotreating increases the volume of product which comes out of the hydrotreater, O'Brien "assumed that the cost of any sulfur plant needed for hydrotreated Coker products would be approximately offset by selling sulfur plus the credits that should be applied to hydrotreating for the increased product volume." *Id.* at p. 34. However, with regard to the sulfur from the coking unit, as there is no increased volume of product in the coking process, O'Brien "determined that additional sulfur recovery capacity would be necessary, and [he] allocated capital and operating costs for sulfur processing using the same methodology that [he] used in treating Heavy Distillate."[33] *Id.* O'Brien further notes that West Coast refiners, typically, maintain a 30% sulfur plant reserve capacity and increased the capacity attributable to the coking process from 47 light tons per day to 59 light tons per day. *Id.* at p. 35.

42. Next, O'Brien turned his attention to Coker utilization, the percentage of time a unit is expected to operate, stating that the more a unit operates, the lower the per barrel cost. *Id.* For the coking unit, O'Brien assumed an 87% utilization factor and, for the

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[31] *See also* Exhibit No. PAI-15.

[32] *See also* Exhibit No. PAI-16.

[33] *See also* Exhibit No. PAI-17.

hydrotreaters, a 92% utilization. *Id.* at p. 36. O'Brien concludes, based on the above that, in Year 1996 dollars, the cost of coking Resid is $4.30 per barrel. *Id.*

43. As a result of his analysis, described above, O'Brien proposes the following formula to value Quality Bank Resid in dollars per barrel:

	(0.0347)	x	Quality Bank Propane Price
+	(0.0040)	x	Quality Bank Isobutane Price
+	(0.0263)	x	Quality Bank Normal Butane Price
+	(0.0469)	x	Quality Bank LSR Price
+	(0.1094)	x	Quality Bank Naphtha Price
+	(0.2140)	x	Quality Bank Heavy Distillate Price
+	(0.3050)	x	Quality Bank VGO Price
+	(0.0600)	x	Coke Price[34]
+	(0.2983)	x	Natural Gas Price[35]
-	(4.30)	x	Quality Bank Nelson Farrar Index

Id. at p. 37; Exhibit No. PAI-18.

44. In his Reply Testimony, O'Brien begins by contending that the same approach should be followed for each cut because "[i]f different approaches are followed for different cuts, then those cuts likely will be overvalued or undervalued relative to each other." Exhibit No. PAI-42 at p. 2. According to him, even though the witnesses appearing on behalf of Exxon Mobil and Tesoro (hereinafter jointly referred to as "Exxon") assert that the cuts should be valued consistently, in practice, he contends, they propose a different approach for each of the three cuts. *Id.*

45. O'Brien asserts that Exxon's economic interests vary by cut. *Id.* at p. 3. With regard to Resid, for example, he claims that a low Resid value favors Exxon's economic interest. *Id.* Therefore, O'Brien asserts, Exxon has an interest in establishing that Resid processing costs are high as it would result in a lower Resid value being used by the Quality Bank. *Id.* He adds that, in contrast, Exxon's economic interests are furthered by higher Heavy Distillate and Naphtha cut values. *Id.* Exxon's witnesses acknowledged at their depositions that they were aware of Exxon's economic interests. These witnesses then developed inconsistent valuation methodologies for each cut that in each instance

[34] By this, O'Brien was referring to the *PCQ* monthly mid point price for West Coast low sulfur (less than 2% sulfur) in dollars per short ton. Exhibit No. PAI-18 at n.1.

[35] By this, O'Brien was referring to the *Natural Gas Week* monthly California natural gas spot price for pipeline south in dollars per million Mbtus plus 15¢ per million Btus transportation cost. Exhibit No. PAI-18 at n.2.

favors Exxon's economic interest, as described below.

46. With regard to Resid, O'Brien criticizes Exxon witness John Jenkins's ("Jenkins") testimony. *Id.* He asserts that Jenkins, rather than using his company's (Jacobs Consultancy) data base to determine the costs of coking Resid, "did a detailed calculation of the costs of each of the elements of a Coker that permitted him to add every conceivable cost to his estimate." *Id.* O'Brien claims that this results in an ISBL cost which is $20 million higher than if Jenkins had used the Jacobs data base ISBL cost and, further, that the "numerous escalators" Jenkins used resulted in increasing this amount to $30 million. *Id*.

47. Exxon's Resid valuation, O'Brien asserts, is unrealistic. *Id.* at p. 5. He explains that Resid's original use was as a blend with lighter products to produce a heavy fuel oil. *Id.* However, he continues, heavy fuel oil does not have a high value, and its value has fallen since environmental regulations have limited its use in the United States. *Id.* Coking technology, he states, was developed specifically to convert Resid into higher valued lighter products and eliminate heavy fuel oil production. *Id.* Even though it is expensive to install coking facilities, he contends, using Resid as a Coker feedstock makes its value higher than were it still used as a blendstock. *Id.* He contends that this must be so because, given the high costs of installing a Coker, a refiner would have no economic incentive to construct the Coker otherwise. *Id.* at pp. 5-6.

48. According to O'Brien, a simple way to test the validity of a calculated Resid Coker feedstock value is to see if that value is higher than the fuel oil blending value of the Resid. *Id.* at p. 6. He states: "If the fuel oil blending value of Resid is higher than the calculated coker feedstock value, then the calculated coker feedstock value must be too low," because, unless this were so, it would not be economically sound to construct and operate a Coker. *Id.* However, O'Brien notes, Exxon witness Dr. David Toof ("Toof") admits that Exxon's proposed Resid Coker feedstock value is below the fuel oil blending value for Resid. *Id.* Furthermore, O'Brien claims that both Jenkins and another Exxon witness, Martin Tallett ("Tallett"), admitted that Resid's value as Coker feedstock should be higher than its value as fuel oil blend. *Id.* at p. 7.

49. Referring to Exxon's comparison of recent Coker projects with its projected costs in Exhibit No. EMT-63, O'Brien contends that its claim that these projects (LCRC; Shell Deer Park (1995); Shell Deer Park (2001); Phillips Sweeny; BP Toledo; Hovensa; Clark Oil; Shell Martinez; and Valero) are in line with Jenkins's cost estimates is misleading. *Id.* at p. 8. According to O'Brien, the projects are misleadingly portrayed and are inconsistent with Jenkins's data. *Id.* Additionally, he asserts that several projects include equipment which is unrelated to the Coker and, thus, allocating the total project costs to the Coker overstates its costs. *Id.* O'Brien maintains that even though "Jenkins does perform an allocation of project costs, those allocations appear to significantly overstate the amount of project costs related to the coker itself." *Id.*

50. According to O'Brien, most of the projects enumerated in Exhibit No. EMT-63 were designed to process very high sulfur crudes, the Resids of which are heavier, and more sulfurous than ANS crude, and, consequently, are much more expensive to process by Coker. *Id.* at pp. 8-9. Such project costs, he asserts, are not directly comparable to the competing cost estimates. *Id.* at p. 9. Furthermore, he maintains that Jenkins failed to include important information about several of the projects (LCRC; Phillips Sweeny; Shell Martinez; and Valero.) *Id.* In his testimony, O'Brien details why he believes that these four projects do not establish a reasonable cost for constructing a Coker because they include the cost of extraneous equipment. *See id.* at pp. 9-11.

51. While O'Brien admits that Jenkins attempted to allocate total project costs between the Coker and the extraneous equipment, he claims that Jenkins did not do so properly. *Id.* at p. 11. For example, according to O'Brien, Jenkins allocated $800 million of the $1.1 billion total cost of the LCRC project to the Coker, leaving only $300 million for all other equipment, without any explanation, and later admitted that the allocation was inappropriate. *Id.* As for the Phillips Sweeney project, O'Brien contends that Jenkins's allocation cannot be correct because the Project includes a large vacuum distillation tower. *Id.*

52. Moreover, O'Brien submits, projects processing crudes from Latin America, which tend to be heavier and more sulfurous than ANS crude, are not directly comparable to the Coker in this proceeding as Cokers designed to process heavy crude Resid are more expensive than Cokers designed to handle ANS. *Id.* More coke drum capacity may be required, he explains, or a refinery may upgrade all its equipment to process heavier crudes, or a refinery may deal with crudes containing acids, which require special, high cost metallurgy that substantially increases project costs. *Id.* at pp. 11-12. ANS, he maintains, is lighter, has less sulfur, and has no corrosion problems and, therefore, Jenkins's Coker cost estimates are significantly overstated and unreliable.[36] *Id.* at p. 12.

53. Referring to the testimony of Exxon witness Dr. William Baumol ("Baumol"), O'Brien further contends that if costs associated with Resid processing are similar to costs not accounted for in valuing other cuts, then those Resid costs should not be included in the calculated costs for coking Resid. *Id.* at p. 13. Asserting that discussing the "Quality Bank Base Refinery" is necessary, he begins by explaining that "all parties appear to agree, [that] in an ideal world there would be a publicly available price for each

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[36] O'Brien submits that neither he nor Jenkins has sufficient information to determine the actual cost of the Cokers for each of the projects, but claims that, with the information he received from Exxon through the discovery process and what he was able to locate on his own, he was able to determine that Jenkins's estimates of the cost for these four projects was overstated. *See* Exhibit Nos. PAI-42 at p. 12 and PAI-45.

product valued by the Quality Bank without the need for any adjustment for additional processing. In that world, each cut could be valued based on the published price without any adjustments." *Id.* at pp. 13-14. In this "ideal world," he continues, the following refinery equipment and personnel would be used to produce and sell the cuts at the published prices in such a scenario: atmospheric distillation, vacuum distillation, light ends fractionation, storage tanks, administrative, waste water and ancillary facilities, management personnel, and labor to operate the Quality Bank refinery. *Id.* at p. 14. O'Brien states that the costs of this equipment and personnel are considered to be part of the Quality Bank Refinery and are charged against the published prices of any of the cuts used to value the TAPS streams. *Id.* He adds that these costs are not subtracted from the Quality Bank reference prices as the refineries recover the costs by selling the cuts at the published reference prices. *Id.* at p. 15.

54. O'Brien next goes on to discuss cuts which require further processing, to wit: Resid and Heavy Distillate. *Id.* at pp. 15-16. With regard to Resid, he claims that the following costs must be included: Coker, incremental downstream processing, incremental ancillary facilities, and incremental management and labor; with regard to Heavy Distillate, he suggests that the following costs should be included: distillate hydrotreater, incremental management and labor, and incremental ancillary facilities. *Id.* at p. 16. He explains that incremental facilities and personnel are required that are not part of the Quality Bank Base Refinery concept. *Id.* Such processing is incremental to the Quality Bank Base Refinery, he notes, and a deduction from the published prices equal to the incremental costs for a particular cut must be taken to account for the additional costs. *Id.*

55. Exxon witnesses, O'Brien claims, are inconsistent when using the Quality Bank Base Refinery concept. *Id.* at p. 17. Baumol, he notes, would deduct all costs associated with Resid processing, including the costs associated with the Quality Bank Base Refinery. *Id.* According to O'Brien, deducting costs incurred in connection with other Quality Bank cuts which do not require additional processing from Resid "would be inconsistent . . . without also subtracting the costs from the reference prices used to value the other products that do not require further processing." *Id.* O'Brien asserts that only incremental costs not included in the Quality Bank Base Refinery should be used. *Id.*

56. O'Brien attacks Jenkins's use of a detailed cost estimate stating that such calculations are not inherently more representative of costs, or more accurate, than cost curves. *Id.* at p. 18. Moreover, he suggests that Jenkins included substantial Quality Bank Base Refinery costs to Resid in his cost calculations. *Id.* O'Brien argues:

> [T]he first step in estimating the costs of a refinery expansion . . . is to perform a general cost estimate using cost curves taken from a general data base of refinery costs. Detailed cost calculations . . . are performed only after a specific project has been scoped out in sufficient detail that such an

> estimate can provide additional useful information. However, a detailed cost estimate for one refinery coker project based on the specifics of that project is unlikely to be more applicable to any other refinery project than a general estimate based on cost curves.

Id. at pp. 18-19. Furthermore, he contends, Jenkins's detailed estimate is less likely to be applicable than costs based on cost curves because Jenkins admits this was his first attempt at creating a detailed cost estimate for a complete Coker. *Id.* at p. 19. According to O'Brien, Jenkins "is substituting his own lack of expertise for the accumulated expertise underlying the numerous projects embodied in the Jacobs data base." *Id.* O'Brien also claims that whatever experience Jenkins has is related to projects involving Latin American crudes which are much heavier than ANS. *Id.* at pp. 19-20. As for Jenkins's use of a West Coast location factor in his analysis, O'Brien believes generalized cost curves are a more appropriate method. *Id.* at p. 20.

57. Jenkins's detailed calculation of Coker costs, according to O'Brien, reveals that he improperly included a number of items in his analysis. *Id.* As an example, he points to Jenkins's adding automatic coke drum deheaders and associated equipment "notwithstanding the fact that few West Coast refineries have such automatic equipment." *Id.* at p. 21. Also, he contends, Jenkins included certain items associated with the recovery of light ends and improperly included items in the ISBL costs that "Gary & Handwerk say are not part of the ISBL factor." *Id.* The impact of these assumptions, he states, is significant. *Id.* at p. 21.

58. O'Brien summarizes his contentions regarding errors allegedly committed by Jenkins as follows:[37]

> Exhibit EMT-46 includes a simple cost for each piece of equipment. Exhibit EMT-47 then takes this "bare cost," and escalates it for various items such as ''piping," "concrete," "instruments," "engineering," etc. At the far right hand column of Exhibit EMT-47 is a "Total" column that shows total installation costs associated with each piece of equipment. The difference between the total and the bare cost varies by category, but on average the totals are about 380% of the bare cost of the equipment. Thus, on average, the cost of each piece of equipment is multiplied by a factor of about 3.8 to arrive at its installed cost. To this installed cost, [Jenkins] adds a 25% OSBL factor, a 10% Owners Costs factor, and a 4.3% Interest During Construction factor, with each multiplier cumulative of each previous multiplier.

[37] *See also* Exhibit No. PAI-46.

Id. at pp. 21-22. While O'Brien believes that the use of such multipliers is an appropriate cost estimating technique when properly applied, he contends that they cause the "bare cost" of equipment to have a substantial impact on total project installed costs. *Id.* at p. 22. O'Brien calculates that the total impact of Jenkins's invalid equipment assumptions on his coking cost capital calculation is $58.9 million. Moreover, as Jenkins's fixed cost calculations are based in part on capital costs, O'Brien claims that his invalid equipment assumptions cause a significant additional impact on his fixed cost calculation. *Id.*

59. Jenkins's OSBL estimate, O'Brien believes, is also problematic. *Id.* at p. 22. It has two parts, he notes, first a $56.8 million cost for storage tanks, a steam system, and cooling water and, second, a 25% OSBL factor to account for other offsite facilities. *Id.* Although O'Brien has no problem with the 25% factor, he contends that the storage tanks are inappropriate because the Coker products tanks would already be part of the refinery, and, consequently, the total impact after Jenkins applies Owners Cost and Interest During Construction costs is $39 million. *Id.* at p. 23.

60. O'Brien asserts that Jenkins improperly applied interest during construction and owners costs multipliers. *Id.* He claims that Jenkins "first increases his capital costs by 10% to reflect 'Owner's Costs'" and then "takes the resulting cost number and multiplies it again times 4.3% for Interest During Construction." *Id.* O'Brien claims that "[w]hatever the validity of these two multipliers . . . Mr. Jenkins' application of [Interest During Construction] to Owner's Costs is questionable . . . [because his] description of Owner's Costs . . . include[s] the cost of the refinery owner's employees related to the construction of the coker." *Id.* at p. 24. According to O'Brien, the Interest During Construction calculation should cover the interest cost on the construction loan used to finance the construction. *Id.* He concludes that it is unlikely that a refinery owner would finance the cost of construction management and engineering tasks performed by its own employees and suggests that, therefore, Owner's Costs should not be increased by Interest During Construction. *Id.* O'Brien contends that, to the extent that Owner's Costs and Interest During Construction are proper elements in cost calculations, each "should be determined as a percentage of the ISBL and OSBL costs." *Id.*

61. As for downstream processing units, O'Brien explains that Jenkins assumes downstream units with uneconomic sizes. *Id.* at p. 25. Refiners, O'Brien contends, typically build larger units to take advantage of economies of scale and Jenkins was not able to identify any refiner "that has ever constructed a hydrotreater limited to the size necessary to treat the coker products." *Id.* O'Brien also claims that Jenkins assumes Coker products would be processed to a better quality than is necessary for Quality Bank specifications, thus increasing costs. *Id.*

62. O'Brien explains that Jenkins fails to compensate appropriately for his unrealistic assumptions because, while he makes economy of scale adjustments to account for the artificially small units he assumed and allows credits for the greater than required

processing, "he erroneously applies a negative economies of scale adjustment to his calculation, and . . . he fails to take his economies of scale into account when calculating his fixed costs." *Id.* at pp. 25-26. O'Brien concludes:

> [Jenkins] determines his economies of scale adjustment for each product by comparing (1) the cost of constructing a single hydrotreater for each product sized to treat the entire refinery output of that product; with (2) the cost of building two hydrotreaters for each product, one at the uneconomic size he assumed for coker products and one at a larger size to process the virgin cut of that product. When the cost of building the single facility is less than building the two facilities, he gives a credit, which is appropriate. My problem is with what [Jenkins] does when he estimates that the cost of building the two smaller facilities is less than building a single facility, which he does with respect to the naphtha hydrotreaters.

Id. at p. 26.

63. O'Brien suggests that Jenkins should not have included any economies of scale with respect to his Naphtha hydrotreater calculation because, if Jenkins is correct that it would be cheaper to build two small hydrotreaters rather than one large one, a refiner would build the two smaller ones. *Id.* However, O'Brien notes, Jenkins penalized the refiner for building the two smaller units by using a negative economy of scale. *Id.* at p. 27.

64. Also, O'Brien claims, certain of Jenkins's fixed cost estimates are calculated as a percentage of capital costs. *Id.* Because the economies of scale are supposed to account for overstating the capital costs of Jenkins's downstream units, O'Brien explains, Jenkins "should have applied the economies of scale credit <u>before</u> calculating the fixed costs," which he did not do. *Id.* (emphasis in original).

65. Jenkins's fixed cost assumptions, O'Brien asserts, are also flawed because he uses too many operators for the Coker, assumes a foreman is part of the Quality Bank Base Refinery, and uses excessive multipliers for his labor costs. *Id.* at p. 28. Instead of Jenkins's 38 operators, O'Brien contends only 25 are necessary. *Id.* As for the foreman, he notes that the Jenkins-assumed foreman is "actually part of the Quality Bank Base Refinery and the costs of that foreman should not be assigned to the costs of coking." *Id.* Finally, he argues that Jenkins used excessive multipliers in calculating labor costs because while, when estimating labor costs, it is appropriate to include a factor to multiply the base wage to account for benefits, overtime and other labor-related costs, Jenkins improperly added 35% for burdens not shown in his exhibits before applying a 15% escalation factor for offsite labor, and a 20% factor for administrative labor. *Id.* at pp. 28-29. O'Brien argues that these "factors are not typically employed in estimating operating labor costs." *Id.* at p. 29. He adds:

> While I am not sure what is intended to be covered by the 35% "burden" factor, I believe that all normal operating labor costs are included in the 45% factor that I have applied. The 15% offsite labor and 20% administrative labor appear to apply to labor not directly associated with the coking facilities. As such, this is not incremental labor hired to operate the coking facilities and should be deemed to be part of the costs associated with the Quality Bank Base Refinery and therefore not allocable to the cost of coking Resid.

Id.

66. During cross-examination, O'Brien, initially, was asked a substantial number of questions regarding his non-use of a location factor to adjust the cost curve which served as the basis for his Resid valuation. *See* Transcript at pp. 213-20. In his answers, O'Brien indicated that his cost curve was generic, i.e., was national in scope rather than focused on a particular geographical location (*id.* at pp. 219-20); that he would not use a location factor adjustment when he was conceptualizing a project, but would wait until the project was more definite[38] (*id.* at p. 215); that, unless he knew what conditions were applicable to a particular project, he would not apply a "subjective location factor" because it would not get "any [ ] better level of accuracy than . . . [using] . . . a generic cost curve," which he did (*id.* at p. 219); that his company's cost curve was updated annually for inflation (*id.* at p. 221); and that the cost curve represents the cost of all of the equipment related to the ISBL costs[39] (*id.* at pp. 222-23). He also admitted that he couldn't identify the projects which underlie his company's cost curve (*id.* at pp. 220-21); that he couldn't say how many two-drum or four-drum Cokers underlie the cost curve (*id.* at p. 222); and that, generally, West Coast costs were higher than those on the Gulf Coast (*id.* at p. 232). Later, he conceded that it would cost more to build a Coker in Los Angeles County than his company's generic cost curve allowed. *Id.* at pp. 1243-44. He further explained that he believed that the use of his company's generic cost curve was appropriate until a specific location on the West Coast for construction of his conceptualized Coker was identified. *Id.* at pp. 1244-45. But he admitted that his company's cost curve was "dominated" by Gulf Coast data. *Id.* at p. 1282.

67. O'Brien agreed with Exxon counsel that the size of a Coker drum was a significant

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[38] Later O'Brien stated that he "did not design a particular coker." Transcript at p. 1310. Rather, he "used a cost curve to estimate the cost of a 40,000 barrel a day coker and the cost curve was based on ANS resid." *Id.* He claims that his proposal was "simply a cost associated with that capacity for that type of feedstock." *Id.*

[39] By "battery," O'Brien means the limits of the processing plant, i.e., the Coker. Transcript at p. 1203.

factor in determining its cost, and that Coker drum sizes have been increasing in recent years. *Id.* at p. 265. He claimed, however, that the per barrel cost of processing Resid through the larger drum will be lower because more Resid can be processed through it. *Id.* at p. 266.

68. After being asked, O'Brien described the equipment in a Coker as follows:

> [The equipment] in a typical coker would be the coke drums, the most important. You've got the cutting equipment to cut the coke out. You've got the heaters that heat the material going in. You've got to have equipment to handle the coke after it comes out of the drums and dispose of it however you're disposing of it.
>
> You have a fractionator to fractionate the products, and you have what's called a blow-down system to sort of take all the slop that comes out of the coker when you're emptying [ ] it.
>
> * * * *
>
> Then you've got all the heat exchangers and strippers and pump-arounds and so forth that go along with that equipment.
>
> * * * *
>
> You have to have - - you also have to have a system for fractionating the light ends.

Id. at pp. 266-67.

69. He also asserted that his proposal is not based on an actual Coker, but is a conceptualization intended to reflect what a "reasonable" Coker to process Resid would be like without considering what specific equipment would be needed.[40] *Id.* at p. 276. Therefore, he did not specifically include coke handlers such as coke crushers, a coke pad, or front-end loaders.[41] *Id.* But, later on, he explained that his cost estimate

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[40] Later on, O'Brien states that the difference between his approach and that of Jenkins was that Jenkins was costing out the actual construction of a Coker to an existing refinery while he was just "conceptualizing" the refinery and its processing costs without considering the actual construction costs. Transcript at pp. 1201-02.

[41] On redirect examination, O'Brien stated that the cost of coke handling equipment was included in his Outside Battery Limit ("OSBL") estimate. Transcript at p. 1084. The term OSBL refers to everything outside the actual processing part of the

including a "mixture" of coke handling equipment. *Id.* at p. 280. O'Brien also admits that the cost of adding coke handling equipment, such as a pit crane, covered storage, and coke crushing and screening equipment to his estimate would more than make up the total difference between his and Jenkins's total costs. *Id.* at p. 408.

70. According to O'Brien, Jenkins's proposal contains "a small inefficient gas plant to process coker gases" instead of making the gas plant a part of the integrated refinery as he did. *Id.* at p. 289. He explained that the Jenkins proposal was more costly because Jenkins "doesn't assume that the Coker would share the gas plant that was being used for the cat cracker." *Id.* at pp. 289, 421-22. O'Brien asserts that, if the Coker gas plant is integrated with the cat cracker gas plant, a substantial amount of money would be saved. *Id.* at p. 428.

71. O'Brien admits that a substantial difference (about $20 million) between his and Jenkins's ISBL proposals is Jenkins's use of an automatic deheader. *Id.* at p. 406. Another distinction between the two proposals is that O'Brien uses a two-drum Coker, while Jenkins uses a four-drum Coker. *Id.* at p. 472. However, O'Brien admitted, on cross-examination, that using his Coker formula, but subtracting the cost of the Coker gas plant,[42] the automatic deheader, and the coke handling equipment, would result in a higher cost for a four-drum Coker than that suggested by Jenkins. *Id.* at pp. 473-74. Under questioning by Judge Wilson, O'Brien stated that he recommended the use of a two-drum Coker because it "was adequate" and was less expensive than a four-drum Coker. *Id.* at p. 1175.

72. Still another difference between O'Brien's proposal and that of Jenkins is that O'Brien proposed the use of a high-pressure hydrotreater[43] ("800 pounds [per square

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Coker, but associated with it. *Id.* at p. 1204.

[42] Under further examination, O'Brien indicated that the Coker gas plant was not part of the Coker battery limits, but was a support facility for the delayed Coker. Transcript at p. 1212. *See also id.* at pp. 1216-17.

[43] Responding to a question from Judge Wilson, O'Brien described the purpose of a hydrotreater as follows:

> A hydrotreater's primary function is to reduce the sulfur content of the products, but in the process of doing that, it can also reduce the nitrogen content of the products, if there's nitrogen in there. It can also reduce the aromatics content, depending on the operating conditions you operate at.
>
> It can saturate what we call - - there are also components called olefins that are available, particularly in things like coker products, and those are converted

inch] or more"), while Jenkins proposed a medium-pressure hydrotreater. *Id.* at pp. 816-18. According to O'Brien, this impacts costs in two ways: first, a medium-pressure hydrotreater is less expensive; and two, it uses less hydrogen when operating. *Id.* O'Brien claims, however, that a medium-pressure hydrotreater cannot be used to "process the virgin ANS stream from .57 weight percent sulfur to .05 weight percent sulfur." *Id.* at p. 818. Rather, he states, a high-pressure hydrotreater is required. *Id.* at p. 821.

73. Discussing how to determine the appropriate size of a Coker drum, i.e., both the height and the width, O'Brien indicated that he would take into consideration the following characteristics: throughput in barrels/day and the amount of coke produced. *Id.* at pp. 492-93. He also indicated that other characteristics he would have to consider would be the pressure of the drum, the operating temperature, the cycle time and the recycle rate. *Id.* at p. 493. Based on these characteristics, O'Brien claims that the breakpoint for use of a two-drum Coker as compared with a four-drum Coker is 2,700 tons per day of capacity. *Id.* at p. 494. He admits, however, that that this is a "conceptual concept." *Id.* at pp. 494-95. O'Brien also suggests that his "conceptual cost curve makes no drum size assumption." *Id.* at p. 502.

74. According to O'Brien, his company's cost curves assume a "typical" Coker and by "typical" he meant

> the type of coking operation that is efficient, of an - - economically sized and that is basically setting the marketplace - - the efficient producer is the one that the producers are going to be based off of - - the price of the products are going to be based off of.
>
> The most efficient producer will be the one who sets the market price - - the high cost producer doesn't set the market price so it's that typical coker out there that's large, efficient and utilizing its capacity to the best it can.

> into what we call saturated products [which have more hydrogen compared to the amount of carbon than does an unsaturated compound]. Olefins are unsaturated and you saturate those. That causes the consumption of hydrogen. There are a whole lot of chemical reactions that take place in addition to just reduction of sulfur.

Transcript at pp. 1169-70, 1181. In addition, he indicated that the chemical reactions in the hydrotreater were accomplished through the use of catalysts which vary in type depending on the type of hydrotreater in use and in size and quantity depending on the feedstock. *Id.* at p. 1171. He added that hydrotreaters used to process the heavier cuts are more expensive than those used to process the lighter cuts. *Id.* at p. 1172.

Id. at pp. 557-58. *See also id.* at p. 1188.

75. Later on, O'Brien asserts that he is assuming that West Coast refineries have economically sized units and that he is attempting to discern the costs of processing material through those units. *Id.* at p. 655. For the variable costs related to a Coker, O'Brien claimed that he used those associated with the PIMS model because it not only provided yields, but also reasonable operating costs. *Id.* at p. 658.

76. With regard to the required sulfur plant, O'Brien agreed that he assumed a 30% backup capacity was needed as compared with the 100% backup capacity proposed by Jenkins. *Id.* at pp. 686, 1227. While he admitted that a refinery would have a problem if the sulfur plant was inoperable, O'Brien suggested that the operators could change the crude slate to one having a lower sulfur content. *Id.* at p. 687. However, O'Brien also granted that, to reach 100% backup capacity, one would not have to build two plants each having the requisite 100% capacity; rather, one could build multiple plants appropriately sized so that if one went down 100% capacity would still be available. *Id.* at pp. 693-94. O'Brien's admits that his proposal includes the cost of one sulfur plant with 30% backup capacity for purposes of simplification. *Id.* at pp. 701-02, 1229. Despite this, O'Brien admits that having more than one sulfur plant as part of the backup provides a refiner with more "flexibility," but at a higher cost. *Id.* at pp. 1227-29.

77. To compute his total capital cost proposal, O'Brien adds the ISBL and 35% of the ISBL and then he increases that amount by 20%. *Id.* at p. 712. He admits that his proposal, based on that formula, exceeds the sum of Jenkins's owner's cost, interest during construction and capital cost. *Id.* at pp. 712-15. O'Brien would adjust the capital cost proposal by use of the Nelson-Farrar capital costs index. *Id.* at pp. 811, 826.

78. Discussing his company's cost curve,[44] O'Brien states that he has used such cost curves for 25 years, that he does not know how it was originally developed, and that it is updated periodically based on new data.[45] *Id.* at p. 745. O'Brien also indicated that his company's cost curve had a "scaling factor" of .64. *Id.* at p. 824. He defined the term "scaling factor" as "a factor that's used to determine what the cost of one unit will be versus another unit at a different capacity."[46] *Id.* Basically, O'Brien states, the scaling

[44] During later examination, O'Brien discussed the derivation of his company's cost curves and how they are used. *See* Transcript at pp. 1218-23.

[45] O'Brien describes the update process as follows: "If we see something that we think is out of line, we'll all get together and talk about it and see if we should do something with our curves." Transcript at p. 745.

[46] O'Brien added: "For example, if I build a unit to double the capacity, that unit

factor is reflected in the slope of the curve. *Id.* at p. 826.

79. On redirect examination, O'Brien unequivocally stated that a two-drum Coker could process 40,000 barrels/day of Resid and that there were two-drum Cokers in existence doing exactly that. *Id.* at pp. 850-51. He also indicated that the yield from a Coker was somewhat dependent on its feedstock, i.e., assuming the same operating conditions, different feedstocks would result in a different product mix and on the Coker's operating conditions, i.e., assuming the same feedstock, changing the operating conditions (e.g. pressure) also would result in a different yield from the same feedstock. *Id.* at pp. 968-70, 1006. According to O'Brien, even though a Coker could be expected to be operable for at least 20 and maybe more than 25 years, his cost proposal would recover the cost of constructing the Coker over a five-year period. *Id.* at pp. 1083, 1238-41.

80. With regard to his cost estimates, on redirect examination, O'Brien indicated that he was "not calculating the cost of expanding a refinery or building a coker," and explained the purpose of his calculations as follows:

> The purpose of my cost calculation was to try to determine or estimate what a reasonable processing cost would be for a typical West Coast refinery with an economically sized delayed coker and an economically sized downstream processing unit [primarily hydrotreaters].
>
> In effect, I'm trying to determine - - and this was the whole objective - - to try and determine what the costs are that are incurred through the coker and the costs incurred to bring the coker products to the quality of the Quality Bank products, all of those costs including capital, variable and fixed costs.

Id. at pp. 1046-47. Later on, he further explained that, since Resid is not saleable and therefore has no value, his cost estimate relates to the cost of converting the Resid from "a gummy-like substance to something" which can be sold. *Id.* at pp. 1137-38.

81. Answering questions I asked, O'Brien explained that, while his cost estimate included the capital costs of adding a Coker to an existing refinery, it did not include the costs of other facilities such as storage tanks. *Id.* at pp. 1190-92. *See also id.* at p. 1301. According to O'Brien, the latter costs are included in the reference prices. *Id.* at pp. 1192, 1203. However, O'Brien did include the incremental capital cost associated with the "difference in the intensity of the processing or the severity of that processing." *Id.* at

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will not cost twice as much as the other unit because there are what we call economies of scale involved." Transcript at p. 824. According to him, the scaling factor is used to take economies of scale into consideration. *Id.*

p. 1191. He summed up his cost estimate as including "only the capital costs associated with processing the resid and the capital costs associated with upgrading the quality of the products to Quality Bank quality." *Id.* at p. 1202.

82. When asked, on redirect examination, about his company's use of cost curves, O'Brien explained that they are used generally in the industry for "conceptual-type studies," by which he means "studies when you don't know or don't have any engineering done on your project yet."[47] *Id.* at pp. 1054-55. In connection with this discussion, O'Brien suggested that Jenkins's proposal was not based on a cost curve, but was based on "subjective assumptions about exactly how you want to design your unit." *Id.* at p. 1063. The subjective assumptions, O'Brien explained, to which he was referring were to those Jenkins made regarding the kinds of equipment used, the types of materials processed, and the ground and soil conditions which affect construction of the Coker. *Id.* at p. 1064.

83. Discussing sponge coke and shot coke,[48] O'Brien asserted that the former was more valuable. *Id.* at p. 1181. However, he pointed out that the value of coke would depend on its sulfur content, the metals included within it, and how easy it is to grind, among other factors. *Id.* at pp. 1181-82. O'Brien claimed that sponge coke of the appropriate quality could be sold to manufacturers of electrical anodes, to the steel industry for use in furnaces, to companies who, through a calcining process, would transform it into the appropriate quality for manufacturing electrodes, if not of a quality for those needs, it could be sold to the coke industry, or to a utility for mixing with coal for use as a fuel. *Id.* at pp. 1182-83. Shot coke primarily would be used as a fuel, according to O'Brien. *Id.* at p. 1183. The market price of shot coke would range from

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[47] O'Brien further explained that, if you don't have engineering or equipment specifications, a cost curve is the only way to get a cost estimate. Transcript at p. 1055. He stated: "When you know what kind of a unit you're going to process through, and you know the size of the unit, but that's fundamentally all you know, that's where the cost curves are used." *Id.* According to O'Brien, a detailed cost estimate could not be done until after the project had been more specifically defined, particularly with regard to the products that the refiner wanted to manufacture. *Id.* at p. 1056.

[48] Earlier O'Brien had described the difference between shot coke and sponge coke: shot coke tends to be hard and comes out of the coker like little "bee-bees," although the clumps of shot coke can be the size of a fist or as big as cannonballs, while sponge coke is softer and doesn't form clumps. Transcript at pp. 860-61. Whether a Coker turns out shot coke or sponge coke, according to O'Brien, depends on the feedstock used. *Id.* at p. 861. ANS crude, asserts O'Brien, would mainly produce sponge coke which would be calcined and used for electrical anodes in the aluminum industry, a high grade use. *Id.* at p. 862.

$2.00 to $5.00/ton although it has ranged as high as $20.00 to $30.00/ton when energy prices were high. *Id.* at pp. 1183-84.

B. DANA DAYTON

84. The next witness to appear was J. Dana Dayton ("Dayton") who testified on behalf of Phillips. She is the owner of Daylight Consulting, an oil and gas consulting company, and previously was employed by ARCO Alaska, Inc., of which Phillips is the successor. Exhibit No. PAI-22 at p. 1. As was O'Brien's, her testimony was also supported by BP, OXY, Petro Star, Alaska, Unocal, and Williams. *Id.* at p. 2.[49]

85. Dayton contended that Tallett used invalid assays[50] in his analysis. Exhibit No. PAI-47 at pp. 8-9. She maintains that, as the assays were conducted by independent labs, as well as ExxonMobil, and as the labs did not always use the same cut points as the Quality Bank, it is impossible to know if the assays are reliable. *Id.* at p. 9. According to Dayton, it is preferable to use assays analyzed by an independent laboratory consistently with the method used by the TAPS.[51] *Id.* In particular, Dayton questions three of Tallett's assays, and notes that Tallett admits that there may be problems with certain of the assays he used. *Id.* at pp. 9-10. She explains that her

> analysis is based on a comparison with the special purpose Quality Bank assays that were done for the TAPS Quality Bank Administrator since 1993. These assays do not have the information necessary to perform the Resid valuation. However, they do show the volume percent of the Resid content of ANS in each month. In my opinion, no assay should be used that shows a Resid content that is either higher or lower than any of the monthly Quality Bank assays for the year in which the sample was taken.

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[49] *See also* Exhibit No. PAI-47 at p. 2.

[50] During her examination at the hearing, Dayton described the purpose of an assay as a tool to allow one to "understand what the constituent makeup of [a] crude is." Transcript at p. 1847. Dayton added that crudes were made up of "various hydrocarbons and hydrocarbon chains, from very simple hydrocarbons to very, very complex hydrocarbons" as well as non-hydrocarbons, including metals, which are of particular importance for refineries to know about. *Id.* She indicated that the cost of an assay could be as little as $10,000 or as much as $60,000, depending upon how much detail is being requested. *Id.* at p. 1861.

[51] Dayton notes that "the TAPS Quality Bank assays are done with the Resid properties determined specifically for the applicable 1050+ cut." Exhibit No. PAI-47 at p. 9.

> Such an assay is likely to be suspect if it is inconsistent with every Quality Bank assay taken in the same year.

Id.

86. Dayton claims that three of assays used by Tallett are outside the range of Resid content shown in the Quality Bank assays. *Id.* at p. 10. She describes these alleged discrepancies as follows:

> The Exxon "PRE_PROD.ANS" assay taken on 03/08/00 shows a Resid content of 16.13% of the crude. The range of Quality Bank Resid contents for that year was 17.1-18.8%. This assay therefore falls well below the range and should not be used.
>
> The Haverly "ANSPL302" assay taken on 07/01/98 shows a Resid content of 16.84% of the crude, while the Quality Bank assay range for that year was 17.3-18.4%. This assay also falls well below the range and should not be used.
>
> The Exxon "VALDEZ96" assay taken on 08/20/96 shows a Resid content of 18.36%, while the Quality Bank range for that year was 16.4-18.1%. This assay is well above the range and should not be used.

Id. According to Dayton, at his deposition, Tallett admitted that "there could be problems with assays whose Resid contents [fell] outside the Quality Bank range in the year in which they were taken" and also admitted that the three assays which she identified above "fall outside" that "range and are suspect." *Id.*

87. Addressing Tallett's criticisms on the assay question, Dayton first notes that Tallett withdrew his criticisms of the Caleb Brett assays, and next states that Toof, another Exxon witness, suggests using a single assay for each TAPS stream to be take by the TAPS Carriers prior to the implementation of the intra-cut differential. Exhibit No. PAI-71 at pp. 16-17. Dayton points out the inconsistency in the Exxon approaches. *Id.* at p. 17.

88. As for the number of assays to be used, Dayton asserts that "[m]ore data does not equate to better data." *Id.* She claims that there are five essential quality assurance criteria met only by the Caleb Brett assays:

> 1. Use of an independent laboratory subject to third party audit and commercial laboratory quality assurance standards. In particular Caleb Brett has been audited by the parties to this proceeding and has met certain quality laboratory standards required to perform the Quality Bank assay

work.

2. Use of industry standard laboratory procedures and industry accepted laboratory equipment.

3. Assays performed using agreed [Trans Alaska Pipeline System] Quality Bank distillations and whole crude analysis procedures. In particular it is essential that the actual Quality Bank cut points be used in the distillation with particular focus on the 1050+ Resid cut.

4. The 1050+ Resid values used for the analysis are the actual laboratory measured values for the 1050+ cut.[52]

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[52] Dayton explains why actual measured properties for the 1050+ Resid cut are essential:

> When assays are performed by a laboratory, that laboratory uses certain cut points to establish the qualities of the various cuts that are measured. Computer programs have been developed that can take an assay that uses certain cut points and in effect "recut" the assay to determine the qualities of cuts with different cut points from those used by the lab that performed the assay. The programs that are used to recut assay data depend upon the accuracy of the interpolation of data between known points. This is not normally possible for the Resid cuts, because the Resid cut is at the end of the boiling range and therefore there are not two points to interpolate between. As a result, recut Resid data is almost always determined by a difference from the sum of the calculated properties of the other cuts. In effect, the Resid cut is deemed to have "whatever is left over" after the qualities of the other cuts, and all errors in estimating the qualities of the lighter cuts cascade down into Resid. This can introduce significant error in the resulting calculated values. Since Resid is the focus of the analysis in the first place, this is a totally unacceptable way to determine its properties.
>
> Further, most of the actual cut properties are not linearly distributed in the crude, making accurate determination of cut properties using these programs difficult. While these programs are useful in some applications they are not accurate enough for this application when millions of dollars shift on the basis of relatively small changes in assay properties.

Exhibit No. PAI-71 at pp. 19-20.

> 5. The 1050+ Resid values and whole crude properties fall within the expected measured range of the known Quality Bank assays for the representative year the sample was taken.

Id. at pp. 17-18.

89. According to Dayton, the assays used by Tallett do not meet this standard because they were performed in a company laboratory using unknown procedures and equipment. *Id.* at pp. 18-19. Moreover, she indicates that it is not known whether Quality Bank distillation procedures, including Quality Bank cut points, were used. *Id.* at p. 19. In addition, Dayton states: "It appears that the Resid properties Mr. Tallett used were not taken from actual laboratory measurements, but rather were derived from an Exxon or Haverly proprietary formula-based program to calculate the cut points." *Id.* Lastly, Dayton asserts that a number of the assays Tallett used did not fall within the range of the TAPS Quality Bank assays for the year in which they were taken. *Id.*

90. Finally, Dayton questions two data sources regarding the 1996 assays used by Tallett in certain calculations. *Id.* at p. 20. She explains:

> The first source was the actual assay reports for each stream, which appear to have been cut at the 1050° cut point used for the Quality Bank, as I recommend should be done. The second source is a spreadsheet prepared by [Exxon] witness Dr. [Karl R.] Pavlovic [("Pavlovic"), another Exxon witness] and given to Mr. Tallett for his use. According to Dr. Pavlovic, the spreadsheet contains data on the same assays, but instead of using the actual data from the assays, the spreadsheet is based on the application of [Exxon's] assay analysis software that can be used to recut assays to estimate cuts and cut qualities.

Id. She goes on to suggest that, even though the assays were performed at the proper 1050ºF cut point, the Exxon software that was used to provide data to Pavlovic shows "Resid quality data that is different from the actual 1050º+F Resid quality data contained in the" Exxon assay and that this resulted in Pavlovic providing wrong data to Tallett. *Id.* at p. 21. Therefore, Dayton argues, Tallett's Resid quality data should not be used. *Id.*

91. Under cross-examination by counsel for Exxon, Dayton discussed the use of two assays, as the Eight Parties suggested, or Exxon witness Tallett's use of an average of 10 assays. *See, e.g.,* Transcript at pp. 1431-33. On the stand, she quantified the difference between the two as about 15¢/barrel of Resid. *Id.* at p. 1434.

92. The two assays used by the Eight Parties were put into evidence as Exhibit No. EMT-96; the first assay (2001 Caleb Brett) is at pages 1-11 and the second (January 1997 Caleb Brett) is at pages 12-31. Transcript at pp. 1434-35. According to Dayton, the 1997

assay was requested to provide ARCO, Phillips's predecessor, with an ANS assay "in anticipation" of litigation. *Id.* at pp. 1437-38. Dayton, who spoke with the technician who performed the assay, stated that the highest cut point used was 1050ºF. *Id.* at pp. 1440-41. She further testified that the two Caleb Brett assays were done using the ASTM procedure detailed in Exhibit No. EMT-44 at page 8, section 10.3.4. Transcript at pp. 1487-88.

93. During her re-direct examination, Dayton addressed the change in the ANS content after the opening of the Alpine field in late 2000 and the Northstar field which opened in late 2001, a subject which had arisen during her cross-examination. *Id.* at pp. 1514, 1814. She described why the crude from those streams changed the ANS common stream as follows: "They're light petroleum fields, crude streams, significantly lighter than what you see with Prudhoe, Kuparuk, Lisborne streams that are out there. In particular, they have a very small amount of resid with essentially different resid properties potentially than what you have in the existing streams." *Id.* at p. 1814. Following that statement, Dayton indicated that only the 2001 Caleb Brett assay referred to above reflected these changes and "would be the best evidence of what the status is of ANS as of" the date of her testimony.[53] *Id.* at pp. 1815, 1819-20, 1855-56.

94. When objections were raised as to this line of re-direct, after a short argument, the examination was allowed to go on, but Dayton, who indicated that there were assays supporting her testimony regarding the Alpine and Northstar fields, was ordered to provide counsel for Exxon with the assays to which she referred. *Id.* at pp. 1815-19. Upon further examination, Dayton agreed with counsel that another representative assay or other representative assays should be averaged with the Caleb Brett 1996 and 2001 assays should the Resid value be made effective retroactively. *Id.* at pp. 1821, 1852.

95. Dayton was asked to describe the method used by the Quality Bank Administrator to take samples for the assay performed by his office and described the method as "continuous" – a little bit of a sample is taken on a continuous basis over a month *Id.* at pp. 1848-49. She contrasted that with sample taken off of a tanker, such as those used in the Caleb Brett 2001 assay, which she described as "spot samples," i.e., "a sample that is taken at a given point in time with a given sample [of]. . . that cargo or [off] that lighter." *Id.* at p. 1850. Dayton further testified that few assays are performed because the properties of crude do not significantly change even on a month to month basis. *Id.* at p. 1862. Moreover, she added, assays may take months to complete, again, depending on the detail required. *Id.* at pp. 1862-64. Also, according to her, companies which have assays performed, generally, keep the results confidential at least for some period of time. *Id.* at p. 1864.

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[53] This testimony was given on October 29, 2002.

96. In still later testimony, Dayton stated that, in December 2001, the total number of barrels tendered at Pump Station 1 was 33,000,000 and that, of that amount, Northstar's production was 913,323 barrels and Alpine's was 3,088,185 barrels. *Id.* at pp. 1940-41.

97. Still later, Dayton testified that one should not use an assay with a single data point from which data has to be extrapolated particularly where the extrapolation is over a range of temperatures. *Id.* at pp. 3638, 3640, 3643, 3645.

C. CHRISTOPHER ROSS

98. The next witness to appear was Christopher Ross ("Ross") who appeared on behalf of BP and the Amoco Production Company ("Amoco"). His testimony also is supported by Phillips, OXY, Petro Star, Alaska, Unocal, and Williams. Exhibit No. BPX-1 at p. 1. Ross notes that he is the Vice President and Senior Director of the Global Energy Practice for Arthur D. Little, Inc. *Id.*

99. With regard to valuing the TAPS Quality Bank Heavy Distillate cut on the West Coast, according to Ross, a logistics adjustment to Platts West Coast LA Pipeline Low Sulfur No. 2 is necessary in order for it to serve as an appropriate reference price. *Id.* at p. 5. The adjustment is necessary, he maintains, to ensure that all liquid cuts are valued on a consistent basis, and should be 1.1¢/gallon, and should be deducted from the quoted price in addition to O'Brien's desulfurization cost. *Id.*

100. Ross advocates two adjustments to the Platts Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil. *Id.* at p. 9. First, he supports O'Brien's desulfurization adjustment, and second, he supports a logistics adjustment. *Id.* The logistics adjustment, he begins, is necessary to ensure that the Heavy Distillate cut is valued on a consistent basis with the other liquid cuts. *Id.* A demonstrated price differential exists, he notes, between waterborne prices and pipeline prices on the West Coast. *Id.* All other West Coast liquid products, he continues, for Quality Bank purposes, are valued using waterborne prices and therefore, without a logistics adjustment, Heavy Distillate on the West Coast would be valued on a different basis than the other liquid cuts. *Id.*

101. Two reasons exist for the price differential, he explains, between waterborne and pipeline prices. *Id.* First, he states, products quoted for pipeline delivery are sold in smaller lots than those quoted for waterborne delivery.[54] *Id.* Second, he continues,

[54] Ross explains further. Exhibit No. BPX-1 at pp. 9-10. Waterborne tanker lots of distillates or gasolines are sold as cargoes of 250-300,000 barrels, he notes, but pipeline tenders are transacted in lots of around 12-25,000 barrels. *Id.* Smaller quantities are transacted at higher prices, he asserts, to cover the costs of breaking bulk, and the higher cost of the greater number of transactions required to sell the same overall quantity. *Id.*

products arriving by sea must first be transported from the harbor area to a pipeline hub before they can be sold.[55] *Id.* at p. 10.

102. Low sulfur distillate products, Ross asserts, are imported into West Coast markets in general and into Los Angeles in particular. *Id.* This market pattern, he notes, is a recent development because, as recently as 1996, there was a net outflow of jet fuel and low sulfur No. 2 fuel oil from the West Coast. *Id.* and Exhibit No. BPX-5 at p. 1. By 1998, he contends, West Coast markets became net deficit in both products and, in 1999, significantly increased the level of their net inflows. Exhibit No. BPX-1 at p. 10. According to Ross, U.S. Customs Service data indicates that imports of low sulfur distillate into the port of Los Angeles and Long Beach account for approximately half the total PADD V imports. Exhibit Nos. BPX-1 at p. 11 and BPX-6 at pp. 1-3. This data, he continues, suggests an average 6 MBD of imports of low sulfur distillate from 1999-2001 into the ports of Los Angeles and Long Beach, while Energy Information Administration (" EIA") data report 11 MBD of imports into PADD V as a whole over the same period. Exhibit No. BPX-1 at p. 11.

103. He explains the reasoning behind his conclusion that these imports are transported inland:

> Platts distinguishes its Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil price from that of CARB diesel, a product that meets the standards of the California Air Resources Board ("CARB"). The price that is quoted for Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil is for products that meet federal quality standards but not those of California. Because these products do not meet California quality standards, they necessarily must be shipped out of state, mainly to Arizona. Thus, cargoes with this product specification arriving at Los Angeles, which cannot be used in California, must be shipped by pipeline to Watson and on to markets east of California.

Id.

104. After identifying the costs involved in moving Waterborne Low Sulfur No. 2 fuel oil to the Watson, California pipeline hub, he explains his cost calculation for the price differential between West Coast waterborne and pipeline prices. *Id.* at p. 12. The

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[55] According to Ross, value is added in moving product to the pipeline hub, allowing product at the pipeline hub to command higher prices than waterborne cargoes. Exhibit No. BPX-1 at p. 10. Where products are delivered into Los Angeles harbor, he explains, the added value at the pipeline hub reflects the logistics costs of moving product from a tanker or barge in Los Angeles or Long Beach harbor into the Kinder Morgan pipeline terminal at Watson, California. *Id.*

identified costs, Ross notes, consist of cargo inspection, dock and wharf fees, leasing tankage at the port, other related regulatory and terminal charges, and transportation from the harbor to the Watson pipeline terminal. *Id.*

105. The costs for any specific tanker, he asserts, depend on a wide variety of factors, such as market conditions, the term of the contract, the characteristics of the tanker, and whether the final destination for the product is Watson or some other final destination. *Id.* According to Ross, the chart below identifies the range of costs in cents/barrel incurred in discharging a tanker in Wilmington, California, moving the product into Kinder Morgan or other commercially available pipeline terminal storage at Watson, and reselling it into pipeline cycles. *Id.* The reported range in cents/barrel, he notes, accounts for these factors and is based on discussions with companies involved in handling the various pieces of such transfers. *Id.*

	Low	**High**
	cents per barrel	
LA cargo inspection, dock and wharf fees	8.7	9.7
Terminal charges at port of Los Angeles	30.0	70.0
Pipeline tariff from Port of LA to Watson	4.8	8.1
Total (cents per barrel)	43.5	87.8
Total (cents per gallon)	1.04	2.09

Id. at p. 13.

106. Based on this chart, Ross notes that the adjustment should fall within the range of 1.04¢ and 2.09¢/gallon. *Id.* He recommends a 1.1¢/gallon adjustment. *Id.* After analyzing where within the range most transactions actually settled by calculating the differential between the reported waterborne and pipeline prices for West Coast LS No. 2 fuel oil, he explains, he compared the result against the waterborne and pipeline differential in the reported prices for similarly situated products, regular motor gasoline, and jet fuel. *Id.*

107. Differences exist, Ross contends, between Gulf Coast and West Coast relationships between waterborne and pipeline prices. *Id.* at p. 15. On the Gulf Coast, he notes, waterborne quotations are slightly higher than pipeline quotations. *Id.* Two factors, he states, account for this phenomena. *Id.* First, he begins, Gulf Coast waterborne cargoes reflect tanker and barge shipments out of Gulf Coast ports to destinations in Florida and the lower Atlantic Coast, where they compete with products imported primarily from Venezuela. *Id.* Second, he continues, pipeline quotations reflect the huge volumes of product shipped up the Explorer and Colonial systems towards

markets in the Mid-West and Middle Atlantic, where they also compete with tanker imports. *Id.* at pp. 15-16.

108. Therefore, he argues, the price differential on the Gulf Coast reflects the complex dynamics between imported and domestic products along the Atlantic seaboard and how those values net back to the Gulf Coast using marine or terrestrial transport. *Id.* at p. 16. As for the West Coast, he contends, there is a clear relationship between the value difference between pipeline and waterborne product prices and the costs of transforming a cargo moving into the port of Los Angeles to a pipeline tender at Watson. *Id.*

109. Finally, with regard to heavy distillate, Ross claims that waterborne quotations for liquid products are consistent with using land based quotations for natural gas liquids. *Id.* He explains that, on the West Coast, natural gas liquids are produced at natural gas plants primarily in the San Joaquin Valley, and at refineries. *Id.* Natural gas liquids, he asserts, are naturally produced in refineries in relatively small volumes and, consequently, the reported prices for these products are the best barometers of the value of these products at refineries. *Id.* at p. 17. Additionally, he notes, there is no waterborne market for natural gas liquids on the West Coast, and attempting to simulate one would be misleading. *Id.* He concludes,

> [b]y contrast there is a waterborne market for liquid products. Natural gas liquid products all need to be kept under pressure or refrigerated to avoid evaporation and their logistics and handling is quite different from liquid products. It is appropriate to use a different pricing basis for the liquid cuts from that used for the natural gas liquids based cuts. However, it is not appropriate to adopt different pricing bases within the group of liquid products.

Id.

110. In further testimony on the heavy distillate issue, Ross argued that Exxon witnesses provide inconsistent and contradictory testimony on it. Exhibit No. BPX-20 at p. 3. Toof, Ross points out, does not provide any justification for setting heavy distillate prices on a different basis from other liquid products, adopting from other Exxon witnesses a mix of bases for other liquid products. *Id.* at p. 4. Ross maintains that all prices should be valued on a consistent basis, but Exxon's inconsistency results in an inaccurate valuation of the cuts relative to each other. *Id.* A methodology, he asserts, where cuts are valued on different bases cannot produce accurate results. *Id.* at p. 5.

111. Addressing Toof's contention that several Quality Bank cuts are not priced on a waterborne basis, Ross states that even if four natural gas liquids cuts are not priced on a waterborne basis, this fact does not diminish the importance of consistently pricing the liquid products. *Id.* He explains that

> the gas plant products have no waterborne West Coast markets and must necessarily be valued based on the largest available parcels. . . . The use of a different (although internally consistent) pricing basis for gas plant products that must be pressurized and for which there is no waterborne West Coast markets in no way obviates the need for a common basis in valuing liquid products.
>
> Second, in any event the four gas plant products (Propane, Normal Butane, Iso-Butane and Natural Gasoline) amount to only approximately 10 percent of the total yield of ANS (Exhibit BPX-21). Using the fact that these products may be priced on a different (although internally inconsistent) basis to excuse the inconsistent pricing of the remaining 90 percent of the West Coast yield is inappropriate.

Id. at p. 6.

112. Ross asserts that the best solution is to adjust the Low Sulfur No. 2 price by 1.1¢/gallon in order to bring the valuation of the heavy distillate onto the same waterborne basis as the other liquid products. *Id.* at p. 9. Such an adjustment, he notes, is consistent with the 1.3¢/gallon similar adjustment included on Exhibit No. EMT-34, sponsored by Karl D. Bartholomew ("Bartholomew") and provided by Pavlovic. *Id.*

113. In his rebuttal testimony on the heavy distillate issue, Ross responded to criticisms of his logistics adjustment.[56] Exhibit No. BPX-55 at p. 4. According to Ross, Pavlovic disagrees with the factual basis for the logistics adjustment for three reasons. *Id.* at p. 5.

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[56] Ross summarizes the rationale for his logistics adjustment:

> [It] is necessary to make a logistics adjustment to Platts West Coast LA Pipeline Low Sulfur No. 2 ("LA Pipeline LS No. 2") in order for it to serve as an appropriate reference price for valuing the [Trans Alaska Pipeline System] Quality Bank Heavy Distillate cut on the West Coast. This adjustment is needed to ensure that all liquid cuts are valued on a consistent basis. Because the other Quality Bank liquid cuts are valued based on waterborne prices, a logistics adjustment must be applied to the LA Pipeline LS No. 2 price in order to bring it onto the same basis as the waterborne prices that are used to value the other liquid cuts. The magnitude of this adjustment should be 1.1 cents per gallon. This adjustment should be deducted from the quoted price in addition to the desulfurization cost that Mr. O'Brien has recommended.

Exhibit No. BPX-55 at p. 4.

> First, [Pavlovic] asserts that the predominant flow of Low Sulfur No. 2 Fuel Oil in Los Angele is not from harbor to pipeline. Second, he asserts that pipeline/waterborne price differentials in the West Coast market do not reflect the cost of harbor to pipeline transport. Finally, he asserts that there is no statistical difference between pipeline and waterborne prices in the West Coast market. Dr. Pavlovic further claims that putting all liquid products onto the same waterborne basis does not achieve consistency.

Id.

114. These criticisms, Ross maintains, are wrong for a number of reasons. *Id.* He begins by claiming that the predominant flow of products in Los Angeles is from the harbor to the pipeline. *Id.*

> Pavlovic seeks to obscure this fact by presenting an unfocused account of generic movement across the entire Western half of the United States, from Arizona to Alaska, for ***all*** petroleum products. Most of this product movement is irrelevant to the issue at hand and is quite unhelpful in establishing the direction that products, and in particular [Low Sulfur No. 2], move in Los Angeles. The closest Dr. Pavlovic gets to a relevant statement is his observation that there are more exports than imports of [Low Sulfur No. 2] from the West Coast in total. This, however, is not true for Los Angeles, which is the relevant location with respect to this issue. Imports of [Low Sulfur No. 2] into the ports of Los Angeles and Long Beach since 1999 have far exceeded exports from these ports. Dr. Pavlovic's unsupported allegation . . . is simply an exercise in sophistry through which he tries to obscure the fact that the predominant flow of ***waterborne*** Low Sulphur No. 2 ***is*** from harbor to pipeline.

Id. at pp. 5-6 (emphasis in original; citations omitted).

115. Ross also contends that Pavlovic's refinery production data is irrelevant to the relationship between waterborne cargo prices and pipeline tender prices in Los Angeles. *Id.* at p. 6. He explains that waterborne cargoes carrying approximately 200,000-250,000 barrels do not arrive daily and, in between cargoes, Platts estimates, and the Quality Bank uses, a waterborne value. *Id.* at p. 7. Pipelines, he notes, "handle multiple tenders of 10,000-25,000 barrels each and every day creating a consistent array of transactions that can be referenced in estimating market prices." *Id.* According to Ross,

> [t]he variability that Dr. Pavlovic detects is variability in estimating techniques and transaction frequency and in no way relates to whether or not the price differentials are driven by the costs of moving from harbor to pipeline.

* * * *

> There is no reason to conclude that two price series using different estimating techniques and reflecting different transaction frequencies should show differentials that are "stable over time."

Id. He also argues that Pavlovic admits that, on an annual basis, waterborne gasoline and jet fuel prices were never above pipeline prices during 1990-2001. *Id.* at p. 8.

116. According to Ross, Pavlovic's data supports a cost-based relationship because of a consistent differential between waterborne and pipeline prices for gasoline and jet fuel.[57] *Id.* As for Pavlovic's analysis of the FO 180 and FO 380 pipeline and waterborne price differentials,[58] Ross contends that there is insufficient data to make any useful

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[57] Ross explains this differential:

> The observed differentials for these products range from .2-3.3[¢] per gallon, a slightly wider but similar range to my cost estimate of 1.04-2.09[¢] per gallon. Based on my experience, there may be a slight upwards bias on waterborne prices, since at times when there are no transactions, traders' answers to Platt's inquiries may be colored by their knowledge of what the price would have to be to attract an import. This slight bias applies to all products, so is not important when assessing the relative values of the [Trans Alaska Pipeline System] streams, and may explain why the average observed price differential has often been at the low end of my cost range. Nevertheless, the similarity between the range of observed price differentials and the range of logistics costs powerfully supports a causal relationship.

Exhibit No. BPX-55 at pp. 8-9 (citations omitted).

[58] Ross explains the problem with using FO 180 and FO 380:

> FO 380 is used entirely as a bunker fuel in ports and is not transported inland like gasoline and jet fuel. Apart from 1994, it seems that the differential between waterborne and pipeline FO 380 is close to zero, which is consistent with similar logistics costs for moving from pipeline to bunker storage at the port and from tanker to bunker storage at the port. When Platt's ceased publication of its waterborne price series for FO 380 the Quality Bank Administrator switched to pipeline prices without adjustments. In essence, because the differential was close to zero the new price basis could be said to include a logistics adjustment, the value of

conclusions to the relevance to the Low Sulfur No. 2. *Id.* at p. 9. Finally, he disagrees with Pavlovic's assertion that LA Pipeline Low Sulfur No. 2 and Waterborne 0.05% Low Sulfur Gasoil are not comparable. *Id.*

> Dr. Pavlovic vastly overstates his case by using outdated Platt's specifications from 1999, which still sets forth the waterborne Gasoil sulfur specification at 0.5%, rather than the current 0.05%. Accordingly, Dr. Pavlovic's evidence is unreliable. I confirmed with Platt's that the specification reference cited in Dr. Pavlovic's testimony is outdated and that the sulfur content is indeed 0.05%. Moreover, Platt's specifically stated that [Low Sulfur No. 2] and Low Sulfur 0.05% Gasoil are interchangeable. Thus, the waterborne price could easily be used as a proxy for Quality Bank purposes for the Heavy Distillate cut just as the [Low Sulfur No. 2] price is being used.

Id. at pp. 9-10 (citations omitted).

117. Ross maintains that a logistics adjustment is required to ensure that the Heavy Distillate cut is valued on a consistent basis with all the other liquid cuts. *Id.* at p. 10. He claims that Pavlovic confuses the issue by "introducing erroneous arguments." *Id.* According to Ross, gas plant cuts necessarily must be valued on a different basis than liquid cuts because there are no quoted waterborne prices available. *Id.*

> Dr. Pavlovic's attempt to reason that these products are liquid at certain temperatures and pressures, and should therefore be valued on the same basis as the liquid cuts, is meaningless. All compounds, except those that sublime rather than boil, can exist in solid, liquid and gaseous phases.
>
> * * * *
>
> The use of unadjusted pipeline prices for Heavy Distillate is a mistake and needs to be corrected to set Heavy Distillate on a consistent basis as the other liquid cuts. Resid will also be corrected and set onto the same basis as the other liquid cuts by adopting Mr. O'Brien's methodology. The fact that a problem exists is not a justification for perpetuating it as Dr. Pavlovic seems to be arguing.

> which was virtually zero. FO 180, another bunker fuel, appears briefly on Dr. Pavlovic's table and disappears again.

Exhibit No. BPX-55 at p. 9.

Id. at pp. 10-11. As long as the proposed Naphtha valuation[59] and Resid formula place these products on a waterborne basis, Ross contends, his logistics adjustment to Heavy Distillate will bring it onto a consistent basis with the other liquid products. *Id.* at p. 13.

118. Furthermore, he claims, using a logistics adjustment to properly value Heavy Distillate and Naphtha does not contradict his prior testimony against using a logistics adjustment to value Resid. *Id.*

> Mr. O'Brien's Resid formula, which I support fully, is already on a waterborne basis. Accordingly, no logistics adjustment is required to that formula. The ExxonMobil and Tesoro formula, however, uses a hodge-podge of proxy prices, at various locations, that is unacceptable as it stands. In particular, it is indefensible, as ExxonMobil prognosis, to include a logistics adjustment to the waterborne Coke price, which would incorrectly adjust a price that is already on a waterborne basis to an internal refinery value. This would take a consistent price and apply an adjustment to make it inconsistent with all of the other product prices used in the Quality Bank.

Id.

119. With regard to Resid, Ross argues that Bartholomew's proposal to adjust for the coke price used in the Resid valuation formula is inconsistent with the other Quality Bank cuts that are on a waterborne basis. Exhibit No. BPX-16 at p. 3. Waterborne prices are the most appropriate basis for liquid prices, he maintains, as they represent cargoes of products at their source or destination harbor and are the largest parcels available including the least marketing margins. *Id.* According to Ross, Bartholomew, in choosing whether to value Naphtha on a waterborne or a pipeline basis, decided on waterborne on the grounds of consistency. *Id.* Further, he states, both Tallett and Toof support a waterborne price for VGO. *Id.*at p. 4.

120. Although Exxon values most of the Resid components on a waterborne basis, he notes, it chooses to deviate from the consistency principle when it comes to valuing coke and recommends valuing coke at the refinery gate. *Id.* Ross argues that there is no clear justification for applying Bartholomew's logistics adjustment for coke without applying similar adjustments to the other liquid cuts. *Id.* at p. 6. According to Ross, if coke is priced at the refinery gate while other products continue to be priced elsewhere, there will be significant inconsistencies between coke values and values for other products. *Id.* at p.

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[59] Ross states that Naphtha also should be valued on a consistent waterborne basis as the other liquid cuts. Exhibit No. BPX-55 at p. 13. He argues that "[i]f a pipeline price is used as a reference . . . then a logistics adjustment is required. If an appropriate waterborne reference price can be found, then no adjustment is necessary." *Id.*

5. Also, he asserts, if a refinery gate adjustment is applied to all of the Quality Bank products across the board, the effect of the change will be negligible. *Id.* Coke, he maintains, should continue to be priced on a waterborne basis. *Id.* at p. 7.

121. Exxon, he believes, proposes an inconsistent hodge-podge of methods to value liquid products that "cannot possibly produce accurate, and certainly not consistent, results." *Id.* He explains that they propose waterborne prices for Naphtha, Light Distillate, and VGO, pipeline prices for Heavy Distillate, and for Resid, a "formula in which is embedded a strange mix of waterborne VGO and pipeline Heavy Distillate; a formula derived itself from an even stranger mix of waterborne Naphtha and VGO, pipeline Heavy Distillate, and refinery gate Coke." *Id.*

122. At the hearing, when asked about his proposed 1.1¢ logistics adjustment, Ross indicated that it should remain constant, unadjusted by an inflation/deflation index. Transcript at p. 1662. In support of this assertion, Ross explained:

> It's my observation, your Honor, that for transportation assets, like pipelines and terminals, the predominant cost is the fixed cost of construction of the facility. My observation of regulatory tariffs is they don't change very often. That's number one.
>
> Number two, is when I observed the differential between waterborne and pipeline prices over a long period of time for regular gasoline and jet fuel, I found there was no evidence of any systemic increase in that which would suggest that the costs that are imbedded in those differentials were, in fact, escalating.

Id. at pp. 1662-63. He admitted that his answer is an indication that he does not believe that those "costs have remained constant and that there is nothing in any transportation and handling cost which has been impacted at all by inflation, deflation or any problem with the economy." *Id.* at p. 1663. The 1.1¢ adjustment would be in addition to the sulfur processing adjustment proposed by all parties.[60] *Id.* at p. 1684.

123. Under further questioning, Ross conceded that, as wharf fees changed, labor costs changed and tariffs changed, the 1.1¢ adjustment could not remain constant from 1992 through "the end of time." *Id.* at pp. 1763-64. He, therefore, also agreed that future adjustments would have to be made. *Id.* at p. 1764.

124. Ross, during his examination, explained that he did not derive the 1.1¢ logistics

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[60] It should be noted that the parties do not agree as to the amount of the sulfur processing adjustment. Transcript at p. 1685.

adjustment out of thin air, but investigated how the waterborne prices for other liquid products (e.g., gasoline and jet fuel) related to their pipeline prices. *Id.* at p. 1743. He claimed that this study indicated that the waterborne prices were lower than the pipeline prices because of the cost of moving the waterborne product from the ship to the pipeline. *Id.* However, he admitted that he could not substantiate, at least, some of these costs[61] as he received them in telephone conversations and did not, or was not able to, verify the information. *Id.* at pp. 1699-1700, 1743, 1746-49.

125. In further testimony, Ross indicated that he did not care whether Quality Bank cuts were undervalued or overvalued, so long as all cuts were treated in the same manner. *Id.* at p. 1672. For example, when asked to define the purpose of his proposed logistics adjustment, Ross stated:

> It is my testimony that all liquid cuts should be valued on a consistent basis, and I have recommended, consistent with the way it's done on the Gulf Coast, that we select waterborne as the consistent basis.
>
> In order to put the heavy distillate out on the same basis as the other cuts, given that the parties have agreed that the reference price ought to be a pipeline price, it's necessary to make a further adjustment to take off the costs required to get from a waterborne cargo to a pipeline tender, and that is what I call a logistics adjustment.

Id. at pp. 1686-87. He added that the costs he included in the logistics adjustment include the costs of moving the cargo from the ship to the dock, terminal charges, and the cost of moving the cargo from the terminal to the pipeline. *Id.* at pp. 1687-88.

126. Under further cross-examination, Ross conceded that there was an alternative to using waterborne prices – using an "X refinery basis." *Id.* at p. 1721. However, he said, that was not possible as the data related to costs were not available. *Id.*

D. CHRISTOPHER CAVANAGH

127. The written testimony of Christopher L. Cavanagh ("Cavanagh") was presented by BP as well. Exhibit No. BPX-60 at p. 3. Cross-examination of Cavanagh was waived.[62] His testimony also is supported by the Eight Parties. *Id.* The purpose of Cavanagh's testimony, he explains, is to evaluate the validity of the statistical methodology used by

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[61] To be precise, the Los Angeles terminal charges, cargo inspection, dock and wharf fees. *See* Transcript at pp. 1692-93, 1698.

[62] Transcript at pp. 1884-85.

Pavlovic to assess the relationship between West Coast waterborne and pipeline prices of various petroleum products. *Id.* at p. 5. He also asserts that, if he finds Pavlovic's methodology to be inappropriate, he was charged with providing correct statistical procedures to assess the relationship between these prices. *Id.*

128. Cavanagh summarizes Pavlovic's method as follows:

> Dr. Pavlovic analyzes monthly prices from January 1990 through December 2001 - both waterborne and pipeline - for five products: regular gasoline, jet fuel, FO 180, FO 380 and LA Pipeline [Low Sulfur] No. 2 versus 0.05% [Gasoil]. For each of these products, he compares waterborne to pipeline prices by computing what is known in the statistics literature as a two-sample t-statistic of the differences in means. He then uses this statistic to perform a t-test. Both of these computations together form the two-sample test procedure.

Id. at p. 6.

129. According to Cavanagh, Pavlovic used an inappropriate statistical methodology (the two-sample t-statistic of the differences in means) in testing whether a statistically significant difference between West Coast waterborne and pipeline prices exists and, therefore, erroneously concluded that there is no statistically significant difference between the prices. *Id.* at pp. 5-6. He summarizes his findings as follows:

> Careful statistical analysis indicates that West Coast pipeline prices of both regular gasoline and jet fuel are higher than the corresponding West Coast waterborne prices. In addition, my analysis indicates that the prices of Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil ("LA Pipeline LS No. 2") are higher than prices for West Coast 0.05% Low Sulfur Gasoil waterborne ("0.05% GO"). These differences are statistically significant and are consistent with the logistics adjustment of 1.1 cents per gallon as computed and proposed by Mr. Ross based on cost considerations. Further, these statistical results are robust, in that they are confirmed by a number of different analyses.

Id. at p. 6.

130. While he agrees that the two-sample test procedure used by Pavlovic is a valid statistical procedure, Cavanagh asserts that it is inappropriate in these circumstances. *Id.* at p. 7. Cavanagh explains that, for the two-sample t-statistic to be valid, the two samples must be statistically independent, i.e., "there is no systematic relationship between them." *Id.* He declares that Pavlovic's methodology is invalid because of the lack of independence in the samples. *Id.* at p. 9.

131. Cavanagh explains how he tested Pavlovic's independence assumption as follows:

> One way to test whether two price series are independent is to compute the correlation between them. Correlation is a statistical measure of association or relatedness. If the measurements are independent, then the correlation would be zero. The maximum value the correlation can be is 1. For each of the five pairs of monthly prices, I have computed the correlation between the waterborne and the pipeline prices. In all cases, the correlation is in excess of .8. For gasoline, jet fuel and the LA Pipeline [Low Sulfur] No. 2 versus 0.05% [Gasoil] waterborne, the correlation between waterborne and pipeline prices is in excess of .995.

Id. at p. 9. Based on this analysis, Cavanagh claims that "[t]hese prices are very far indeed from being independent." *Id.*

132. According to him, Cavanagh also carried out two further analyses. *Id.* First, expecting, if the two price series were independent, to find that waterborne prices would be greater than pipeline prices about one-half the time, he examined the two. *Id.* at p. 10. However, he found that "pipeline prices are higher: (i) in 134 of 144 months for gasoline; (ii) in 129 of 144 months for jet fuel; (iii) in 39 of 72 months for FO 380; (iv) in 16 of 24 months for FO 180; and (v) in 26 of 26 months for LA Pipeline [Low Sulfur] No. 2 versus 0.05% [Gasoil] waterborne." *Id.* Cavanagh claims that there is less than a one in a million chance that gasoline or jet fuel pipeline prices would exceed waterborne prices on such a consistent basis, or that Low Sulfur No. 2 pipeline prices would exceed Gas Oil waterborne prices on such a consistent basis "if there were not a systematic excess of pipeline prices over waterborne prices." *Id.*

133. Secondly, Cavanagh sought to determine whether Pavlovic's methodology would detect a statistically significant difference in a test case. *Id.* He describes the methodology he used as follows:

> I constructed an example in which the waterborne price for gasoline is exactly as it is in Dr. Pavlovic's monthly data and the pipeline price for each of those months is always exactly 50 cents per barrel greater than the waterborne price. Although we know for certain that there is a consistent relationship between the two numbers, the statistical procedure used by Dr. Pavlovic in developing his testimony would require one to conclude that there is no statistically significant difference between these prices. Similar results hold true for the other products. Of course, common sense dictates a conclusion that when a differential is of exactly the same magnitude in 100% of the observed months, a statistically significant difference must exist. Dr. Pavlovic has simply applied the wrong test to measure these

> relationships.

Id. at pp. 10-11 (citations omitted).

134. Applying the correct statistical test, Cavanagh asserts, demonstrates that there is a systematic cost differential between West Coast waterborne and pipeline prices. *Id.* at p. 11. Cavanagh tested whether pipeline prices consistently exceeded waterborne prices for the subject commodities. *Id.* at pp. 11-13. The first test he applied was the matched pairs test. *Id.* at p. 11. This test, he states, "computes the t-statistic by a formula that takes into account the potential dependence between the pairs of observations that are being compared. *Id.* Cavanagh found "[b]ased on this methodology, using the same data that Dr. Pavlovic used, . . . that the t-statistics take on the following values: (i) 11.86 for gasoline; (ii) 14.27 for jet fuel; (iii) 2.10 for FO 380; (iv) 3.23 for FO 180; and (v) 9.95 for [Low Sulfur] No. 2 pipeline versus 0.05% [Gasoil] waterborne." *Id.* at pp. 11-12.

135. According to Cavanagh, he interpreted these statistics by computing the p-value.[63] *Id.* at p. 12. He claims that, based on the matched pair t-statistics, "the p-values at issue here are as follows: (i) less than 1 in one billion for regular gasoline, jet fuel, and [Low Sulfur] No. 2 pipeline versus 0.05% [Gasoil] waterborne; (ii) less than four (4) in one thousand for FO 180 and less than four (4) in one hundred for FO 380." *Id.* Cavanagh asserts that based on these values, he "would reject the hypothesis that there is no systematic difference between pipeline and waterborne prices in favor of the hypothesis that pipeline prices are higher than waterborne prices." *Id.*

Cavanagh described the second test he applied as follows:

> Second, just as the dependence across geography (pipeline/waterborne) invalidated Dr. Pavlovic's analysis, time series dependence could make the simple matched-pairs analysis invalid. Therefore, to control for time series

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[63] According to Cavanagh,

> [t]he p-value is the probability that we would observe, by chance, a statistic at least as large as that which we actually observe if there were no systematic difference between the waterborne and pipeline prices. Small p-values indicate that the observed differences are much larger than what one might observe by chance, so they indicate that the price differentials represent a systematic difference.

Exhibit No. BPX-60 at p. 12.

> dependence, I examined these price differentials in even greater detail than provided for in the matched pairs test procedure. I constructed t-statistics based on first order auto-regressive dependence in the price differentials. This is a standard statistical method to account for time series dependence. Based on this model, I find the following t-statistics: (i) 7.01 for gasoline; (ii) 8.82 for jet fuel; (iii) 1.49 for FO 180; (iv) 1.08 for FO 380; and (v) 8.38 for [Low Sulfur] No. 2 pipeline versus 0.05% [Gasoil] waterborne. These correspond to p-values of: (i) less than 1 in one billion for gasoline and jet fuel; (ii) less than 1 in 10 million for [Low Sulfur] No. 2 pipeline versus 0.05% [Gasoil] waterborne; (iii) .15 for FO 180; and (iv) .29 for FO 380. These p-values again reveal strong statistical evidence that pipeline prices exceed waterborne prices for gasoline, jet fuel and [Low Sulfur] No. 2 pipeline versus 0.05% [Gasoil] waterborne.

Id. at pp. 12-13 (internal citations omitted).

136. As for Pavlovic's contention that the p-values for FO 180 and FO 380 indicated a waterborne and pipeline price differential of approximately zero, Cavanagh disagrees for two reasons. *Id.* at p. 13. First, he notes, Ross demonstrates that FO 180 and FO 380 have different economics and applications than the other products and, consequently, it is unreasonable to "draw conclusions about waterborne/pipeline differentials in general based on the results of statistical analysis of these particular products." *Id.* Second, in computing the t-statistics, he explains, the relatively high variability in the waterborne and pipeline differentials for FO 180 and FO 380, results in large standard errors relative to the magnitude of the observed price differences and, consequently, the data are not informative enough to draw meaningful conclusions about the magnitude of these price differentials. *Id.*

E. JAMES F. BOLTZ

137. James F. Boltz ("Boltz"), Vice President of Engineering and Refining for Petro Star, Inc., was the next witness. Boltz asserts that his testimony was designed to answer several criticisms made by other witnesses. Exhibit No. PSI-9 at p. 1. He summarizes the purpose of his testimony as

> [D]emonstrat[ing] that if the Quality Bank fails to account for the economic impact of replacing the waterborne reference price for Heavy Distillate with a pipeline price, the impact on Petro Star will be severe. In short, my testimony supports the Logistics Adjustment for Heavy Distillate proposed by Mr. Ross.

Id. at pp. 1-2. Reiterating that the Heavy Distillate valuation is particularly important to

Petro Star,[64] Boltz claims that a West Coast Heavy Distillate logistics adjustment is necessary because "the use of pipeline-based reference price without a logistics adjustment would cause West Coast Heavy Distillate to be overvalued relative to the other West Coast liquid cuts, which consistently are valued by reference to waterborne prices." *Id.* at pp. 2-3. After analyzing the impact of the proposed logistics adjustment for the 2000 and 2001, Boltz claims that excluding the adjustment would reduce Petro Star's net income (for those years) by nine percent. *Id.* at p. 3 and Exhibit No. PSI-10 at p. 1. Additionally, Boltz claims that

> [t]he Logistics Adjustment is necessary to prevent overvaluing the West Coast Heavy Distillate Cut relative to the other cuts. For the new reference price to be just and reasonable, the Quality Bank must make <u>all</u> adjustments necessary to place the Heavy Distillate Cut on the same footing as the other West Coast liquid cuts.

Exhibit No. PSI-9 at p. 4 (emphasis in original).

138. At the hearing, Boltz stated that he relied on Ross's analysis with respect to the proposed logistics adjustment. Transcript at p. 1888. He added that, through his testimony, he is "showing . . . that the logistics adjustment is a significant adjustment that's needed on the heavy distillate cut, along with the sulfur correction." *Id.*

139. In later testimony, Boltz was asked to address the cost of building distillate storage tanks. *Id.* at p. 11695. He claimed that over the ten years preceding his testimony, Petro Star has incurred costs, at each of its two Alaska refineries, ranging from $14 to $18 per barrel (depending on the size of the tank).[65] *Id.* at pp. 11695-96. In support, Boltz

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[64] According to Boltz,

> Petro Star makes almost all of its products from the Light and Heavy Distillate Cuts, together with a portion of the Naphtha Cut. This means that Petro Star makes its money from selling products made from these cuts. Consequently, it retains these cuts disproportionately, and they are in correspondingly low concentrations in its return stream. Approximately one-half of Petro Star's product slate is manufactured from Heavy Distillate. Therefore, if Heavy Distillate is overvalued, the resulting increased Quality Bank assessments will directly and significantly impact Petro Star's financial performance.

Exhibit No. PSI-9 at p. 2. Additionally, Boltz claims that if the valuations were imposed retroactively the impact on Petro Star would be "catastrophic." Exhibit No. PSI-1 at p. 9.

[65] Boltz stated that the tanks ranged in size from 10,000 to 60,000 barrels.

offered two exhibits[66] which he indicated did not include the cost of the "gravel and sand pads for the tanks, the dikes and liners for the tanks, the instrumentation that would be placed on the tank, . . . [or the] auxillary piping to these tanks." *Id.* at pp. 11696-97. Boltz stated that these costs were less than half that to which Exxon witness Jenkins testified.[67] *Id.* at p. 11696. However, on cross-examination, he admitted that these were costs to construct facilities at Petro Star's Alaska facilities and that he had not compared them to the cost of constructing similar projects in California. *Id.* at pp. 11705-07.

F. DAVID I. TOOF

140. Toof was the first witness presented by Exxon. He is a self-employed independent consultant providing economic and financial services to the gas, oil, electric and telecommunications industries. Exhibit No. EMT-1 at pp. 3-4.

141. Toof describes the current valuation of the Resid cut as:

> West Coast Resid is priced at Platts U.S. West Coast spot quote for pipeline 380 cst at Los Angeles converted to $/Bbl using 6.37 Bbl/MT less 4.5 cents per gallon adjusted for inflation by the Nelson-Farrar index. . . . Gulf Coast Resid is priced at Platts U.S. Gulf Coast spot quote for Waterborne No. 6 Fuel Oil 3% Sulfur less the same 4.5 cent per gallon adjustment, adjusted for inflation by the Nelson-Farrar index.

Id. at p. 14.

142. The appropriate Resid valuation method, according to Toof, is to calculate the value of Resid as a feedstock to a Coker unit. *Id.* at p. 15. The Resid cut's market value, Toof explains,

> would be determined by calculating the volume and value of the various products that a barrel of Resid would produce in a Coker. From this calculated value one subtracts the variable, fixed and annual capital costs of production. The net of product value less the cost of production is the coker feedstock value of the Resid cut. This analysis is performed for both West Coast and Gulf Coast Resid.

Transcript at p. 11696.

[66] *See* Exhibit Nos. PSI-21 and PSI-22.

[67] *See* Exhibit No. EMT-56.

Id.

143. Exxon's approach, Toof states, is to calculate the before-cost value of Resid, develop a linear regression equation as a proxy for the before-cost value, and determine the variable, fixed, and capital recovery costs associated with Coker and downstream Resid processing units. *Id.* at p. 16. Explaining this approach, Toof adds, the before-cost valuation step assumes nine Coker products. *Id.*

144. The expected product yield on a per barrel basis, Toof continues, is from a composite of eight assays of the ANS Resid. *Id.* Seven of the nine products, Toof states, have Quality Bank prices. *Id.* Fuel Gas is based on the Natural Gas Week's natural gas spot prices, according to Toof, and monthly coke price is developed by Bartholomew of Jacobs Consultancy. *Id.* To determine the individual product's value per barrel for each Coker product, Toof specifies, "the expected yield is multiplied by the product's assigned price." *Id.* Toof concludes that "[t]he sum of the individual product values is the total before-cost value of the coker products." *Id.*

145. Toof sets out the regression formula he developed for West Coast Coker product value as: West Coast Product Value ($/Bbl) = (.55843*West Coast Heavy Distillate + .23272*West Coast VGO) - $0.74157. *Id.* at p. 17. For the Gulf Coast, Toof sets out the equation: Gulf Coast Product Value ($/Bbl) = (.41026*Gulf Coast Heavy Distillate + .38027*Gulf Coast VGO) -$0.48435. *Id.* Toof claims that the fit is excellent in both cases, "with an R-squared value of .958 for the West Coast and .984 for the Gulf Coast." *Id.*

146. The final step in the Resid cut valuation, according to Toof, is determining costs associated with the units processing the Coker products. *Id.* These costs, Toof states, are made up of fixed and variable operating costs and capital recovery costs. *Id.* Using a 13.0% weighted average cost of capital and a 4.0% depreciation rate, Toof yields a 17.0% annual capital recovery factor. *Id.* at pp. 18-19. Applying the Exxon and Tesoro methodology, for the period January 1992 through December 2001, Toof calculates the average value of Resid as a Coker feedstock on both the Gulf and West Coasts: 10.54 $/BBL (Gulf Coast) and 10.32 $/BBL (West Coast). Exhibit Nos. EMT-7 at p. 3 and EMT-8 at p. 2.

147. Toof explains the blending Resid valuation methodology as "assuming that Resid is blended with a lighter product . . . so as to produce fuel oil. The value of Resid is the value of the resultant fuel oil less the cost of the cutter stock." Exhibit No. EMT-1 at pp. 19-20. For 1995, under the blending valuation method, Toof relates that the calculated Resid values were between $10.40 and $10.74 per barrel. *Id.* at p. 20.

148. The revised value for Resid, Toof argues, should be made retroactive to December 1, 1993, because there has never been a just and reasonable Resid rate. *Id.* at p. 21.

Additionally, Toof alleges that "[a]ll parties have been on notice since the inception of the distillation methodology in 1993 that the prevailing rate for the Resid cut was challenged as not just and reasonable." *Id.* Toof asserts that the financial impacts are significant and that Dr. Karl Pavlovic has calculated the amount Exxon is owed as $86,558,958. *Id.* at p. 22.

149. The valuation of the Heavy Distillate cut, according to Toof, has been frozen at the October 1999 Platts West Coast price for Waterborne Gas Oil reduced by 1¢/gallon since November 1, 1999. *Id.* at p. 23. Toof states that "[w]hile all of the parties have agreed that Platts West Coast LA Pipeline Low Sulfur No. 2 price should be the new benchmark, there has not been agreement as to the appropriate price adjustment to reflect the processing costs required to take account of the low sulfur content of the proxy product." *Id.* Since the new proxy product has a low sulfur content (.05%), Toof argues that an appropriate adjustment would be 4.3¢/gallon. *Id.* at pp. 23-24. He also argues that the effective date should be February 1, 2000. *Id.* at p. 24.

150. In his Answering Testimony, Toof explains the parties's positions on the valuation of West Coast Heavy Distillate as "[t]he parties concur that the proxy price for the West Coast Heavy Distillate cut . . .should be Platts West Coast LA Pipeline Low Sulfur No. 2 Fuel Oil adjusted for the difference in the sulfur content between the proxy product and ANS Heavy Distillate." Exhibit No. EMT-76 at p. 21. However, he notes that the parties have differing positions on the amount of the adjustment. *Id.* Regarding the processing cost adjustment, Toof states that O'Brien proposes a 4.1¢/gallon sulfur adjustment while Jenkins proposes a 4.3¢/gallon sulfur adjustment. *Id.* Certain other parties, Toof relates, also propose a 1.1¢/gallon logistics adjustment. *Id.* Toof concludes that Jenkins's proposal of 4.3¢/gallon sulfur adjustment is the most reasonable and that the 1.1¢/gallon logistics adjustment is unnecessary. *Id.*

151. For West Coast VGO, Toof explains, all the parties agree that, on a prospective basis, it should be valued using OPIS West Coast High Sulfur VGO, but the parties disagree as to how it should be valued for past periods. *Id.* at p. 25. Toof contends that the appropriate date for the repricing should be June 19, 1994. *Id.* at p. 26.

152. Exxon, Toof explains, proposes to value Resid as a feedstock to a delayed Coker. *Id.* This approach, he states, consists of two steps. *Id.* According to Toof, the values of the products produced by the Coker and the costs associated with such production must be calculated. *Id.* at pp. 26-27. This approach, Toof notes, is similar to the Eight Parties's approach, although significant differences exist in before-cost valuation issues and Coker costs. *Id.* at p. 27.

153. Three major differences exist, Toof believes, between the Eight Parties's and Exxon's approaches. *Id.* These are, he states, "(1) the determination of the appropriate temperature or cut point for C_5, (2) the issue of how many and which assays should be

used, and (3) whether or not substantial transportation and handling costs should be included in the value of Coke." *Id.*

154. The C_5 cut point issue is important, Toof explains, because it is used to allocate the PIMS model's liquid Coker outputs to the appropriate Quality Bank Cuts. *Id.* at p. 28. He asserts that O'Brien sets his cut point at 100˚F while Tallett sets his at 60˚F. *Id.* Lowering the temperature, Toof notes, increases the yield for the LSR while decreasing the Naphtha and Distillate cut yields. *Id.* According to Toof, Tallett's approach is the more reasonable because it conforms with the Quality Bank C_5 cut point, and he also comments that O'Brien concedes that the Quality Bank's temperature is 60˚F. *Id.*

155. As for the assay issue, Toof states that O'Brien averages two assays (from 1996 and 2001), but notes that O'Brien "has not reviewed the validity of his two assays." *Id.* Toof asserts that Tallett used every available, credible assay, averaging eight assays taken between 1994 and 2000, including O'Brien's 1996 assay. *Id.* The more reasonable approach, Toof argues, is to employ all available reliable data because the related Coker product yields serve as the basis for the Coker feedstock model. *Id.* at pp. 28-29.

156. Regarding the difference in opinion over the price of coke, Toof explains the dispute, stating that Exxon believes that coke should be valued at the refinery gate while O'Brien advocates valuing coke on an FOB vessel basis, which results in a significant difference. *Id.* at p. 29. O'Brien, Toof contends, does not take shipping costs into consideration in his Resid valuations even though shipping costs, according to Bartholomew's estimates, can comprise more than 60 percent of the coke price. *Id.* and Exhibit No. EMT-31 at p. 11.

157. Exxon's proposed valuation of coke at the refinery gate, Toof claims, is consistent with their opposition to Ross's heavy distillate logistics adjustment because the magnitude of coke transportation and handling costs are on a greater and more significant scale than the heavy distillate transportation and handling costs, which are merely about 1.3% of the Heavy Distillate's value. Exhibit No. EMT-76 at pp. 29-30.

158. Addressing the differences between the parties regarding the cost of coking Resid, he states that there are five major areas where O'Brien and Jenkins disagree – location factor, Coker ISBL and OSBL costs, sulfur plant costs, hydrotreating costs, and capital recovery factors – and asserts that Jenkins's approach is more reasonable because of certain "flaws" in O'Brien's methods. *Id.* at p. 30. These flaws, Toof contends, include failing to use a West Coast location factor, understating Coker costs, insufficiently supporting sulfur removal costs, inconsistently treating hydrotreater costs, and using a simplistic 20% capital cost recovery factor. *Id.* at pp. 30-31.

159. A location factor, Toof maintains, is necessary to differentiate between Gulf Coast and West Coast construction costs, and O'Brien fails to include such a factor or a

reasoned defense for his failure. *Id.* at p. 31. At best, Toof explains, O'Brien claims his project is conceptual and non-specific, not requiring location factors. *Id.* Toof assaults this claim, arguing that "O'Brien's study is quite specific [and].… there is no objective basis for omitting a West Coast location adjustment factor." *Id.* at pp. 31-32.

160. As for O'Brien's Coker cost calculation, Toof finds two major errors. *Id.* at p. 32. First, he contends that, when O'Brien relied on a cost curve/data base approach in estimating Coker construction costs, he incorrectly compared the cost curve analysis to certain public sources. *Id.* Toof notes that, at his deposition, O'Brien was incapable of explaining the composition of his Coker cost curves. *Id.* He explains that O'Brien begins his calculation with the Gary and Handwerk text's ISBL $162 million cost curve estimate, then escalates the cost to $175 million to bring the estimate to a June 1996 date. *Id.* O'Brien continues, Toof states, by subtracting $37.5 million from the Gary and Handwerk cost curve to deduct the cost of three items O'Brien claims are included in the curve, but are not included in his Coker configuration. *Id.* However, Toof maintains, O'Brien cannot have known whether the three items were included or excluded from the Gary and Handwerk cost curve. *Id.* Additionally, Toof asserts, O'Brien does not present any cost estimate for the three deducted items. *Id.*

161. The other major error in O'Brien's estimate, Toof contends, is a serious inconsistency. *Id.* at p. 33. O'Brien, Toof notes, asserts that the Coker must be costed as if it were part of an integrated refinery, benefiting from significant economies of scale, but admits that if a Coker were actually built in such a fashion, an OSBL factor of 50 percent would be used. *Id.* Instead, O'Brien uses much smaller OSBL factors, Toof states, "more appropriate to estimating the cost of adding units to an existing refinery." *Id.* Additionally, Toof complains, O'Brien admits that his Coker and its products benefit from using existing refinery facilities at no cost. *Id.*

162. Toof contends that O'Brien makes certain unsupported assumptions resulting in understated costs in making his sulfur removal cost estimates. *Id.* He explains that O'Brien's "product swell" assumption -- that it would cover the sulfur cost associated with hydrotreating Coker products -- is not supported by any hard evidence. *Id.* Furthermore, he argues that O'Brien's back-up sulfur capacity argument is also defective because O'Brien ignores the number of separate units necessary to provide adequate back-up capacity. *Id.*

163. In his hydrotreater costs, Toof asserts, O'Brien also makes certain problematic assumptions. *Id.* at p. 34. He enumerates these problems as follows:

> [O'Brien] develops his price for hydrotreating the Coker LSR product on the basis of a medium pressure Naphtha hydrotreater even though he admits that only one Naphtha hydrotreater would be built and that it would have a higher cost. Additionally, his discussion of the OSBL factors to be used for

> his high pressure Naphtha and VGO hydrotreaters appear to be contradictory. In the case of the Naphtha Hydrotreater, he asserts that the OSBL factor to be applied to the high pressure unit should be a lower percentage than the medium pressure unit (18% versus 31%) because the OSBL costs of the high pressure unit do not rise proportionately with the increase in ISBL costs. However, he does not follow this same principal with respect to his VGO hydrotreater where the OSBL factors are the same despite a comparable difference in ISBL costs. Finally, Mr. O'Brien offers no documentation to support the assumption, which is critical to his analysis, that changes in cost between a high pressure hydrotreater and a medium pressure hydrotreater are linear.

Id.

164. O'Brien's capital cost recovery plan, Toof claims, is also flawed because O'Brien uses a 20% simple payback method rather than identifying underlying cost components such as owner's costs, interest during construction, depreciation, and return on capital. *Id.* at pp. 34-35.

165. Toof also addresses the difference in how the parties propose to calculate the before-cost value of Coker products. *Id.* at p. 35. Exxon, he explains, use a two variable (heavy distillate and VGO) linear regression formula to estimate the before-cost value of the Coker products while O'Brien advocates "a specific enumeration method where the monthly value of Resid is based on the monthly prices for each of the underlying nine coker products." *Id.* Toof notes that, although both approaches have "strengths and weaknesses," Exxon is willing to adopt O'Brien's method which will slightly increase the accuracy of the Coker feedstock value of Resid. *Id.*

166. In his rebuttal testimony, Toof addresses the criticisms witnesses O'Brien, Ross, Sanderson, Boltz, and Dayton made regarding his testimony, concluding that the criticisms are "wholly unjustified." Exhibit No. EMT-123 at p. 4. He notes that Exxon attempted the most reasonable estimate of value, making conservative assumptions even when those assumptions "cut against their interests." *Id.*

167. In contrast, he contends, the Eight Parties advance arguments designed to support pre-established positions. *Id.* at p. 5. O'Brien's Resid cut processing cost calculation, he asserts, is only one example. *Id.* This calculation is flawed, Toof explains, because O'Brien ignores West Coast location costs and also uses a Quality Bank Base Refinery concept without applying the concept consistently. *Id.* In particular, he states, O'Brien does not assign coking storage costs to the Coker plant, but, instead, assigns the costs to the Quality Bank Base Refinery. *Id.*

168. He also accuses the Eight Parties of blatantly manipulating the West Coast

Naphtha valuation because O'Brien and Ross insist on using Gulf Coast costs to determine West Coast Naphtha cut processing costs. *Id.* Unocal, Williams, and Petro Star, he asserts, are unjustified in arguing that West Coast VGO should be valued on the basis of West Coast prices but that West Coast Naphtha should be valued on the basis of Gulf Coast prices. *Id.* Moreover, Toof contends that Ross's governor proposal is "wholly contrived . . . [and] is not supported by any empirical evidence." *Id.*

169. According to Toof, Exxon proposes to value Resid as a Coker feedstock, i.e., "the value of the Coker's products less the costs of Coker production." *Id.* at p. 9. He then acknowledges and summarizes the Eight Parties's criticisms of this approach and addresses each in turn. *Id.* at pp. 9-10.

170. Toof first turns to the blending question, stating that O'Brien asserts that the Exxon proposal produces a value for Resid which is less than its value if Resid were used as a blendstock for fuel oil. *Id.* at p. 10. He goes on to claim that O'Brien reasoned that, if that were the case, refiners would not build Cokers and, because they have, Toof states, O'Brien posits that Exxon's proposal "produces illogical results." *Id.*

171. Claiming that O'Brien's criticism is without merit, Toof states that Exxon's method produces a Resid value which is higher than its value as a fuel oil blendstock. *Id.* at pp. 10-11. He "find[s] it incredible that O'Brien can break down everyone else's cost estimates but has no knowledge as to the make-up of his own cost estimate." *Id.* at p. 6. Additionally, he believes Ross's coke transportation handling cost arguments are erroneous. *Id.*

172. O'Brien's position, he explains, is "based on a mistaken factual premise" because Exxon's Resid values are not uniformly lower than Resid values as a West Coast fuel oil blendstock. *Id.* at p. 11. He notes that Exxon's Resid values exceed, on average, the Resid value as a fuel oil blendstock. *Id.* Furthermore, he contends, O'Brien's argument is based on an incorrect premise that Resid's value as a Coker feedstock will always exceed its blending value based on fuel oil prices, ignoring the fact that West Coast demand for fuel oil is limited. *Id.*

173. Toof explains the blending analysis he conducted with Pavlovic to determine that Exxon's Resid values exceed Resid's value as a fuel oil blendstock:

> I have calculated the blending value of Resid under three scenarios. All scenarios assume that the blended product is FO-380 priced as Platts Los Angeles pipeline FO-380. The three scenarios are: (1) LS No. 2 as the diluent; (2) light cycle oil ("LCO") as the diluent; and (3) Heavy Distillate. For each month, I also present the [Exxon] coker feedstock Resid value.

Id. at pp. 11-12.

174. According to Toof, his analysis reflects that Exxon's Resid Coker feedstock value, from December 1993 through December 2001, using its Coker feedstock methodology, is $10.48/barrel, exceeding the blending value using Heavy Distillate by $1.13/barrel, and the blending value, assuming LS No. 2, by $2.07/barrel. *Id.* at p. 12. He notes that this result is $1.37/barrel less than the blending value assuming light cycle oil as the diluent. *Id.* However, Toof argues that a comparison to light cycle oil blending is unreasonable because it would require 30,000 barrels/day of light cycle oil to blend 40,000 barrels/day of Resid. *Id.* Such quantities of light cycle oil, be believes, may not be available, and, even if the quantities were available, such a large demand would exert upward pressure on the price of LCO and thus reduce the value of Resid as a fuel oil blend. *Id.* at pp. 12-13.

175. Toof also argues that O'Brien's criticisms are not economically sound because the West Coast fuel oil market is shrinking. *Id.* at p. 13. Therefore, he explains, new Coker capacity investment and the incremental fuel oil production would have to take into account the impact that the additional fuel oil supplies would have on the market price of the fuel oil. *Id.*

176. He next answers the Eight Parties's criticism of Tallett's Resid before-cost value calculation -- that Tallett's eight assay average was defective and adjusting for coke price transportation and handling costs is erroneous. *Id.* at p. 14. Neither criticism, he contends, is valid. *Id.* Tallett, Toof asserts, used every available credible assay, including the 1996 assay used by O'Brien and the 2001 assay produced in discovery. *Id.*

177. Toof also does not believe that adjusting coke prices for transportation and handling undervalues the coke product because, according to him, "[n]o reasonable valuation of the coke portion of Resid could be based on an unadjusted FOB ship coke price." *Id.* at p. 15. Furthermore, he argues that Ross's assertion that the impact on coke of transportation and handling costs is less than their impact on other products is inaccurate and irrelevant. *Id.*

178. The impact of coke transportation and handling costs on the value of the Resid, he contends, is much greater than the impact of the transportation and handling costs on the other Coker products. *Id.* Additionally, he explains, failing to similarly adjust other Coker products does not serve Exxon's interests because, if transportation and handling were taken into account, Resid's before-cost value would be further reduced, ultimately increasing the refund amounts. *Id.* at pp. 15-16. Finally, Toof states, the suggestion that all Quality Bank cuts would need to be valued at the refinery gate is irrelevant because Issue No. 1 relates only to Resid valuation. *Id.* at p. 16.

179. Toof next defends Jenkins's cost calculations against O'Brien's criticisms of the location factor, ISBL costs, storage, finance costs, and hydrotreater cost allocations. *Id.*

Using a location factor, Toof argues, is essential, while relying on Gulf Coast capital costs is wrong because "[a]ll of the credible evidence presented in this proceeding supports the application of a West Coast location factor." *Id.* at p. 17.

180. In addition, Toof responds in great detail to O'Brien's argument that the Coker ISBL cost estimates are either unnecessary or part of Jenkins's OSBL estimate. *Id.* at p. 18. First, he notes that O'Brien identified items that O'Brien believes Jenkins improperly included in his Coker ISBL cost, estimating the cost of these items. *Id.* According to Toof, Jenkins presented detailed Coker configuration item and cost descriptions while O'Brien merely presents a black box number, providing only "a single sheet of paper with a 'tailored' cost curve." *Id.*

181. Also, Toof notes, all the equipment, other than the Kero salt dryer, that O'Brien argues is unnecessary is actually required. *Id.* at pp. 18-19. In particular, Toof explains, the automatic deheading and coke handling facilities are necessary given O'Brien's assumed cycle time. *Id.* at p. 19.

182. Jenkins's inclusion of the Coker gas plant in his Coker OSBL cost estimate, Toof contends, is appropriate and O'Brien's argument to the contrary is baseless. *Id.* O'Brien, Toof explains, admitted he was mistaken in claiming that these costs were included in Gary & Handwerk's OSBL cost factor. *Id.;* Exhibit No. EMT-125 at p. 12. Additionally, Toof notes, O'Brien admitted that Gary & Handwerk requires these costs to be estimated separately, as Jenkins did. Exhibit No. EMT-123 at p. 19.

183. Finally, Toof asserts, a four-drum system is necessary in order to process 40,000 barrels/day of ANS Resid. *Id.* at p. 19. He notes that O'Brien has often misstated details regarding Coker operations:

> [A]t his May 7, 2002 deposition, Mr. O'Brien made a number of misstatements regarding coker operations and admitted he was not an expert in such matters as cycle time. Indeed, after the first break in the deposition, Mr. O'Brien found it necessary to correct a number of errors that he had made in the first hour of the deposition. *See* Exhibit EMT-125, pages 587-615. Given this lack of familiarity with the basic fundamentals of coker operations, one has to question the credibility of his assertions regarding the feasibility of his 2-drum coker proposal.

Id. at p. 20.

184. As for O'Brien's claim that storage tanks and consequent costs are not necessary because they are part of the Quality Bank Base Refinery, Toof argues that misallocates costs "clearly relate[d] to the coking process." *Id.* at pp. 20-21. It is not credible to argue, he believes, that no storage costs should be recognized as a result of a Coker

addition. *Id.* at p. 21. In O'Brien's Quality Bank Base Refinery, he explains, every Quality Bank cut has a market price recovering all of costs associated with the production of that cut, and, consequently, Resid costs, including storage tank costs, should be recovered by Resid's market price. *Id.* However, Toof notes, no storage costs would be recovered by the market price of the other eight Quality Bank cuts. *Id.*

185. O'Brien, Toof states, asserts that only Coker incremental costs (downstream and ancillary facilities), along with incremental management and labor costs should be assigned to the value of Resid as a Coker feedstock. *Id.* The end result, according to Toof, of this "sleight of hand" is that O'Brien eliminates approximately $19 million of storage related capital costs. *Id.* Concluding, he explains that, "[b]y his own theoretical predicate, these costs are not captured in the market prices of the eight other Quality Bank products and for this reason should be assigned to the Coker. Nevertheless, Mr. O'Brien specifically excludes these costs in his Coker feedstock analysis. This is not credible." *Id.*

186. Regarding O'Brien's doubts over including interest during construction costs in the finance cost, Toof finds O'Brien's criticism "incredible." *Id.* at p. 22. He asserts that "O'Brien fails to grasp the underlying economic principle of cost recognition and cost recovery." *Id.* Owner's costs, Toof insists, are real, because they represent a commitment of personnel that must be accounted for. *Id.*

187. Finally, O'Brien's questions over Jenkins's hydrotreater costs, Toof argues, are unwarranted. *Id.* at p. 23. Jenkins, Toof insists, recognizes and accounts for economies of scale existing in constructing downstream hydrotreaters in an integrated refinery. *Id.* In contrast, he contends, O'Brien uses a number of contradictory assumptions:

> Mr. O'Brien's costs are based upon an assumption of economies of scale attributable to an integrated refinery with large hydrotreaters. For example, he has assumed a 50,000 barrel per day Distillate hydrotreater. This size hydrotreater could only have been built if the Coker had been constructed as part of a complex refinery. However, his diagram of the Quality Bank Base Refinery shows that the 50,000 barrel per day hydrotreater, like the Coker, is added on to his Base Refinery. Mr. O'Brien must decide how and when the various facilities of his "Quality Bank Base Refinery" are constructed. If he assumes a 50,000 barrel per day high pressure heavy distillate Hydrotreater, he must also assume that it was built concurrently with the "virgin" units. In that case according to his earlier deposition testimony, it would bear a "grass roots" OSBL burden (50%). Similarly, if he is to size his Naphtha Hydrotreater and VGO Hydrotreater to process both the virgin and Coker product, they must bear a "grass roots" OSBL factor.

Id. at. pp. 23-24.

188. Also, Toof states, O'Brien admits that the Quality Bank Base Refinery does not have any hydrotreaters. *Id.* at p. 24. Virgin VGO and virgin Naphtha Quality Bank cuts, he adds, are sold into the market without hydrotreating and, consequently, the Quality Bank prices do not cover the costs of hydrotreatment. *Id.* Nevertheless, Toof explains, O'Brien assumes Coker VGO and Coker Naphtha should only bear the incremental costs of hydrotreating. *Id.*

189. Toof believes that O'Brien's criticism of Jenkins's Coker project cost comparisons are not valid. *Id.* at p. 25. Jenkins, Toof explains, used actual project costs to demonstrate the complexity of contemporaneous Coker projects and to ensure that his detailed costing methodology produced reasonable results. *Id.*

190. Finally, Toof notes that Exxon agrees to use the Eight Parties's specific enumeration methodology instead of the two variable linear regression methodology. *Id.* at p. 26. He explains that the impact on Resid's before-cost value is very small. *Id.* Additionally, he states that he has recomputed these values using the specific enumeration method, incorporating several minor changes. *Id.* at p. 27. Tallett, Toof states, uses two more assays (the 2001 assay included in O'Brien's analysis and a BPXA assay provided in discovery) and, also, the Quality Bank values of West Coast Naphtha, West Coast VGO, and West Coast Heavy Distillate have been adjusted to be consistent with Exxon's position regarding the valuation of those proxy prices. *Id.*

191. Consequently, he explains, for December 1993 through December 2001 the specific enumeration method, along with the changes, reduce the before-cost value of Resid by approximately 5¢/barrel on the West Coast and raise the value by 8¢/barrel on the Gulf Coast. *Id.* Additionally, Toof notes, Jenkins adjusts his Coker cost analysis by removing the Kero salt dryer from his Coker ISBL cost estimate, removing the negative economies of scale component, and adjusting his fixed operating costs to take into account the economies of scale in the underlying capital costs. *Id.* at pp. 27-28. The net result of these adjustments, Toof states, is to reduce the 2000 West Coast Coker cost estimate from $7.17/barrel to $6.97/barrel while Gulf Coast Coker costs for 2000 are reduced from $5.88/barrel to $5.75/barrel. *Id.* at p. 28. As for the refund impact, Toof notes that Pavlovic calculated that the net impact reduces refunds due to Exxon by approximately $3 million for the period December 1993 through December 2001. *Id.*

192. Toof next turns to Heavy Distillate criticisms. *Id.* Both O'Brien and Ross, Toof begins, criticize Exxon's argument that reducing the sulfur content of ANS virgin Heavy Distillate to the proposed Quality Bank proxy price standard of 0.05% would cost 4.3¢/gallon and is the only necessary adjustment. *Id.* According to Toof, O'Brien's assertion that a high Heavy Distillate value is in Exxon's financial interest is incorrect. *Id.* at p. 29. Of the four streams delivered to Pump Station No. 1, Toof explains, the

Prudhoe Bay Unit has the smallest percentage of Heavy Distillate and, consequently, an increased Heavy Distillate value works to Exxon's disadvantage. *Id.*

193. As for Ross's logistics adjustment, Toof is again dismissive. *Id.* He argues that Ross's "quantitative support is little more than happenstance and has little, if any, logical underpinning." *Id.* at p. 30.

194. During cross-examination, Toof admitted that Tesoro would benefit if its competitors, Williams and Petro Star, had to pay more for their Heavy Distillate feedstock. Transcript at p. 2044. However, he denied that ExxonMobil would benefit from a higher Heavy Distillate price. *Id.* Rather, he suggested that, "based on an analysis of the workings of the Quality Bank through pump station 1 and through the GVEA and PSVR interconnections," it believed a higher deduction and a lower heavy distillate price would be in its economic interest. *Id.* at p. 2045. Toof asserted, therefore, that ExxonMobil would be economically advantaged by the use of a logistics adjustment which would lower the value of Heavy Distillate. *Id.*

195. Toof agreed with Dayton that, on a going forward basis, new assays should be performed when a "known or knowable event takes place." *Id.* at p. 2077. However, he also suggests that new assays should be taken when the Quality Bank Administrator judges that the "underlying character" of the ANS common stream has changed. *Id.* at pp. 2077-78. Toof also agreed that the Quality Bank Administrator should have the discretion to make this determination. *Id.* at p. 2079.

G. KARL D. BARTHOLOMEW

196. Exxon also presented Bartholomew as a witness. Bartholomew was president of Pace Consultants, Inc., until its merger with Jacobs Engineering Group to form Jacobs Consultancy, Inc., of which he is Managing Director of the Refining, Chemical & Petrochemical practice area. Exhibit No. EMT-31 at p. 3. Bartholomew acknowledges that Jacobs Consultancy publishes the *PCQ*. *Id.* at p. 6; Transcript at p. 2167. According to Bartholemew, the price reported in *PCQ* is based only on reports of export prices. *Id.* at p. 2238. He adds that, because they try to speak with both parties to a transaction, he believes in the accuracy of the reported prices. *Id.* at p. 2239.

197. His testimony addressed the issue of the value of coke to a refiner operating a Coker on the West Coast and the Gulf Coast. Exhibit No. EMT-31 at p. 7. He explained that the current method for determining the relative values of crude oil injected into TAPS is the distillation method, "which values crude oil on the basis of the market price of the various component products (called 'cuts') created when the crude oil is heated to a series of specific temperatures and the evaporated products produced at each temperature are recondensed." *Id.*

198. Bartholomew relies on a Resid valuation method involving estimating the value of Resid as a feedstock to a type of refinery called a Delayed Coker. *Id.* Resid value, according to Bartholomew, in this method equals the value of the products produced from coking Resid. *Id.* The method deducts the costs of producing the Coker products and treats them to meet the quality specifications of the proxy products upon which the Quality Bank values of the Coker products are based. *Id.* at pp. 7-8.

199. Bartholomew begins his analysis by examining the range of prices for low sulfur green coke (>2% sulfur) sold on the West Coast and the range of prices for high sulfur green coke (>50 HGI) sold on the Gulf Coast between January 1992 and December 2001. *Id.* at p. 9. Continuing, he explains that the prices quoted in *PCQ* are not the same as the value of coke at a refinery because the *PCQ* values are on an FOB vessel basis,

> meaning those prices include all costs and commissions to transport the coke from the refinery into and through a storage terminal, and then to load it on a vessel. These charges can vary widely, depending on the refinery location, the amount of coke handling and transportation require, the storage terminal used, and the marketing fee or commission charged by the coke reseller who has purchased the coke for shipping. The transportation, handling, and reselling charges are very significant, and at times can constitute most of the FOB value of the coke loaded on the vessel. In order to determine the value of coke at a refinery on the West Coast and the Gulf Coast, these transportation, handling, and reselling charges must be deducted from the *PCQ* prices.

Id. at pp. 9-10.

200. Applying this process, Bartholomew calculated an estimate of $10.75/short ton for the West Coast and $6.00/short ton for the Gulf Coast. *Id.* at p. 8. Bartholomew states "[t]hese amounts are reasonable and should be deducted from the applicable *PCQ* prices to determine the value of coke to the refinery." *Id.*

201. Coke transportation and handling, Bartholomew explains, differs significantly from transportation and handling of other refined petroleum products because

> Coke is a solid product . . . that can take many shapes and sizes. Coke particles can be as large as cannonballs or as small as fine grit. . . . it can only be moved by truck, rail, or solid bulk vessel. Additionally, it typically moves only one way – from the refinery out to storage terminals or end users.

Id. at pp. 10-11. Bartholomew states that substantial charges for transporting, handling, and reselling coke distinguish it from other refined coke products, for which such costs typically constitute only a small portion of their values. *Id.* at p. 11.

202. Continuing, Bartholomew relates that, for the West Coast, transportation, handling, and reselling charges account for an average of 61% of the coke proxy price and the Gulf Coast comparable charges account for an average of 60% of the coke proxy price. *Id.* Additionally, "the FOB vessel price quoted each month in the *PCQ* can mask the true value of the coke to the refinery," Bartholomew relates, because the coke, on occasion, has an intrinsically negative or zero value. *Id.* at 12. Even when the value of the coke is negative or zero, Bartholomew states, the coke must be removed (and shipping, handling, and reselling charges must be incurred) "because the refinery cannot store it and still continue its refining operations." *Id.*

203. Bartholomew calculates typical coke transportation, handling, and reselling charges for the West Coast based on the major export terminals in the Los Angeles basin – Los Angeles Export Terminal and the Port of Long Beach. *Id.* at pp. 13-14. For this area, Bartholomew explains, transportation costs vary widely – from $1.50 to $19.00/short ton – because coke is transported from the refinery to the terminal by truck and the distances from the refineries to the terminals differ. *Id.* at p. 14. Bartholomew determines that "a reasonable range of trucking costs . . . is $1.50 to $3.50 per short ton, and a reasonable average cost for transportation is $2.00 per short ton." *Id.* at p. 15.

204. Handling costs for this area, Bartholomew continues, "range from $6.00 to $7.50 per short ton . . . . A reasonable range of handling costs in the Los Angeles area is $6.00 to $7.50 per short ton. Therefore, a reasonable average cost for handling is $6.75 per short ton." *Id.* Reselling commissions, in Bartholomew's view, range from $1.50 to $2.50/short ton and "[t]herefore, a reasonable average reseller fee or commission on the West Coast is $2.00 per short ton." *Id.* at pp. 15-16. Averaging all these costs for the West Coast, Bartholomew concludes that "[a] conservative estimate of the average cost for all of these charges combined is approximately $10.75 per short ton." *Id.* at p. 16.

205. On the Gulf Coast, Bartholomew states, coke is transported by barge transport over typically long distances and a reasonable average transportation cost is $2.50 per short ton. *Id.* at p. 17. The reason the Gulf Coast transportation average is higher than the West Coast transportation average ($2.00 West Coast versus $2.50 Gulf Coast), Bartholomew explains, is because of the greater distance between refineries and export facilities on the Gulf Coast. *Id.*

206. Handling costs for unloading coke from barges, storing it until a vessel is available, loading and moving the coke from storage to the vessel, in Bartholomew's view, range from $2.00 to $3.00/short ton on the Gulf Coast and "[a] reasonable average cost for handling is $2.50 per short ton." *Id.* at pp. 17-18. The difference in West Coast and Gulf Coast handling costs ($6.75 West Coast versus $2.50 Gulf Coast), according to Bartholomew, is a result of higher labor costs, land values, and stricter environmental

requirements on the West Coast, as well as a greater competitive environment on the Gulf Coast. *Id.* at pp. 17-18.

207. As for Gulf Coast reselling commissions, Bartholomew states, “a reasonable average reseller fee for the Gulf Coast is $1.00 per short ton. This figure is lower than the West Coast estimate because the Gulf Coast market is more competitive.” *Id.* at p. 18. Bartholomew concludes that “[a] conservative estimate of the average cost for all of these charges combined is approximately $6.00 per short ton” on the Gulf Coast. *Id.* at p. 19.

208. At the hearing, Bartholomew acknowledged that the purpose of his testimony is to value coke to a refiner operating a Coker on the West Coast and to a refiner operating a Coker on the Gulf Coast. *Id.* at p. 2168. Bartholomew also agreed that the process he used contained two steps: (1) select a price from the *PCQ*; and (2) adjust that price for the cost of handling, transportation, and reselling. *Id.*

209. Discussing the *PCQ* price, Bartholomew noted that it reported two prices: the first for greater than 2% sulfur cokes and the second for less than 2% sulfur coke. *Id.* at p. 2170. Bartholomew states that he used the greater than 2% sulfur price for the West Coast analysis he performed. *Id.* According to Bartholomew, marketers on the West Coast value coke at about 30¢/metric ton per 1/10 of a percent sulfur. *Id.* at p. 2236.

210. Bartholomew defined “green coke” as coke which comes from a Coker. *Id.* at p. 2186. He said that “calcine coke” was coke which has been further processed. *Id.* at p. 2185. According to Bartholomew, calcine coke is made by passing green coke through a long heating tube to remove the remaining hydrocarbons, leaving just carbon. *Id.* at pp. 2185-86. However, he added, not all green coke can be calcined. *Id.* at p. 2230. Factors determining whether green coke can be calcined included the quality of the Coker’s Resid feedstock and its operating conditions. *Id.* According to Bartholomew, a “higher cut point typically produces a lower quality feedstock that very likely would not make the resid suitable for calcining.” *Id.* at p. 2233. He also pointed out that calcining coke is much more expensive than producing fuel-quality coke. *Id.* at p. 2234.

211. Calcine coke, Bartholomew stated, can be used to make anodes for aluminum production and to help make titanium dioxide, the white pigment for paper. *Id.* at p. 2185. However, he added, anode grade calcine coke is made only from a certain quality of coke, the exact quality depending upon the specifications of particular aluminum companies. *Id.* at p. 2186. Bartholomew conceded that the value of calcine coke depends, in part at least, on the aluminum companies’s demand for it which, in turn, may affect the value of green coke. *Id.* at p. 2187.

212. In later testimony, Bartholomew indicated that “ANS quality coke is . . . a 3 percent sulfur coke. The metals are okay. Part of it is used for calcining, some for fuel.”

Id. at p. 2200.

213. Bartholomew, who claimed in his pre-filed testimony that "refiners" were paying to have their coke hauled away, at the hearing could only name one – "the Equilon refinery in Los Angeles" – later further identified as "the Equilon Wilmington L.A. refinery." *Id.* at pp. 2204, 2206.

214. According to Bartholomew, the cost of moving coke from a refinery to a "pricing point" was a disproportionate part of its market price in comparison with the part of the market price representing the cost of moving other products from a refinery to their pricing points. *Id.* at p. 2206. Because of this, as noted above, Bartholomew recommends adjusting coke market prices by $10.75 on the West Coast and $6.00 on the Gulf Coast. Exhibit No. EMT-31 at p. 8. According to him, the $10.75 represents $2.00 for transportation, $6.75 for handling and $2.00 for reseller's commission. Transcript at pp. 2211-12. The $2.00 transportation cost is based, Bartholomew said, on conversations with "resellers[,] marketers and people doing this work in the Los Angeles Basin." *Id.* at p. 2212. During these conversations, Bartholomew claims, he was quoted costs ranging from "$1.50 to $3.50 per month." *Id.* He also claims that his company did "several past studies" which were in the same range. *Id.* at pp. 2212-13. Defending his estimate, Bartholomew stated:

> I have a good sense of the range of cost, and the refiners that are farther away are going to pay the upper end of that range. The refiners closer to the port facility, they're typically at the lower end, the $1.50 part of the range. It's the normal course of business talking with them because those costs are going to vary.

Id. at pp. 2221-22. He further acknowledged that he "picked" the $2.00 out of the $1.50 to $3.50 range because he "didn't want to overestimate the cost of the range." *Id.* at p. 2222. In doing so, Bartholomew admitted, he did not distinguish between refineries processing ANS as compared with refineries processing other crudes, nor did he attempt to calculate the average distances which the coke would have to be shipped. *Id.* at p. 2224.

215. Although Bartholomew included a $2.00 resellers cost in his proposed $10.75 West Coast coke price adjustment, he conceded that some refineries on the West Coast do not use resellers. *Id.* at p. 2225. Moreover, he indicated that refineries do not use resellers for their domestic sales, but only for their export sales. *Id.* at p. 2226. Later, Bartholomew agreed that as many as 25% of refineries do not use resellers. *Id.* at p. 2227.

216. Bartholomew also recognized that his $6.75 estimate for storage and handling was merely based on his "normal course of business discussions with the resellers, the people

at the port, as well as . . . client studies [we have done] in the past [where] we've looked at their costs." *Id.* at p. 2229. Later, he added:

> We've actually had numbers that showed much significantly higher costs at times when coke had to be moved from the port to another storage facility because vessels weren't available, inventory was building, and so I took the low range of those numbers, $6 and 7.50 and took a midpoint over the time period.

Id. at p. 2246.

217. According to Bartholomew, the coke market is not stable, moving in different directions than other markets. *Id.* at p. 2248. He notes that it "really floats between coal as a competing fuel source for power, cement and other applications" and that it "moves on its own supply and demand, but generally within boundaries of some percentage of coal." *Id*.

H. MARTIN TALLET

218. Tallett also was a witness presented by Exxon. He is the founder, owner and president of EnSys Energy & Systems, Inc., an engineering consulting firm which provides services to domestic and foreign members of the petroleum industry, as well as the co-founder of, and principal in, EnSys Yocum, Inc., a consulting firm which provides specialized engineering services for design and performance improvement of oil and gas production systems. Exhibit No. EMT-11 at pp. 3-4.

219. Tallett developed a method to determine before-cost value for ANS Resid as a Coker feedstock. *Id.* at pp. 29-30. His method, Tallett explains, uses the AspenTech PIMS refinery linear programming modeling system, average assay data for ANS Resid, and values for every product produced from coking ANS Resid. *Id.* at p. 30.

220. According to Tallett,

> PIMS divides the liquid product produced by coking Resid into three cuts based on the temperature ranges at which the cuts boil off: Naphtha (C_5-390ºF), Distillate (390º-650ºF) and Gas Oil (650º+F). The Quality Bank, on the other hand, divides the liquid product which boils off within this temperature range into four cuts: LSR (also called "light straight run" or "natural gasoline") (C_5-175ºF), Distillate (350º-650ºF) and VGO (650º-1050ºF). The Quality Bank further divides Distillate (350º-650ºF) into a Light Distillate cut (350º-450ºF) (which is made into, and valued as, jet fuel) and a Heavy Distillate cut (450º-650ºF) (which is made into, and valued as, fuel oil). However, when dealing with the liquid product which

> comes out of the coker and that boiled off between 350º-650ºF, all of that coker liquid product is normally treated as Heavy Distillate, because the liquid product of too poor a quality to be made into, or valued as, jet fuel.

Id. at p. 31.

221. To convert the PIMS yields into cuts recognized by the Quality Bank, Tallett said he used the following formula:

C_5-175ºF LSR yield	=	((175-60)/(390-60)) * PIMS C_5-390 yield
175º-350ºF Naphtha yield	=	((350-175)/(390-60)) * PIMS C_5-390 yield
350º-650ºF Total Distillate yield	=	((390-350)/(390-60)) * PIMS C_5 390 yield + PIMS 390º-650ºF Heavy Distillate yield
650º-1050ºF VGO yield	=	PIMS VGO yield

Id.

222. Tallett stated that he acquired four assays from the Chevron assay database, three more from ExxonMobil and an eighth from an August 28, 2000, O'Brien affidavit submitted in support of a settlement proposal. *Id.* at p. 33. By averaging the eight assays, Tallett indicated that he got a Resid with a Conradsen Carbon Residue (weight %) content of 23.143; sulfur (weight %) content of 2.557; and gravity API content of 5.499. *Id.* This data, he says, was then entered into PIMS to produce yields that correspond to nine products: Propane, Isobutane, Butane, LSR, Naphtha Distillate, VGO, Coke and Fuel Gas. *Id.* To determine the total worth of the nine products, the first seven of which have comparable Quality Bank cuts, Tallett said he used the following values:

West Coast Naphtha	-	the value produced by the regression formula he developed
West Coast VGO	-	OPIS West Coast price for high sulfur VGO
West Coast Distillate	-	Los Angeles Pipeline Low Sulfur No. 2 base price (the Quality Bank current proxy for Heavy Distillate) less a 4.3¢/gallon sulfur processing cost

		adjustment
Coke	-	The price derived by Karl Bartholomew
West Coast Fuel Gas	-	*Natural Gas Week* monthly average California South (Los Angeles) delivered to pipeline natural gas spot price in \$/million Btu + the cost of transporting the natural gas to the refinery converted to a \$/barrel fuel oil equivalent -- 1¢/bbl was credited for the Hydrogen Sulfide produced in the coker
Gulf Coast Fuel Gas	-	*Natural Gas Week* monthly average Texas Gulf Coast Onshore delivered to pipeline natural gas price in \$/million Btu converted to a \$/barrel fuel oil equivalent-- 1¢/bbl was credited for the Hydrogen Sulfide produced in the coker

Id. at pp. 34-35.

223. Tallett says he calculated the total monthly values of the products produced from coking Resid by adding the values for each of these products for each month. *Id.* at p. 35. The January 1992 through December 2001 monthly values, Tallett adds, are reproduced in Exhibit No. EMT-30. Exhibit No. EMT-11 at p. 35.

224. In his Answering Testimony, Tallett addressed O'Brien's before-cost Resid valuation. Exhibit No. EMT-84 at pp. 42-49. He contends that O'Brien errs in only using only two assays. *Id.* at p. 43. On the other hand, Tallett says, he used "every reliable ANS assay that [he] could find from 1994 to the present" – seven plus one which O'Brien included in an August 28, 2000, affidavit. *Id.* at pp. 44-45. Tallett said he then averaged the results of the eight assays "to determine the representative ANS crude qualities." *Id.* at p. 45. According to Tallett, using his eight-assay average reduces the value of Resid by 22¢/barrel as compared with O'Brien's two-assay average. *Id.*

225. Tallett claims that O'Brien also used the wrong cut point for C_5 -- 100ºF. *Id.* at pp. 45-46. According to Tallett, "[t]he standard figure accepted by the petroleum industry for this cut point is 60ºF." *Id.* at p. 46. Although certain documentation accompanying the PIMS program shows a C_5 cut point of 96ºF, Aspen Technology, Inc., the owner of PIMS, states that "this documentation is not intended to represent a standard database, and was prepared merely for illustrative purposes." *Id.* at p. 47.

226. Adding that use of a 100ºF disregards the true boiling point of C_4s and C_5s, Tallett asserts the following:

> Iso-butane boils at 10.9ºF, normal butane at 31.1ºF. Iso-pentane boils at 82.1ºF, normal pentane at 96.9ºF and cyclo-pentane at 120ºF. Thus, on pentane pure boiling points alone, Mr. O'Brien's use of 100ºF is incorrect because iso-pentane – the lowest boiling C_5 – boils at 82.1ºF. . . . Pentenes boil between 68º and 100ºF. Thus, for a coker, consideration of pure boiling point alone would lead to the conclusion that 68ºF is an appropriate initial boiling point for the C_5+ fraction. . . . It [also] is necessary to consider that, in all refineries, real world fractionalization is not perfect. Some C_5's [sic] end up in the C_4 stream and some C_4's [sic] in the C_5+ naphtha stream. This imperfect fractionalization has the effect of lowering the effective C_5+ cut boiling point to approximately 60ºF.

Id. at pp. 47-48. He adds that, use of a 60ºF cut point, rather than a 100ºF cut point, reduces the before-cost value of Resid by 11¢/barrel during the period beginning in 1992 and ending when his testimony was filed in March 2002. *Id.* at p. 48.

227. Tallett also criticizes O'Brien's use of the *PCQ* coke price series without adjusting for the costs of transportation, handling and reselling. *Id.* He claims that this failure overvalues coke by 65¢/barrel over the 1992-2001 period. *Id.* at p. 49.

228. In addition, Tallett disparages O'Brien's 4.1¢/gallon sulfur processing cost deduction as well as his 1.1¢/gallon logistics deduction for Heavy Distillate rather than the 4.3¢/gallon recommended by Jenkins. *Id.* He claims that this undervalues Resid by 8¢/barrel. *Id.* Moreover, Tallett claims that O'Brien's "use of the existing Quality Bank Gulf Coast Naphtha price for valuing West Coast Naphtha understates the ANS Resid before-cost value by 27 cents per barrel." *Id.*

229. In his Rebuttal Testimony, Tallett argues that the criticisms of his Resid cut analysis do not have merit. Exhibit No. EMT-133 at p. 5. He summarizes the major criticisms of his analysis, and asserts that his approach produces "a more reasonable estimate of the before-cost value of the Resid cut than the proposal advanced by the Eight Parties." *Id.* at p. 6.

230. Describing the criticism's impact on the Resid cut valuation, Tallett states,

> [u]sing . . . O'Brien's two assay average, rather than my eight assay average, increases the before-cost value of Resid by, on average, $0.22 per barrel of Resid. . . . When I add Mr. O'Brien's second assay as well as an assay produced in discovery, the before-cost value of Resid (using this ten assay average) decreases by $0.01 per barrel of Resid, on average. With

> respect to the second issue, erroneously failing to deduct Coke transportation and handling costs, as Mr. Ross proposes, adds approximately $0.65 per barrel to the value of Resid.

Id. at p. 6.

231. After describing his methodology again, Tallett explains that his "method calculates the before-cost value of the Resid cut, from which the costs associated with processing Resid in a Coker and processing Coker products in downstream units are deducted to obtain the value of Resid." *Id.* at p. 8. Next, he notes that his approach and the Eight Parties's approach is similar because both use "(1) the Aspentech [sic] PIMS system to calculate the yield of coker products; (2) an average of the Resid qualities contained in two or more [Alaska North Slope] assays; (3) Quality Bank cut values to value seven of the nine coker products and (4) the same value for Fuel Gas." *Id.* at p. 9.

232. As for the differences in the methodologies, Tallett states that there are three major differences: (1) the Eight Parties use of the average of only two assays rather than using the average of all available assays as he did; (2) O'Brien's failure to adjust his coke price for transportation and handling as did Bartholomew; and (3) O'Brien's use of a 100ºF C_5 cut point rather than the 60ºF cut point which Tallett used. *Id.* at p. 10.

233. Tallett first summarizes Dayton's criticisms of his eight assay average:

> Dayton asserts that it is "preferable" to use only assays prepared by the Caleb Brett company, which performs assays used by the TAPS Quality Bank Administrator. She states that "it is not possible to determine" whether other laboratories — here the Chevron and Exxon laboratories — may have used a different procedure than Caleb Brett, and she claims that these other laboratories "did not always use the same cut points as the Quality Bank" cut points. Finally, Ms. Dayton opines that three of my eight assays should be disregarded because they have Resid contents either higher or lower than those shown in monthly Quality Bank assays for the years in which the samples were taken.

Id. at pp. 10-11 (citations omitted).

234. Tallett does not agree with Dayton that only the Caleb Brett assays are reliable. *Id.* at p. 11. He argues that, even though test results may vary, using standard testing procedures on a given assay should result in equally valid results no matter which lab performs the test. *Id.* He further argues that Dayton's argument that varying results from different labs invalidates those assays actually supports his use of eight assay average rather than her use of a two assay average because the use of an average of "multiple assays reduces the likelihood that the manner in which a single lab has produced an

assay, or performed a single relevant test, will unduly impact the ANS Resid qualities used to determine the ANS Resid cut's value." *Id.*

235. Regarding the criticism that his assays used different cut points than the Caleb Brett assays, Tallett asserts that the criticism is invalid. *Id.* at p. 12. First, Tallett casts doubt on the reliability of the Caleb Brett assays, stating that it "is not clear that Caleb Brett did the assays in the way suggested by Ms. Dayton." *Id.* He adds:

> Dayton suggested that the assays were done by distilling the sample to the specific Quality Bank cut points. However, the two Caleb Brett assays state that the distillation yields were determined using the standard methods ASTM D2892 and ASTM D5236. ASTM D2892 is commonly referred to as a true boiling point ("TBP") 15/5 distillation and recommends cutting the sample at *5 or 10 degree centigrade increments* with the ability to vary the still pressure. ASTM D5236 was developed to extend the distillation of heavy hydrocarbon mixtures above the limits of D2892 (about 730ºF atmospheric equivalent temperature or "AET"). The still is run at a pressure below atmospheric and the overhead vapor temperatures are corrected to AETs using the same method as specified for ASTM D2892. Second, if, as Ms. Dayton's testimony appears to suggest, Caleb Brett did not follow the recommended ASTM procedures of distilling in narrow increments and instead followed a practice of distilling the sample to the specific Quality Bank cut points, that procedure would not make the Caleb Brett assay results any more reliable. In fact, this possible departure from industry practice only tends to raise questions concerning the reliability of the results obtained.

Id. at p. 12 (emphasis in original; citations omitted).

236. On the other hand, Tallett suggests that the assays he "used were done in accordance with the recommended procedure of taking small incremental cuts, examining their quality, and then using standard mathematical procedures (referred to as interpolation) to reconcile and balance quality results and to state the qualities of cuts specifically matching the Quality Bank cuts." *Id.* at p. 13. He criticizes Dayton for suggesting that only assays prepared for the purposes of this litigation are usable because the other assays were re-cut. *Id.* According to Tallett, "[t]he petroleum industry has been 'recutting' assays for at least 50 years and in the process has developed reliable, accurate methods for interpolating both yields and quality properties." *Id.* He adds that, if the industry could not do this, new assays would have to be done each time a company wanted to change a cut point and argues that re-cutting assays by use of "highly advanced, proven algorithms and 'crude assay manager' tools" is the industry practice. *Id.* Tallett asserts further that he has

> been specifically informed by Haverly that the CCR contents provided in their assays for the 1050ºF+F Resid cut are reliable. Indeed, crude assay managers arguably improve assay quality because they reconcile inevitable variances in original test points. The assay manager used by Haverly, and other sophisticated assay managers, perform cross checks that are likely to highlight test point errors and force a rigorous mass and property balance across the whole assay.

Id. at p. 14.

237. In addition to defending the assays he used, Tallett attacked the two Caleb Brett assays stating that its attempt to cut the ANS crude precisely along Quality Bank cut points raises questions regarding the assays's reliability. *Id.* Tallett claims that this procedure is not the "recommended ASTM distillation procedures." *Id.* He also argues that "such a procedure lacks the cross checks and quality assurance gained from applying standard interpolation techniques to data obtained through the recommended ASTM distillation procedures." *Id.*

238. Tallett next argues that Dayton's attempt to exclude three of the eight assays is baseless. *Id.* at p. 15. He believes that Dayton's argument is inconsistent, arbitrary, and illogical. *Id.* The result, Tallett maintains, of Dayton's attempt to exclude three of the assays would "[affect] the before-cost value only by increasing the value six cents per barrel of Resid. The effect of excluding the three assays is small and . . . no reasoned basis has been provided for excluding them." *Id.* at p. 16.

239. Finally, Tallett maintains that adding the two assays produced in discovery is appropriate and impacts his analysis by decreasing the before-cost value of Resid by 1¢/barrel. *Id.* at p. 17.

240. Further on the Resid issue, Tallett believes that using Bartholomew's coke price adjustments to account for the transporting, handling, and reselling costs is appropriate. *Id.* He argues that Ross's criticisms of Bartholomew's analysis is unjustified. *Id.* Noting that Ross accepts much of Bartholomew's testimony, Tallett asserts that Ross's testimony supports Bartholomew's testimony in Exhibit No. BPX-17 that "indicat[es] that without Mr. Bartholomew's adjustment, the Resid cut will be overvalued by approximately $10.82 million dollars for every 100 million barrels of petroleum passing through TAPS." *Id.* at p. 18. Further, Tallett asserts that Ross's testimony does not provide a reasonable basis for failing to adjust coke prices for the Resid cut, but merely claims that other cuts suffer from some degree of overvaluation due to transportation costs. *Id.* He concludes, "it would be arbitrary to overvalue Coke and the Resid cut on the grounds that perhaps some other cuts are overvalued." *Id.* at p. 19.

241. At the hearing, Tallett defended his use of a 60ºF cut point. Transcript at p. 2270.

Looking at the break point between C_4 butane and lighter streams, of which the highest boiling temperature is 41ºF (normal butane) and C_5 pentane of which the highest boiling point is 82ºF (isopentane), Tallett claims that it is "common practice in the industry to take those two temperatures and take the average between them, and that works out to 57 degrees, rounding to the nearest degree." *Id.* at p. 2271. Moreover, Tallett notes, as he was discussing a Coker and not a crude unit, a pentene unit with a 68ºF boiling point "would suggest a lower boiling point than for a corresponding crude." *Id.* at pp. 2271-72. He claimed that even ignoring the C_4 interaction "still suggests" a 58ºF cut point. *Id.* at p. 2272.

242. In additional support for his position, Tallett declared that the C_5 cut point used by Chevron was 60ºF, by Exxon 68ºF, by BP 70º, and that three assays submitted by Phillips for Alpine and Northstar used a 70ºF cut point. *Id.* He argues that "people who are in the business tend to pick somewhere in the range of 60 to 70 degrees Fahrenheit as the effective cut-point." *Id.* Tallett also declared that experts told him that "60 to 70 degrees" was the correct cut point. *Id.* at pp. 2272-73. Lastly, in this discussion, Tallett asserted that ASTM procedure D-2892 uses a 59ºF cut point between C_4 and C_5. *Id.* at p. 2273. He concludes by stating that: "When you add all of those together, I think that indicates, from a variety of angles, that 60 to 70 degrees is the typical accepted figure in the industry." *Id.* at pp. 2273-74. Questioned about what C_5 cut point was used in the PIMS model, Tallett noted that it was 96ºF. *Id.* at p. 2550. However, he noted that the assays in this record reflected a C_5 cut point range of 60º to 70º F and that the Quality Bank used 70ºF. *Id.* at pp. 2550-51. Tallett also asserted that, in a Coker, isopentene, the lowest boiling point C_5, boils at 68ºF, while the lowest boiling point C_5 in a crude cut is isopentane at 82ºF. *Id.* at p. 2551.

243. Tallett, in further direct examination, again addressed the matter of changes in the ANS common stream, stating that an increase in the percentage of natural gas liquids in the stream increased "the volumes of C_3, C_4s and potentially light straight run naphtha, and reduce the percentages of all the other streams, including resid." *Id.* at p. 2547. He also indicated that these changes have offset the increased take of distillates by the refineries which, otherwise, might have caused an increase in the Resid content of the common stream. *Id.* at pp. 2546-47. Moreover, he added, while the Kuparuk stream (which includes the Alpine and Northstar streams) may have stayed constant as the other streams composing the ANS common stream have decreased, changes in the latter have been sufficient to offset the increase one would have expected from the increased percentage of the common stream represented by the Kuparuk stream. *Id.* at p. 2547.

244. On cross-examination, Tallett admitted that the lowest C_5 boiling point is 82ºF. *Id.* at p. 2352. He also agreed that pentenes are C_5 olefins, which are lighter (have a lower molecular weight) than C_5 pentanes, whose lowest boiling point is 68ºF. *Id.* Tallett added:

What we're looking at here is to try to determine what is a reasonable representation of the cut-point between C_4s and lighter on the one hand, and what we're terming C_5 and heavier on the other hand.

So we're concerned about the barrier or the edges of those cuts. When you do that, what you're concerned about is you have lighter boiling compounds in the C_4 minus cut methane, ethane, propane and you have heavier boiling compounds in the C_5, the LSR cut.

And as you just mentioned, as you said, you have these other pentanes you have these other pentanes that boil on the higher temperatures and you have hexanes, heptanes and so on all boiling at progressively higher temperatures.

We're trying to get at, as I said, what's the edge here? What are the two edges? What's the end of the C_4 and the beginning of the C_5? What we're concerned with is the highest boiling point compound in the C_4 minus fraction, and that's normal butane, the lowest boiling point compound in the C_5 plus LSR fraction, and that's isopentane. That's what we're concerned with - - those two, one boils at 31 degrees and one at 82.

The reason people tend to take an average of those two in real-life distillation units, you do not get absolutely perfect fractionation - - separation between the fractions. So you tend to get some small amounts of C_4s in the C_5 plus cut and you tend to get some small amounts of C_5s in the C_4 minus cut, and that's the reality of life in refining. Consequently, to reflect that, what people do is to take often the middle of the range of boiling points between, in this case, the highest C_4 and the lowest boiling point C_5.

Again, going back to another point I made this morning is I think if you were correct, the question is why does the ASTM procedure D-2892 say what it says? Why are the instructions to the operator in the debutinization section of the text, why do they say, when you boil it off to 15 degrees centigrade, which is basically 59 Fahrenheit, then stop and wait, hold at that temperature to make sure you've got all the C_4 minus material boiled off.

If [the Eight Parties] are correct, I think what that procedure would say is to stop and wait at 100 degrees F. It doesn't say that. It says 59.

Id. at pp. 2364-66.

245. When asked to discuss which assay(s) should be used on a going forward basis, i.e., which assay should be used to set the value of ANS cuts from the present into the future, Tallett agreed that the 2001 Phillips (Caleb Brett) assay, which reflected the opening of the two newest ANS fields for production, was a "start," but suggested that at least a second assay should be taken. *Id.* at pp. 2391-92. But, on further cross examination, Tallett agreed that another assay would not be needed "until such time as there were significant changes that would impact the ANS common stream at pump station 1" provided there was a system for signaling when such an assay was necessary *Id.* at p. 2398. Later, Tallett suggested that, if a second assay was taken, he would recommend that that assay be used rather than the one performed in 2001. *Id.* at p. 2474.

246. Tallett agreed that all ANS cuts should be treated alike, i.e., if one is over-valued, all should be over-valued. *Id.* at p. 2461. He also conceded that "if you were to undervalue the resid cut and overvalue the heavy distillate cut, . . . it could have adverse effects on some of the shippers on TAPS." *Id.* at pp. 2461-62. But Tallett argued that differences in handling and transportation cost allows for treating one cut differently than the others. *Id.* at p. 2462. He claimed, for example, that coke "is unlike any other product that goes out of the refinery" because it is solid, lower valued, and costs more to transport. *Id.* at pp. 2462-63.

I. JAMES H. GARY

247. The next Exxon witness was Professor James H. Gary ("Gary"), a retired chemical engineering professor. Exhibit No. EMT-116 at p. 3. Gary explains that he is the co-author, with Glenn Handwerk, of *Petroleum Refining, Technology and Economics*. *Id.* at p. 4.

248. According to Gary, use of a location factor is necessary because refinery construction costs are higher on the West coast than on the Gulf coast. *Id.* at p. 7. In that claim, Gary includes construction labor costs, permitting costs, the costs of meeting environmental standards, as well as the cost of meeting other governmental regulations. *Id.* Citing the data in his book, Gary claims that "these costs vary from 20% higher in the northern West Coast areas to 40% higher in the Los Angeles area as compared to Gulf Coast costs." *Id.* He adds:

> This cost differential is too great to ignore. The accepted way to make a cost curve estimate is to make as accurate an estimate as possible by including the ISBL and the OSBL costs, and then to multiply the sum of these two by a location factor based on where the refinery is to be built. Even using this technique, the accuracy of cost curve estimates is only within ±25%. To neglect including known items using the excuse that the cost curve estimates are not precise, means that the final estimate may vary from actual by as much as ±50% or more.

Id.

249. Claiming a range of 1.20 to 1.40, Gary asserts that, in general, the appropriate location factor for a West Coast facility should be 1.30. *Id.* at p. 8. He criticizes O'Brien for not using a West Coast factor. *Id.* According to Gary, even if a West Coast refiner could get portions of a refining unit built in Asia at a lower cost, the higher labor costs as well as the higher permitting costs and the higher costs of meeting stricter West Coast environmental standards more than offset those savings. *Id*.

250. Gary also declares that O'Brien misused the Gary & Handwerk text in estimating the ISBL and OSBL costs for a 40,000 barrels/stream day West Coast Coker in four particular areas:

> First, Mr. O'Brien used a cost curve from the Gary & Handwerk text based on Gulf Coast costs to estimate the cost of building a Coker on the West Coast. . . . Mr. O'Brien should have multiplied the Gulf Coast costs by a factor of at least 1.3 to convert Gulf Coast construction costs to West Coast construction costs.
>
> Second, cost curves are designed to reflect the significant effect of unit size or capacity on costs of similar process units. However, cost curve estimates do not allow one to identify the costs of individual components that make up a process unit. Therefore, Mr. O'Brien's attempt to back out the costs of specific elements from the costs of a Coker – namely, dewatering and water purification, Coke crushing and screening equipment, and covered storage – is an inappropriate use of cost estimates obtained from cost curves.
>
> Third, Mr. O'Brien provided very little information about the costs deducted from the cost curve-based ISBL estimate of $175.0 million. . . . In addition, the costs deducted ($37.5 million) comprise over 21% of the total cost of the Coker ($175.0 million) using the Gary & Handwerk cost curves and more than 33% of Mr. O'Brien's ISBL Coker cost. Although these facilities' costs are not insignificant, they would not account for such a large portion of the total Coker cost.
>
> [Fourth,] Mr. O'Brien misapplied the Gary & Handwerk text in determining the costs of OSBL facilities needed for the Coker.
>
> * * * *
>
> To estimate OSBL costs, Mr. O'Brien applied an OSBL cost factor of 22.5% . . . to the cost of the Coker. If Mr. O'Brien is adding a coker to an existing refinery, that is a correct application of the Gary & Handwerk

> text. . . . However . . . one must also add to these OSBL costs the costs of storage tanks, steam generation equipment and cooling water systems. Mr. O'Brien's omission of the costs of these major refinery facilities . . . substantially understates the costs of coking Resid.

Id. at pp. 9-10, 12. On the other hand, Gary applauds Jenkins's use of the Gary & Handwerk text in his estimate of OSBL costs for a Coker and downstream processing units. *Id.* at p. 12.

251. Continuing his critique of O'Brien's analysis, Gary delves into the second point – the costs of sulfur recovery facilities. *Id.* at p. 12. He explains that sulfur recovery facilities are needed when Resid is processed in a Coker because the sulfur in crude oil is concentrated in the heavier cuts, i.e., those having a higher boiling point. *Id.* at p. 13. Therefore, according to Gary, the concentration of sulfur in Resid is frequently twice as high as that in the crude. *Id.* Consequently, he adds, during the coking process, the "sulfur will be converted to hydrogen sulfide and other volatile organic sulfur compounds." *Id.* While, through hydrotreating, the organic sulfur compounds are converted to hydrogen sulfide, environmental regulations require that "the sulfur in hydrogen sulfide and in other Coker products must be converted to elemental sulfur in the refining process." *Id.*

252. Gary next asserts that 100% sulfur processing equipment backup is necessary because, he argues, "if one unit has operation problems and has to be take off-stream, the other unit could be placed on-stream to process the sulfur-laden gas" to avoid having to shut down the refinery entirely as it cannot operate without processing the sulfur in the crude. *Id.* at pp. 13-14, 15-16. According to Gary:

> [u]sing methods described in the Gary & Handwerk text, the sulfur and tail-gas treating units for the two 50 LT/D units (Mr. O'Brien's figures) would cost approximately $45 million (ISBL and OSBL) for Gulf Coast construction and $58 million (ISBL and OSBL) for West Coast construction in 1999 dollars. The costs for the two 90 LT/D units (Mr. Jenkins' figures) would be approximately $56 million ISBL and OSBL, Gulf Coast) and $73 million (ISBL and OSBL, West Coast) in 1999 dollars.

Id. at p. 14.

253. Addressing the issue of the benefit to a refiner from the sale of sulfur and from product "swell" created in hydrotreating Coker products raised by both O'Brien and Jenkins, Gary, disagreeing with the two experts, states that "[t]here is an excess of sulfur on the world market today, and, as a consequence, it is necessary to pay up to $15 per LT to remove it from the refinery." *Id.* at p. 15. He continues, arguing that as "the product 'swell' is produced by adding hydrogen to the sulfur-containing components . . . .

because hydrogen is expensive, hydrogen costs will tend to offset any value increase due to product 'swelling.'" *Id.*

254. In his Rebuttal Testimony, Gary responds to O'Brien's contention that certain facilities should be excluded from ISBL costs. Exhibit No. EMT-191 at p. 3. He states that O'Brien was incorrect in asserting that the Gary & Handwerk text argues that light ends recovery and off-gas compression facilities are typically included in the OSBL factor. *Id.* According to Gary, gas recovery facilities are typically included in ISBL costs. *Id.* at pp. 3-4. He explains that, as these facilities are part of the gas processing unit, they are "inside" the battery limits of the refinery – and properly treated as ISBL costs – rather than OSBL costs. *Id.* at p. 4.

255. However, he notes, the Gary & Handwerk text does not include the costs of these facilities in the ISBL costs for the Delayed Coking unit. *Id.* Instead, he asserts, the costs of the gas recovery facilities are separately estimated. *Id.* The specific light ends recovery and off-gas compression facilities that O'Brien proposes to exclude from Jenkins's detailed Coker cost estimate, Gary maintains, are among the facilities listed for the refinery gas processing unit. *Id.* at p. 5.

256. These light ends recovery and off-gas compression facilities, he argues, are part of a refinery process unit, and, consequently, these facilities costs should be separately estimated. *Id.* at p. 5. Gas recovery facilities, he notes, are fundamentally different from facilities typically captured in the OSBL factor. *Id.* Therefore, he contends, it is unusual to treat gas recovery facilities as OSBL facilities. *Id.*

257. Under cross-examination, Gary agreed that he has no experience in "assessing the value of domestic or foreign crude oil[,] . . . the value of petroleum products[,] . . .with oil pipelines[, nor before this proceeding] . . . relating to oil pipeline quality banks." Transcript at pp. 2600-01. He also agreed that he had done no "research with respect to delayed cokers" and that he had no data related to the capital cost of "specific West Coast and Gulf Coast coker products." *Id.* at p. 2601.

258. Gary testified further that the cost curves in his book were based on data collected in the two years prior to publication of each edition, as was the information on processing units in the book. *Id.* at p. 2604. According to Gary, the data was received from people either he or his co-author knew in the industry and is, for all intents and purposes, based on anecdotal information. *Id.* at pp. 2656, 2658-59. He also indicated that some of the data in the first edition, e.g., yield data, was unchanged in the fourth edition because "[i]t's hard to get data like that." *Id.* at pp. 2657-58.

259. According to Gary, it would be impossible to construct a cost curve for which a location differential did not have to be used. *Id.* at p. 2659. That is, if a cost curve was created based upon data for a specific geographical location, to use that curve in another

location, a location factor would have to be applied. *Id.* He added that the cost curves in his book are based on Gulf Coast data as most refinery construction takes place there. *Id.* at p. 2660. Moreover, according to Gary, use of a cost curve adjusted for geographical location is only going to be ±25% accurate.[68] *Id.* Without the use of a location factor, Gary asserts, the cost curve will only be ±50% accurate. *Id.* He went so far as to express surprise that cost curves were being used in this case because of their inherent inaccuracy and added that both he and his co-author believe that it would be "much better to do a detailed estimate where even though it's going to cost $2 or $3 million to get it, rather than something you can get out of a book like ours." *Id.* at p. 2661. He explained the reason why the cost would rise so high:

> [I]t requires a lot of engineering manpower, and to get a detailed estimate, you have to really specify the equipment to a detail such that you can get adequate costs on it, whereas in a cost curve we're talking about an average cost. And that's why it's plus or minus 25 percent, because when you design a unit, you might be using all average pumps – all average fractionating towers and so on.

Id. at pp. 2665-66. In other words, Gary stated, sufficient engineering would have to take place so that all of the equipment would be specified. *Id.* at pp. 2666-67.

J. JOHN H. JENKINS

260. The next witness presented by Exxon was Jenkins. He is a Director of Jacobs Consultancy, Inc., which is a wholly owned subsidiary of Jacobs Engineering,[69] one of the ten largest engineering and construction companies in the United States. Exhibit No. EMT-37 at pp. 4-5.

261. Jenkins explains that prior to November 24, 1999, the Quality Bank used the price reported in Platts Oilgram Price Report for West Coast High Sulfur Waterborne Gasoil to set the value of West Coast Heavy Distillate. *Id.* at p. 11. On November 24, 1999,

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[68] Jenkins agreed with Gary that a cost curve with a location differential might be as much as ±25% off and may be as much as ±50% off without a location differential. Transcript at p. 3895.

[69] Jenkins explains that Jacob Engineering is "a large engineering company doing engineering construction procurement for refinery, petrochemical and a wide range of other industries." Transcript at pp. 3329-30. He adds that Jacobs Consultancy "does a little more of the front end feasibility, economics, those kinds of things than the engineering company." *Id.* at p. 3330. According to Jenkins, he used the resources of Jacobs Engineering in preparing his testimony. *Id.* at pp. 3330-31.

Jenkins continues, the Quality Bank Administrator notified the Commission, that on November 1, 1999, Platts had discontinued reporting prices for West Coast High Sulfur Waterborne Gasoil, and, instead, "Platts had introduced price assessments for a product having a much lower sulfur content – 0.05 wt% sulfur." *Id.*

262. Consequently, the parties in this case, Jenkins states, agreed that the replacement price should be Platts reported price for West Coast LA Pipeline Low Sulfur No. 2 Fuel Oil, but the parties disagreed "as to the appropriate adjustment to make to this price to reflect the costs incurred in reducing the sulfur content of the West Coast Heavy Distillate (which has a sulfur content of 0.57%) to 0.05 wt%." *Id.* at p. 12. Jenkins argues that the sulfur processing cost adjustment for virgin West Coast Heavy Distillate[70] cut should be \$1.82/barrel (4.3¢/gallon) in Year 2000 costs. *Id.* at p. 12.

263. Jenkins begins addressing the Heavy Distillate processing costs by detailing the capital costs involved in desulfurization. *Id.* at p. 13. "The unit needed to desulfurize the virgin Heavy Distillate cut from 0.57 wt% sulfur to 0.05 wt% sulfur is a medium-pressure Distillate Hydrotreater."[71] *Id.* (Internal quotes omitted; footnote added). Using a 50,000 barrel/day medium-pressure Distillate Hydrotreater in his cost study, Jenkins calculates three components of cost: capital recovery, fixed operating costs, and variable operating costs. *Id.*

264. The total capital costs for the West Coast, according to Jenkins, including the cost of the Distillate Hydrotreater, is \$86.3 million in Year 2000 dollars. *Id.* at p. 14. Jenkins states that he used costs reflecting a West Coast location because the reference price at issue is for a West Coast product and because construction costs on the West Coast are higher than the construction costs on the Gulf Coast. *Id.* Using Jacobs Consultancy's data base,[72] Jenkins continues, "the cost of a medium-pressure Distillate Hydrotreater on

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[70] Heavy Distillate is produced from a simple distillation of ANS crude oil, Jenkins explains, as well as from when the Resid cut of ANS crude is run through a coker and further processed in downstream units. Exhibit No. EMT-37 at p. 12. Jenkins states that he uses the term virgin Heavy Distillate to "distinguish the Heavy Distillate cut that is produced directly from the distillation of ANS crude . . . from the Heavy Distillate product that is produced in the coker operation. . ." *Id.* at p. 13.

[71] Jenkins explains that "[a] Hydrotreater is a refinery process unit whose primary purpose is to saturate and/or reduce the amount of certain impurities" in the feedstock. Exhibit No. EMT-37 at p. 13.

[72] On cross-examination, Jenkins described the database as follows: "It is a database that relates things like for fixed cost number of operators, percentage maintenance. I think those are the primary variables under fixed costs." Transcript at p. 2712. He also states that it includes a database of variable costs based on a "compilation

the Gulf Coast is $44.4 million in 2000 dollars. I multiplied that figure by a location factor of 1.3 to obtain a West Coast capital cost of $57.7 million, again in 2000 dollars" for the Distillate Hyrdotreater cost.[73] *Id.*

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of data. . . . from a number of projects [and published sources] over the years." *Id.* at p. 2713. Jenkins added the following:

> The database lists essentially every type of refining and some petrochemical units, and has figures for variable costs for each of those individually, and for fixed costs, we have operators. I believe that's the only component under fixed costs that is specific. Of course, fixed costs are driven by the capital, which is also in the database.

Id. at p. 2714.

[73] According to Jenkins, several outside sources support his West Coast location adjustment:

> First, a widely-regarded treatise – Gary & Handwerk's *Petroleum Refining, Technology and Economics* (4th ed. 2001) – notes at page 340 that "Plant location has a significant influence on plant costs." Based on 1999 data, Gary & Handwerk give a location adjustment of 1.4 for Los Angeles and 1.2 for Portland and Seattle. Second, a National Petroleum Council-commissioned study by Bechtel – one of the largest engineering contractors in the world – estimated in 1992 that the cost to build a unit in California would be 20% higher than the cost of building the unit on the Gulf Coast. Bechtel further opined that differences in building codes, environmental rules, and other design parameters would add another 20% for a total California factor of 1.4. Third, the September 11, 2000 edition of *Engineering News Record* provides relative cost indices for U.S. cities, including New Orleans, an area in which numerous refineries are located. While [*Engineering News Record*] applies to all types of construction and buildings, the data show that West Coast construction is far more costly than Gulf Coast construction. Of particular interest to this discussion is the difference in the hourly rate for common labor: 222% higher on the West Coast.
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> Fourth, an August 2000 study prepared for the American Petroleum Institute jointly by Charles River Associates and Baker and O'Brien, shows relative location factors on page 35. The study indicates that the factor used for the Gulf Coast is 1.0, that the average factor for Petroleum Allocation Defense District ["PADD"] 1-3 (Gulf Coast, East Coast, and the

265. Besides the cost of the Distillate Hydrotreater, Jenkins opines, "a refinery would have to construct utility systems and other facilities[74] to support operation of the Distillate Hydrotreater" as well as owner's costs and interest during construction. *Id.* at p. 16 (footnote added). Continuing, Jenkins states that offsite costs are typically estimated as a percentage of the cost of the major refinery unit in question "because, without having considerable detail regarding the precise design of a specific refinery, it is very difficult to identify all of the particulars of the offsite facilities that will be required to support new units added to the refinery." *Id.*

266. Jenkins adds that offsite costs typically account for a substantial portion of the total cost to a refinery, and that he uses the approach recommended in Gary & Handwerk's *Petroleum Refining, Technology and Economics* (4th ed. 2001) to estimate an appropriate offsite factor for the Distillate Hyrdotreater. *Id.* at pp. 16-17. The Gary & Handwerk method, Jenkins explains, separately estimates costs for three specific types of major support facilities (storage tanks, steam generation equipment, and cooling water systems) and then applies a percentage factor to the process unit costs to account for the costs of all of the other offsite facilities.[75] *Id.* at p. 17. Continuing, Jenkins adds that "the largest single support facility cost . . . would be for tankage to store the Distillate product. It is likely that a refiner would install two tanks[76] with total product storage capacity of

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> Midwest) is 1.075, and that the average factor for the entire country is 1.16. Because the difference between the PADDs 1-3 average and the U.S. average represents the addition of PADDs 4 and 5 to the mix (and PADD 4, primarily Mountain States, has less refining capacity than the other PADDs), one can make a very good estimate of the underlying West Coast (PADD 5) location factor. I estimate the PADD 5 factor inherent in the data to be 1.4. Thus, I believe that my use of 1.3 as a West Coast location factor is conservative.

Exhibit No. EMT-37 at pp. 14-15.

[74] Jenkins explains that these utility and other facilities are known as offsites or outside battery limit facilities. Exhibit No. EMT-37 at p. 16.

[75] For other facilities, Jenkins states, Gary & Handwerk suggest a factor equal to 20% to 25% of the process unit costs. Exhibit No. EMT-37 at p. 17.

[76] Jenkins argues that "any existing piece of equipment that will be used exclusively, or almost exclusively, by the Distillate Hydrotreater . . . should be part of the cost allocated to that unit. The product storage tank is not without cost, and would have alternative uses if not used to support the Distillate Hydrotreater." Exhibit No. EMT-37 at p. 18.

about 10 days' output. I estimate that the tanks would add about $10.5 million to the West Coast cost." *Id.* at p. 18 (footnote added). Concluding, Jenkins states that his estimate for all offsite costs is $22 million after using 20% of the process unit costs ($57.7 million) yielding $11.5 million to cover the other offsite costs. *Id.* at p. 19. According to Jenkins, the $22 million offsite costs is about 38% of the total onsite costs. *Id.* at 19.

267. As for owner's costs,[77] Jenkins estimates they are "6% of onsite and offsite capital costs, or $4.8 million in 2000 dollars." *Id.* at pp. 20-21. Jenkins further estimates that "[p]roject management can easily cost 2% - 3% of the total budget, while permitting, commissioning and start-up activities would account for the balance of the owner's costs." *Id.* at p. 21. Regarding interest during construction,[78] Jenkins estimated a total project schedule of 20 months for the initial engineering, permitting, construction, and start-up, including a 14 month construction period, and concludes that interest during construction adds $1.8 million in 2000 dollars for a Distillate Hydrotreater built on the West Coast (2.1% of the total capital cost of the project). *Id.* at pp. 21-22.

268. Using a capital recovery factor of 17% (representing both a return on capital and a return of capital), Jenkins multiplies the total capital cost by this percentage to yield an annual recovery charge. *Id.* at p. 22. Then, Jenkins divides the resulting figure by the total number of barrels processed in the Distillate Hyrdrotreater in an average year which yields a capital charge per barrel of 87¢/barrel in Year 2000 dollars. *Id.* Jenkins states

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[77] Jenkins describes owner's costs as

> [T]hree broad categories of capital costs: (1) the costs for owner's personnel at the construction site; (2) the cost of managing the construction project; and (3) preliminary operating costs. Thus, owner's costs include, for example, salaries and benefits for owner's personnel at the construction site; the cost of initial feasibility studies, permits, and licensing; and the costs for project management. . . . Preliminary operating expenses include the costs of recruiting and training operators, the costs of process unit commissioning start-up charges, and other costs normally associated with bringing a plant on-line.

Exhibit No. EMT-37 at p. 20.

[78] Interest during construction, according to Jenkins, is "the cost of borrowed funds, commonly referred to as 'interest expense,' incurred during the construction phase of a project. [Interest during construction] is a function of the interest rate, the amount of money borrowed to build the unit, and the spending schedule." Exhibit No. EMT-37 at p. 21.

that his cost estimate does not include costs for a Sulfur Plant because "both the sulfur and the additional hydrocarbon product[79] are sold by the refiner, revenues from these sources largely offset the cost of the Sulfur Plant." *Id.* (footnote added). Consequently, Jenkins explains that he chose not to include the costs for a Sulfur Plant because it would unnecessarily complicate the analysis. *Id.* at pp. 22-23.

269. Addressing fixed operating costs, Jenkins states that his study includes fixed costs such as operator wages, maintenance, administration, laboratory, and similar costs totaling just over $4.2 million per year, or 25¢/barrel in Year 2000 dollars. *Id.* at p. 23. As for variable operating costs, Jenkins explains that the variable costs include fuel, electricity, hydrogen, catalysts and chemicals, cooling water and process water and these costs total nearly $12 million per year, or 69¢/barrel in Year 2000 dollars. *Id.*

270. Jenkins explains how he valued the Resid cut by estimating its value as a feedstock to a Coker. *Id.* at p. 24. Under this approach, according to Jenkins, Resid's value is

> equal to the value of the Coker products, net of the costs incurred to convert Resid into Coker products that meet the quality specifications of the proxy products used to value the Coker products. These costs include capital, fixed operating and variable operating costs of building and operating a Coker and the downstream process units needed to refine the Coker products . . . to meet the quality specifications of the proxy products used by the Quality Bank to value the [ANS] cuts.

Id. He summarizes his conclusions regarding the total processing costs associated with processing Resid in a Coker to total $7.17/barrel on the West Coast and $5.88/barrel on the Gulf Coast in Year 2000 dollars. *Id.* Jenkins breaks down the summarized numbers further:

> (1) capital costs are $5.20 per barrel on the West Coast and $4.07 per barrel on the Gulf Coast for a Coker and all downstream units needed to process the Coker's output; (2) fixed operating costs of $1.71 per barrel on the West Coast and $1.41 per barrel on the Gulf Coast for operating the Coker and downstream processing units necessary to get the Coker products to proxy product specifications; and (3) variable operating costs

[79] The additional hydrocarbon product, according to Jenkins, is a byproduct of hydrotreating virgin Heavy Distillate and results in sulfur. Exhibit No. EMT-37 at p. 22. Additionally, Jenkins explains, there is a hydrotreating phenomenon known as "product swell," where a "greater volume of liquid and fuel gas product comes out of the hydrotreating process than went into the hydrotreater." *Id.*

> of \$1.30 per barrel on the West Coast and \$1.22 per barrel on the Gulf Coast for the same operations.

Id. at pp. 24-25.

271. As the sums of the capital, fixed operating, and variable operating costs Jenkins identifies are greater than the \$7.17/barrel and \$5.88/barrel on the West and Gulf Coasts, respectively he explains this outcome as a result of a credit he applies. *Id.* at p. 25. The credit, Jenkins explains, results from his choice to size the hydrotreating equipment and to select operating conditions which produce products exceeding the applicable proxy product specifications. *Id.* Therefore, Jenkins states, it is

> appropriate to apply a "credit" against the costs[80] to reflect the fact that some of the coker products are higher in quality than the virgin ANS cuts that are being valued in this estimate. These credits, in total, amount to \$1.04 per barrel on the West Coast and \$0.82 per barrel on the Gulf Coast in 2000 dollars.

Id. (footnote added).

272. Jenkins explains the capital costs line item estimate that he used: "I first identified all major equipment required in the Coker and the downstream units and calculated the cost of acquiring and installing that equipment. I then calculated the other capital costs associated with construction of the Coker and the downstream units – offsite costs, owner's costs and interest during construction." *Id.* at p. 26. He describes the West

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[80] Jenkins explains how he generally calculated these costs:

> I estimated the capital costs of the Coker and downstream processing on the basis of a detailed "line item" cost estimate in which I estimated the size and cost for all major equipment required in the Coker and downstream units as well as other capital costs. I then adjusted that estimate to account for the potential economies of scale that might be achieved in the downstream units if those units were sized to handle Coker outputs as well as the outputs of other upstream refinery units. Finally, I compared that estimate to the costs of nine actual Coker projects that were either completed within the last eight years or are currently under construction. For operating costs, I utilized Jacob Consultancy's in-house database to estimate the fixed and variable operating costs of the Coker and downstream units.

Exhibit No. EMT-37 at p. 26.

Coast location adjustment utilized in his estimates as adjusting “costs for all of the major construction components: equipment, piping, concrete, steel, electrical, insulation, painting, labor, engineering, and direct costs.” *Id.* at p. 27.

273. According to Jenkins, the major processing units required for Resid processing are a Delayed Coker, a Coker Gas Oil Hyrdrotreater, a Coker Naphtha Hydrotreater,[81] a Coker Distillate Hydrotreater and a Sulfur Plant.[82] *Id.* at pp. 27-28. The total cost estimate for these units, Jenkins continues, is $246.7 million on the West Coast and $194.1 million on the Gulf Coast in Year 2000 dollars. *Id.* at p. 28. Jenkins excludes the cost of installing selective catalytic reduction technology on these units.[83] *Id.*

274. A Delayed Coker, Jenkins states,

> is a refinery processing unit in which Resid is heated until it decomposes into light liquid petroleum products, gas, and Coke. Its equipment falls into two general classifications: (1) “Typical refinery equipment,” which includes the main fractionator (where the Coker Naphtha, Coker Distillate, and Coker Gas Oil are separated), most of the pumps and exchangers, and the gas separation equipment; and (2) “Specialty equipment,” which includes the Coke drums, jet pump, Coker furnace feed pump, the deheading system, and other equipment that is specific to cokers and is not used in any other type of refinery process.

Id. at pp. 28-29.

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[81] Under examination by Judge Wilson, Jenkins explained how a Coker Naphtha hydrotreater functioned. *See* Transcript at pp. 3880-81. According to Jenkins, a Coker Naphtha hydrotreater is unique because it must handle “diolefin materials” (a compound deficient in hydrogen) which are in the stream. *Id.* In order to accomplish this, the stream containing the diolefins must be heated to 650ºF so that the molecules combine with hydrogen, become less reactive, and can be heated up and moved on without gumming. *Id.* at p. 3881.

[82] Jenkins states that the Sulfur Plant consists of an amine unit, a sulfur recovery unit, and a tail gas treating unit. Exhibit No. EMT-37 at p. 28.

[83] Selective catalytic reduction technology, Jenkins explains, “is currently installed on fired heaters to reduce nitrous oxide emissions, and is required on large furnaces in California. Adding this equipment to [Jenkins’s] estimate would increase the capital costs on the West Coast by approximately $10 million in 2000 dollars.” Exhibit No. EMT-37 at p. 28.

275. Jenkins explains that his Coker cost study calculated the cost of constructing a 40,000 barrel/stream day Coker, which is a Coker with a capacity to process 40,000 barrels/day of 1050º+F Resid, and he assumes an annual utilization rate for the Coker of 87% (reflecting downtime for maintenance and related functions). *Id.* at p. 29. Cokers operate, Jenkins states, in a semi-batch mode, where two drums are simultaneously filled while two already filled drums are "de-Coked." *Id.* at p. 30. The methodology for Jenkins's capital costs in the cost study, he maintains, used standard cost estimating techniques.[84] *Id.* at p. 32. Additionally, for the capital costs of the Coker's specialty equipment, Jenkins states he uses vendor quotations. *Id.* In addition to costs for the principal specialty equipment, Jenkins applies installation multipliers[85] to arrive at a total installed cost for each item of equipment. *Id.* at p. 33. The resulting Coker cost[86] estimate, Jenkins relates, is $173 million for the West Coast and $138 million for the Gulf Coast in Year 2000 dollars.[87] *Id.*

276. The Coker Gas Oil Hyrdrotreater, Jenkins explains, is a refinery unit downstream of the Coker used for hydrotreating[88] Gas Oil produced from the Coker.[89] *Id.* at p. 35.

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[84] The standard cost estimating techniques, according to Jenkins, were developed by Jacobs Consultancy and the Jacobs Engineering Group, and are based on computer estimates, public data, and vendor quotations. Exhibit No. EMT-37 at p. 32.

[85] The multipliers, Jenkins states, include individual factors for all of the major cost components such as cement, steel, labor. Exhibit No. EMT-37 at p. 33.

[86] The items included in this estimate, Jenkins explains, include the Coker costs, a basic handling system for the Coker (a coke pit, clamshell loader, hopper, and closed conveyor), as well as equipment to process the liquefied petroleum gas produced by the Coker. Exhibit No. EMT-37 at p. 33.

[87] In support of the cost estimates, Jenkins offers that Gary & Handwerk's treatise calculates a higher cost than Jenkins's study ($255 million versus $173 million), and a treatise by R.A. Meyers, *Handbook of Petroleum Processes* (1993), provides a range of $158 million to $316 million on the West Coast based upon tons of coke produced per day. Exhibit No. EMT-37 at p. 34.

[88] According to Jenkins, "hydrotreating is a process whose primary purpose is to saturate and/or reduce the amount of certain impurities . . . in the feedstock to the unit." Exhibit No. EMT-37 at p. 35.

[89] Jenkins explains why a Coker Gas Oil Hydrotreater is necessary:

> One of the nine Quality Bank cuts is Vacuum Gas Oil. . ., the material that boils off between 650ºF - 1050ºF. The sulfur content of this virgin Gas Oil cut is 1.28 wt% sulfur. I refer to this as "virgin" Gas Oil to distinguish it

He chose to design a Coker Gas Oil Hyrdrotreater, Jenkins states, having about 0.3 wt% sulfur rather than 1.28% sulfur because such a unit is more representative of what a refiner would do in these circumstances as well as because the resulting product's other quality parameters would be closer to those of virgin Gas Oil. *Id.* at p. 36. In order to compensate for the differing sulfur content, Jenkins relates, he estimated a product quality credit that he subtracted from the overall capital cost of the Coker Gas Oil Hydrotreater. *Id*. Jenkins explains his process:

> On the West Coast, there are quotes for low and high sulfur Gas Oil. The price differential between these two products averaged 5.4 cents per gallon during the year 2000. Multiplying this differential times the yield of Coker Gas Oil produces a credit of $0.67 per barrel of Resid feedstock to the West Coast Coker. There are similar quotes for low- and high-sulfur Gas Oil on the US Gulf Coast. Using differentials in this market for 2000, I calculated a capital cost credit of $.51 per barrel on the Gulf Coast.

Id. at pp. 36-37. Characterizing the Coker Gas Oil Hyrdrotreater as a medium-pressure Gas Oil Hyrdrotreater operating at 750 psig, Jenkins concludes that such a Hydrotreater would cost $20.8 million on the West Coast, and $16.3 million on the Gulf Coast in Year 2000 dollars. *Id.* at p. 37.

277. A Coker Naphtha Hydrotreater,[90] Jenkins explains, is necessary because coking ANS Resid produces substantial quantities of Coker Naphtha which is poor in quality

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> from the coker Gas Oil that is produced by the coking of Resid. The sulfur content of this Coker Gas Oil is higher – approximately 2.3 wt% – in comparison to the virgin Gas Oil sulfur content. Coker Gas Oil also contains olefins and other contaminants that are not found in the virgin material. Consequently, Coker Gas Oil must be hydrotreated to reduce its sulfur content to the virgin Gas Oil specification for this cut. . . . However, it is technically impossible to design a refinery unit that can produce a product... that simultaneously conforms to all of the virgin Gas Oil specifications. If one were to hydrotreat Coker Gas Oil to 1.28 wt% sulfur, the nitrogen content (which is an important quality parameter) of the resulting product would still be much higher than the nitrogen content of the virgin Gas Oil.

Exhibit No. EMT-37 pp. 35-36.

[90] Jenkins explains that the Coker Naphtha Hyrdrotreater is a refinery unit downstream of a Coker used for hydrotreating the Naphtha produced from the Coker. Exhibit No. EMT-37 at p. 37.

relative to virgin ANS Naphtha. *Id.* at p. 38. Expanding on the quality of the Coker Naphtha, Jenkins states that "Coker Naphtha contains olefins and di-olefins and is higher in nitrogen and sulfur than virgin Naphtha. A unit designed to bring these non-sulfur properties in the Coker Naphtha up to the proxy product's specifications would produce a product with less sulfur than the proxy product specification." *Id.* Jenkins explains how the Coker Naphtha Hyrdrotreater works,

> Because di-olefins readily form harmful gums at higher temperatures, hydrotreating of Coker Naphtha requires a two-step process using two reactors in series. The first reactor saturates di-olefins at moderate temperatures, while the second reactor completes the saturation process and also removes sulfur and nitrogen. A small tower, used to separate light Naphtha and heavy Naphtha, is also required to produce cuts that are consistent with the Quality Bank cut specifications.

Id. at p. 38. Furthermore, Jenkins concludes, [u]sing the same approach in estimating the cost of [a Coker Naphtha Hydrotreater] . . . for estimating the cost of the Coker itself, [he] estimate[s] the capital cost of the Coker Naphtha Hydrotreater to be $10.8 million on the West Coast and $8.4 million on the Gulf Coast in 2000 dollars." *Id.* at p. 39.

278. The Coker Distillate Hydrotreater,[91] according to Jenkins, "is necessary because coking ANS Resid produces substantial quantities of Coker Distillate, which must then be treated in a Distillate Hydrotreater to reduce the sulfur content to that of the proxy product . . . used by the Quality Bank to value the Heavy Distillate cut." *Id.* The cost for a Coker Distillate Hydrotreater, Jenkins continues, is similar to the Distillate Hydrotreater processing virgin ANS Distillate cut; however, the Coker Distillate Hydrotreater is more expensive on a per barrel basis because the Coker Distillate contains more sulfur and other contaminants than does virgin Heavy Distillate cut. *Id.* at pp. 39-40. Jenkins estimates that the cost for a Coker Distillate Hydrotreater would be $16.6 million on the West Coast and $12.9 million on the Gulf Coast in Year 2000 dollars. *Id.* at p. 40.

279. Adding that the output of the hypothetical Coker Distillate Hydrotreater would be lower in sulfur than the sulfur content of the virgin Heavy Distillate cut, Jenkins compensates by calculating a product quality credit which is subtracted from the hydrotreating costs to account for the higher quality product. *Id.* Jenkins, explaining that there is no market-based differential available in this case, uses the results of his study of the cost to hydrotreat virgin Heavy Distillate to produce 0.05 wt% sulfur Distillate. *Id.* "Applying the 4.3 cents per gallon figure (in 2000 costs) to the yield of Coker Distillate

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[91] According to Jenkins, a Coker Distillate Hydrotreater is a refinery unit downstream of the Coker used for hydrotreating the Distillate produced from the Coker. Exhibit No. EMT-37 at p. 39.

results in a credit of $0.37 per barrel of ANS Resid which should be subtracted from the cost of processing the coker Distillate," Jenkins states. *Id.* Furthermore, after adjusting for lower costs on the Gulf Coast, Jenkins concludes that the Gulf Coast credit should be 31¢/barrel of ANS Resid. *Id.* at p. 41.

280. Jenkins explains that a Sulfur Plant "is a refinery unit downstream of the Coker, the purpose of which is to convert hydrogen sulfide gas produced from coking and desulfurization into elemental sulfur." *Id.* at p. 42. Also, Jenkins continues, a Sulfur Plant is necessary because "[h]ydrogen sulfide gas is one of the outputs of the Coker and the three downstream hydrotreater units. Hydrogen sulfide must be removed from the gas before it can be burned as fuel in a refinery." *Id.* at p. 42. Continuing, Jenkins describes how the process works,

> In crude oil refining, hydrogen sulfide is separated from fuel gas in an "amine unit" using a special class of chemicals. The hydrogen sulfide is then sent to a "sulfur recovery unit," where it is converted into elemental sulfur. A basic sulfur recovery unit converts only about 98% of the hydrogen sulfide to sulfur, so it is necessary to add a "tail gas" treating unit to meet environmental regulations. It is also necessary to remove small amounts of hydrogen sulfide and light hydrocarbons/sulfur compounds from the Propane, Normal Butane, and Isobutane . . . that are produced by the coking of the Resid. The processing is typically done in a refinery unit known as a "caustic wash tower," followed by a licensed process called a "Merox unit."

Id.

281. Jenkins explains that a sulfur recovery unit and tail gas unit are necessary to protect the environment from releases of harmful sulfur dioxide, and, consequently, most states require a 100% back up capacity – two sulfur recovery/tail gas units. *Id.* at p. 43. The recovery/tail gas unit, Jenkins adds, are proprietary. *Id.* Furthermore, Jenkins maintains, "sulfur plants are typically a combined 'package' of each of these units, meaning the refiner buys an entire plant rather than its constituent parts." *Id.* As a result, Jenkins states, he could not use the same approach for the Sulfur Plant as for the other facilities and, therefore, relies on the Gary & Handwerk treatise to estimate the cost of the Sulfur Plant. *Id.*

282. Back up Sulfur Plant capacity, according to Jenkins, is determined in the permitting process and California has been requiring increased amount of back up capacity over approximately the past ten years. *Id.* Consequently, Jenkins assumes a 100% back up capacity. *Id.* The Sulfur Plant, Jenkins states, will produce a daily total of approximately 90 long tons of sulfur. *Id.* at p. 44. Furthermore, Jenkins explains, sulfur produced from the Coker and downstream hydrotreaters should be treated differently

because hydrotreaters produce product swell and the revenues from the sale of the product partially offsets the cost of constructing a Sulfur Plant to handle the sulfur produced from these units (however this is not so for sulfur produced directly by a Coker). *Id.* at pp. 44-45. Consequently, Jenkins assumes that the "revenues resulting from product swell and sulfur sales would offset the costs of the Sulfur Plant to handle sulfur from these hydrotreaters." *Id.* at p. 45. Jenkins states that, if the Coker produces 50 long tons of Sulfur per day, it is reasonable to include a single 100 long tons Sulfur Plant to treat Sulfur produced directly from the Coker. *Id.* Concluding, Jenkins adds that he estimates costs of $24.7 million in Year 2000 dollars on the West Coast, and $19.0 million on the Gulf Coast, also in Year 2000 dollars, for the net cost of all sulfur recovery facilities. *Id.* at p. 46.

283. Other capital costs, according to Jenkins, include offsite costs, owner's costs and the cost of borrowed funds used in construction (or interest during construction.) *Id.* The total amounts for these costs, Jenkins concludes, are $172 million on the West Coast and $133 million on the Gulf Coast in Year 2000 dollars. *Id.*

284. Jenkins explains offsite costs as referring to support systems required to service the coker and downstream processing units. *Id.* at p. 47. These costs, Jenkins relates, include additional electric power distribution, steam generation/distribution, boiler feed water preparation, cooling water systems, fire water systems, waste water treating, compressed air, instrument air, and nitrogen. *Id.* Additionally, Jenkins continues, "[t]he Coker and downstream processing units also require a new flare system because, in petroleum refining, flare systems prevent over-pressuring of vessels and pipes during emergency situations . . . by allowing the safe ventilation and burning of gaseous hydrocarbons." *Id.* Finally, Jenkins adds that the Coker and downstream processing units require offsite equipment such as roads, buildings, and tanks for storage of feedstock and intermediate products. *Id.*

285. Explaining that he relied on the Gary and Handwerk methodology to estimate offsite costs for the Coker and downstream units, Jenkins states that he first estimated the costs for the three primary offsite components (steam, cooling water, and storage tanks) and then applied a factor to the process unit costs to obtain the costs of the other offsite facilities needed to support the Coker and downstream units. *Id.* at p. 48. The total offsite costs, according to Jenkins, are $118 million on the West Coast, including $57 million for storage tanks,[92] steam and cooling water, and $62 million (after applying a

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[92] Jenkins explains that:

> Tanks are a major component of the offsite costs, with the largest and most costly tanks being for Coker feedstock. For my estimate, I sized the feed tank to hold 15 days' volume of Coker feed (Resid). . . . Because Cokers have lower utilization rates than do most other refinery units, failure to

25% factor) for other offsites; for the Gulf Coast, Jenkins states that the total offsite costs are $91 million. *Id.* at p. 49. In Jenkins's view, a Delayed Coker and the associated downstream hydrotreaters require more offsite support than the Distillate Hydrotreater. *Id.* Additionally, Jenkins states, these offsite cost estimates include only those costs for the offsite facilities that would be added or modified to support the Coker and downstream processing units. *Id.* at p. 50. Jenkins maintains that, although some storage tanks would already exist at a refinery, these existing tanks would have alternative uses at the refinery and, because their entire use is dedicated to Coker feedstock service, their entire cost should be attributed to the coking process. *Id.* at pp. 51-52.

286. As for owner's costs for the Coker and downstream units, Jenkins determines that owner's costs range from 9% to 17% of the total construction costs, and recent projects financed with general corporate funds incurred owner's costs in the range of 10%.[93] *Id.* at p. 52. Using the 10% figure, Jenkins concludes that the owner's costs estimate is $36 million on the West Coast and $28.5 million on the Gulf Coast. *Id.* Regarding interest during construction, Jenkins concludes that it adds $17.3 million for the West Coast, and $13.5 million for the Gulf Coast in Year 2000 dollars. *Id.* at pp. 53-54.

287. The total combined estimate, according to Jenkins, for the total capital costs for the West Coast Coker and downstream processing units ($246.7 million), total offsite costs, owner's costs, and interest during construction ($172.3 million) is $419 million in Year 2000 dollars. *Id.* at p. 54. Using the 17% capital recovery recommended by Toof, Jenkins concludes that the proper capital recovery is $5.61/barrel of Resid feedstock in Year 2000 dollars. *Id.* The comparable numbers, Jenkins states, for the Gulf Coast Coker and downstream processing units ($194.1 million), owner's costs, and interest during construction ($132.2 million) is $327.3 million in Year 2000 dollars. *Id.* Applying the 17% capital recovery rate, Jenkins concludes, the proper capital recovery for the Gulf Coast is $4.38/barrel of Resid feedstock. *Id.*

> install sufficient Coker feedstock tankage would make the overall refinery operation dependent upon the Coker operation. In other words, without a Coker feed tank, all refinery units would have to shut down if the coker were not operating, simply because there would be no place to put the Resid while it was waiting to be run in the Coker.

Exhibit No. EMT-37 at p. 48.

[93] Jenkins explains that "many recent coker projects have used off-balance sheet financing known as 'project financing,' and these projects tended to incur higher owner's costs than corporate-financed projects due to lender's fees and special requirements. However, most of the projects using the 'project financing' approach have not been built in California." Exhibit No. EMT-37 at p. 52.

288. Jenkins explains that his cost estimates assume that a Coker is added to an existing refinery, and, consequently, each downstream processing units is sized to handle the specific requirements of the Coker. *Id.* at p. 55. However, Jenkins admits that

> [i]f the coker were to be built at the same time as the refinery, some savings might be realized by sizing the hydrotreaters and Sulfur Plant to handle both the coker outputs . . . and the outputs of the other upstream refining units. However, because the coker products contain significantly more contaminants than the virgin ANS cuts, it might be necessary to install higher-pressure units to process both the virgin material and the coker products, which in turn would result in higher capital costs for those units. The costs of the coker unit would be the same regardless of whether the coker was constructed at the same time as the refinery, or was added later.

Id. The potential cost savings attributable to economies of scale, Jenkins relates, could be as high as $23.3 million on the Gulf Coast and $30.3 million on the West Coast. *Id.* at pp. 55-56. Consequently, Jenkins reduces his West Coast and Gulf Coast capital cost estimates to reflect these potential cost savings and determines that, for the West Coast, the capital cost for Coking Resid is reduced from $5.61/barrel to $5.20/barrel and, as for the Gulf Coast, it is reduced from $4.38/barrel to $4.07/barrel. *Id.* at p. 57.

289. Jenkins compares his adjusted capital cost estimates to seven real world Coker projects,[94] and explains that one of these projects is a West Coast project whose costs are $10,331/barrel as compared to Jenkins's estimate of $9,720/barrel (including owner's costs and interest during construction) for his model. *Id.* at pp. 59-60. As for the Gulf Coast, Jenkins states that four of the remaining six projects are Gulf Coast projects and the costs associated with these projects fall in a range between $6,667 and $9,375, and that his Gulf Coast estimate of $7,600/barrel (including owner's costs and interest during construction) falls within the range of the four projects. *Id.* at p. 60.

290. Addressing the question of operating costs, Jenkins states, there are two components of operating costs – fixed and variable costs. *Id.* at p. 61. Fixed operating costs for the Coker, downstream units, and offsites, Jenkins estimates to be $1.71/barrel on the West Coast, and $1.41/barrel on the Gulf Coast.[95] *Id.* The variable operating

[94] Jenkins explains that these seven Coker projects are either currently under construction or have been completed within the past eight years and that the source for the project data was public, except for two projects. Exhibit No. EMT-37 at p. 58.

[95] Jenkins states that the "Gary and Handwerk treatise yield[s] fixed operating costs for the Gulf Coast of $1.62 per barrel." Exhibit No. EMT-37 at p. 61.

costs, Jenkins continues, for the Coker, downstream units and offsites, are $1.30/barrel on the West Coast and $1.22/barrel on the Gulf Coast.[96] *Id.*

291. Finally, Jenkins explains why he believes his estimates are conservative:

> my detailed cost estimate does not include any costs for "contingencies." In refinery cost estimating, the term contingency is normally used to refer to costs that are not included in a line item, but that are likely to be spent. In any estimate of this type, it is normal to include a contingency factor of up to 20% to the total capital cost. I did not add any amount for contingencies. . . .I did not include an allowance for the cost of equity capital used during construction. I included only the cost of borrowed funds. . . . I did not include a cost for selective catalytic reduction equipment that would have to be installed to treat the combustion products from the coker furnace. . . . I have deducted a significant amount from my capital cost estimate to account for potential economies of scale, which economies may or may not be achievable. . . . I did not allocate any of these costs of the shared offsite facilities.

Id. at pp. 63-64.

292. In his rebuttal testimony, Jenkins responds to criticisms regarding his Resid processing cost calculations as well as his sulfur removal costs from West Coast Heavy Distillate. Exhibit No. EMT-146 at p. 4. As a preliminary matter, Jenkins compares his Resid approach with that of O'Brien. *Id.* at pp. 6-7. He notes that the difference in cost between the two approaches for the Gulf Coast is approximately $1.15/barrel in Year 2000 dollars. *Id.* at p. 11. Most of the difference, according to Jenkins, (90¢/barrel) is attributable to differences in capital cost estimates. *Id.* As for the West Coast, he asserts, the difference is greater ($2.37/barrel) because O'Brien does not adjust his cost estimate by using a location factor. Id.

293. Jenkins explains that he disagrees with O'Brien on location factor, Coker costs, sulfur removal costs, fixed operating costs, and variable operating costs. *Id.* at pp. 11-12. Regarding the location factor, Jenkins asserts that

> [f]or my detailed line-item estimates of the cost of constructing a Coker on the West Coast, I used a reasonable location adjustment for all of the major construction components: equipment, piping, concrete, steel, electrical, insulation, painting, labor, engineering, and indirect costs. Because there

[96] Using Gary and Handwerk data, according to Jenkins, yields calculated variable operating costs of $1.62/barrel. Exhibit No. EMT-37 at p. 62.

> are differences between the types of refinery units, this analysis resulted in slightly different location factor adjustments for the coker and for the downstream hydrotreaters (ranging from 1.26 to 1.29). I did not do a detailed estimate on the sulfur plant or offsite facilities. There, I used a generalized factor of 1.30.
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> [T]he West Coast location factors that I used were based on my professional judgment as well as my review of a number of source documents that made clear both that use of a West Coast location factor was appropriate and would generally fall in the range of 1.2 to 1.4 or even higher.

Id. at p. 13. Also, he claims that O'Brien acknowledged, in his answering testimony, that West Coast construction costs are generally higher than Gulf Coast costs. *Id.*

294. Jenkins asserts that O'Brien's contentions that using cost curves is more appropriate than using location factors and that, in his view, a project may cost less on the West Coast are unjustified. *Id.* at p. 14. He adds that any credible analyst "would apply a location factor to better reflect the expected cost of the project." *Id.* According to Jenkins, O'Brien's suggestion that Coker construction costs on the West Coast may be lower than the Gulf Coast is wrong. Id. More than half the difference between the two estimates, Jenkins explains, or approximately $1.22 of the $2.37/barrel of ANS Resid is the result of their fundamentally different approaches. *Id.* at p. 15.

295. As for the differing Coker ISBL costs, Jenkins states that the difference is approximately $21 million dollars in Year 2000 dollars. *Id.* Jenkins summarizes O'Brien's four criticisms of his cost estimates as follows:

> First, he asserts that I should have used the Jacobs Consultancy database estimate for a Coker. Second, he asserts that my coke drums are oversized. Third, he criticizes my inclusion of certain costs on the grounds that the equipment is alleged to be "unnecessary." Finally, he asserts that certain of my ISBL costs are double-counted in that Gary & Handwerk includes them as OSBL costs.

Id. at p. 16.

296. Criticizing a failure to use the Jacobs Consultancy database estimate for a Coker, Jenkins asserts, is not valid. *Id.* He explains:

> As with most data base estimates of capital cost, the Jacobs Consultancy

> capital cost data base uses one parameter -- unit capacity. A Delayed coker is one of the refinery units in which a number of technical factors other than capacity influence cost. These factors include coke make, feedstock sulfur, coke handling system and other technical factors. To insure an accurate estimate it is necessary to do a line-item estimate.

Id. While the Jacobs Consultancy database, Jenkins notes, provides a quick initial estimate, its reliability varies depending on the refinery unit type. *Id*. at p. 18. Due to this reliability factor, Jenkins declares that "a more vigorous method of analysis is needed for a Coker." *Id*. He further asserts that a line item approach, which "is transparent and subject to critical analysis, is far superior to" a cost curve analysis. *Id*. at pp. 18-19.

297. Also, Jenkins disagrees with O'Brien's criticism of his coke drum configuration. *Id.* at p. 19. He asserts that, in order to process 40,000 barrels/day of ANS Resid, a 4-drum Coker is required. *Id.* Additionally, he states, the key factors to be taken into account are feed rate, coke yield, outage, cycle time, and vapor velocity. *Id.* at p. 20.

298. Jenkins begins explaining the decoking cycle by stating that when a coke drum is at the end of the on-line cycle, the drum is full of a mixture of coke, liquids, and gases. *Id.* at p. 22. The first step, he continues, is to steam out the drum to recover the remaining liquid and gaseous products. *Id*. This is done, he adds, by injecting steam into the bottom of the drum and the steam-hydrocarbon mix is sent to a fractionator where the products are condensed and recovered. *Id.* During the steam-out process, he relates, the Resid goes to the other coke drum and vapor from both drums is going to the fractionator. *Id.* at p. 23. When the steam-out process is over, he notes, the full drum is blocked and the cooling cycle begins. *Id.*

299. At the end of the coking cycle, he states, the material in the drum is approximately 850ºF and the coke drum is about 700ºF. *Id.* Two cooling steps follow, he explains, the first with steam and the second with water. *Id*. At this time, he notes, the coke drum vapors are routed to the blowdown scrubber, which condenses and recovers heavy hydrocarbon material that is still in the coke. *Id.* The waste gases, according to Jenkins, are typically sent to a flare dedicated to the Coker. *Id.* If the system cools too quickly, he asserts, "the mechanical integrity of the drum can be affected due to thermal stress. Cracks and/or bulges in the drum can occur." *Id*. at p. 24. He further describes the process as follows:

> Next you drain the water out of the coke drum and take the heads off the bottom and top of the drum. This is where improvements in deheading technology come in. Years ago, Cokers were typically designed for a 24 hour cycle -- that is, 24 hours to fill the drum with coke, then 24 hours to decoke. In the design cycle time I have assumed (16 hours), deheading and decoking would take about four and one-half hours. . . . I note that the

> main reason that automatic deheading has become popular is safety, but there is also some time savings that result in shorter cycle times.
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> [There are two typical coke cutting steps.] First, a pilot hole is drilled through the coke bed using water at high pressure. Then coke is cut from the bottom of the drum up so that it will fall into the coke pit. . . . The drum heads are [then] reattached, and the sealed coke drum is pressure-tested. . . . The pressure test, which uses steam, ensures that the coke drums are not leaking. The empty drum is then gradually warmed up, again to avoid damaging the drum from thermal shock.
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> [The drum is warmed when] a portion of the vapor from the active drum is diverted back into the cold drum. Obviously, this vapor condenses on the walls of the cold drum. The condensed oil, along with any free water in the drum, is sent to the slop oil system until the oil is about 300 degrees. After the operator is certain that all of the free water is out of the drum, this stream is routed back to the fractionator. The Resid feed is not reintroduced into the drum until the drum's temperature reaches 500 degrees Fahrenheit.

Id. at pp. 24-25.

300. The large volumes of water used to cool and cut the coke, Jenkins states, are recycled within the Coker as much as possible through a water handling system which "is designed to settle out coke fines in the water so the water can be reused as cutting or cooling water without damaging the pumps within the system." *Id*. at p. 26. He adds that a Delayed Coker is the only refinery unit that has its own water handling system. *Id.* Additional water treatment is necessary, according to Jenkins, because

> [t]he recycled water is contaminated with dissolved oil and carcinogenic material, and must be purged for environmental and employee-health reasons. For this reason, water from the Coker's water handling system must be routed to the refinery's water treatment facilities for biological treating prior to release outside the refinery.

Id.

301. According to Jenkins, O'Brien's critique of his analysis is mistaken because O'Brien misrepresents his model. *Id.* at p. 27. Jenkins argues:

> First, the calculation underlying Mr. O'Brien's claim that my drums are "oversized by 42.5%" is based on a 14-hour cycle time, rather than the 16-hour cycle time used in my coker design. Using a 16 hour cycle time reduces the "excess" capacity claimed by Mr. O'Brien to 24.7%.
>
> Second, Mr. O'Brien and I have used different assays of ANS crude oil to determine the amount of Conradson Carbon Residue in the Resid cut, which, in turn, affects the yield of coke and liquid products from coking Resid. My assay indicates a yield of 2476 tons/day rather than the 2400 tons/day that Mr. O'Brien assumed. Using my coke yield further reduces the "excess" capacity claimed by Mr. O'Brien to 20.9%.
>
> Third, Mr. O'Brien's calculations used a target outage of only 20 feet from the tangent, whereas my drum design uses a target outage of 25 feet from the tangent. Using my target outage further reduces the "excess" capacity claimed by Mr. O'Brien to 11.3%.

Id. at pp. 27-28. Jenkins asserts that an 11.3% excess capacity is below the lower limit of prudent design for this type of unit. *Id.* at p. 28.

302. O'Brien's 2-drum assumption, Jenkins contends, is unreasonable because it cannot continuously process 40,000 barrels/day of ANS Resid. *Id.* at p. 30. According to Jenkins:

> [T]he maximum size of a coke drum is 30 feet in diameter and 120 feet tall. Furthermore, Mr. O'Brien has made no allowance in his estimate for the costs that would be required to decrease cycle time. He makes no provision for the use of automatic deheading equipment, he has not made adequate provision for the increased costs that would be associated with running two large drums at their maximum capacity, nor has he taken into account the other costs that would be necessary to achieve the "short" cycle times that would be required to produce the amount of coke that he has assumed.
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> Even if he were to incur the costs needed to reduce the decoking cycle, he would still have a problem with vapor velocity.
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> If the vapor velocity is too high, coke will be carried over with the vapors into the fractionator, resulting in poor operation and, ultimately, unit

> shutdown. The vapor velocity in Mr. O'Brien's 2 drum coker would be too high.
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> [There is no way to solve that problem] within the existing technology. In order to slow the vapor velocity, Mr. O'Brien would have to install bigger coke drums with diameters well in excess of 30 feet which is beyond the capabilities of available coke cutting equipment.

Id. at pp. 30-31.

303. Jenkins disputes O'Brien's criticism of the equipment he included in his ISBL cost estimates. *Id.* at p. 32. Explaining that, except for the Kero Salt Tower, every piece of equipment on the list is necessary to achieve his shorter operating cycle time, Jenkins believes that O'Brien's contention is meritless. *Id.* at pp. 32-33. He argues:

> [T]he automatic deheading system is critical to my estimate that the coker could be operated on 16-hour cycles. For the drums that I have specified -- four 27-foot inner diameter vessels -- the bottom head would be approximately six feet in diameter and the flange connecting the head to the vessel would have about 50 bolts. Prior to the development of automatic deheading equipment, these bolts and the head were manually removed. The manual removal of the coke drum heads was not only time-consuming, but also dangerous. The equipment is heavy and hot. Indeed, workers have been killed deheading coke drums. Consequently, the use of automatic heading equipment also has important safety considerations. <u>Automatic chutes</u> are also a safety device and help ensure that all of the coke and water ends up in the coke pit. The use of a <u>conveyor system</u> to transport the coke away from the coker is also a commonly used technique.

Id. at p. 33 (emphasis in original).

304. According to Jenkins, a typical West Coast coke handling system also would include the following:

> After the coke has been cut into the pit, a clamshell crane is used to pick it up and put it into a hopper where it is crushed and screened. The crushing and screening is a very "rough cut" system which is designed to get the larger "chunks" of coke to a size that they can be handled by the conveyor. This coke is then conveyed to a storage barn. From the barn, the coke is eventually loaded into trucks using a smaller conveyor system. . . . For environmental reasons, the trucks must be washed before they leave the

> refinery for the coke terminal, so a washing system is also needed.

Id. at pp. 33-34.

305. In Jenkins's view, O'Brien's criticism of his ISBL Coker costs is unconvincing. *Id.* at p. 35. According to Jenkins, O'Brien criticizes the inclusion of a gas plant, as well as the high pressure separator, absorber/stripper system, and the sponge absorber, in the ISBL Coker costs. *Id.* at p. 36. These costs, Jenkins asserts, should not be treated as OSBL costs, as O'Brien suggests, because "[i]n over thirty years in the business, I have never seen the light ends recovery section of any refinery described as an OSBL cost." *Id.* at p. 37. According to Jenkins,

> [w]hile Gary & Handwerk does not include these costs as part of their ISBL Coker estimate, they are not treated as offsites. Rather, a separate cost curve is set forth . . . for this process unit. . . . [T]he costs of these facilities can be estimated based on gas throughput and liquid recovery load. Although my equipment list is not identical to the [Gary & Handwerk] list . . . I estimate that the installed cost of the gas plant using Gary & Handwerk's cost curves would be approximately $17 million, whereas my cost estimate calculated on a comparable Gulf Coast basis is $14 million.

Id.

306. Regarding O'Brien's criticisms of his OSBL cost calculations, Jenkins explains that he followed the Gary & Handwerk approach. *Id.* at p. 38. In contrast, he notes, O'Brien assumed that the OSBL costs for a Delayed Coker would be 35% of the ISBL costs. *Id.* at p. 39. According to Jenkins, O'Brien includes "electrical power distribution, boiler feed water, process and cooling water facilities, fuel gas facilities, steam systems, plant and instrument air systems, fire protection systems, and flare system and system tie-ins" in his OSBL factors. *Id*. However, he states, O'Brien does not include any storage costs in either his OSBL or ISBL cost estimates, but instead assumes that the Coker would use storage already existing within the refinery. *Id.* at p. 40. Such an assumption, Jenkins asserts, is unreasonable because a Coker needs storage for feedstock (Resid) and for the products coming out of the Coker. *Id*. Also, he notes, O'Brien admitted at a deposition that additional storage is necessary, but insisted that such storage costs should be allocated to the Quality Bank Base Refinery. *Id.* at p. 41.

307. Jenkins summarizes O'Brien's description of the Quality Bank Base Refinery:

> [He] describes the "Quality Bank Base Refinery" as the refinery that would exist in an "ideal world [where] there would be a publicly available price for each product valued by the Quality Bank without the need for any adjustment for additional processing." According to Mr. O'Brien, this

> refinery would include only the refinery equipment and personnel needed to distill the ANS crude into the various Quality Bank cuts. This equipment would include the atmosphere distillation tower, the vacuum distillation tower, the light ends fractionation unit, and certain additional facilities (such as storage tanks, administrative, waste water and other ancillary facilities) associated with the production and sale of the Quality Bank cuts. The costs of these facilities would be recovered from sale of the Quality Bank cuts at published market prices.

Id. (alteration in original).

308. In Jenkins's view, the Quality Bank Base Refinery concept is flawed for a number of reasons. *Id*. at pp. 41-43. First, according to Jenkins, O'Brien departs from the approach he initially took in developing a Coker cost estimate. *Id* at p. 42. Specifically, notes Jenkins, O'Brien originally estimated the costs of a Delayed Coker built as part of a complex integrated refinery; now he is estimating the cost of construction of a Delayed Coker plus downstream processing units to be added to an existing "Quality Bank Refinery." *Id*. Moreover, while Jenkins agrees with O'Brien that some of the costs of producing Quality Bank cuts can be recovered in the prices paid for them, he does not believe that the costs of storage tanks used in processing Resid can be included in that category. *Id*. Jenkins argues:

> In the "Quality Bank Base Refinery," the costs for such facilities (e.g., fuel oil tanks) would be recovered through the sale of fuel oil, <u>not</u> from the prices paid for the other Quality Bank cuts. Because the Resid is not valued as fuel oil, the costs of the storage facilities associated with the Resid cut (whether those facilities are constructed new, or are modified and reassigned for use in the coking process) must be allocated to the Coker. Likewise, the costs for the storage needed for the coker products must be allocated to the Coker; these costs would not be recovered from the sale of other Quality Bank products.

Id. (emphasis in original).

309. Lastly, Jenkins argues, it is "absurd" to suggest that ancillary facilities in a Quality Bank Base Refinery, such as storage and waste water treatment facilities, would be the same as such facilities are in a complex refinery including a Coker and downstream units. *Id.* However, Jenkins suggests, that this is what O'Brien proposes as he does not include allowances for these costs. *Id.* at pp. 42-43. As a result of O'Brien's reliance on the Quality Bank Base Refinery concept, Jenkins asserts, he significantly understates OSBL costs, and this understatement, as well as their differences in handling storage costs, accounts for the difference between his and O'Brien's OSBL cost estimates. *Id*. at p. 43.

310. Addressing the differences in sulfur processing costs, Jenkins states that his sulfur processing costs are approximately 18¢/barrel higher than O'Brien's. I*d*. at p. 45. He accounts for the difference as follows:

> Of the $0.18 per barrel difference, $0.05 is for variable cost. It is obvious from Mr. O'Brien's analysis that he did not include any incremental variable cost for the amine plant and sour water stripper that would be needed to process the sulfur produced by the Coker and the downstream hydrotreaters. The balance of the difference is largely due to the difference in our capital cost estimate. . . . [O]n a comparable dollar basis, Mr. O'Brien includes approximately $8.7 million for the sulfur plant, whereas my estimate is $15.4 million.

Id. The difference in capital costs, Jenkins explains, is due to O'Brien's assuming only 30% back-up capacity, while he assumed 100% back-up capacity. *Id*. As a result of how he and O'Brien conducted the cost estimates, Jenkins asserts, "a higher capital cost translates into a higher operating cost estimate, and thus explains in part the $0.04 differential in our fixed operating cost estimates for the sulfur plant." *Id.* at p. 46.

311. As for the difference in their fixed cost estimates (Jenkins's estimate is approximately 24¢/barrel higher than O'Brien's), Jenkins asserts that O'Brien criticizes his approach in four ways and addresses each in turn. *Id*. at p. 47. First, Jenkins agrees with O'Brien that he failed to include economies of scale savings in his estimate, and Jenkins claims that he has corrected this error by reducing his Gulf Coast estimate by 11¢/barrel and his Gulf Coast estimate by 14¢/barrel. *Id*. Secondly, Jenkins states that O'Brien is wrong in suggesting that only six operators per shift would be able to achieve the reduced cycle times that both he and O'Brien assumed. *Id*. Third, Jenkins disputes O'Brien's claim that increased management would not be needed to operate a complex refinery including a Coker and downstream facilities than would be needed to operate a Quality Bank Base Refinery. *Id*. at pp. 47-48. Lastly, addressing O'Brien's claim that he used "excessive multipliers," Jenkins argues:

> As an initial matter, Mr. O'Brien's assertion that we both used the same multiplier of 45% to account for benefits, social security and other such costs is not correct. I used a multiplier of 35%. I further disagree with his assertion that I buried one of my multipliers in a spreadsheet. The three multipliers of which he complains (Operating Overhead, Offsite Labor, and Administrative Labor) are all identified in Exhibit EMT-64, and are generally used by Jacobs Consultancy in its cost estimation work. Operating Overhead pays for technical support such as engineering MIS, laboratory and environmental services. Offsite labor would be incurred for the additional storage, steam generation and cooling water systems that would be required for the coker and downstream processing units.

> Administrative labor costs would increase due to additional demand for personnel services, product accounting and other administrative services.

Id. at p. 48.

312. Regarding downstream hydrotreater cost estimates, Jenkins disagrees with O'Brien's criticisms of his approach. *Id.* at p. 50. He disputes O'Brien's claim that he overstated the cost of downstream processing stating that he adjusted the costs to take savings resulting from economies of scale into consideration and that, with such an adjustment, his and O'Brien's costs are "quite close." *Id.* Jenkins also argues that his "approach produces a more accurate result" because

> [b]y basing my initial cost estimate on the expected Coker yields, I was able to determine the costs that the Coker would be assigned if no economies of scale were available. I then adjusted these cost estimates to reflect the economies of scale that would potentially be available if the Coker products were to be processed in larger units. To the extent that such economies of scale were available, I included them in my analysis.

Id. Jenkins does agree with O'Brien's contention that he included negative economies of scale, and claims to have adjusted his estimate to eliminate those identified costs thereby reducing the difference in cost estimates "by $0.03 per barrel [Gulf Coast] and $0.04 per barrel [West Coast]." *Id*. at pp. 50-51.

313. Jenkins also disagrees with O'Brien's contention that he inappropriately included a finance cost in the owner's cost estimate. *Id*. at p. 51. He responds that, typically, "refinery managers assign their own employees to a construction project. These costs are captured and capitalized and, thus, are part of the entire project cost." *Id*.

314. For Issue 2, the West Coast Heavy Distillate cut, Jenkins notes that his costs are slightly higher than O'Brien's. *Id*. at p. 53. He explains that the major points of difference stem from his using a location factor, including a medium-pressure instead of a high-pressure hydrotreater, and using a lower level of hydrogen consumption in the hydrotreater. *Id*.

315. Jenkins asserts that a medium-pressure hydrotreater "is quite sufficient to do the job of reducing the sulfur in virgin ANS heavy distillate from 0.57 wt% sulfur to 0.05 wt%." *Id.* at p. 55. O'Brien claims, according to Jenkins, that a high-pressure unit is necessary because of the high nitrogen content in the ANS Distillate cut. *Id*. According to Jenkins, there is no nitrogen specification for 0.05 wt% sulfur diesel fuel, and, consequently, no reason exists to install a higher pressure unit to deal with nitrogen. *Id.* at p. 56. The difference in costs resulting from the differing hydrotreater pressures, he states, is difficult to quantify given O'Brien's calculating methodology; however, if

O'Brien used a medium-pressure unit, "the cost that he calculated to desulfurize virgin ANS heavy distillate would be approximately $0.5 per gallon less." *Id.* at p. 56.

316. According to Jenkins, O'Brien contends that his hydrogen consumption calculation of 180 cubic feet/barrel of Heavy Distillate is too low compared with O'Brien's 250 cubic feet/barrel which results in an underestimate of the Heavy Distillate processing cost by 12.2¢/barrel (using O'Brien's estimate) or 21¢/barrel (using Maple's estimate.) *Id*. According to Jenkins, using either in place of his estimate (4.3¢/gallon) would result in sulfur processing costs ranging from 4.6¢ to 4.8¢/gallon. *Id*. Jenkins asserts that his approach is correct because he calculated the hydrogen consumption based on the specific ANS Heavy Distillate cut properties while O'Brien relies on Gary & Handwerk data. *Id*. at p. 57. If O'Brien used his hydrogen consumption figure, he relates, it would lower O'Brien's cost by approximately 0.3¢/gallon. *Id.*

317. On cross examination, Jenkins admitted that the Jacobs Consultancy does not maintain "extensive documentation supporting its cost curve database" and that, while the Jacobs Consultancy cost curves had been updated five or six years prior to 2002, he didn't know whether the Coker cost curve was updated at that time.[97] Transcript at pp. 2727-28. He also admitted that he didn't know how many Coker projects were included in the Jacobs Consultancy Coker cost curve and could not even name one. *Id.* Jenkins further admitted that he never designed a Coker, and never relied solely on the cost curve to cost a Coker. *Id.* at p. 2728.

318. Under further cross-examination, Jenkins admitted that to do a "detailed" cost estimate, he would need to know, at least, the feedstock, the throughput, the product slate and the specific environmental control requirements for a specific location.[98] *Id.* at pp. 2751-52. However, in preparing his cost estimate for the instant case, Jenkins did not select a specific site, but used the Los Angeles area in general.[99] *Id.* at p. 2752. Jenkins

[97] In later testimony, Jenkins indicated that major changes to the database were made in 1992 and that there were further changes in 2000 and 2001 "to input costs for hydrotreaters and equipment associated with gasoline, desulfurization, and the production of low sulfur diesel." Transcript at p. 2843. Later, he indicated that the cost curves were updated "about 1993" on the basis of "data from Jacobs Engineering. . . . text[s]. . . and things of that nature and specific projects" when they were available. *Id.* at pp. 3896-97. But, he admitted that not "every number was updated in 1992." *Id.* at p. 3908.

[98] Jenkins claimed that he used a "more detailed approach when the cost curve doesn't supply sufficient detail to make sure [he understood] what [he's] got or is not verifiable enough." Transcript at p. 3895.

[99] Jenkins believes that Los Angeles is representative of the West Coast. Transcript at p. 2777.

also admitted that site preparation was not a part of his cost estimate. *Id.* He added that, to do a "detailed" cost estimate, about 30% of the engineering would have to be completed. *Id.* at p. 2762. According to Jenkins, as a general rule, while it costs more to construct a larger refinery than a smaller one, the per barrel cost for the larger refinery would be less. *Id.* at p. 3734. Although, he added, a refinery's cost may be affected by the "complexity of the refinery" and the "amount of downstream processing." *Id.*

319. With regard to the Heavy Distillate cut, Jenkins admitted that reducing the owner's costs increases the value of the cut in the Quality Bank. *Id.* at p. 2877.

320. Jenkins testified that, since 1992, no refineries with a Coker have been built in the United States, but that 10-12 Cokers have been built. *Id*. at p. 3892. The Cokers which have been built range from 24,000 barrels/day to 80,000 barrels/day with 40-50,000 being most typical. *Id.* at pp. 3892-93. He agreed that a 35,000 barrel/day Coker probably would have been designed with two drums, while a 45,000 barrel/day Coker clearly would be designed with four drums. *Id.* at p. 3893. Jenkins suggested that a 45,000 barrel/day Coker is more typical than a 35,000 barrel/day Coker. *Id.* at p. 3894. He also testified that most, if not all, of the Cokers built since 1992 had automatic deheaders. *Id.* Jenkins later agreed that none of the Cokers processing ANS, which are all located on the West Coast, were built after 1992. *Id.* at p. 3938.

321. According to Jenkins, O'Brien did not plan enough redundancy in the sulfur plant. *Id.* at p. 3931. Moreover, Jenkins claims that O'Brien failed to include costs for tanks which Jenkins believes are required and that O'Brien's design lacks "flexibility" with regard to coke drum design. *Id.* He also states that it was unlikely that a Coker could be added to an existing refinery without constructing additional storage tanks. *Id.*

K. WILLIAM J. BAUMOL

322. Exxon also introduced Baumol, Professor of Economics at New York University and senior research Economist and Professor of Economics Emeritus at Princeton University, as a witness to address the economic principles applicable to ANS crude oil Resid valuation. Exhibit No. EMT-66 at pp. 3-4. Baumol begins by stating that "[o]ne of the principal issues in this proceeding is the value of the ANS Resid cut in a competitive market." *Id.* at p. 6. Describing the current Resid valuation method as estimating its value as a feedstock to a Delayed Coker, Baumol states that

> [t]he calculation of values for the Coker products is based on the prices of relatively similar products . . . for which the markets exist. The value of Resid under this approach is taken to be equal to the value of the products produced from the coking of Resid, net of the costs that must be incurred in treating the Coker products to meet the quality specifications applicable to the proxy products upon which the Coker products' values are based.

Id.

323. His testimony, Baumol explains, addresses the question of determining the value of Coker products as well as estimating the total costs of the coking and processing operation. *Id.* at p. 7. Arguing that the valuation of each of the Coker products must be carried out on a comparable basis, Baumol states that "[i]f valuation is carried out on a basis that favors one supplier relative to another, a competitive advantage would plainly be provided to those firms that received the more favorable valuation." *Id.* at p. 9. Furthermore, Baumol adds, all the parties have agreed that, in order for the Quality Bank System to work, each of the component cuts should be carried out on a comparable basis. *Id.* at p. 10.

324. According to Baumol, in the interest of consistency and comparability and to create a defensible valuation, the costs of reselling, transporting, handling, storing, and loading coke must be deducted from the proposed proxy price in order to obtain a valid estimate of the value of the coke at the refinery gate. *Id.* at p. 13. He explains his rationale as follows:

> [O]n average approximately two-thirds of the *PCQ* "price" for Coke simply covers the cost of numerous activities entailed in getting [Coke] from the refinery onto a vessel. In other words, almost two-thirds of the *PCQ* price does not correspond to the value of the Coke at the refinery gate, but, rather, represents the value added to the Coke by reselling, transporting, handling, storing, and loading it onto ocean vessels. In contrast, the transportation, storage, loading, and handling costs for the cuts and Coker products other than Coke are insignificant (two to eight percent of their overall value) so that even if they are not taken into account they do not materially affect the estimates of the values of these products at the refinery gate.

Id. at pp. 12-13.

325. Regarding the Resid cut valuation, Baumol states that "*all* of the costs of processing Coker feedstock must be included. If a cost would be incurred in the construction or operation of a Coker in a competitive market, that cost must be included in the valuation." *Id.* at p. 13 (emphasis in original). According to Baumol, the appropriate methodology to determine the Resid cut valuation requires the identification of all of the components required to process Resid onto the products meeting the applicable proxy product specifications, and, then "reliable data must be obtained to estimate the costs associated with those components." *Id.* at pp. 13-14. In Baumol's view, all the costs include the costs associated with facilities and equipment in existence when the Coker unit is constructed because "the fact that a facility has already been

constructed does not mean that its use has become costless."[100] *Id.* at pp. 14-15.

326. Baumol explains that where a cost is incurred exclusively to coke or process Resid, as well as to upgrade units or pieces of equipment, all of that cost must be attributed to the cost of coking and processing Resid and not attributed to the cost of processing other products. *Id.* at p. 17. He continues "[f]ailure to attribute properly to the Resid all of the costs it imposes will necessarily lead to an undervaluation of its processing costs and overestimation of the value of the Resid." *Id.* As for facilities serving all of a refinery's throughput, the cost of these facilities, Baumol states, should be attributed to all of the refinery's throughput. *Id.* at p. 18. Additionally, Baumol maintains that the cost of capital during construction must be included in the Resid valuation. *Id.* at p. 20. Finally, Baumol states that "[*c*]*urrent* costs, rather than *historical* costs, should be used in estimating the costs of the assets necessary for the Coker process." *Id.* at p. 21 (emphasis in original).

327. While he does not disagree with everything O'Brien states, Baumol claims, O'Brien misunderstands his testimony regarding which facilities ought to be included in the costs of processing Resid. *Id.* at p. 30. Baumol explains that O'Brien "failed to attribute to the Resid coke processing costs that would have to be covered by that process in any competitive market." *Id.* According to Baumol, he would include only the costs of the "common facilities, that is, those facilities that serve all of a refinery's throughput, that should be divided among all of the components of the refinery's throughput – *including the Resid cut*." *Id.* at pp. 30-31 (emphasis in original). As an example of which "common facilities" he would include, Baumol pointed to storage tanks. *Id.* at p. 31.

328. Baumol also addressed O'Brien's suggestion that Resid should be valued as a fuel oil blendstock. *Id.* at pp. 31-32. While he found no problem with that suggestion, he did add that, if using Resid as a fuel oil blendstock increased the fuel oil supply so as to affect the supply/demand relationships and lower the price of fuel oil, then it would be improper to use "the price that prevailed in the absence of additional Resid blending as a pricing benchmark." *Id.* at p. 32.

329. Finally, Baumol asserts, the valuation of each of the Quality Bank cuts and Coker products should be carried out on a comparable basis, including a comparable geographic basis where possible, and claims that all parties agree with this assertion. *Id.* at p. 34. Regarding Ross's contention for the valuation of West Coast Heavy Distillate, Baumol reiterates his position that the ideal valuation point is at the refinery, and not on a

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[100] Baumol explains that this is what "economists call its *opportunity cost, i.e.,* the foregone opportunity to provide earnings in uses other than its current employment entails." Exhibit No. EMT-66 at p. 15 (emphasis in original).

waterborne basis. *Id.* at p. 36. Despite the geographic disparity in the bases for pricing of proxy products, Baumol explains that the portion of each of the prices of the proxy products attributable to transportation from the refinery gate is in the 3% to 8% range. *Id.* at p. 37. Consequently, he asserts, "the addition of a relatively small and uniform transportation component should not have a significant effect on the Quality Bank adjustment process." *Id.*

330. However, Baumol adds that, due to its physical characteristics, the transportation, handling and sales commissions necessary to move coke from the refinery to the ocean vessels is significant in comparison to its value at the refinery gate. *Id.* at pp. 37-38. Relying on Bartholemew's testimony, Baumol estimated the value of coke at the refinery as zero (or even less than zero) and the costs necessary to get it on board an ocean vessel as $6/ton on the Gulf Coast and $10.75/ton on the West Coast. *Id.* at p. 38. Also relying on Bartholemew's testimony, Baumol states:

> [O]n average approximately two-thirds of the published waterborne "price" for Coke simply covers the costs of numerous activities entailed in getting Coke from a refinery onto a vessel, including, [sic] transportation, handling and sales commissions. In other words, almost two-thirds of the published price does not correspond to the value of Coke at the refinery gate but, rather, represents the value added to the Coke by transporting it to ocean vessels. In contrast, the transportation, storage, loading and handling costs for the Quality Bank cuts and Coker products other than coke are insignificant (three to eight percent of their overall value) so that, even if such costs are not taken into account, they do not materially affect the estimates of the values of these products at the refinery gate.

Id. Baumol concludes that, in view of the above, "the costs of Coke transporting, handling and sales commissions must be deducted from the proposed proxy price, to obtain a valid estimate of the value of the Coke at the refinery gate." *Id.* at pp. 38-39.

331. Under cross-examination, Baumol admitted a lack of familiarity with the purchase and sale of crude oil or retail petroleum products. Transcript at pp. 3556-57. He further agreed that his testimony was based on "general economics." *Id.* at p. 3557.

332. Baumol also agreed that attributing too much cost to Resid will overvalue its processing cost and underestimate its value. *Id.* at p. 3573. He further agreed that, if ANS coke had a higher value than other coke, this must be taken into consideration. *Id.* at p. 3575.

333. According to Baumol, it is important to value ANS crude accurately as a matter of equity. *Id.* at p. 3605. Also, an accurate valuation will avoid "overcompensating those who have produced or injected higher quality raw materials" which will, in turn, avoid

"forcing consumers to pay more for the lower quality products." *Id.* Baumol added that an inaccurate valuation would "lead to more expenditure in those areas that produce the sort of products that are overvalued and under exploration in those areas that are undervalued." *Id.* at p. 3606.

334. Asked about distortions in the market place, Baumol suggested that he considered California's strict environmental standards to be a market place distortion which resulted in the anomaly between the California and Gulf Coast petroleum prices. *Id.* at p. 3607.

L. WILFRED HERBERT DICKMAN, JR.

335. Exxon also produced Wilfred Herbert Dickman, Jr. ("Dickman"), a chemical engineer employed by Jacobs Consultancy, Inc., to testify on the value of Resid.[101] Exhibit No. EMT-118 at p. 3. Dickman begins his testimony by stating that O'Brien significantly understated the costs of building a Delayed Coker. *Id.* at p. 7. He indicates that O'Brien errs by: (1) planning a two-drum rather than a four-drum Coker; (2) using an inefficient coke handling system; (3) creating a cost curve to "generate a desired result;" (4) insufficiently estimating the combined ISBL and OSBL costs which "would be incurred in connection with coking the ANS Resid;" and (5) mistakenly relying on the Jacobs Consultancy database estimate of ISBL Coker costs. *Id.* at pp. 7-8.

336. Expanding on each of these criticisms in turn, Dickman begins by examining the assumptions underlying O'Brien's two-drum Coker.[102] *Id.* at p. 8. First he points out that

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[101] Dickman states that, on behalf of Jacobs Consultancy, Inc., he provides "consulting services to clients in the oil and gas and petrochemical industries on matters involving refining, chemicals, and project management, estimation and evaluation." Exhibit No. EMT-118 at pp. 3-4.

[102] According to Dickman,

> [t]he coke drums are one of the major components in a Coker. The drums are the point at which the coking reaction takes place. The long chain hydrocarbons are cracked (broken by applying heat), producing the full spectrum of hydrocarbons from methane to a gas oil range fraction, including olefins, diolefins and aromatics. The carbon that remains from the cracking accumulates in the coke drum where it has to be cooled in the blowdown step of the operation. Along with the hydrocarbons, there are impurities in the coke such as hydrogen sulfide, mercaptan sulfur compounds, nitrogen and other metals that need to be removed.

Exhibit No. EMT-118 at p. 8.

> [t]ypically, coke drums are configured in pairs. A four-drum Coker has an additional heater and associated process and mechanical appurtenances. A four-drum Coker also would require additional concrete in the mat, pedestals and tabletop where the drums sit, and would need more structural steel to support the cutting level and derricks for the two additional drums.

Id. at p. 9. Dickman then asserts that a four-drum Coker is necessary to process 40,000 barrels/day of ANS Resid[103] and argues that "given current process design constraints, the coke cutting systems available today, and sound engineering practice" a two-drum configuration could not process this amount per day. *Id.* Claiming that he is unaware of any two-drum Coker with a 40,000 barrels/day capacity, Dickman argues that if O'Brien had used a four-drum Coker in his analysis, the costs would have been much higher because he would have had to add in the cost of two more drums plus the "appurtenances" necessary for them.[104] *Id.* at pp. 9-10.

337. The next area in which Dickman criticizes O'Brien's analysis is O'Brien's assumptions regarding coke handling equipment.[105] *Id.* at p. 10. Dickman explains that,

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[103] During Dickman's examination, there was, in part, a discussion of why a 40,000 barrel/day Coker, rather than a 30,000 or 50,000 barrel/day Coker, was the criteria addressed in this case. Transcript at pp. 4717-19. The question arose because, while everyone agrees that a 30,000 barrel/day Coker would have two drums and a 50,000 barrel/day Coker would have four drums, there is a major dispute between the parties as to whether a 40,000 barrel/day Coker would have two or four drums. *Id.* at pp. 4718-19. Dickman's response was to indicate that, were a new refinery built to process ANS, it would be build to process 200,000 barrels/day which would result in 40,000 barrels/day of Resid to be processed by the Coker. *Id*. at p. 4719.

[104] Dickman argues that the increased costs would result from

> not only hav[ing] to add two additional drums, but . . . also . . . hav[ing] to add certain additional equipment including: (1) drum appurtenances – top and bottom head closures, insulation, instruments, process piping, utility piping, switch valves, isolation valves, pressure safety relief valves; (2) drilling structure appurtenances – high pressure water piping isolation valves, drill stems, cross heads, rotary joints, cable hoists, controls, air systems, hoses; (3) an additional heater and associated equipment; and (4) instrumentation.

Exhibit No. EMT-118 at p. 10.

[105] According to Dickman, O'Brien assumes that coke would be dumped on the

in a modern refinery, coke is cut from a drum into an open pit from which it is removed by either a bucket crane (large Coker) or a front-end loader (small Coker) and placed in a crusher and screened, and then moved into storage. *Id.* According to Dickman, the reasons for the current methods are "[a]side from basic efficiency considerations, environmental regulations require that coke be handled to minimize environmental impacts. This is particularly true on the West Coast, where Best Available Control Technology . . . limits the amount of dust generated at a facility by controlling conveying, storage and handling." *Id.* at p. 11. He concludes that O'Brien's elimination of this handling equipment in unreasonable and that "[u]se of a front-end loader in [a 40,000 barrel/day] Coker is not practical." *Id.*

338. O'Brien's use of cost curves is the next area in which Dickman claims he has concerns. *Id.* He declares

> [a]s a general rule, database cost curves are non-specific. . . . [O'Brien's] "speed bump" coker cost curve appears to have been designed specifically for ANS Resid in that it assumes the precise feed rate for the ANS Resid and it has an assumption regarding the use of drums that is not typical. Further, Mr. O'Brien's cost estimate is not fully consistent with the information set forth on Exhibit PAI-10, which indicates that his curve was generated from a Coker reference capacity of 35,000 bbl/d with a scaling factor of 0.6. That data should generate a straight line on a logarithmic paper.

Id. at pp. 11-12. Dickman states that, rather than a straight line, he would have expected to see "a single curve or multiple curves for different types of Resid feeds." *Id.* at p. 12.

339. As for O'Brien's total Coker costs, Dickman argues that O'Brien's costs, in comparison with Jenkins's cost,[106] are underestimated and that "O'Brien's comparison of

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ground, not crushed into smaller pieces, and handled by a front-end loader. Exhibit No. EMT-118 at p. 10.

[106] Dickman summarizes Jenkins's cost estimates as

> [t]he detailed cost estimate was based of an equipment list that included all towers, drums, heaters, heat exchange equipment, pumps and compressors, specialty items and other miscellaneous equipment. Bare equipment costs were calculated using weights, square footage, differential pressure and horsepower, vendor quotes for specialty items, and factors applicable to the equipment being estimated. These bare equipment costs were tabulated and factors were applied to develop costs for pipe, concrete, structural steel, instruments, electrical, insulation, painting, other items, labor, engineering

his cost estimate with the cost estimates derived from the Gary & Handwerk, Maples and Myers tests is flawed." *Id.* at p. 12. Dickman claims that the major equipment components's costs are as follows: towers and the coke drums – approximately $12 million; heaters – approximately $9 million; heat exchange equipment – approximately $3.7 million; pumps and compressors – approximately $6 million; specialty items and other miscellaneous equipment – approximately $14 million. *Id.* at pp. 13-14. Further, Dickman maintains that he was "unable to extract the major equipment costs from [O'Brien's] estimate." *Id.* at p. 14.

340. Additionally, Dickman states that O'Brien's comparison of his cost estimate to the cost estimate attributed to Gary & Handwerk is flawed for two reasons: (1) O'Brien excludes the cost of certain ISBL equipment which should have been included;[107] and (2) O'Brien made no allowance for the costs of storage, cooling water systems, and steam systems which Gary and Handwerk make clear should be included. *Id.* at pp. 14-15. In Dickman's view, if the Gary & Handwerk cost estimate were properly done, the cost would be "in excess of $200 million, consisting of the Gary & Handwerk $175 million ISBL cost, an estimate for storage, steam and water cooling systems, and an OSBL estimate similar to the one used by Mr. O'Brien." *Id.* at p. 15.

341. Dickman criticizes the provenance of the Maples text, also relied upon by O'Brien, as out-of-date. *Id.* According to Dickman, the Maples's ISBL estimates are based on "eight sources . . . from Oil & Gas Journal articles [published] in the 1950s." *Id.* As, Dickman asserts, Coker technology has changed significantly since that time, these "older cost estimates are not a reliable indicator of the costs of a modern Coker project." *Id.* at p. 16.

342. The last major area Dickman questions is O'Brien's reliance on the Jacobs Consultancy Database.[108] *Id.* at p. 16. He states that the database's primary purpose is

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> and indirect costs. To the sum of these costs, location factors were then applied to adjust the costs from the Gulf Coast to the West Coast.

Exhibit No. EMT-118 at p. 13.

[107] Dickman adds: "I find it difficult to understand how Mr. O'Brien can dissect the Gary & Handwerk cost curve data but was unable at his deposition to estimate the costs of specific equipment included within his own cost curve estimate." Exhibit No. EMT-118 at p. 14.

[108] According to Dickman, "[t]he Jacobs database consists of cost curves for various refining technologies" and has been "in existence since the 1960s as part of Jacobs' (formerly Pace's) studies in refining economics and design." Exhibit No. EMT-118 at p. 17. Dickman concedes that the Jacobs database has been updated as the refining

"to give initial cost estimates for units as part of a refinery LP analysis, or a refinery feasibility study," but maintains that "[a]lthough cost curve databases can be used to provide an initial estimate of costs associated with a process unit, the level of accuracy inherent in a cost curve-type database is not sufficient to calculate the ISBL costs of a Coker." *Id.* at p. 17. In support, Dickman argues that, while a cost curve might be sufficient to estimate the costs of a "less complex" piece of refinery equipment, the cost of a Coker "is dependent on more details than can be provided in a cost curve or generic database." *Id.* at p. 18. According to Dickman, for this reason, Jenkins "developed a more detailed cost estimate for the Coker." *Id.*

343. Additionally, Dickman enumerates several other concerns he has with O'Brien's analysis: (1) his failure to use a location factor; (2) his use of a high-pressure distillate hydrotreater to process the Virgin Heavy Distillate cut; (3) certain of his assumptions underlying his estimate of the cost of hyrdrotreating Coker products; (4) his inadequate provision for sulfur removal; and (5) his lumping of all finance costs into a single 5-year payback calculation. *Id.*

344. "A location factor," according to Dickman, "is a common . . . technique that is used to take into account differences in costs between geographic regions." *Id.* at p. 19. He adds that, as most refineries are located on the Gulf Coast, costs at other geographical locations are usually stated as a multiple of the Gulf Coast costs. *Id.* According to Dickman, O'Brien claims that a location factor is unnecessary "because his analysis was conceptual and non-specific." *Id.* With regard to this claim, Dickman states:

> First, the fact that the analysis is conceptual does not justify ignoring the fact that costs are generally higher on the West Coast than the Gulf Coast. Second, and just as important, Mr. O'Brien's analysis is not non-specific. To the contrary, he knows the specific crude (ANS) that is being coked, he knows its qualities, he knows the specific refineries that process ANS crude, and he knows the sizes of their Cokers. Additionally, at certain points in his analysis, he makes specific design assumptions based on ANS quality. . . . Additionally, he makes specific assumptions regarding the "coke make" of the ANS Resid.

Id. at pp. 19-20. Dickman states that a reasonable location factor would be in the 20% to 40% range for the West Coast. *Id.* at p. 20.

345. Dickman has misgivings regarding O'Brien's assumption that a high-pressure distillate hydrotreater is necessary because he believes that only a medium-pressure hydrotreater is needed. *Id.* He does "not agree with Mr. O'Brien's claim that the high

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industry has modernized. *Id.*

nitrogen level of ANS justifies the additional costs (which are significant) for a high-pressure unit" and claims that the cost impact of using a high-pressure distillate hydrotreater would unnecessarily increase the capital costs associated with processing the virgin Heavy Distillate, while lowering the costs of processing the Coker Distillate product. *Id.* at pp. 20-21. According to Dickman, this occurs because O'Brien attributes all of the costs of the hydrotreater to treatment of the virgin Heavy Distillate (that is, the Heavy Distillate derived from the crude rather than the Coker) and none to the treatment of Coker Distillate. *Id.* at p. 21.

346. Dickman also asserts that O'Brien's "assumption that the coker LSR product would be processed through a 'medium pressure LSR/Naphtha hydrotreater' is clearly inconsistent with his assumption regarding the use of large integrated downstream processing units." *Id.* at p. 22. In connection with this assertion Dickman claimed that, at his deposition, O'Brien stated that he did not propose to build two separate Naphtha hydrotreaters in his refinery. *Id.*

347. In addition, Dickman claims that O'Brien's use of varying OSBL factors is confusing. *Id.* Dickman states:

> At his deposition, [O'Brien] explained that he used a different OSBL factor for his high pressure Naphtha hydrotreater than for his medium pressure Naphtha hydrotreater because he did not believe that those costs would increase proportionately with the increase in ISBL costs between a medium and a high pressure Naphtha hydrotreater. . . . In costing out his high pressure VGO hydrotreater, however, Mr. O'Brien did not follow that approach, but instead assumed that the OSBL factors for the two hydrotreaters would be the same.

Id. at p. 22.

348. Dickman declares that he does not believe that "O'Brien's estimate of 30% sulfur back-up capacity for a West Coast refinery is defensible." *Id.* at p. 23. He claims, first, that West Coast environmental regulations require a greater back-up capacity. *Id.* Second, Dickman disagrees with O'Brien's "claim that the number of sulfur plants is not relevant to an assessment of the need for back-up capacity." *Id.* Rather, Dickman asserts that "the number of the sulfur plants will have an impact on the amount of back-up capacity needed." *Id.* Dickman claims O'Brien's 30% sulfur back-up is insufficient because a 100% sulfur back-up capacity is required. *Id.* at p. 24.

349. Finally, Dickman criticizes O'Brien's use of a five year pay back calculation. *Id.* According to him, "individual estimates of specific costs like Interest During Construction . . . and owner's cost" should be used instead of assuming that they would be "captured by the [5-year] 'pay back' approach" as did O'Brien. *Id.*

350. In his rebuttal testimony, Dickman points out that Jenkins's ISBL cost estimate was based on an equipment list on which each of the equipment used in a Coker was identified. Exhibit No. EMT-167 at p. 5. According to Dickman, Jenkins then determined the cost of buying and installing each individual item on the equipment list and added "other capital costs associated with the construction of the Coker such as offsite costs, owner's costs, and interest during construction" to calculate his total ISBL cost estimate. *Id.* Dickman contrasts this approach with O'Brien's which he characterizes as a "cost curve" depicted on a "single piece of paper." *Id.*

351. Dickman notes that Jenkins's ISBL cost estimate is somewhat higher than O'Brien's - $127 million in 1996 dollars compared to $107.4 million. *Id.* at p. 6. Further, he asserts that it is difficult to account for the difference between the two numbers because O'Brien "has not produced any detail identifying the specific types of costs included in his cost curve estimate. . . ." *Id.* However, Dickman speculates that much of the cost difference results from O'Brien's using a 2-drum rather than a 4-drum Coker because, he asserts, logically, the cost of four drums is higher than the cost of two drums. *Id.* at p. 7. Dickman adds:

> [A]t his May 7, 2002 deposition, Mr. O'Brien conceded that the cost curve on which his Coker cost estimate is based was actually the product of two separate cost curves, one that was more appropriate for a 2-drum Coker and the other that was more appropriate for a 4-drum Coker. Mr. O'Brien further admitted that if one used his 4-drum Coker cost curve to determine the cost of constructing a 40,000 bbl/d coker on the Gulf Coast, the ISBL cost would be between $130 and $135 million, which is higher than Mr. Jenkins' comparable Gulf Coast estimate.

Id. (citations omitted).

352. Next, Dickman addresses five criticisms O'Brien made of Jenkins's ISBL Coker cost estimate. *Id.* at p. 8. First, he asserts that Jenkins was correct in using a location factor because its use is a standard practice when estimating Coker and other refinery construction costs. *Id.* at p. 9. Additionally, he notes, West Coast construction costs are greater than Gulf Coast construction costs and, consequently, Jenkins's location factor is appropriate. *Id.* at pp. 9-10. Dickman, addressing O'Brien's assertion that use of a location factor in this case is inappropriate because it "adds a 'level of specificity' to the cost estimate that is not appropriate given the general nature of this project," states that this ignores "the reality that construction costs are higher on the West Coast." *Id.* at pp. 8, 10.

353. Dickman begins answering O'Brien's contention that Jenkins's coke drums are oversized by noting that O'Brien incorrectly assumes that Jenkins's coke drums use a 14-

hour cycle time in calculating coke drum capacity, when Jenkins, instead, uses a 16-hour cycle time. *Id.* at p. 11. He explains that "cycle time" is "the length of time that it takes to remove the coke from the drum and then return the drum to service" and notes that this process is known as "decoking." *Id.* According to Dickman:

> There are basically eight steps in decoking a coke drum. These steps are described in R.A. Meyers' *Handbook of Petroleum Refining Processes* 12.33 (2nd ed. 1997) . . . as follows:
>
> 1. *Steaming*. The full coke drum is steamed out to remove any residual-oil liquid. This mixture of steam and hydrocarbon is sent first to the fractionator and later to the Coker blowdown system, where the hydrocarbons (wax tailings) are recovered.
>
> 2. *Cooling*. The coke drum is water-filled, allowing it to cool below 93°C. The steam generated during cooling is condensed in the blowdown system.
>
> 3. *Draining*. The cooling water is drained from the drum and recovered for reuse.
>
> 4. *Unheading*. The top and bottom heads are removed in preparation for coke removal.
>
> 5. *Decoking*. Hydraulic decoking is the most common cutting method. High-pressure water jets are used to cut the coke from the coke drum. The water is separated from the coke fines and reused.
>
> 6. *Heading and testing*. After the heads have been replaced, the drum is tightened, purged, and pressure-tested.
>
> 7. *Heating up*. Steam and vapors from the hot coke drum are used to heat up the cold coke drum. Condensed water is sent to the blowdown drum. Condensed hydrocarbons are sent to either the Coker fractionator or the blowdown drum.
>
> 8. *Coking*. The heated coke drum is placed on stream, and the cycle is repeated for the other drum.

Id. at pp. 11-12. Dickman notes further that the Meyers book states that a typical cycle time is 24 hours, a figure which Gary & Handwerk asserts is the maximum used, but that the Maples text "indicates that coke drum cycles range from 16 to 24 hours." *Id.* at p. 12.

354. If O'Brien had used a 16-hour cycle time, Dickman states, then "[t]he amount of

coke produced in a day by Mr. Jenkins' 4-drum Coker would decrease from 3,400 short tons to approximately 3,000 short tons, and Mr. O'Brien's claimed 'excess capacity' would decrease from 42.5% to approximately 25%." *Id.* at pp. 12-13. Furthermore, he states, Jenkins's decision to include an allowance for spare capacity is reasonable because: (1) it is prudent to plan spare capacity into a system to "provide for operational flexibility in the event of mechanical problems with the array of coke cutting equipment;" (2) designing spare capacity is a common practice with "most refinery equipment;" and (3) designing in 25% spare capacity is not unreasonable. *Id.* He adds:

> As opposed to the other operations in a refinery which generally run continuously, the coker operation is cyclical. As a result, there are a significant number of mechanical equipment components that are performing repetitive tasks. Additionally, the cutting and coke handling operations are very labor intensive. Every few hours, the cutting and coke handling operations commence on one of the coke drums. This means there is a potential for delays due to mechanical problems or other unforeseen occurrences. It is therefore important to build flexibility into the Coker's design so that overall performance is not impacted. One way of providing for such flexibility is in the design of the coke drums (*i.e.*, spare capacity).

Id. at pp. 13-14.

355. Dickman declares that he cannot decipher the size of the drums which O'Brien used in his design. *Id.* at p. 14. According to Dickman, in March 2002, O'Brien testified at a deposition that the largest drums were 27.5 feet in diameter and 110 feet long, while on May 5, 2002, counsel representing O'Brien emailed parties that the drums were 29 feet in diameter and 120 feet long, and in a May 7, 2002, deposition O'Brien was "reluctant to commit to a specific drum size." *Id.* Dickman further states that, using a 16-hour cycle time and a coke drum 27 feet in diameter, O'Brien's 2-drum Coker would only have a capacity of about "1,500 tons per day which is well short of the requirement of 2,400 tons per day." *Id.*

356. In addition to coke drum size, the number of coke drums, and cycle time, Dickman claims there are two additional points that O'Brien failed to consider – vapor velocity and recycle from the fractionator. *Id.* at p. 15. According to Dickman, vapor velocity is the speed at which vapor flows in a coke drum. *Id.* He adds that when the vapor velocity in the coke drum is too high, it causes carryover of coke fines into the Coker fractionator, which has a major detrimental impact on the Coker's operation. *Id.* Maximum vapor velocity, he explains, is .625 feet per second for a drum operating at 15 psig with a 22.5% Conradsen Carbon Residue (CCR) feed used by O'Brien. *Id.* at p. 16. Also, the maximum vapor velocity, he maintains, acts as a constraint on the rate that fresh feed can be processed by a coke drum. *Id.* O'Brien's calculations, Dickman states, do not account

for vapor velocity. *Id.*

357. Dickman explains that he developed a calculation for vapor velocity in a 29-foot diameter Coker drum:

> The calculated velocity is .78 [feet per second] when using a recycle rate of 5%, a water content of 1% by weight, a pressure of 15 psig, a temperature of 850ºF, and a molecular weight of the vapor of 118. . . . [However, the vapor velocity is unacceptable because the] top of the coke bed in the drum would be in a turbulent state such that coke fines (very tiny particles) would be entrained and carried over into the piping system and fractionator, resulting in plugging, reduced capacity and eventual shut-down.

Id. at p. 17. He claims that there is no method, within the context of a 2-drum Coker, to compensate for this problem. *Id.* at p. 18. To solve the problem, he states, "O'Brien would need to have a coke drum with a significantly larger diameter than the coke drums that are currently available . . . [or] . . . he would have to reduce the fresh feed rate in his Coker design." *Id.* at. p. 18 (citations omitted).

358. Regarding the issue of the amount recycled from the fractionator, Dickman explains that

> [i]n a standard Coker fractionator design, the vapor from the coke drum enters the bottom of the fractionator, where it exchanges heat with the fresh feed being charged to the fractionator. In so doing, a portion of the coke drum vapor is condensed, creating additional liquid that circulates continuously from the fractionator to the drum and back to the fractionator. This is sometimes referred to as "natural recycle."

Id. The recycle from the fractionator, he asserts, would impact O'Brien's capacity calculation. *Id.* He explains that "[w]hen using a standard design natural recycle rate of 5%, the Resid entering the coke drum is effectively increased by 2,000 bpd, increasing the vapor velocity in the coke drum from .74 [feet per second] to .78 [feet per second]." *Id.*

359. Decreasing cycle time, Dickman maintains, would solve neither the vapor velocity nor the natural recycle rate problems:

> Both of these factors . . . are related to the rate at which Resid can be fed to the Coker. Decreasing Mr. O'Brien's cycle time allows an increased amount of coke to be produced in a day. The increased production of coke results from increased feed rate which leads to increased vapor velocity. To design a Coker that will operate within vapor velocity limitations,

> Mr. O'Brien, as stated above, would have to either reduce the feed rate, increase the diameter of the drum, or increase the number of drums.

Id. at pp. 18-19.

360. Dickman notes several other factors limiting O'Brien's ability to reduce cycle time. *Id.* at p. 19. First, he states, O'Brien, unreasonably, assumes that a 40,000 barrel/day Coker can be operated on a 16-hour cycle with only a 6-man crew when a 4-drum Coker, which requires a 9-man crew, is required.[109] *Id.* Moreover, Dickman

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[109] Dickman argues that, while a single Coker operating on the Gulf Coast (Citgo Corpus Christi Coker) has achieved this goal, it is not comparable to O'Brien's Coker:

> [The capacity] has varied over time. The Coker was originally designed as a needle Coker processing 22,500 bbl/d. Over time, certain steps have been taken to increase the processing capacity. In 1997, the Energy Information Administration reported a stream day capacity of 36,000 bbl/day. In 2001, that number had risen to 41,896.
>
> * * * *
>
> The fact that a single Coker operating on the Gulf Coast has achieved such results does not validate Mr. O'Brien's cost estimate. As Mr. O'Brien acknowledged at his May 7, 2002 deposition, the Citgo Corpus Christi Coker uses automatic deheading equipment and produces "shot coke." As implied by its name, shot coke is spherical in shape and can range from the size of marbles to cannonballs. Shot coke is much easier to remove from the coke drums, which explains one of the contributing factors to the reduced cycle times (as low as 11 hours) and the increased fresh feed rate. ANS Resid, by contrast, produces "sponge coke" which must be cut from the coke drums, resulting in longer cycle times. In addition, Citgo has undoubtedly expended considerable amounts of money to debottleneck the coking process in order to achieve the reduced cycle times. Nowhere in his analysis does Mr. O'Brien identify or provide for such costs. Further, the Citgo Coker is not representative of the type of Coker modeled by Mr. O'Brien's 2-drum Coker cost curve, because the Citgo coker has been modified from its original design, whereas Mr. O'Brien's cost curves are based on new construction. Finally, it is unlikely that a Citgo-type operation could generate the yields of liquid products that both Mr. O'Brien and Mr. Tallett assume in their analyses. One of the drawbacks of reducing cycle time is that the yields of liquid Coker products are also reduced. Another drawback is that the drum operates at a higher pressure, which also reduces liquid products yields.

argues, O'Brien could not "achieve a 16-hour cycle time without using automatic deheading equipment, automatic chutes, and a sophisticated coke handling system." *Id.* Also Dickman asserts, O'Brien neglected to include "sufficient costs for the blowdown system, water recovery and purification system that would be needed if the Coker were to be operated on a shortened cycle." *Id.* Dickman also challenges O'Brien's estimate for the "costs of fabricating coke drums from special alloy steel, as is required for drums used for shorter cycle times." *Id.*

361. As for O'Brien's claim that a number of Jenkins's ISBL costs are unnecessary, Dickman agrees that the Kero Salt Dryer should be excluded, but believes the remaining excluded items should be included. *Id.* at p. 23. Including the equipment, he explains, is appropriate because "it is necessary to include automatic equipment to shorten cycle time and to have a consistent cyclic operation." *Id.* It is impossible to tell whether these equipment costs, Dickman points out, are included in O'Brien's ISBL cost estimate since O'Brien uses cost curves. *Id.* Consequently, he asserts, these costs contribute to the difference in costs between Jenkins's and O'Brien's ISBL cost estimates. *Id.* at p. 24.

362. Dickman also disagrees with O'Brien's claim that Jenkins's included certain costs in the ISBL costs that properly belong in the OSBL costs. *Id.* at pp. 24-25. The equipment in dispute, he explains, is part of the equipment referred to as a gas plant and includes a wet gas compressor taking the off-gas from the Coker fractionator overhead system and compressing it from approximately 5 psig to approximately 210 psig. *Id.* at p. 25. Such equipment, he adds, is not OSBL equipment and "should either be costed out as part of the coker ISBL, or costed out independently as the ISBL component of the gas plant." *Id.* Finally, Dickman notes that he believes that these costs are not even included in O'Brien's OSBL cost estimate. *Id.* at p. 26.

363. Under cross-examination, Dickman stated that price information used by (Jenkins) was derived from three different sources: (1) "information from specific existing projects related to specific equipment;" (2) information contained in the Jacobs Consultancy or Jacobs Engineering files; and (3) calls to vendors. Transcript at pp. 4151-52. In particular, he cited the Coker 1 safety project at the Citgo refinery at Lake Charles[110] and indicated that it was the only individual project at which he looked. *Id.* at pp. 4152-53. However, he added that Jenkins might have gotten individual information from other sources. *Id.* at p. 4153. On re-direct, Dickman testified that a 14-hour cycle time was not reasonable, that a 16-20 hour cycle time was more typical, and that he would not use a cycle time that was less than 16-hours. *Id.* at pp. 4573, 4711-12.

Exhibit No. EMT-167 at pp. 20-21 (citations omitted).

[110] Both sponge and shot coke are produced at Lake Charles. Transcript at p. 4178.

364. With regard to the Lake Charles project, Dickman indicated that he was the project manager on behalf of Jacobs Engineering and that it was involved in all aspects of that project. *Id.* at pp. 4154-55. The price information which Dickman provided to Jenkins from that project was related to the automatic chutes, "[t]he automatic deheading and bo[l]tless closure system for the bottom and top heads of the coke drum and the conveying system for coke." *Id.* at pp. 4155, 4157. He acquired that information from an employee of Citgo. *Id.* at pp. 4167-68.

365. Another project taking place at the Lake Charles refinery after the safety project, according to Dickman, involved upgrades at both Coker 1 and Coker 2. *Id.* at p. 4161. That project involved a review of the cycle time at the Cokers which, at the time of the review, Dickman states, was 16 hours. *Id.* at p. 4162. Dickman indicated that, after his review, he recommended ways for Citgo to reduce the Cokers's cycle time to 12 hours.[111] *Id.* at pp. 4162-63.

366. According to Dickman, the price for a hydraulic deheading system[112] quoted by Jenkins ($5.8 million)[113] was based on the cost of refitting the existing Cokers at Lake Charles which Jenkins and he decided to "treat . . . as if it were suitable for a new installation." *Id.* at p. 4179. Dickman stated that he believed that this was "representative of the cost of [the] same type of equipment on a new installation," although he thought the cost of installation on a new system would be lower. *Id.* at p. 4180. This figure, however, Dickman asserts, only includes the cost of getting the deheader to the site, and does not include the costs of installing, hooking up, handling, storage, commission, etc. *Id.* at p. 4181. Later, Dickman suggested that the price quote used for the estimate was based on a proposed Year 2000 delivery date. *Id.* at p. 4189.

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[111] Dickman admits that, when he reviewed the Citgo Lake Charles refinery's Cokers's cycle time, he was aware that the Cokers at the Citgo Corpus Christi refinery were being operated on 11 hour cycles. Transcript at p. 4166.

[112] On redirect examination, Dickman described the workings of an automatic deheading device as follows:

> [A]n operator would be in an area that was shielded or protected, and he would have a control panel that he would use to engage or start the operation of the deheading of the coke drum, and from that point on, mechanical equipment hydraulic systems or other devices would perform the steps to remove the head from the coke drum.

Transcript at p. 4536.

[113] Dickman indicated that the $5.8 million represented $4.1 million for the bottom heads and $1.7 million for the top heads. Transcript at p. 4476.

367. Dickman indicated that the price quote Citgo received for the coke crusher and the conveying system to be used at Lake Charles was higher than the $2.7 million used by Jenkins for the same equipment. *Id.* at pp. 4184-85. He further indicated that the conveying system to be used at Lake Charles was "a considerable [length] . . . over a mile or so." *Id.* at p. 4185. According to Dickman, he received the $2.7 million quote used by Jenkins from Ron Smith, an employee of TGS Conveying and Engineering Systems, a Houston, Texas firm who he asked to provide him with "an estimate for the hopper crusher transitions[114] to a conveyor and 2500 foot or so of conveying equipment." *Id.* at pp. 4193, 4480 (footnote added). In terms of size, the quote was to be based on "tonnage, an hourly rate" and sponge coke. *Id.* at pp. 4194-95.

368. Among the other equipment about which Dickman was asked during cross-examination were automatic chutes,[115] and a cutting pump[116] and cutting equipment including spare parts.[117] *Id.* at pp. 4200-10. Included among the additional equipment about which he was asked were coke heaters,[118] air fin exchangers, and Coker switch valves. *Id.* at pp. 4214-27.

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[114] On redirect examination, Dickman defined the "hopper crusher transition" as "an enclosure device that contributes to control of coke fines emissions." Transcript at p. 4479.

[115] According to Dickman, these chutes are below the platform and out of the way of the deheading equipment. Transcript at p. 4200; s*ee also id.* at p. 4478. He added: "Once the. . . deheading device has been moved out of its position connecting to the flange of the coker drum, then the automatic chutes raise up and connect to or latch to the bottom flanges of the coke drum." *Id.* at p. 4200. The price for the automatic chutes on the Citgo summary sheet was $1.1 million. *Id.; see also id.* at pp. 4478-79.

[116] Dickman later indicated that this "is a high pressure/high volume pump that provides the water necessary to cut the coke out of the drum." Transcript at p. 4486. He also testified that such a pump would cost around $900,000. *Id.* at p. 4487.

[117] Dickman specified the following equipment: "cross head assembly, the bits, freefall arresters, control panels, drilling panels, all of the necessary equipment to be able to put in an estimate for a four-drum coker." Transcript at p. 4204. He indicated that, in seeking the estimate, he specified a 27-foot wide, 120-foot long drum. *Id.* at p. 4206. Dickman also described, in some detail, the spare equipment he included in the estimate. *See id.* at p. 4229.

[118] Dickman specified a 5000 barrel per day per pass, 90% efficient heater. Transcript at pp. 4215-16. He indicated that the coker would need one heater for each pair of drums and that each heater would cost around $4.5 million. *Id.* at pp. 4491-92.

369. Discussing the difference in cost between a 2-drum Coker and a 4-drum Coker, Dickman indicated that the difference would be no more than $50 million. *Id.* at p. 4355. Called upon to explain that, he stated:

> If you have the same design basis, and when I say design basis, I'm speaking 40,000 barrels a day, resid from ANS. Now, if you have a four-drum configuration, you clearly have two extra drums and all of the appurtenances associated with that. You have one extra heater, and the appurtenances associated with that complex, the heater and the drums.
>
> When you go to a two-drum configuration, then you have one heater, but that heater is essentially the equivalent size from a Btu standpoint, heat standpoint, the two heaters that are in the four-drum configuration.
>
> You also have an increased coke drum size on the order of going from 26 or 27 feet, 27 feet in the instance of Mr. Jenkins's four drums, to something in excess of 30 foot [sic] to be able to handle the same quantity of coke and meet the vapor velocity considerations and all the other process parameters that are involved in that coke drum design.
>
> So you have an increased coke drum size, and I believe quite significantly larger that currently available. In addition to that, the appurtenances of those two drums, the concrete foundation, the cutting . . . equipment are all larger. The blowdown system and all of its equipment are all larger. And all of the piping and valving around that structure are all larger. That's where I'm saying that that delta or that gap gets narrow.

Id. at pp. 4356-57.

370. Asked about cycle time, Dickman agreed that reducing cycle time increases throughput, but added that it would also increase costs. *Id.* at pp. 4364, 4369-70. He also agreed that the increased cost would be spread over the larger throughput. *Id.* at p. 4364. Dickman further agreed that refiners try to get as much throughput as possible in order to reduce the per barrel processing cost. *Id.* at p. 4372.

371. During further cross-examination, Dickman criticized O'Brien's analysis of West Coast reserve sulfur treatment capacity in which O'Brien concluded that 30% was sufficient. *Id.* at p. 4383. According to Dickman, 54-57% reserve capacity is required. *Id.* at p. 4384. He stated that O'Brien's analysis "was based on an incomplete sulfur balance with respect to those refineries that he had in his list" and that it did not include an analysis of "all of the streams, nor did [it] include the total capacity to each one of those refineries." *Id.* at pp. 4385-86. Under further examination, Dickman agreed that the appropriate configuration would be three units, each of which could operate at 50% of

capacity. *Id.* at pp. 4741-42.

372. During re-direct examination, Dickman testified that it would not be prudent to install a manual switch valve system rather than an automatic switch valve system due to safety concerns. *Id.* at p. 4503. He added that new Cokers are being designed with automatic valve switching systems and that existing Cokers are being retrofitted with them. *Id.*

M. DR. KARL R. PAVLOVIC

373. Pavlovic, president of DOXA, Inc., whose degrees and training are in Philosophy, but who claims an expertise in "formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling," a business and litigation consulting firm, was the next witness presented by Exxon on these issues. Exhibit Nos. EMT-69 at p. 1 and EMT-102 at pp. 3-4. He begins his answering testimony by criticizing Ross's Heavy Distillate and Naphtha logistics adjustment of 1.1¢/gallon. Exhibit No. EMT-102 at p. 6.

374. Asserting that the factual assertions upon which Ross's arguments rest are incorrect, Pavlovic begins his criticism by explaining the product flows[119] on the West Coast in general and in the specific Los Angeles market. *Id.* at pp. 7-8. He maintains that Ross's assertion that West Coast waterborne transactions primarily represent movements from harbor to pipeline and, consequently, West Coast waterborne prices

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[119] The general product flows on the West Coast, according to Pavlovic,

> consist[ ] of refinery centers in California, Washington, Alaska, and Hawaii. . . . [t]hese refinery centers produced 1,035,132,000 barrels of refined products in 2001. . . . [p]ipeline transactions include products shipped on the Olympic pipeline from Puget Sound to markets in Washington and Oregon and on the Kinder Morgan pipeline from San Francisco, Bakersfield, and Los Angeles to inland markets in California, Oregon, Washington, Nevada, and Arizona. The pipeline shipments to Washington and Arizona inland markets compete with pipeline shipments from the Rocky Mountains and Gulf Coast (43,330,000 barrels). West Coast waterborne transactions consist of (1) imports from Canada, the Caribbean, South America, and the Far East totaling . . . 45,955,000 barrels; (2) exports totaling 87,453,000 barrels; (3) shipments from other domestic markets totaling 66,537,000 barrels; and (4) shipments among refinery centers and consumption markets within the West Coast.

Exhibit No. EMT-102 at pp. 7-8 (citations omitted).

principally reflect import transactions is incorrect because "import movements do not constitute the dominant movement in this market, but rather are dwarfed by export movements." *Id.* at p. 8. He explains that,

> West Coast refinery centers are located at ports where . . . there are also pipeline terminals for inland transport of products. The primary flow of products is from the refineries (1) to the pipeline terminal for further shipment to inland markets and (2) to the harbor for export and shipment to other West Coast markets. This primary flow is then supplemented by imports and domestic shipments from outside the West Coast . . . and waterborne shipments from other West Coast refinery centers.

Id. at pp. 8-9.

375. Continuing his analysis, Pavlovic states that Ross's Light Straight No. 2 flows analysis is misleading because he combined waterborne and pipeline shipments in the amounts he reports as net receipts erroneously giving an impression of both the volume and direction of waterborne shipments. *Id.* at p. 9. However, according to Pavlovic, the "overwhelming majority of the shipments . . . report[ed] as net receipts are pipeline shipments to the West Coast."[120] *Id.* Concluding on this point, Pavlovic maintains that a correct analysis would reflect that refinery production and its attendant product outflows exceed import and domestic waterborne inflows to the West Coast market. *Id.* at p. 10. He also asserts that Low Sulfur No. 2 waterborne outflows have equaled or exceeded waterborne inflows in all but one of the last seven years. *Id.*

376. A similar analysis and conclusion, Pavlovic states, is applicable to the Los Angeles market: "The primary flow of products is . . . from the refineries (1) to the pipeline terminal for further shipment to inland markets in California, Nevada, and Arizona and (2) to the harbor for export and shipment to other West Coast domestic markets, supplemented by imports and domestic shipments from other refinery centers." *Id.* at pp. 10-11.

377. Next, Pavlovic claims that Ross's West Coast pipeline/waterborne price differentials bear no relationship to the cost of transport from harbor to pipeline because the proposed 1.1¢/gallon logistics adjustment shows no correlation[121] with the observable

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[120] Pavlovic adds that, "[w]ith the pipeline shipments included in net receipts, Exhibit BPX-5 gives the false impression that waterborne LS No. 2 shipments into the West Coast greatly outweigh waterborne shipments out of the West Coast and that this is a trend that has been occurring for a number of years." Exhibit No. EMT-102 at p. 10.

[121] According to Pavlovic, between 1990 and 2001, Platts has published waterborne and pipeline daily spot assessments for four West Coast refined petroleum

pipeline/waterborne differentials on the West Coast and that "the differences between the pipeline and waterborne prices are not due to the costs involved in moving waterborne product from the harbor to a pipeline terminal."[122] *Id.* at pp. 12-14. He states that "[t]he evidence is that the proposed logistics adjustment is at best only coincidentally related to the pipeline/waterborne differential. In fact, there really is no pipeline/waterborne differential to which Mr. Ross logistics costs could be related." *Id.* at p. 13 (emphasis in original).

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products – regular gasoline, jet fuel, FO 380 residual fuel oil and FO 180 residual fuel oil. Exhibit No. EMT-102 at p. 11. After analyzing these reported prices for these products, Pavlovic claims that

> for none of these four price pairs has it been the case that the waterborne price was consistently lower than the pipeline price. In all four cases, there have been many times when the waterborne price was higher than the pipeline price. Moreover, the differentials between waterborne and pipeline prices are extremely volatile rather than being a constant amount that could be attributed to a "logistics" cost.

Id. (emphasis in original).

[122] As evidence, Pavlovic claims that

> First, the logistics costs for similar products should be the same because the products use the same infrastructure facilities. . . . Clean products like gasoline and jet fuel use the same facilities and should incur the same costs in moving from a harbor terminal to a pipeline terminal. Yet, the Platt's prices show an average gasoline pipeline/waterborne differential of 1.5 cents/gallon for regular gasoline compared to 1.1 cents/gallon for jet fuel. . . . Moreover, these two differentials not only differ on an average basis, they differ on a daily basis. When the daily gasoline differentials are regressed against the daily jet fuel differentials, there is virtually no correlation. . . .
>
> Second, dock and storage fees and pipeline tariffs are not volatile. They change little from period to period. Thus, if the pipeline-waterborne differentials reflected a simple logistics cost relationship between, for example, Los Angeles Harbor and the Kinder Morgan pipeline terminal, they should be stable over time. Yet, the pipeline-waterborne differentials for gasoline, jet fuel, FO 380, and FO 180 show extreme volatility.

Exhibit No. EMT-102 at pp. 14-15 (emphasis in original).

378. Addressing the appropriate cause of the West Coast pipeline/waterborne differentials, Pavlovic asserts the differentials "are the result of the competitive dynamics of the West Coast market. . . . Changes in . . . various markets induce changes in the relative demand at waterborne and pipeline market locations and the result is the West Coast market-driven differentials." *Id.* at p. 15. He claims that "there is no need to make an adjustment to the West Coast LS No. 2 proxy product price to make it consistent with the other waterborne proxy product prices used by the Quality Bank, because there is no statistically significant difference between waterborne and pipeline prices." *Id.* at p. 16.

379. Pavlovic argues, contrary to Ross's claim, that a logistics adjustment is not needed to ensure that the Heavy Distillate cut is valued on a consistent basis with all other liquids. *Id.* at p. 17. According to Pavlovic, were that done, similar adjustments would have to be made for each of the other cuts. *Id.* at pp. 19-20. He adds that "[in] any event, Mr. Ross' logistics adjustment purports to adjust the LS No. 2 pipeline price, not to the refinery gate, but rather to the harbor." *Id.* at p. 20.

380. In his Rebuttal Testimony, Pavlovic states that Ross asserts that "in order to value cuts on a consistent basis, a logistics adjustment should be made with respect to Heavy Distillate cut, but not to the Coke component of Resid, leaving both valued on a waterborne basis." Exhibit No. EMT-194 at p. 11. Pavlovic questions such an approach claiming that this proposal would not alleviate the current inconsistencies found with the Quality Bank pricing (i.e. with respect to location and transaction size). *Id.* at p. 12. According to him, given the nature of the distillation methodology for valuing ANS crude adopted by the Commission, "the value of the ANS cuts to the refiner should ideally be determined at the refinery gate." *Id.*

381. Pavlovic explains that Exxon valued only the coke component of Resid at the refinery gate because coke was "the only product for which the costs of transporting and handling between the refinery and the pricing point . . . is a substantial portion of the value of the product . . . being valued." *Id.* Additionally, he notes that it is possible to value all the Quality Bank cuts and Resid components at the refinery gate and that no party has taken issue with his estimates of the costs of transporting and handling the other cuts between the refinery gate and pricing points. *Id.* at pp. 12-13. Concluding, Pavlovic maintains that if all Coker products were valued at the refinery gate, Exxon's Resid refunds would increase because the before cost value of all Resid components would be reduced. *Id.* at p. 13.

382. On cross-examination, at the hearing, Pavlovic admitted that his formal training was in epistemology which he described as "a branch of philosophy. . . . referred to as the theory of knowledge . . . concerned with the questions of what do you know and how do you know it." Transcript at pp. 4801-02. He further admitted that he does not have a degree in engineering or chemistry, and that he had no "formal academic training in economics. . . . [or] statistics." *Id.* at p. 4802. Pavlovic did claim that he has taken

"graduate courses in the foundations of mathematics and statistics." *Id.* at p. 4803.

ISSUE NOS. 3 (NAPHTHA) AND 4 (VGO)

A. JOHN O'BRIEN

383. O'Brien explains that, on the Naphtha question, his testimony is presented only on behalf of Phillips and Alaska. Exhibit No. PAI-33 at p. 1. He notes that, ideally, a Naphtha price published by a reliable pricing service would be used for the Quality Bank, but explains that, because Naphtha is not widely traded on the West Coast, there is no such published price.[123] *Id.* at p. 3. Currently, according to O'Brien, the Gulf Coast Naphtha price is used to value the West Coast Naphtha, but, he claims, "there is no reason to believe that the reported price of Naphtha on the Gulf Coast should reflect the value of Naphtha on the West Coast." *Id.* He summarizes his Naphtha proposal as follows:

> My proposed valuation for West Coast Naphtha is based on the fact that virtually all of the Naphtha produced by refineries on the West Coast is first processed through catalytic reformers (to raise its octane level) and subsequently used as a blending component in gasoline. Thus, the value of Naphtha to a West Coast refiner will be related primarily to the value of gasoline on the West Coast, less the cost of reforming Naphtha and blending the product (termed, "reformate") into gasoline. Accordingly, I have performed a calculation of the West Coast Naphtha value which is based on the cost of processing Naphtha into conventional gasoline. This calculation is based on the published price in Seattle for conventional regular unleaded gasoline.

Id.

384. Almost all West Coast Naphtha, he asserts, produced by West Coast refineries is processed through catalytic reformers and ultimately blended into gasoline.[124] *Id.* at p. 4. Consequently, he adds, there is insufficient trade in the remaining surplus Naphtha to support any published Naphtha prices. *Id.* The Gulf Coast Naphtha price used for West

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[123] According to O'Brien, ANS crude represents about 40% of the total crude processed on the West Coast. Transcript at pp. 6052-53.

[124] O'Brien adds that, "[u]nlike the Gulf Coast, (a) there is no petrochemical industry to speak of on the West Coast, (b) there is no regular 'trade' in Naphtha, (c) there are few, if any, imports of Naphtha; and (d) there are no economic alternative uses for Naphtha." Exhibit No. PAI-33 at p. 6.

Coast Naphtha, he contends, is improper because, unlike the West Coast where Naphtha is used as a gasoline blendstock, on the Gulf Coast it is used as a petrochemical feedstock as well as being used in the manufacture of gasoline. *Id.* at p. 4. In fact, O'Brien declares, some refineries on the Gulf Coast do not even process Naphtha into gasoline. *Id.* Additionally, he asserts that Naphtha is imported into the Gulf Coast, but not the West Coast. *Id*. at pp. 4-5. From these "facts," O'Brien concludes, there is a "trade" in Naphtha on the Gulf Coast, but not the West Coast which results in different market forces applying. *Id*. at p. 4. Valuing West Coast Naphtha on a West Coast basis, he asserts, is more appropriate. *Id.* at p. 5.

385. According to O'Brien, on the West Coast, almost all refineries use all of the Naphtha they produce to make gasoline.[125] *Id.* at p. 7. *Id.* at p. 7. The primary product coming from the reformer,[126] he explains, is reformate, which is also almost entirely used to produce gasoline, and, consequently, has no published West Coast price. *Id.* O'Brien contends that there is no West Coast published price for any product that could be used to derive a West Coast Naphtha value.[127] *Id.* at p. 8.

386. The West Coast gasoline market, according to O'Brien, is complicated and unique

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[125] O'Brien concedes that some small refineries sell Naphtha to larger adjacent refineries in private deals and that some "small isolated refineries" sell Naphtha out-of-state. Exhibit No. PAI-33 at p. 7.

[126] O'Brien explains that the reformer raises the octane number which is a "measure of the combustion properties." Exhibit No. PAI-33 at p. 7. Toof defined it as "a measure of a motor fuel gasoline's ability to prevent what's known as detonation. . . . [referred to by s]ome people . . . [as] engine knock." Transcript at p. 13355.

[127] O'Brien states that

> [i]ntermediate products, like Naphtha, are valued by refiners based on the products that can be produced from them and the costs of processing. Since almost all Naphtha on the West Coast goes into making gasoline, it is logical that the value of Naphtha will be clearly related to the price of gasoline less processing costs. The prices of other intermediates traded on the West Coast, including [Light Straight Run] and [Vacuum Gas Oil], are commonly established by buyers and sellers in exactly the same way-in relation to the products that can be produced from them-less the costs of processing. If a refiner could sell Naphtha at a price higher than its gasoline cost-based value, then he would do so, and forgo the expenditures associated with converting Naphtha into gasoline.

Exhibit No. PAI-33 at p. 8

because of California's strict environmental specifications established by the California Air Resources Board (sometimes "CARB"). *Id.* at p. 8. The CARB gasoline standards, he asserts, are the most "stringent" in the United States and, as a result, CARB gasoline is the most difficult to produce and the most expensive. *Id.* He adds that California refineries also produce Federal reformulated gasoline (sometimes "RFG") for shipment to Las Vegas and Phoenix. *Id.* However, he adds, refineries in the Pacific Northwest (Oregon and the State of Washington) do produce conventional gasoline which is less expensive to produce than CARB gasoline or RFG and is all that is required in those states. *Id.* at pp. 8-9. Nevertheless, O'Brien concludes that "it would be difficult to develop a value for Naphtha that would relate to the prices of" CARB gasoline and RFG because "there are no published prices for [all] of [the] blending components" required to make them. *Id.* at p. 9.

387. The Pacific Northwest, O'Brien contends, uses substantial amounts of conventional gasoline,[128] and is a robust, growing market with a published price. *Id.* at p. 9. He claims that a West Coast Naphtha value based on the Pacific Northwest's conventional gasoline price could be derived. *Id.* at p. 10. As conventional gasoline is easier to make, O'Brien asserts, a price easily could be determined:

> For example, an acceptable conventional regular unleaded gasoline can be blended from reformate, and two Quality Bank components, namely, LSR[129] and Normal Butane. Since there are published prices for the latter two components, and a published price for conventional regular unleaded gasoline in the Pacific Northwest, the value of reformate can be calculated. With this, and a knowledge of the cost of processing in a catalytic reformer, a Naphtha value can be calculated. Such a calculation would be no more complex than my Resid calculation.

Id. at p. 10 (footnote added). He adds that he recommends use of "Platt's Oilgram Seattle waterborne spot price for conventional regular unleaded gasoline." *Id.*

388. After first summarizing it, O'Brien described the four-step process he proposes to calculate the West Coast Naphtha value based on the Seattle conventional regular unleaded gasoline price before explaining each step in greater depth. *Id.* at pp. 10-11. According to O'Brien, the first step is to calculate the volume of the products yielded

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[128] O'Brien explains that "[c]onventional gasoline is much easier, and less costly, to manufacture and blend because it does not need to meet the more stringent CARB or RFG specifications." Exhibit No. PAI-33 at p. 9.

[129] LSR is light Naphtha separated from the heavier material in the Coker's distillation column that has not been further processed. Transcript at p. 5661.

from the Naphtha processing. *Id.* at p. 11. He uses the PIMS model to calculate the three individual processes[130] needed to transform Naphtha into reformate, and concludes that 85.7% of the Naphtha is converted into reformate and the remainder into hydrogen gas, fuel gas, propane (C3), isobutane (IC4), normal butane (NC4). *Id.* Step two, he explains, is to value the reforming product yield by "multiplying the price or value of each product by the volume of that product" and then adding "the results to give the total value of the yield." *Id.* at pp. 11-12. This result, he notes, is the yield value in dollars per barrel of Naphtha processed. *Id.* at p. 12.

389. Addressing the value of the products produced by the Naphtha processing, O'Brien explains, Propane, Isobutane and Normal Butane have West Coast Quality Bank reference prices and he uses those prices in his calculations. *Id.* As for fuel gas, he notes, he uses the California south natural gas prices as quoted in *Natural Gas Week,* a public natural gas prices source. *Id.* Reformate and hydrogen value, however, he states, do not have published prices, and he calculates them. *Id.*

390. Discussing how he valued reformate, O'Brien begins by claiming that conventional unleaded gasoline is produced by blending reformate produced from Naphtha, Normal Butane, which he says is available in a refinery, and LSR, also known as "natural gasoline."[131] *Id.* For the reformate calculation, he explains that he "calculated a typical blend of these three components that met the octane, [Reid Vapor Pressure], and [vapor to liquid ratio] specifications for conventional regular unleaded gasoline." *Id.* at p. 13. He adds that, "[o]nce that blend is determined, it is a simple matter to use the published price for Seattle regular unleaded gasoline, and Quality Bank prices for LSR and Normal Butane to calculate a value for reformate." *Id.* at pp. 13-14.

391. As for hydrogen gas, he asserts that it is a valuable West Coast commodity

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[130] These processes, O'Brien states, require "(1) a hydrotreating unit to prepare the Naphtha for reforming; (2) the catalytic reformer itself, in which the reformate is produced; and (3) a small gas plant to separate the reformate and the by-products." Exhibit No. PAI-33 at p. 11.

[131] O'Brien admits that manufacturing gasoline is a complex process, that it is "different at each refinery because each refinery has different blending components available, different economics, and a different 'mix' of products." Exhibit No. PAI-33 at p. 13. However, he asserts, "no calculation will apply to every refinery" and, for simplicity's sake, he used the three-component blend. *Id.*

Under cross-examination, O'Brien admitted that he did not "know. . . for sure" of any West Coast refinery using his three-component blend, but claimed that he "expect[ed] that they do." Transcript at p. 5461.

because of its use in desulfurizing other petroleum products. *Id.* at p. 14. Since he calculated a hydrogen gas value for his Resid and Heavy Distillate testimony, he states, he uses the same $1.75 per thousand cubic feet (Mcf) in 1996 dollars price. *Id.* However, O'Brien states, unlike his approach for Resid and Heavy Distillate, he adjusted this price for "variations in the price of natural gas" as the value of hydrogen, he claims, will "vary over time with fluctuations in West Coast natural gas prices." *Id.* at pp. 14-15. He reasoned that this adjustment was necessary because, while hydrogen has only a minor impact on the variable cost of processing Resid and Heavy Distillate, hydrogen gas is "produced in significant quantities" by the reforming process and its value is significantly impacted by changes in the natural gas price. *Id.* at p. 15.

392. Next, he describes the third step in calculating the West Coast Naphtha value by determining the costs of reforming Naphtha. *Id.* at p. 16.

> I assumed a typical economic-sized operation with a capacity of 30,000 barrels/day (B/D) of Naphtha processing. . . . I included variable costs, fixed costs and capital recovery costs in my calculations. I estimated the costs, per gallon of Naphtha processed, to be: (a) variable costs, 3.3¢; (b) fixed costs, 1.1¢; and (c) capital recovery costs, 4.6¢, for a total cost of 9.0¢/gallon. The capital costs of this operation were estimated using . . . conceptual cost curves. . . Because . . . these curve cost estimates are conceptual in nature, I did not try to make any adjustments for location or other factors. I applied an allowance of 30% for [Outside Battery Limits] costs. In total, the cost of the hydrotreater, reformer and gas plant was estimated to be $97.5 million. I then used a 92% utilization factor and [a] five year simple payback assumption . . . to derive the 4.6¢/gallon capital cost allowance.

Id. at p. 16. The final step, he states, is to subtract the step three processing costs from step two Naphtha yield value to arrive at a West Coast Naphtha value. *Id.* at p. 17.

393. Finally, O'Brien compares his results for the West Coast Naphtha value with the published Gulf Coast Naphtha value currently used to value the West Coast Naphtha. *Id.* at p. 18. He asserts that, following his calculations, West Coast Naphtha values are consistently higher than Gulf Coast Naphtha values, and, furthermore, "[t]he difference has increased in recent years as gasoline prices on the West Coast have generally increased relative to gasoline prices on the Gulf Coast." *Id.*

394. In his Reply Testimony, O'Brien responds to criticisms raised by Tallett, Ross, S. Frank Culberson ("Culberson"), and William J. Sanderson ("Sanderson"). Exhibit No. PAI-52 at p. 2. According to O'Brien, Tallett improperly derives a West Coast Naphtha value based on Gulf Coast market prices. *Id.* O'Brien argues that a separate West Coast Naphtha value is necessary because the West and Gulf Coast markets are different as, he

claims, Tallett acknowledges in his testimony.[132] *Id.* Relationships between West Coast product values, O'Brien maintains, are different from the relationships between Gulf Coast product values. *Id.* As this is so, he asserts, Tallett's West Coast Naphtha valuation proposal based on Gulf Coast Naphtha, gasoline, and jet fuel "cannot have any validity." *Id.* at pp. 2-3.

395. Ross's proposed West Coast Naphtha valuation, in O'Brien's view, is also flawed. *Id.* at p. 5. Although Ross's West Coast Naphtha valuation,[133] using a cost-based calculation reflecting Naphtha's value in the production of gasoline, is correct, O'Brien maintains that Ross understates Naphtha's value, and, consequently, Ross's governor is improper. *Id.* Ross understates Naphtha's value, O'Brien explains, by improperly assuming a 50% Outside Battery Limits (sometimes "OSBL") factor, valuing hydrogen at only its variable costs, and valuing reformate at the premium unleaded gasoline price. *Id.* at p. 6. O'Brien expands on each of the assumptions. *Id.*

396. A 50% OSBL,[134] O'Brien contends, is inappropriate. *Id.* He notes that Ross admits he is not a cost estimation expert and that his OSBL factor is taken from an unidentified 1996 Bechtel database owned by his firm. *Id.* Furthermore, O'Brien argues, the 50% OSBL factor, is a higher factor than any party has used for any other process unit. *Id.* There is nothing about a reformer, he maintains, that would result in such a high OSBL factor. *Id.* Following the Gary & Handwerk textbook, he comments, leads to a 20-25% OSBL factor for process units being added to an existing refinery. *Id.* Concluding, he states that if his 30% OSBL factor were substituted for Ross's 50% factor, then his calculated Naphtha value would increase by 36¢/barrel in November 2001. *Id.* at p. 7.

397. The variable cost of hydrogen, O'Brien explains, impacts the calculated value of Naphtha because it is one of the products of the reforming process. *Id.* Ross and O'Brien both calculate Naphtha value, O'Brien notes, by assuming Naphtha is processed through a reformer and then valuing the products of the reforming process. *Id.* As there is no published hydrogen price, he continues, he and Ross agree that the value of the hydrogen produced in the reforming process is equal to the cost a refiner otherwise incurs to purchase or produce that hydrogen in a hydrogen plant. *Id.* However, according to

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[132] *See* Exhibit No. EMT-11 at p. 14.

[133] Ross, in later testimony, withdrew his proposed Naphtha valuation. *See* Exhibit No. BPX-67 at p. 6.

[134] Ross's Inside Battery Limits cost number used for his Naphtha reformer, O'Brien explains, is $75.79 million, to which Ross then adds a 50% OSBL factor, for a total of $113.68 million. Exhibit No. PAI-52 at p. 6.

O'Brien, Ross limits his hydrogen value to the variable cost of producing hydrogen, which, O'Brien contends, results in a lower hydrogen value than if Ross had also included capital and fixed costs associated with the hydrogen production. *Id.* Consequently, O'Brien asserts, Ross's "assumption results in a significant understatement of the calculated value of Naphtha." *Id.* at p. 8.

398. O'Brien maintains that Ross's justification for his approach "is not an explanation at all." *Id.* He contends that Ross does not explain why using variable costs to calculate the value of by-products of "non-core process units" is an appropriate approach, but merely asserts that it is so. *Id.* and Exhibit No. BPX-8 at p. 9. Further, O'Brien states, Ross's method is not similar to O'Brien's Resid valuation approach because he "used the full costs for all of the downstream processing units, including the distillate hydrotreater." Exhibit No. PAI-52 at p. 8. Consequently, Ross's method, O'Brien argues, results in a significant Naphtha value understatement. *Id.* at p. 9. O'Brien explains the impact of Ross's assumption:

> [T]he capital and fixed costs of hydrogen production, which should have been added to the value of hydrogen to reflect its true value to the refiner, were 84¢/Mcf in 1996 and 89 ¢/Mcf in November 2001. Given Mr. Ross' projection that 1.595 net Mcf of hydrogen is produced from each barrel of Naphtha, his failure to include these amounts in his hydrogen value results in an undervaluation of $1.34/barrel in 1996 and $1.42/barrel in November 2001.

Id.; Exhibit No. PAI-36.

399. Addressing Ross's Naphtha reformate value, O'Brien argues that Ross's approach, valuing the reformate as premium unleaded gasoline without any adjustments, improperly undervalues Naphtha. Exhibit No. PAI-52 at p. 9. O'Brien explains that Ross, erroneously, assumes that a reformate with a Research Octane of 100 and a Reid Vapor Pressure[135] of 6 is worth the same as premium unleaded gasoline. *Id.* at p. 10. According to O'Brien, Ross's reformate assumption is significantly higher in octane and lower in Reid Vapor Pressure than premium unleaded gasoline and is, therefore, more valuable because a refiner could blend it with less valuable components such as LSR or butane in order to produce gasoline that is closer to the required octane and Reid Vapor Pressure

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[135] According to O'Brien, the Reid Vapor Pressure measures the propensity of the reformate to boil off. Transcript at pp. 6161-62. Ross stated that it was "a measure of the volatility of the product." *Id.* at p. 8159. He added: "If you have a high [Reid Vapor Pressure], evidence suggests that you get evaporative loss from your tanker, especially during the start-up of a motor vehicle and that trends to push out ozone precursors into the atmosphere." *Id.* That presents an environmental hazard. *Id.*

specifications. *Id.* He asserts that Ross's method would increase reformate value, and, consequently, Naphtha value. *Id.* O'Brien argues that if Ross's reformate value calculation included blending of LSR and butane, the result would increase the value of Naphtha by $1.67/barrel in November 2001. *Id.* at pp. 10-11; Exhibit No. PAI-54.

400. The impact of improperly assuming a 50% OSBL factor, valuing hydrogen at its variable costs, and valuing reformate at the premium unleaded gasoline price, O'Brien contends, for November 2001, increases the Naphtha value by $3.45/barrel. Exhibit No. PAI-52 at p. 11.

401. Ross's governor proposal, O'Brien contends, is unsupportable.[136] *Id.* He notes that there are products with published prices on both coasts and, if Ross's theory were correct, the differences between the published West Coast and Gulf Coast prices for these products would not be greater than the Gulf Coast price plus or minus the cost of transporting products between the two coasts. *Id.* at p. 12. After comparing Gulf Coast and West Coast prices for regular unleaded gasoline, high sulfur VGO, Heavy Distillate, and Light Distillate, O'Brien asserts that the product prices for the two coasts frequently vary by amounts in excess of Ross's governor. *Id.* and Exhibit No. PAI-56. He concludes, therefore, that "Ross' theory underlying the governor simply is not supported by the actual relationship between product prices on the two coasts." Exhibit No. PAI-52 at p. 12.

402. Acknowledging Ross's claim that the variance which O'Brien reported related to a "time lag" between the reported Gulf Coast price and when imports could drive the differential down, O'Brien maintains that Ross's explanation for gasoline prices on the two coasts exceeding his calculated transportation differential is insufficient. *Id.* at p. 13. According to O'Brien,

> the data for LA unleaded regular gasoline prices shows that the difference exceeded [Ross's] $1.85/barrel transportation differential for long periods of time. Since 1992, the price differential exceeded $1.85/barrel for six months or more on six different occasions, including a period of 15 months in 1995-96 and two periods that approached a year in 1999 and 2000. This data would appear to be inconsistent with Mr. Ross' conclusion that there is

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[136] O'Brien explains Ross's governor:

> If Mr. Ross' cost-based calculation of the West Coast Naphtha value in a particular month exceeds the published Gulf Coast price by more than $1.85/barrel, then Mr. Ross would set the West Coast price at the Gulf Coast price plus $1.85/barrel.

Exhibit No. PAI-52 at p. 11

only a short time lag before prices on the two coasts converge.

Id.

403. Barriers to entry, O'Brien argues, account for the failure of Ross's theory. *Id*. at p. 14. Further, according to O'Brien, Ross understated the cost of transportation. *Id.* Ross, O'Brien asserts, fails to consider that West Coast refiners typically have reformers full of Naphtha produced from the crude that they are refining. *Id.* To take advantage of imported Naphtha, O'Brien continues, refiners would need to switch to a different crude slate to free space in reformers used to process imported Naphtha. *Id.* Furthermore, he explains, since West Coast refineries purchase crude under long-term purchase contracts and vessels are scheduled months in advance, switching can involve a considerable amount of time and expense. *Id.* Consequently, according to O'Brien, a refiner would purchase imported Naphtha only if the price was so much lower for an extended period of time that the lower cost would compensate him for all the costs incurred by buying Naphtha. *Id.*

404. Ross's transportation costs, O'Brien claims, are understated. *Id.* at p. 15. He explains that there is no back haul on product vessels between the Caribbean and the West Coast to keep transportation costs down. *Id.* Higher rates, he states, result when there is no back haul and Ross does not factor these rates into his methodology. *Id.*

405. O'Brien also argues that Culberson's and Sanderson's approach, using Gulf Coast prices to value West Coast Naphtha, is unsupportable. *Id.* Culberson's approach,[137] O'Brien states, suffers from the same flaws as Ross's governor.[138] It is premised, he begins, on assuming a lack of demand for Naphtha, which, O'Brien counters, is incorrect as the entire Naphtha demand is satisfied by West Coast refiners. *Id.* at p. 16. Also, O'Brien notes, there are substantial barriers to moving Naphtha from the Gulf to the West Coasts. *Id.*

406. Sanderson asserts, O'Brien states, that refiners on both coasts have the choice of

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[137] O'Brien summarizes Culberson's approach, stating that Culberson "calculated transportation differentials from various locations to the Gulf Coast and West Coast, and inferred from those transportation differentials that the two markets are closely linked and that prices on the West Coast would not greatly exceed prices on the Gulf Coast." Exhibit No. PAI-52 at p. 16.

[138] O'Brien notes that one West Coast Naphtha trader specifically disagreed with Culberson's methodology and, instead, agreed with a methodology valuing West Coast Naphtha on the price of West Coast gasoline minus some differential. Exhibit Nos. PAI-52 at p. 17, PAI-57.

purchasing Naphtha to fill their reformers or purchasing crude oils with higher Naphtha contents. *Id.* at p. 18. O'Brien contends that there are differences between Gulf Coast and West Coast product markets. *Id.* Sanderson's claim that refiners can choose, O'Brien argues, is not borne out by the facts as refiners purchase additional Naphtha "only in the rare instance of excess capacity or refinery outages." *Id.*

407. Additionally, O'Brien notes that the Naphtha contracts produced in discovery demonstrate that West Coast Naphtha values are consistently higher than Gulf Coast Naphtha prices, thus contradicting Culberson's and Sanderson's conclusions. *Id.* at p. 19. He asserts that none of these contracts tied Naphtha West Coast values to Platts published Gulf Coast Naphtha prices. *Id.*

408. At the hearing, during further direct testimony, O'Brien defended his gasoline formula from claims that "the blend [he] prepared would exceed [the] toxic limits" set by the Environmental Protection Agency under the Clean Air Act. Transcript at p. 5028. To respond to these allegations, he prepared an exhibit which, he claims, shows how to process his gasoline formula "to meet the exhaust toxics limit." *Id.* at pp. 5031-32; Exhibit No. PAI-148 at p. 4. According to O'Brien, the cost for this processing would be 54¢/barrel or 1.29¢/gallon. Transcript at pp. 5032-37; Exhibit No. PAI-148 at p. 3.

409. Under cross-examination, O'Brien agreed that prices for petroleum products follow the market, the cost of production and the cost of crude oil. Transcript at p. 5360. He further agreed that the cost of production was the most constant factor, that there was little variance between the costs of crude oil on the Gulf Coast and the West Coast, and that the "most variable cost difference between the Gulf Coast and the West Coast is changes in market prices." *Id.* at pp. 5360-61. O'Brien further indicated that there were differences between the market factors on the West Coast as compared with those on the Gulf Coast, stating that, on the Gulf Coast, there was excess capacity resulting in the exportation of a lot of product. *Id.* at p. 5361.

410. Questioned about his three-component blend for conventional gasoline, O'Brien agreed that he could not state that all gasoline manufactured in the Pacific Northwest used the formula,[139] that he couldn't state a percentage which did, and that there were "a number of different. . . blend[s] that could be used to make unleaded gasoline." *Id.* at pp. 5461-62. He further indicated that, if any of these other formulas used components which had to be processed, the costs for producing the conventional gasoline could be

[139] O'Brien later identified three (the Paramount refinery in Los Angeles, CA, the Kern Oil refinery in Bakersfield, CA, and the U.S. Oil refinery in Tacoma, WA), all of which are "simple hydroskimming refineries," which *could* manufacture gasoline using his three-component blend. Transcript at pp. 5469-70. However, later, this claim was questioned. *Id.* at pp. 5471-82.

higher than his three-component blend. *Id.* at p. 5462. But he added later, that the cost also could be lower. *Id.* at p. 5464. O'Brien did indicate that refineries will use the most economical blend they can whether it had three components or eight. *Id.* at p. 5490.

411. In using the three-component blend, O'Brien claimed, he "assumed . . . there are complex refineries on the West Coast that can make this type of blend" and he "assumed a [refinery] size . . . reasonable for that type." *Id.* at p. 5492. O'Brien declared that he did not have a particular refinery in mind, but simply that there were a number of refineries on the West Coast which could make the three-component blend. *Id.* at p. 5493. During later cross-examination, O'Brien stated that he proved his three-component model against Gulf Coast conditions, but was unable to do so using West Coast conditions because there is no "benchmark to compare it against." *Id.* at pp. 5903-04. He did suggest that "it does pretty good against the [Naphtha] contracts" discovered by the parties, although he admitted that those contracts are "not representative of the bulk of naphtha transactions – the bulk of naphtha usage on the West Coast" which is produced by the refiners which use it. *Id.* at p. 5904.

412. During a discussion with counsel regarding the definition of "Naphtha," O'Brien testified that he would define it as "a light boiling petroleum fraction with an end point or a boiling point usually less than about 400 degrees Fahrenheit." *Id.* at p. 5660. Admitting that this definition was broad, O'Brien also agreed that while one person might be referring to a product with a boiling point range of 175° to 350ºF., another person might be referring to a product with a boiling point range of 165° to 400°F "or something like that." *Id.* at pp. 5660-61. He indicated that terms such as "light naphtha, heavy naphtha, [or] full range naphtha" are used to narrow the reference. *Id.* at p. 5661.

413. Asked about the Naphtha contracts entered into evidence here,[140] O'Brien testified that they represented a small portion of the Naphtha processed in West Coast refineries, a lot of them were small volume transactions, and that they did not represent a reportable market price because the trades were not "transparent,"[141] "robust," or "frequent

[140] In a discussion between counsel, O'Brien, Judge Wilson and me, it became apparent that a total of 349 contracts (some of which may be duplicates) were available to be reviewed by the witnesses, that O'Brien, personally, reviewed about 250 of them (although his staff may have reviewed them all), that he included only 172 of the 349 contracts in his analysis, that other witnesses may have included more or fewer in their analysis, and that none of the analyses are based on precisely the same group of contracts. Transcript at pp. 6028-33. O'Brien also stated that, while almost all of the West Coast Naphtha is processed into gasoline, some of it (less than 1%) is used to make specialty applications such as solvents. *Id.* at pp. 6039-41.

[141] O'Brien defines a "transparent" market as "one in which all of the various participants in the market are aware of the various transactions that are taking place, or

enough."[142] *Id.* at p. 5520. However, he agreed that the average price on those contracts was $5.40/barrel. *Id.* at pp. 5519-21. Regarding those contracts, O'Brien testified that he (directly or indirectly) reviewed 300 contracts of which he eliminated 120.[143] *Id.* at p. 5524. The remaining 180 contracts represented, according to O'Brien, "valid naphtha contracts [from which] we could determine the information we needed for our analysis." *Id.* In later testimony, based on the total universe of these contracts, O'Brien expressed surprise "there were as many sales and transactions of naphtha as there are." *Id.* at pp. 5600-01, 6033.

414. O'Brien was asked about the differences between the contracts he included in his analysis and those included in Pulliam's analysis and, in reply, he stated that Pulliam divided the contracts into those meeting Quality Bank standards and those that only had the potential for meeting those standards. *Id.* at p. 5820. According to O'Brien, he tried to include as many contracts as possible in his analysis and would only exclude those which he "had a reason to kick . . . out." *Id.* Later, he added that he did everything he could to verify whether a contract should be included. *Id.* at p. 5913. O'Brien agreed with counsel that there were differences between the universe of the contracts he analyzed and those which Pulliam included in his analysis. *Id.* at pp. 5822-23. Moreover, while he had had no contact with Tallett, O'Brien assumed that the universe of contracts which Tallett used in his analysis also differed from those O'Brien used. *Id.* at p. 5824.

415. Questioned about his proposal for valuing Naphtha, O'Brien admitted that it would produce a higher price for Naphtha than the gasoline price for a seven or eight month period beginning in late 2000 and ending June 30, 2001. *Id.* at pp. 5604-09.[144] As to his proposal, O'Brien indicated that he was attempting to "get a reasonable value for naphtha based on the methodology [he] used." *Id.* at p. 5611. According to him, his "calculated value of naphtha is what [he] would call the 'equilibrium value for naphtha.'"

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there is a reporting service that reports information on those transactions that they rely on . . . to do their pricing and develop their contracts for these various commodities." Transcript at p. 6121.

[142] O'Brien stated that only 1%-5% of the total amount of West Coast Naphtha is traded. Transcript at p. 6034.

[143] O'Brien declared that the contracts were eliminated because they were duplicates, illegible, contracts for sales of Naphtha which did not meet ANS standards, intercompany transfers, lacked of sufficient information, did not involve a West Coast delivery, and for other unspecified reasons. Transcript at pp. 5524-25.

[144] *See* also Exhibit Nos. PAI-82 at p. 4, UNO-35.

Id. However, he noted that the price which actually will be paid for Naphtha will reflect its supply and the demand for it at the time of the transaction. *Id.*

416. Asked about his proposition that, "if the price of naphtha exceeded the price of gasoline, that companies would sell naphtha rather than use it to produce gasoline," O'Brien suggested that it couldn't be tested and was not provable. *Id.* at pp. 5611-12. He further claimed that it was an "economic proposition [that i]f you can sell something for more than it would cost you and [if you can] make a better profit than it would cost you to process it, why would you process it?" *Id.* at pp. 5612-13. O'Brien also agreed that, with regard to the Naphtha contracts he has seen, all involve formula prices of a gasoline price "less something." *Id.* at p. 5614.

417. During further cross-examination, O'Brien was asked whether a refiner would process Naphtha through a reformer if the Naphtha price exceeded the price of gasoline because of a high price for fuel gas. *Id.* at p. 5884. O'Brien replied that the refiner still would process the Naphtha through the reformer for two reasons: (1) the refiner needs the hydrogen produced through that process to reduce the sulfur content of other products which he would otherwise have to purchase at a very high price;[145] and (2) the refiner is in the business of making and selling gasoline and must make gasoline in order to meet its contractual obligations. *Id.* at p. 5885.

418. O'Brien stated, during further cross-examination, that the Naphtha price he calculated represented its value "to a refiner who turns it into gasoline." *Id.* at p. 5906. He testified that, in his opinion, a refiner would not pay more than that price for Naphtha unless he needed it to make gasoline to meet a contractual obligation. *Id.* at p. 5906. O'Brien also asserted that, in those circumstances, a refiner would not make gasoline if he had another option. *Id.* at p. 5907. However, he indicated that that price is an "equilibrium value" and that market conditions could make the price higher or lower although he added "market forces will tend to push it towards this value." *Id.* at pp. 5907-08.

419. Questioned about the value of octane, O'Brien testified that it was "one of the more important elements in the production of gasoline," and was available in limited amounts at refineries. *Id.* at p. 5876. He also stated that higher octane gasoline sells for a higher price than lower octane gasoline, and that "[t]he higher the octane of the material generally, the more valuable it will be for a given material." *Id.*

[145] According to O'Brien, hydrogen is manufactured from natural gas which can be a costly item. Transcript at pp. 5885, 5887-88. He also indicated that the value of hydrogen to a refiner resides in the cost to purchase it from a third party rather than the refiner's cost to make it in the reformer. *Id.* at pp. 5888-89.

420. O'Brien was asked about how a high price for natural gas could impact the refiner and indicated that it would in three ways: (1) since natural gas fuels the hydrotreater and the reformer, a higher price raises the cost of operating those pieces of equipment; (2) the refiner can use natural gas produced in the reformer and the hydrotreater or sell if it has a surplus; and (3) the price of natural gas may affect the cost of products, such as hydrogen,[146] produced by using it. *Id.* at p. 5890-91.

421. At a later point during cross-examination, O'Brien discussed reformer technology stating that the "semi-regenerative reformer," an older technology, was the one most prevalent in use, but that, perhaps in 1996 and certainly in 2003, a refiner would have built a "continuous reforming refinery." *Id.* at p. 5897. This newer technology, although it costs more to construct, generates higher yields and operates more efficiently than the semi-regenerative reformer, according to O'Brien. *Id.* at 5898.

422. During a discussion of why he valued West Coast Naphtha at a higher level than Gulf Coast Naphtha, O'Brien acknowledged that a "competitive market"[147] for Naphtha existed on the Gulf Coast, but not the West Coast. *Id.* at p. 6042. Despite that, he said, because virtually all of the West Coast Naphtha is used to make gasoline, and because gasoline prices are higher on the West Coast than the Gulf Coast "it follows that naphtha will be higher on the West Coast also." *Id.* O'Brien added that there was no surplus of Naphtha on the Gulf Coast, but there is a trade in it, a "market clearing price," and sources which will supply Naphtha when demand requires it. *Id.* at pp. 6042-43. On the other hand, he stated, since most refiners use all of the Naphtha they produce and supply all of the Naphtha they need, there is only a "thinly traded market" for Naphtha on the West Coast. *Id.* at pp. 6043-44. Though he claimed that his proposal is not based on his contract analysis,[148] O'Brien also admitted that his analysis of the West Coast Naphtha

[146] On further examination, O'Brien stated that he used a different method for valuing hydrogen as a cost in Resid processing than he did in valuing it as a yield product in the Naphtha reforming process because he treated all costs in the same manner and all yields in the same manner. Transcript at p. 5972. He further testified that, in establishing a cost for processing Resid, he assigned hydrogen a 1996 value of $1.75, converted that to a per barrel cost and added that cost to the total per barrel cost for processing Resid. *Id.* With regard to hydrogen's value as a reformer yield product, he stated that he also began with a $1.75 and "then adjusted it for the fuel gas value of each month." *Id.* at p. 5973.

[147] A "competitive market" for Naphtha was defined as one in which competition for Naphtha existed "between petrochemical companies individually and gasoline manufacturers individually." Transcript at p. 6041.

[148] O'Brien does declare that "the contract data appear to support [his] methodology." Transcript at p. 6045.

market was based on "a very limited number of transactions over a significant period of time." *Id.* at p. 6044-45.

B. WILLIAM BAUMOL

423. Baumol addresses the Naphtha valuation question in his Rebuttal Testimony. Exhibit No. EMT-144. He notes that there are two "fundamental difficulties" with evaluating the intercompany compensation methodology used by the Quality Bank. *Id.* at p. 8. First, he states, the Commission has determined that compensation must be carried out by reference to intermediate products, such as Naphtha and Resid, derived from crude oil and used to manufacture final products, such as gasoline, jet fuel and fuel oil. *Id.* Consequently, according to Baumol, the steps involved in the calculation process are multiplied and the complexity increases "by requiring the acquisition for each such component of the pertinent factual data that are necessary to carry out the requisite calculations." *Id.*

424. Second, Baumol maintains, in order to properly calculate a component's product value, it is necessary to obtain information "about the price of that component *in the market in which the item is actually to be used*." *Id.* (emphasis in original). Because there are no published West Coast market prices for some of the intermediate products, he explains, the prices must be created by an indirect process, and the process must be inherently imperfect. *Id.* at pp. 8-9. Referring to the various proposals presented here for valuing these intermediate products, Baumol states:

> The different parties have come up with three basically different approaches, along with several variants. Each has been defended with the aid of plausible arguments and some evidence. The proponents of each approach have also provided protracted criticisms of the alternative proposals, clearly intended to undermine their credibility. Many of these criticisms also have some degree of persuasiveness. But here I must reemphasize that, given the nature of the issue and the available data, there simply cannot be a perfect estimation method. This means that any method must be vulnerable to some degree of legitimate criticism. The task that must be undertaken is not to search for an approach that qualifies as an abstract ideal, and to reject anything subject to whatever reservations, but to design and adopt a procedure that is as effective and defensible as the circumstances allow.
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> Ultimately, the validity of the analysis in each such submission should be judged not by its sponsorship, but on the basis of the merits of its logic and the supporting evidence.

Id. at pp. 9-10.

425. Baumol categorizes the proposals in three categories. *Id.* at p. 10. The first, he says, is advocated by Culberson and Sanderson who, Baumol adds, support continued use of the reported Gulf Coast Naphtha prices as "acceptable estimates of the appropriate West Coast prices."[149] *Id.* According to Baumol, the second approach, which he describes as a "deconstruction of the price of the finished product for which the Naphtha is used, attributing a residual portion of that price to the Naphtha cut," is supported by O'Brien and Ross.[150] *Id.* Tallett, Baumol states, has presented the third option,[151] which

> employs . . . a standard statistical device – regression analysis . . . to determine the relationship among several economic variables, such as gasoline, jet fuel and Naphtha prices on the Gulf Coast . . . and then transfers the calculated relationship to the West Coast, to determine from the equation that encompasses the Gulf Coast result *and from West Coast finished-product prices* his estimates of West Coast Naphtha prices.

Id. at pp. 10-11 (emphasis in original). The nature of the Naphtha valuation issue, Baumol asserts, "admits no perfect solution . . .[and] . . . it is to be expected that any method . . . must have its imperfections." *Id.* at p. 16.

426. After the criticisms of each of the proposals made by the proponents of competing proposals, Baumol evaluates the various proposals beginning by asserting that, as the Gulf Coast market is "substantially different" from that on the West Coast, he would reject the proposals which base West Coast prices on prices reported on the Gulf Coast.[152] *Id.* at p. 20. Baumol includes proposals for a price cap based on Gulf Coast prices in that same category.[153] *Id.* He then states:

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[149] Baumol further describes the Culberson-Sanderson approach in his testimony. *See* Exhibit No. EMT-144 at pp. 11-12.

[150] Baumol further describes the O'Brien-Ross approach in his testimony. *See* Exhibit No. EMT-144 at pp. 12-14.

[151] Baumol further describes the Tallett approach in his testimony. *See* Exhibit No. EMT-144 at p. 15.

[152] Baumol further discusses why he would reject the Culberson-Sanderson approach in his testimony. *See* Exhibit No. EMT-144 at pp. 21-22.

[153] Baumol further discusses why he would reject the Ross price cap (governor) proposal in his testimony. *See* Exhibit No. EMT-144 at pp. 22-23.

> Before coming to the specifics, let me offer several observations that may be helpful for evaluation of the proposed methods. First, I reiterate, in light of the nature of the issue, there can be no approach that is guaranteed to offer perfect results and is beyond criticism. Second, I note that methods can differ in terms of the degree of ambiguity entailed in the data requirements or the steps entailed in carrying them out. If two methods are judged to be equally meritorious otherwise, the one whose procedures and data are most unambiguously identified and whose execution is therefore least likely to be a source of controversy is evidently to be preferred. Third, it must be recognized that it may prove desirable or even necessary to modify further some of the proposed methods either before or after the Commissions have considered them. A method that lends itself easily to modification and improvement therefore clearly has an advantage over one that does not.

Id. at pp. 20-21.

427. After rejecting the Culberson-Sanderson-Ross approaches, Baumol states that there "is something to be said in favor" of both remaining proposals -- O'Brien's processing cost deduction approach and the Tallett regression approach. *Id.* at p. 24. He notes that these methods may be complementary and claims that the Naphtha contracts[154] discovered in the proceeding "show that both methods accurately predict Naphtha values" and both can be valid. *Id.* Baumol adds:

> In markets that face any substantial competitive pressures, it is surely true that the price of a finished product will tend to equal the value of its inputs plus the cost that must be incurred in transforming those inputs into the finished product. If the final-product price is lower than this, output of that product will not be profitable, and the result will be a reduction in supply and a rise in the final-product price. Similarly, a price well above the level just described will attract entry or increased production by the incumbent suppliers and, in the meantime, before the supplies expand, the suppliers of the inputs will be in a position to capture some of the profits that the high finished-product prices offer. That is, with some oversimplification, the model that underlies the O'Brien approach and it surely is not unjustified.

Id.

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[154] Baumol indicates that Tallett describes these contracts in his testimony. Exhibit No. EMT-144 at p. 24.

428. Baumol states that the same analysis which supports O'Brien's methodology also supports Tallett's regression method unless there is evidence that market conditions on one coast or the other "cause the differences between the value of Naphtha and the price of the finished product to differ materially." *Id.* at p. 25. Without such evidence, Baumol claims, "the logic of the O'Brien model" establishes that the relationship between the West Coast Naphtha price and finished products on the West Coast must be the same as the relationship between the price of Gulf Coast Naphtha and finished products on that coast. *Id.*

429. Commenting on criticisms of the Tallett's regression formula approach, Baumol asserts that the regression approach "merely implies" that something can be learned from the Gulf Coast about the applicable relationships on the West Coast. *Id.* Another advantage of this approach, he maintains, is that it is straightforward and "has fewer points that invite needless dispute." *Id.* at p. 26. In contrast, he states, O'Brien's calculations "lead to a number of questions whose answers affect the reliability of his results."[155] *Id.* He ends by stating that Tallett's regression formula approach avoids these "invitations to disagreement, and if the underlying analysis that is the common foundation for both approaches is valid, they should in principle yield similar results." *Id.*

430. During cross-examination,[156] Baumol agreed that there were two points of subjectivity in any regression analysis: (1) the variables used must be chosen; and (2) the choice of which set of data to use. Transcript at pp. 5106-09. He also agreed that number of variables chosen affect the regression. *Id.* at p. 5109.

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[155] Baumol lists a series of questions that undermine O'Brien's analysis and invite disagreements:

> [U]navailability of data forces [O'Brien] to use statistics that pertain to differentgeographic locations. Does this materially distort his results? And in calculating processing costs, how does he avoid all the ambiguities and disagreements that invariably arise in the costing arena in a litigation process? Does he employ accounting costs with their arbitrary apportionment of common outlays or does he use economic costs? If he employs the latter, are the numbers incremental costs, avoidable costs, or some other figure? And what is the justification for use of one of these cost concepts rather than another?

Exhibit No. EMT-144 at p. 26.

[156] Before he was cross-examined, on further direct examination, Baumol discussed regression formulæ in general. Transcript at pp. 5085-5106.

431. Discussing the contracts discovered in this proceeding, Baumol declared that without them, there was no "direct evidence of naphtha values on the West Coast." *Id.* at p. 5152. He characterized the contract prices as "actual West Coast prices" derived by knowledgeable individuals in arms-length transactions. *Id.* at p. 5152-53. Baumol further stated that, as the contract prices were higher than the prices derived by all but two of the Naphtha proposals put forth by the parties, only one of two possibilities exist: either the latter two proposals have verisimilitude or the buyers involved in those contracts were systematically fooled into overpaying for the Naphtha they purchased an occurrence he believes "implausible." *Id.* at p. 5153.

432. Asked whether, if those contracts represented all of the Naphtha traded and if all of the Naphtha traded represented only 1% of the Naphtha produced, the contract prices for that 1% could establish the value of the remaining 99% of the Naphtha, Baumol gave a resounding "Yes" in reply. *Id.* at p. 5159. He added: "Not to six decimal places, but we're not going to get to six or even two or one decimal place in this process." *Id.*

C. DAVID TOOF

433. In his Direct Testimony, addressing the Naphtha cut, Toof notes that "[b]oth Gulf Coast and West Coast Naphtha . . . are valued as the Gulf Coast product using [Platts] U.S. Gulf Coast spot quote for Waterborne Naphtha," but argues that the current valuation fails to value West Coast Naphtha reliably. Exhibit No. EMT-1 at p. 24-25. He explains that the two products – gasoline and jet fuel – produced from Naphtha determine the value of the Naphtha stream and concludes that "[t]he prices for West Coast Gasoline and Jet Fuel exceed by a substantial margin comparable prices for Gulf Coast Jet Fuel and Gasoline." *Id.*

434. Proposing that West Coast Naphtha be valued as a function of West Coast gasoline and Jet Fuel prices, Toof argues that a significant relationship exists between the prices of Naphtha, gasoline, and Jet Fuel on the West Coast. *Id.* at pp. 27-28. The effective date, according to Toof, of the change in cut valuation should be June 19, 1994, because this is two years prior to the Exxon complaint. *Id.* at 28.

435. Toof asserts that the financial impacts are significant as a result of the West Coast Naphtha undervaluation and that Pavlovic has calculated the amount Exxon is owed as $52,737,172 for the period June 19, 1994, through December 31, 2001. *Id.* at p. 29. Additionally, Toof argues that Tesoro has been harmed because Naphtha is removed from the common stream by Petro Star and MAPCO, and that the Naphtha undervaluation is a direct subsidy to these refiners. *Id.* at pp. 29-30.

436. In connection with the VGO cut, Toof explains that "[b]oth West Coast and Gulf Coast VGO . . . are valued at OPIS's U.S. Gulf Coast spot price for High Sulfur VGO." *Id.* at p. 30. Such a valuation, according to Toof, produces an unreasonable result

because the valuation ignores the basic idea of the TAPS Quality Bank system, which is "that West Coast values should be based on West Coast products and Gulf Coast values should be based on Gulf Coast products." *Id.* at p. 31. Toof suggests that a proper valuation of West Coast VGO would be to use the OPIS West Coast VGO price. *Id.* at p. 31. The effective date, according to Toof, as with Naphtha, should be June 19, 1994, because that is two years prior to the Exxon complaint. *Id.* at p. 32. However, the only reason given for this contention is its consistency with Toof's "position on the repricing of Naphtha." *Id.* at p. 26.

437. In his Answering Testimony, Toof explains that there are significant differences in the various parties valuation of West Coast Naphtha. Exhibit No. EMT-76 at p. 8. Toof summarizes the different party proposals for valuing West Coast Naphtha,

> Williams and Unocal advocate the continued use of a Gulf Coast proxy product price for the valuation of West Coast Naphtha. Phillips and the State of Alaska, BP/Amoco and ExxonMobil/Tesoro take the position that West Coast Naphtha should be valued on the basis of a separate West Coast proxy price. ExxonMobil and Tesoro propose the use of a regression equation that relates the value of West Coast Naphtha to the value of West Cast gasoline and West Coast jet fuel. Both BP/Amoco and Phillips/State of Alaska propose to value West Coast Naphtha as a feedstock to a catalytic reformer. The output of the reformer, reformate, is a primary component of gasoline. In addition, BP/Amoco advocates that their reformer feedstock value be capped by a "governor." The governor is the Gulf Coast Naphtha price adjusted by an imputed transportation cost.

Id. at pp. 8-9.

438. The most reasonable valuation method, in Toof's opinion, is the Exxon method because he believes that West Coast Naphtha "should be priced as a West Coast product, not at the Gulf Coast level." *Id.* at p. 9. Additionally, Toof states, the Exxon approach "is based on West Coast product values, is simple to administer, and is not dependent upon the host of complicated assumptions underlying the reformer feedstock methods proposed by Phillips/State of Alaska and BP/Amoco." *Id.*

439. Toof comments that Culberson's testimony in support of using the reported Gulf Coast Naphtha price to value West Coast Naphtha "conflicts with actual pricing in the marketplace and is contradicted by his own workpapers." *Id.* at p. 10. Culberson's testimony is unconvincing, Toof begins, because, were he correct, "then the ability to trade, on which [Culberson] relies, would have the same impact on West Coast and Gulf Coast prices for other petroleum products, and would tend to make their prices similar. But West Coast and Gulf Coast prices for other petroleum products are not similar." *Id.* at p. 11. According to Toof, it is unlikely that the possibility of moving Naphtha from the

Gulf Coast to the West Coast would equalize prices "when the prices of so many other intermediate and finished products[157] are different on the two Coasts." *Id.* (footnote added).

440. According to Toof, Sanderson believes that Gulf Cost Naphtha prices should continue to be used to set West Coast Naphtha values.[158] *Id.* Toof claims that Sanderson's testimony is unconvincing, stating because the reported West Coast and Gulf Coast prices for intermediate products such as VGO and LSR differ, it is unlikely that the Naphtha prices are related. *Id.* at p. 13. Additionally, Toof states that Culberson's workpapers[159] contradict his conclusions as "[t]he traders that [he] . . . contacted rejected the claim that West Coast Naphtha is valued at prices similar to Gulf Coast Naphtha prices. They stated that West Coast Naphtha should be valued at an increment off of gasoline prices." *Id.* at p. 14.

441. Regarding O'Brien's testimony,[160] while Toof states that he and O'Brien agree that Naphtha should be valued on a West Coast basis, Toof suggests that O'Brien's

[157] Toof explains that his review of the West Coast Naphtha contracts discovered by the parties reflect that the contract prices, for the most part, use West Coast gasoline prices less an increment which results in West Coast Naphtha prices higher than Gulf Coast Naphtha prices. Exhibit No. EMT-76 at p. 11.

[158] Toof summarizes Sanderson's proposal as being based on Sanderson's view that, because "transportation rates from Saudi Arabia to the West and Gulf Coasts, and from parts of Latin America to the West and Gulf Coasts, are approximately equal . . . imported crudes are being delivered to the West and Gulf Coasts from those parts of the world for approximately the same price." Exhibit No. EMT-76 at p. 13. According to Toof, Sanderson argues that Naphtha prices on the two Coasts are similar because at least some crude oil is available at equivalent prices on both Coasts, and Naphtha prices, as well as the prices of other intermediate petroleum products, are linked to crude oil prices. *Id.* Toof suggests that Sanderson concludes that, as "some imported crude oils are being delivered to both Coasts at approximately the same prices, Naphtha must be priced similarly on both Coasts." *Id.*

[159] According to Toof, the workpapers contain telephone interviews with Naphtha traders which undercut Culberson's testimony because the traders disagree with Culberson's valuation methods. Exhibit No. EMT-76 at p. 12.

[160] According to Toof, O'Brien claims that "West Coast Naphtha should be valued as a feedstock to a catalytic reformer. He values the reformate as a component of regular gasoline and deducts the costs of constructing and operating the reformer." Exhibit No. EMT-76 at p. 15.

methodology may be too complex to be appropriate. *Id.* at p. 15. Toof states that he finds fault with O'Brien's proposal, particularly O'Brien's failure to adjust Gulf Coast construction costs to account for the increased costs on the West Coast.[161] *Id.* at pp. 15-16.

442. According to Toof, Ross's governor proposal is based on Ross's contention that West Coast Naphtha prices do not track West Coast gasoline prices when gasoline prices peak. *Id.* at p. 19. Toof claims there is no such evidence and that "none of the contracts [he] reviewed had a cap." *Id.* Equally important, Toof asserts, is that most of the Naphtha contracts he reviewed "tied the price of West Coast Naphtha directly to the price of West Coast gasoline" and did not except "periods when West Coast gasoline prices peaked." *Id.* In addition, Toof finds fault with Ross's governor proposal because, he asserts, "the application of the governor assumes both an instantaneous response and a perfect knowledge on the part of Naphtha traders." *Id.* at p. 20. Toof states, "Ross conceded in his deposition that there would not be an immediate response to a price anomaly and that the price spike would have to be of sufficient duration to warrant redeployment of Naphtha shipments from the Gulf Coast to the West Coast." *Id*. He also finds fault with Ross's use of a fixed transportation cost for the entire period without consideration of the possibility that prices might rise during periods of high demand. *Id.*

443. In his Rebuttal Testimony, Toof addresses the Naphtha question, disagreeing with O'Brien, Ross, and Sanderson's critiques of Tallett's proposal. Exhibit No. EMT-123 at p. 31. These witnesses, he states, raise a number of issues: (1) whether the inclusion of jet fuel as an independent variable is appropriate; (2) whether the price of Gulf Coast Naphtha is influenced by the Gulf Coast petrochemical market; (3) whether "Tallett's results are 'skewed' by higher refining margins for finished products;" and (4) whether Tallett's results should be capped. *Id.*

444. The jet fuel criticism, Toof begins, is without merit. *Id*. at p. 32. He notes that Boltz testified that West Coast Naphtha valuation impacts his refinery because Petro Star retains a portion of the higher boiling range Naphtha to use in jet fuel manufacture. *Id*. and Exhibit No. PSI-1 at p. 4. Also, Toof points out, James Dudley ("Dudley") listed jet fuel manufacture as one of Naphtha's uses. Exhibit Nos. EMT-123 at p. 32 and EMT-126 at p. 2. As for Ross's questioning the appropriateness of using jet fuel based on an r-

[161] In addition to O'Brien's failure to adjust Gulf Coast costs, Toof states that he finds fault with O'Brien's proposal because O'Brien: (1) accepts "the reformer output balances imbedded in the PIMS model" without knowing "the vintage of the data underlying the [PIMS] yield equations" or verifying them; and (2) uses Seattle gasoline prices, but Los Angeles/Bakersfield prices for all other products, and uses some waterborne, some pipeline and some truck/rail prices, while pricing hydrogen at the refinery gate. *Id.* at pp. 15-16.

squared statistic, Toof contends that the question carries no weight:

> Mr. Ross asserts that an even better fit could be achieved by using normal butane as an independent variable. This observation is a non sequitur. The first step in any regression analysis is to postulate the relationship between the dependent and independent variables. Then, the statistical method is employed to test the reasonableness of that hypothesis. Mr. Tallett selected jet fuel as an explanatory variable because Naphtha is a component of jet fuel. Normal butane has no such relationship with Naphtha. Accordingly, Ross' regression analysis including normal butane is baseless.

Id. at pp. 32-33. As for Naphtha's higher value on the Gulf Coast, Toof notes that the price of Naphtha follows the market price of gasoline, tending to undercut Ross's contention that the petrochemical market is influencing Gulf Coast Naphtha prices. *Id*. at p. 33.

445. Tallett's results are not skewed by higher refining margins for finished products, Toof asserts, and he states criticisms to the contrary are misplaced. *Id*. Ross and O'Brien's West Coast Naphtha value calculation as a feedstock to a reforming unit, Toof explains, produces similar West Coast Naphtha valuations to Tallett's values. *Id*. at pp. 33-34. He adds that O'Brien and Ross both include a 20% simple payback return on investment, capturing the West Cost refinery margin. *Id*. at p. 34. Regarding Ross's governor proposal, Toof believes it to be inappropriate. *Id*.

446. Toof states that, even though there is no disagreement with Exxon's position that West Coast VGO should be valued on the basis of the OPIS West Coast high sulfur VGO price, Ross argues that the change should be applied only prospectively, while Exxon believes that the change should be made retroactive to June 1994. *Id*. at pp. 36-37. He notes that Ross concedes that the OPIS West Coast High Sulfur VGO price is a reasonable price for the entire period. *Id*. at p. 37 and Exhibit No. EMT-128 at p. 2.

447. Criticizing Dudley's proposed West Coast Naphtha valuation method, Toof asserts that there is no basis for valuing West Coast Naphtha on the basis of Gulf Coast Naphtha plus the volume weighted incremental differences between West Coast and Gulf Coast VGO and West Coast and Gulf Coast LSR. Exhibit No. EMT-123 at p. 38. Furthermore, he contends that Dudley did nothing to validate his methodology which, according to Toof, produces "results contradictory to the testimony of all the other witnesses." *Id*. According to Toof, Dudley's "method is plucked from thin air." *Id*. He notes that Dudley admits that he was asked to formulate a methodology for valuing West Coast Naphtha which "did not take into account the value of gasoline." *Id*. According to Toof, this ignores the product from which West Coast Naphtha derives 90% of its value. *Id*.

448. Additionally, he states that Dudley's justification for using VGO and LSR to value

West Coast Naphtha – that the products are Quality Bank cuts which are processed in refining facilities to make gasoline blendstocks and that these products sit above and below Naphtha in the distillation range – has no good explanation. *Id*. at pp. 38-39. Toof adds that Dudley concedes that even though his two comparison products bracket Naphtha in the distillation curve, the price of both products is almost always less than Naphtha on the Gulf Coast. *Id*. at p. 39. He also question why Dudley would weigh the components by their monthly percentages in the TAPS common stream, noting that Dudley's response that "his weighting factor is representative of how much LSR a refinery could extract from ANS crude and process through its facilities" is simply wrong. *Id*. From January 1992 to December 2001, he explains, the average percentage of LSR in the TAPS common stream was 6.47%, while Dudley's weighting factor is 19.2%. *Id*.

449. Finally, Toof accuses Dudley of attempting to derive a formula resulting in West Coast Naphtha being valued at the Gulf Coast price stating that LSR, one of the products Dudley chose, was 5.4¢/gallon, on average, more expensive on the Gulf Coast than on the West Coast and the other, VGO, was 0.57¢/gallon more expensive on the West Coast than on the Gulf Coast. *Id*. According to Toof, Dudley ignores "this basic inconsistency . . . and weights the VGO four times more heavily than the LSR, yielding an average differential of .56 cents per gallon." *Id*. Dudley's results, Toof asserts, are unreasonable because Dudley never examined the reasonableness of his assumption that Gulf Coast and West Coast prices are approximately the same. *Id*. at p. 40.

450. According to Toof, had Dudley examined the relationship between the reported prices for Gulf Coast Naphtha and his weighted average composite of Gulf Coast VGO and Gulf Coast LSR, he would have seen that the weighted composite understates Gulf Coast Naphtha value by an average of $2.04/barrel. *Id*. Toof points out that Dudley's analysis "runs contrary to the economic and contract analysis presented by every other witness and the commentary of the various traders interviewed by Mr. Culberson" and ultimately produces the "patently unreasonable" result where West Coast Naphtha is actually less valuable than Gulf Coast Naphtha. *Id*. at p. 40-41.

451. Lastly, Toof addresses Boltz's arguments. *Id*. at p. 41. He notes that Boltz originally adopted Culberson's and Sanderson's position that West Coast Naphtha should be valued as a Gulf Coast product, or, alternatively, Dudley's proposal. *Id*. at p. 42. Dudley's original testimony calculated West Coast Naphtha value at 56¢/gallon more than Gulf Coast Naphtha, Toof explains, but in the corrected testimony Dudley now maintains that West Coast Naphtha is 56¢/gallon less valuable on the West Coast than the Gulf Coast. *Id*.

452. According to Toof, Boltz argues that Petro Star uses Naphtha stripped from the TAPS stream only to make jet fuel, making a gasoline-based valuation inaccurate and unfair. *Id*. Toof states that this argument is irrelevant because the purpose of the Quality

Bank is not to subsidize Petro Star, but, rather, to make the shipper economically indifferent to the diminution of its stream. *Id*. at pp. 42-43.

453. On cross-examination, Toof admitted that he never purchased crude oil or petroleum products and that, prior to this proceeding, he had “virtually no experience . . . in valuing crude oil streams.” Transcript at pp. 5282-85. Toof agreed that, on the Gulf Coast, Naphtha is used to make reformate which can be used by the petrochemical industry where the petrochemical plant is tied to a refinery. *Id.* at pp. 5285-86. Asked whether such “married facilities” existed on the West Coast, Toof stated that he was not aware of any. *Id.* at p. 5286. According to Toof, only 3-5% of the reformate is used by Gulf Coast petrochemical plants and does not influence the Gulf Coast Naphtha market. *Id.* at p. 5287.

454. According to Toof, on the Gulf Coast, there is a significant relationship between the prices of Naphtha, gasoline and jet fuel. *Id.* at p. 5288. However, he claims that no such relationship exists on the West Coast. *Id.* Toof stated, when asked by counsel, that about 28½% of reformate is used on the West Coast to make gasoline, while about 16% of the national jet fuel pool is derived from Naphtha. *Id.* Moreover, Toof indicated that he believed that the gasoline market on the West Coast was different that the gasoline market on the Gulf Coast. *Id.* at p. 5294.

455. Toof, in response to questions from a cross-examiner, admitted that, prior to working on this proceeding, he never reviewed a West Coast Naphtha contract. *Id.* at p. 6352. Moreover, he also admitted that he was not familiar with all of the companies trading Naphtha on the West Coast. *Id.* at p. 6353.

456. Asked about Tallett’s Naphtha proposal, Toof stated that he believed that Tallett correctly found a common relationship between jet fuel, Naphtha and gasoline on both coasts. *Id.* at p. 6430. He indicated that he had several reasons for this belief:

> The first is that the uses of naphtha are the same on both coasts. It’s primarily used to make reformate which goes into gasoline, and it also can be cut a little lower to go into the jet fuel pool. Just from the physical uses, and the applications are the same.
>
> Second, we have some information, other additional information that’s been gathered during the course of this proceeding by various witnesses and various analyses.
>
> * * * *
>
> We also have the results of the pooled data test. While there are strengths and weaknesses in any statistical analysis that can be performed,

> the results of the test, when taken together with these other pieces of information, I think, are pretty persuasive.

Id. at pp. 6430-31. However, Toof also admitted that the use of jet fuel in Tallett's regression analyses was not statistically significant though he still recommended using it in order to "accurately [model] the market." *Id.* at pp. 6433-34.

457. Toof also agreed that no methodology for valuing Naphtha should be used which could be subject to manipulation by monopolistic or other interests. *Id.* at pp. 6527-28. He further agreed that, if the price of natural gas in California was the product of manipulation, California natural gas prices might not be representative of West Coast prices. *Id.* at p. 6528. If that were the case, he suggests, it would be appropriate to use a composite price which would include other markets. *Id.*

458. With regard to VGO, Toof stated that it was a more valuable cut on the West Coast than on the Gulf Coast because of the use of CARB gasoline. *Id.* at pp. 5303-04. He added that VGO provides "cat crack gasoline, which is a major component of the gasoline pool" and olefins which are used to make alkylate.[162] *Id.* at p. 5304.

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459. Tallett also testified on Exxon's behalf regarding Naphtha. The Quality Bank valuation of Naphtha, according to Tallett, uses a single Gulf Coast price published by Platts Oilgram valuing Naphtha sold on the West Coast and the Gulf Coast. Exhibit No. EMT-11 at p. 13. This method, Tallett alleges, does not appropriately value ANS crude oil, but penalizes certain shippers "by significantly undervaluing West Coast Naphtha." *Id.* The undervaluation results, Tallett states, because West Coast and Gulf Coast prices for the same product never match. *Id.* at p. 14. Using Gulf Coast prices to value it, Tallett continues, "has undervalued West Coast Naphtha by an average of $2.44/bbl . . . over the ten-year period from January 1, 1992 through December 31, 2001." *Id.*

460. According to Tallett, he reaches this conclusion after analyzing the value of the products into which Naphtha is blended or refined[163] – unleaded gasoline, reformulated gasoline, and jet fuel – on both the Gulf and West Coasts. *Id.* at p. 15. The analysis, Tallett explains, indicates that these products are more valuable on the West Coast than on the Gulf Coast.[164] *Id.* at p. 15. He deduces that, since "gasoline and jet fuel are more

[162] Alkylate is required as a component of CARB gasoline. Transcript at p. 6520.

[163] These products, Tallett states, have publicly reported prices on both the West and Gulf Coasts. Exhibit No. EMT-11 at p. 15.

[164] As an example, Tallett uses jet fuel prices for the period 1992 to 2001 and finds

valuable on the West Coast, it stands to reason that Naphtha would also be more valuable on the West Coast." *Id.* at 16.

461. The analysis Tallett conducted, he argues, demonstrates "a very high correlation between the price of Naphtha and the prices for unleaded gasoline and jet fuel"[165] for the Gulf Coast. *Id.* at p. 18. Using the same analysis, Tallett applies West Coast unleaded gasoline and jet fuel prices to yield predicted West Coast Naphtha values. *Id.* at p. 19. The result, Tallett states, is that, "from 1992 to 2001, the predicted average price of West Coast Naphtha is $24.91/bbl." *Id.* at p. 20, Exhibit No. EMT-19.

462. Tallett concludes that the "current Quality Bank Methodology unreasonably prices West Coast Naphtha at the Gulf Coast price, far below the West Coast prices for unleaded gasoline and jet fuel." Exhibit No. EMT-11 at p. 20. He explains that

> the West Coast unleaded gasoline price has averaged 6.50 ¢/gal more than the Gulf Coast price for unleaded gasoline, and the West Coast jet fuel price has averaged 5.08¢/gal above the price for Gulf Coast jet fuel. Application of the formula for Naphtha price as a function of West Coast unleaded gasoline and jet fuel prices yields an average price for West Coast Naphtha that is 5.80¢/gal higher than the ten-year average Gulf Coast Naphtha price. This 5.80¢/gal differential lies between the differentials for gasoline and jet fuel, and the Naphtha price is a few cents per gallon below the prices of those products on the West Coast, consistent with the relationship on the Gulf Coast.

Id.

463. The "statistically derived relationship" between Gulf Coast Naphtha and Gulf Coast gasoline and jet fuel, he argues, is applicable to West Coast Naphtha, gasoline and

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that the West Coast price averaged $2.13/bbl more than the Gulf Coast price. Exhibit No. EMT-11 at p. 15. In the same period, unleaded gasoline was $2.73/bbl higher on the West Coast than on the Gulf Coast, Tallett states, while from October 1994 to 2001, reformulated gasoline was $4.45/bbl more on the West Coast than on the Gulf Coast. *Id.* at p. 15. Tallett explains that reformulated gasoline prices on both coasts were published beginning in October 1994. *Id.* at pp. 15-16.

[165] Tallett explains that "[o]ver the ten-year study period, the regression formula explains 98.4% of the variation in Naphtha prices . . . only 1.6% of the price variation remains unexplained . . . In other words, the value of Gulf Coast Naphtha bears an almost one-to-one correlation with the prices of Gulf Coast Gasoline and jet fuel." Exhibit No. EMT-11 at pp. 18-19.

jet fuel because "[a] regression analysis uses market-specific data to establish a statistically reliable relationship." *Id.* at p. 21. Additionally, Tallett continues, there are fewer outlets for Naphtha on the West Coast, and, therefore, unleaded gasoline and jet fuel prices on the West Coast should account for even more of the fluctuation in West Coast Naphtha prices. *Id.*

464. Tallett claims that he used unleaded gasoline rather than reformulated gasoline for three reasons: (1) he wanted to look at price relationships beginning in 1992, but Platts prices for reformulated gasoline do not extend back that far; (2) the price series on the Gulf Coast relates to Federal reformulated gasoline while the West Coast price series relates to CARB and there are quality differences between the two; and (3) Naphtha prices are often quoted as a differential from regular unleaded gasoline prices. *Id.*

465. The formula Tallett proposes to use, he states, to value ANS Naphtha on the West Coast is "Calculated Naphtha price in $/bbl = 0.653 * gasoline price + 0.306 * jet fuel price - 0.780, where gasoline price = Platt's ULR mid value waterborne, and jet fuel price = Platt's Jet Fuel 54 waterborne." *Id.* at p. 24.

466. Regarding the Quality Bank's current valuation of VGO, Tallett explains that VGO is valued on both the Gulf and West Coasts using Gulf Coast high sulfur waterborne VGO price indice published by OPIS. *Id.* This valuation, according to Tallett, misrepresents West Coast VGO. *Id.* On both Coasts, Tallett states, VGO prices track the prices of the products[166] that are produced from VGO, and West Coast VGO prices vary appreciably from Gulf Coast prices. *Id.* at p. 25. Concluding, Tallett argues that "there does not appear to be any consistent relationship between [West Coast and Gulf Coast VGO] prices, which only serves to further confirm my belief that the Quality Bank's method of valuing West Coast VGO at a Gulf Coast price does not reflect the true or a reasonable price for West Coast VGO." *Id.*

467. Tallett suggests that the OPIS published West Coast VGO prices should be used for the Quality Bank purposes. *Id.* at pp. 27-28. The OPIS West Coast VGO prices, according to Tallett, are reliable prices because his analyses, for the period 1993[167] to 2001, indicate that "95.2% of the Gulf Coast VGO price variation and 93.0% of the West Coast VGO price variation is explained by the crack spread formula[168] correlation against

[166] These products, according to Tallett, are gasoline blendstock and Heavy Distillate blendstock. Exhibit No. EMT-11 at p. 25.

[167] Tallett explains that the West Coast price series for high sulfur distillate was discontinued in the period January 1992 to July 1993. Exhibit No. EMT-11 at p. 28.

[168] The crack spread formula, Tallett states, is a petroleum industry number that relates VGO price to the price of gasoline and distillate, which are the main products

gasoline and distillate prices." *Id.* at p. 28 (footnote added). Using the OPIS published West Coast VGO prices, Tallett states that, for the period 1992 through December 2001, the average West Coast VGO price is $21.10/bbl. *Id.* at p. 29.

468. In his Answering Testimony, Tallett criticizes O'Brien's Naphtha proposal. Exhibit No. EMT-84 at p. 9. First, Tallett explains that O'Brien "proposes to value Naphtha based on his estimate of Naphtha's value when processed in a catalytic reformer to make reformate, which is blended into gasoline, and other products." *Id.* As a preliminary matter, Tallett agrees with O'Brien's analysis regarding West Coast Naphtha valuation recognizing that the West Coast and the Gulf Coast are separate markets for Naphtha with differing values and that, therefore, the Quality Bank should use a West Coast Naphtha value. *Id.* Also, Tallett agrees with O'Brien's analysis of Naphtha's value recognizing that West Coast Naphtha's value is linked to the products produced from Naphtha (chiefly gasoline). *Id.* at p. 10.

469. At this point, Tallett takes issue with O'Brien's analysis. *Id.* He begins his criticism by declaring that O'Brien used an outdated PIMS catalytic reformer model (version 6.1) which does not reflect current technology. *Id.* According to Tallett, the yields "O'Brien presents understate what a refiner can be expected to obtain and therefore understate the before-cost value of the Naphtha feed by approximately 0.9 cents per gallon." *Id.* O'Brien, Tallett suggests, failed to consider improved energy efficiency currently being achieved, "apparent in the absence of a steam generation credit and a high electricity consumption rate," resulting in an 8¢/gallon undervaluation of Naphtha. *Id.*

470. Tallett next accuses O'Brien of being inconsistent in the pricing bases he chose for "valuing the yields in his reformer analysis." *Id.* at p. 11. For example, Tallett states, O'Brien uses a Seattle, Washington gasoline price, but Los Angeles prices on the other products and "mixes pipeline, waterborne and truck and rail delivered prices and even uses an avoided cost calculation that values the product at the refinery." *Id.* Tallett argues that O'Brien should be consistent as to the geographical area he uses and should use only Los Angeles area prices. *Id.* He adds:

> Substituting Los Angeles unleaded regular gasoline prices for Seattle gasoline prices would reduce Mr. O'Brien's estimated Naphtha value by approximately 0.1¢/gal. The effect is small since there is only minimal difference between the Seattle and the Los Angeles waterborne unleaded regular price series over time.

Id. at p. 11.

VGO is refined into through cat cracking. Exhibit No. EMT-11 at p. 27.

471. He continues his criticism of O'Brien's Naphtha by questioning the latter's "reformer yields produced from Naphtha" and his failure to use a location factor to adjust Gulf Coast costs "upwards" to what Tallett refers to as "West Coast levels." *Id.* at p. 12. A West Coast location factor, Tallett maintains, should be used in adjusting labor, construction, and other costs. *Id.* Tallett claims that "O'Brien's consulting firm . . . recommended use of a West Coast location factor adjustment of approximately 1.4 with the Gulf Coast being set at 1.0" although he did not explain the context in which that recommendation was made. *Id.* Further, Tallett argues, "the landmark August 1993 National Petroleum Council *U.S. Petroleum Refining* study used location factors for each U.S. region, including 1.4 for California and 1.2 for other West Coast areas." *Id.* According to Tallett, applying the West Coast location factor would increase processing costs and lower O'Brien's estimated West Coast Naphtha value while correcting O'Brien's Naphtha reformer yield values would increase the value of West Coast Naphtha. *Id.* at p. 13.

472. Tallett extensively criticizes Ross for using a "governor"[169] in his analysis. *Id.* at p. 18. To begin with, Tallett states, it is unreasonable to apply a governor holding West Coast Naphtha values flat during periods where West Coast gasoline prices are high. *Id.* at p. 19. He claims that "[t]here is no justification for imposing such a cap on West Coast Naphtha values." *Id.* at p. 20. According to Tallett, Ross's "primary justification for the governor is his claim that prices for intermediate products used to make gasoline like VGO and Naphtha do not rise proportionately with increases in the price of gasoline, especially increases that occurred during the period 1999 through 2001." *Id.* However, Tallett disagrees, arguing that the "[a]vailable pricing data contradicts [Ross's] claim." *Id.* Using the same data[170] Ross allegedly uses, Tallett plots a chart[171] he claims demonstrates that West Coast VGO prices closely track gasoline price increases while LSR and Butane prices do not. *Id.* at pp. 20-21. He declares that prices for LSR and Butane do not track gasoline prices as well as VGO because CARB gasoline production, whose Butane and LSR components are greatly reduced due to summer seasonal reductions in allowable Reid Vapor Pressure level, dominates on the West Coast. *Id.* at p. 21. Tallett adds that he

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[169] Tallett explains Ross's governor as capping West Coast prices at the Gulf Coast Naphtha price plus $1.85/barrel. Exhibit No. EMT-84 at p. 19. He states that Ross claims that "the $1.85 represents an eight-year average of the difference between the transportation cost from Venezuela to Houston and from Venezuela to Los Angeles." *Id.* Tallett further indicates that Ross used this differential "because [Ross claims that] that there are insufficient shipments of Naphtha from Houston to Los Angeles to know what the actual transportation costs would be." *Id.*

[170] Exhibit No. BPX-12.

[171] Exhibit No. EMT-88.

> would not expect reformate or Naphtha prices to suffer the same seasonal impact as do LSR and butane prices. Rather, [he] would expect Naphtha prices to continue through the Summer, as well as the Winter, to track gasoline prices closely. These seasonal profiles of depressed LSR and butane prices relative to gasoline prices are less marked on the Gulf Coast as there the Summer production of very low RVP gasoline is much less significant.

Id.

473. According to Tallett, 90% of the West Coast Naphtha used to make gasoline is Quality Bank quality. *Id.* Tallett explains that a higher percentage of Naphtha than VGO is used to make gasoline on the West Coast and claims that this is significant because "one would expect the value of West Coast Naphtha to track West Coast gasoline prices more closely than does the value of West Coast VGO." *Id.* at pp. 21-22. Furthermore, Tallett claims that one can test whether Naphtha and VGO prices track increases in gasoline prices on the Gulf Coast as long as there are reported prices for both Naphtha and gasoline. *Id.* at p. 22. Tallett plots the reported Gulf Coast waterborne Naphtha prices, along with Gulf Coast VGO, LSR, Butane prices, and Gulf Coast regular unleaded gasoline priced for the months from 1992 to 2001.[172] *Id.* He claims that the graph demonstrates "that Gulf Coast Naphtha and VGO prices closely track gasoline prices, rising rapidly on essentially every occasion that gasoline prices have risen." *Id.* The significance of West Coast Naphtha and VGO prices following West Coast gasoline prices, according to Tallett, is that "it would be an error to set a flat cap on West Coast Naphtha prices during periods of rising West Coast gasoline prices, which is what Mr. Ross' 'Governor' is designed to do." *Id.* at p. 23.

474. A governor is also unreasonable, in Tallett's view, because "the West Coast is largely self-sufficient with respect to Naphtha." *Id.* In other words, according to Tallett, little Naphtha is imported into the West Coast because refiners produce all they need or, if they need more, can buy it from other West Coast refiners. *Id.* He claims that it is "bizarre" for Ross, who claims that gasoline prices are driven up by factors other than a shortage of Naphtha, "to suggest that flows of imported Naphtha from the Gulf Coast would 'cap' rising Naphtha prices. There would be no such imports." *Id.*

475. Tallett further declares that, if Ross's governor worked for Naphtha, West Coast gasoline prices should never exceed Gulf Coast prices for gasoline plus freight rates. *Id.* at p. 24. Tallett claims this proposition, however, is demonstratively false because West Coast gasoline prices did exceed Gulf Coast gasoline prices plus freight in 59 of 94

[172] Exhibit No. EMT-89 at p. 1.

months at which he looked.[173] *Id.* He adds that, also, West Coast Vacuum Gas Oil prices often exceeded Gulf Coast prices plus freight.[174] *Id.* at pp. 24-25.

476. Finally, Tallett claims that he tested Ross's governor theory by examining whether there has been transportation of Naphtha into the West Coast at times of high West Coast gasoline prices.[175] *Id.* at p. 25. He concludes "the facts simply do not support Mr. Ross' untested 'Governor' theory; rather they show clearly it does not operate, i.e. that Naphtha imports do not occur in appreciable volumes during periods of West Coast gasoline price spikes." *Id.* at pp. 25-26. Additionally, Tallett states that another reason West Coast prices do not attract Gulf Coast Naphtha is because, since West Coast price spikes are of short duration and since it "typically takes about three weeks to package, load, ship and off-load a Naphtha cargo brought in from Venezuela or the Gulf Coast," no shipper could be sure that Naphtha prices would still be as high on the West Coast by the time the cargo could be delivered. *Id.* at p. 26.

477. Even if a governor is reasonable during periods of high West Coast gasoline prices, Tallett continues, the methodology Ross chooses is unreasonably calibrated. *Id.* at pp. 19, 27. He argues that, rather than using a "ten-year average of freight rates," as Ross did, were a governor to be applied, "the actual, monthly freight rates" should be used. *Id.* at p. 27. Tallett adds that, even using Gulf Cost prices plus actual freight rates, West Coast product prices were higher. *Id.*

478. Tallett also criticizes Culberson's West Coast Naphtha testimony. *Id.* at p. 28. Preliminarily, Tallett states that Culberson claims that there is a linkage between Naphtha submarkets which prevents prices in the various submarkets from diverging greatly. *Id.* Also, Tallett continues, Culberson further suggests that, if Naphtha had a higher West Coast value, there would be significantly more Naphtha imports into the West Coast. *Id.* To begin his critique, Tallett claims that Culberson's analysis is "conclusively refuted by

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[173] Exhibit No. EMT-90.

[174] Exhibit No. EMT-25.

[175] Tallett states that

> [a]ccording to Mr. Ross' work paper BPAM 00042, his Governor should have been activated to cap West Coast Naphtha prices at Gulf Coast plus freight in seven of the months in 2000. However, the EIA *Petroleum Supply Annual* 2000 Table 20 shows essentially no imports of naphtha into PADD V for the whole year.

Exhibit No. EMT-84 at p. 25.

price data from the two markets." *Id.* He states that if trade between the Gulf Coast and the West Coast "and the 'diversion' of cargo ships that Mr. Culberson describes 'linked' these markets and equalized their prices, available price data[176] for the two markets would show this linkage," but does not. *Id.* at p. 29 (footnote added).

479. Tallett further questions Culberson's contention that, if Naphtha commanded higher prices on the West Coast than on the Gulf Coast, there would be larger Naphtha shipments to the West Coast. *Id.* at p. 30. He claims that "[t]he reason that Naphtha has a higher West Coast value without large volumes of West Coast Naphtha imports occurring is that refiners on the West Coast produce in their refineries approximately the volume of Naphtha they are capable of using in the catalytic reformers they own to make reformate for blending into gasoline." *Id.* at p. 30.

480. According to Tallett, the high West Coast values for gasoline, jet fuel, and Naphtha as well as limited imports of Naphtha can be explained by the characteristics of West Coast petroleum demand. *Id.* at pp. 30-31. He states, and asserts that Culberson agrees, that West Coast petroleum demand is heavily tilted towards gasoline and jet fuel consumption because of extensive car commuting and long distance flights. *Id.* at p. 31. Additionally, Tallett maintains, the West Coast has a heavier crude oil slate available than other parts of the United States. *Id.* Consequently, Tallett claims, Naphtha has a higher value on the West Coast than on the Gulf Coast because of the high demand for gasoline and jet fuel. *Id.* at p. 31. From this, he argues, ANS Naphtha "imported to the West Coast by the refining affiliates of parties to these proceedings has a higher value to these refineries than it does to refineries on the Gulf Coast because the gasoline and jet fuel made from Naphtha has a higher value on the West Coast." *Id.* at pp. 31-32.

481. Tallett also disagrees with Culberson's position that there is no evidence West Coast refineries are willing to pay a higher price than Gulf Coast Naphtha in order to attract supply. *Id.* at p. 32. On the contrary, Tallett claims, "[w]hen a West Coast refiner finds itself short on Naphtha, however, one would expect it to be willing to pay prices for Naphtha approaching the prices of gasoline and jet fuel less processing costs." *Id.* Continuing, Tallett states

> [m]y preliminary review of the West Coast naphtha purchase and sale contracts that have been produced in discovery indicates that prices in these contracts are higher than Gulf Coast Naphtha prices. Most of the West Coast Naphtha contracts I have reviewed to date state the Naphtha prices in terms of West Coast gasoline prices, typically either CARB unleaded pipeline Los Angeles or regular unleaded pipeline Los Angeles, less a differential. These contract prices are higher than the Gulf Coast prices for

[176] Exhibit Nos. EMT-14, EMT-16.

Naphtha.

Id. at p. 33.

482. Finally, Tallett questions Sanderson's position on West Coast Naphtha valuation. *Id.* at p. 34. According to Tallett, Sanderson asserts that, because shipping costs from major foreign crude oils suppliers are about the same for both the West Coast and the Gulf Coast, crude oil prices are equalized on both coasts. *Id.* at p. 34. Thus, Tallett suggests, Sanderson argues, "because crude oil prices are allegedly equal on the West Coast and Gulf Coast, and Naphtha prices are allegedly linked to prices for crude oil rather than to prices for the gasoline that is made from Naphtha, Naphtha prices on both Coasts should be similar." *Id*. According to Tallett, Sanderson is incorrect because "[t]here is little evidence to support his claims that transportation costs and crude oil prices are similar on both coasts. . . . [and] reported price data demonstrates that intermediate product prices are not similar on the West Coast and Gulf Coast markets." *Id.*

483. Tallett continues his criticism of Sanderson's testimony by questioning Sanderson's transportation cost analysis. *Id.* at p. 35. He notes that Sanderson uses the reported Spot Rate for transportation from Saudi Arabia to the Gulf Coast to calculate both the rate to the Gulf Coast as well as to the West Coast even though a West Coast Spot Rate exists.[177] *Id.* Moreover, Tallett adds, Sanderson failed to also use the West Coast Spot Rate from Esmeraldas, Ecuador, assuming instead that the Spot Rate was the same as that to the Gulf Coast. *Id.*

484. Another mistake in Sanderson's analysis, Tallett states, is Sanderson's assumption that crude oil shipments to the West Coast could be carried on Very Large Crude Carriers, as they are on shipments to the Gulf Coast. *Id*. at pp. 35-36. However, Tallett notes, these large ships cannot be docked at Los Angeles, and Los Angeles lacks a lightering operation at its ports.[178] *Id.* at p. 36. Therefore, he adds, crude oil must be shipped from the Persian Gulf to Los Angeles in ships having a dead weight of only 80,000 to 165,000 tons. *Id.* Consequently, Sanderson's analysis is unreliable, according to Tallett.[179] *Id.*

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[177] Exhibit No. EMT-91.

[178] Lighters are small ships which are used to transfer crude oil from Very Large Crude Carriers which are too big to dock at ports. Exhibit No. EMT-84 at p. 36; Transcript at p. 10588.

[179] Tallett claims that Sanderson makes a similar mistake with the transportation analysis from Esmeraldas to Houston because "Sanderson assumes an 80,000 ton ship . . . but this size cannot fit through the Panama Canal." Exhibit No. EMT-84 at p. 36.

485. Additionally, Tallett states that "[t]here are no reported prices for the same crudes on both coasts that could be used to prove Mr. Sanderson's claim. Hence, no hard evidence supports his claim that whole crude oil prices have 'equalized' on the two coasts." *Id.* Another area of disagreement between Tallett and Sanderson, Tallett continues, is that Sanderson argues that Naphtha prices are not influenced by the prices of products produced from Naphtha. *Id.* at p. 37. However, Tallett maintains that "[e]ven assuming that some crude oils had equivalent delivered prices on the Gulf Coast and West Coast, Naphtha prices on the two coasts would still differ because the prices of gasoline and jet fuel are substantially higher on the West Coast than the Gulf Coast." *Id.*

486. Tallett rejects Sanderson's claim that prices of intermediate products like Naphtha are solely tied to whole crude prices, rather than product prices because

> there is abundant evidence that the price of reformer-grade Naphtha is tightly linked to the prices of the products made from reformer-grade Naphtha. . . . In fact, changes in the gasoline prices account for 96% of changes in the reformer-grade Naphtha prices. When Naphtha prices are compared to gasoline and jet fuel prices, 98% of variations in the Naphtha prices are explained by variations in the gasoline and jet fuel prices.

Id. at p. 38.[180] Furthermore, according to Tallett, if Sanderson's theories were correct, intermediate feedstocks such as VGO and LSR should be priced equivalently on both the West and Gulf Coasts. *Id.* However, Tallett explains that the "published. . . high sulfur VGO prices and LSR prices have been markedly different on the West and Gulf Coasts" and only occasionally coincide.[181] *Id.* at p. 39.

487. Also, Tallett criticizes Ross's position on VGO valuation. *Id.* at p. 40. He summarizes Ross's position as suggesting that "the West Coast OPIS price for high sulfur VGO should be used to value West Coast VGO. . . prospectively, from the date that the Commission approves use of a West Coast, rather than Gulf Coast, price to value West Coast Naphtha." *Id.* Preliminarily, Tallett agrees with Ross that the West Coast OPIS price for high sulfur VGO should be used as the Quality Bank value for West Coast VGO. *Id.* He explains "[t]he Quality Bank distillation methodology should seek to use product values from the same market, that is, the West Coast, in determining the relative value on the West Coast of the streams delivered to TAPS." *Id.* at p. 41. According to Tallett, it would be unreasonable to continue to use a Gulf Coast Naphtha price to value West Coast Naphtha while switching to a West Coast VGO price to value West Coast

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[180] *See* Exhibit No. EMT-89 at p. 2.

[181] *See* Exhibit Nos. EMT-93, EMT-94.

VGO. *Id.*

488. In his Rebuttal Testimony, Tallett responded to criticisms of his proposal made by other witnesses. Exhibit No. EMT-133. First, he asserts that West Coast Naphtha should be valued on the basis of West Coast prices and notes that both Ross and O'Brien agree with this premise. *Id.* at p. 6. Next, he explains the benefits of his regression analysis approach, stating that it is easy to administer, free from manipulation, produces a reasonable estimation of the value of West Coast Naphtha, is consistent with O'Brien's and Ross's processing cost estimates (absent Ross's governor), and is similar to "hundreds of West Coast Naphtha contracts" produced in discovery. *Id.* at pp. 6-7.

489. Tallett addresses the assorted criticisms[182] made against his methodology in turn, maintaining that they have no merit. *Id.* at pp. 7, 19. He argues that:

- Including jet fuel in his regression analysis was appropriate because refiners use Naphtha to produce it

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[182] According to Tallett, there are a number of major criticisms of his approach:

- The inclusion of jet fuel in the regression analysis is wrong because refiners do not blend a portion of the Naphtha cut into jet fuel;

- The relationship found on the Gulf Coast between Naphtha, Regular Unleaded Gasoline and Jet Fuel prices does not exist on the West Coast;

- The methodology he used does not take significant changes in the West Coast market into consideration;

- His proposal fails to explain West Coast Vacuum Gas Oil prices;

- According to Ross, his proposal violates Ross's "self-evident" principle that West Coast Naphtha prices cannot exceed for any extended period the price of Gulf Coast Naphtha plus transportation costs from the Gulf Coast to the West Coast; and

- O'Brien also claims that he failed to do a reformate processing cost study similar to his and Ross's because such a study would have arrived at a lower value of Naphtha.

Exhibit No. EMT-133 at p. 20.

- Parallel relationships exist between Naphtha, gasoline and jet fuel on the Gulf Coast and the same commodities on the West Coast

- Naphtha is not higher valued on the Gulf Coast because of its use as a petrochemical feedstock

- Gulf Coast Naphtha prices exceed Ross's and O'Brien's estimated processing costs.

Id. at pp. 7, 23.

490. In further defense of his proposal, Tallett argues that his regression analysis produces results which are similar to O'Brien's. *Id.* at p. 23. Tallett also responded to Ross's assertion that he wrongly assumed a relationship between Naphtha and jet fuel pointing out that it is "unrefuted" that "refiners blend a portion of the high boiling end of the Naphtha cut into jet fuel."[183] *Id.* He also claimed that he made no assumption about the precise amount of Naphtha which is used to make jet fuel. *Id.* As for Ross's claim

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[183] Regarding this evidence, Tallett notes the following:

> There is substantial evidence [that refiners blend a portion of the Naphtha cut into jet fuel]. For example, data from TRW Petroleum Technologies, formerly NIPER, shows that nationwide approximately 16% of jet fuel is made from Naphtha, defined as material with a true boiling point ("TBP") boiling range of 350°F or lower. To estimate the amount of the Quality Bank cut range (175-350°F) material in jet fuel, I obtained ten years of annual surveys of military and commercial jet fuel data from TRW/NIPER. These ten annual surveys (1992 to 2001) included 366 commercial Jet A samples. I analyzed the annual average survey qualities and averaged them to arrive at ten-year composite average values. Using standard industry techniques, I then calculated on a TBP basis the amount of 350°F minus material in Jet A and concluded that, on average, 16% of Jet A was derived from 350°F minus material. I also looked at the lightest and the heaviest samples shown in each year and calculated a ten-year average for those. On average, the lightest jet samples contained 28% of 350°F minus material, and the heaviest samples contained 8% of 350°F minus material. These results show clearly that, when the TBP distillation curves of Jet A are analyzed, they show significant proportions of 350°F minus material, *i.e.*, Quality Bank Naphtha boiling range material, in Jet Fuel.

Exhibit No. EMT-133 at p. 24; s*ee also* Exhibit No. EMT-408.

that refiners blend less than 5% of Naphtha into jet fuel, Tallett asserts that this claim is an "inexcusable error."[184] *Id.* at p. 25. In partial support of this assertion, Tallett notes that Boltz testifies that Petro Star does not manufacture gasoline, but retains a portion of the higher boiling range Naphtha to use in jet fuel manufacture. *Id.* Regarding Ross's calculations using American Society for Testing and Materials ("ASTM") specifications for commercial jet fuel, Tallett claims that his use of the ASTM data is flawed because Ross misapplies the data and argues that Ross "all but admits this, conceding . . . that refiners do blend 'quantities of the 300-350°F cut into jet fuel.'" *Id.* at p. 26.

491. Furthermore, Tallett states that Ross's claim that he relies on statistical analysis to justify inclusion of jet fuel in his valuation formula is incorrect, explaining that he relied on his experience to determine that a portion of the Naphtha cut is commonly blended into jet fuel. *Id.* at p. 27. He adds that he then performed a regression analysis which proved that "the price of jet fuel influences Gulf Coast Naphtha prices." *Id.* Tallett also commented on the regression analysis Ross performed on products other than jet fuel against Naphtha, declaring that none of the other products has "a perceived relationship" with Naphtha as does jet fuel. *Id.* Moreover, removing jet fuel from the regression formula, Tallett concludes, would result in higher West Coast Naphtha values than if jet fuel prices are included. *Id.*

492. Next, Tallett claims that it is reasonable to apply the Gulf Coast Naphtha and unleaded regular gasoline and jet fuel prices relationship to the West Coast for the following reasons:

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[184] Tallett explains Ross's contention and his response to it as follows:

> Mr. Ross reproduces part . . . of the TRW/NIPER Aviation Turbine Fuels 2000 survey. That exhibit sets forth the initial boiling point ("IBP") and 10% distillation temperatures for each sample which Mr. Ross used to compute, via interpolation relative to 350°F, the amount of 350°F minus material in the jet fuel. From this calculation, Mr. Ross then computed an average 350°F minus Naphtha in jet fuel of 4.56%. In doing so, however, Mr. Ross failed to take account of the fact that the distillations reported by TRW/NIPER were produced using ASTM Method D-86, which are not calculated on a TBP basis. He also completely ignored the necessity of converting these distillations to TBP before computing the 350°F minus content. In Exhibit [No.] EMT-137, I have corrected Mr. Ross' analysis. When properly done on a TBP basis, the actual amount of 350°F minus material in the jet fuel is almost 16%.

Exhibit No. EMT-133 at p. 25.

> First, in developing my regression formula I used as my independent variables Platt's published prices on the Gulf Coast for waterborne regular unleaded gasoline and for jet fuel. Comparable published prices exist on the West Coast for these two products. The availability of comparable West Coast product prices supports using those reported monthly prices in the regression-derived formula to provide a reasonable estimate of West Coast Naphtha values.
>
> The second reason is that the same basic procedures are used on the Gulf Coast and West Coast for processing Naphtha into reformate and for blending the high-boiling end of the Naphtha cut into jet fuel. Because the same basic processing relationships exist on both the Gulf and West Coasts, it is reasonable to apply my regression-derived formula to the West Coast.
>
> A third reason is that use of Naphtha as a feedstock for gasoline or jet fuel constitutes virtually the only use for Naphtha on the West Coast.
>
> * * * *
>
> Finally, the West Coast Naphtha values produced by my proposal are similar to the values shown in West Coast Naphtha contracts produced in discovery in these proceedings. The values my approach produces are also comparable to the West Coast Naphtha values produced by Mr. O'Brien and Mr. Ross before Mr. Ross applies his unsupportable "governor."

Id. at pp. 28-29 (internal citations omitted).

493. Additionally, applying this relationship is reasonable, Tallett asserts, for a number of reasons: (1) published prices exist for the independent variables he used on both the Gulf Coast and the West Coast; (2) the same basic procedure is followed on both coasts for processing Naphtha into reformate and blending high end Naphtha into jet fuel; (3) virtually the only use for Naphtha on the West Coast is as a gasoline feedstock and for making jet fuel; and (4) the West Coast Naphtha values produced by his regression formula are similar to the values represented by the contracts discovered in this proceeding. *Id.* at pp. 28-29.

494. Tallett claims that Ross erred in suggesting that his proposal "link[ed] West Coast Naphtha values to Gulf Coast Naphtha prices" or to a "'differential' between West Cost and Gulf Coast gasoline prices," suggesting instead that his proposal "'links' *West Coast* Naphtha values to West Coast gasoline and jet fuel prices." *Id.* at pp. 29-30 (emphasis in original).

495. In response to Ross's claim that Gulf Coast Naphtha prices are affected by the demands of the petrochemical market, Tallett states that Ross errs because he fails to acknowledge that the prices Platts reports for Gulf Coast Naphtha "are expressly designated by Platt's as prices for 'reformer-grade' or Heavy Naphtha, most of which is processed into gasoline." *Id.* at p. 30. He adds that the evidence upon which Ross relies for his assertion "makes clear that Naphtha's value as a gasoline feedstock is *higher* than its petrochemical value and *caps* such petrochemical value." *Id.* at p. 31 (emphasis in original). This, according to Tallett, contradicts Ross's suggestion that Gulf Coast Naphtha's use as a petrochemical feedstock increases its value beyond its worth as a gasoline feedstock. *Id.* Moreover, Tallett claims, "less costly grades of Naphtha and also other potential feedstocks besides reformer grade Naphtha are available to Gulf Coast petrochemical producers." *Id.* at p. 32.

496. Third, Tallett finishes, profit or refining margins[185] between gasoline prices and Naphtha values are similar on both coasts. *Id.* at p. 32. He explains that Sanderson and Ross's refinery margins argument do not conflict with his approach because "[w]hat is relevant to [his] approach is whether the relationship between unleaded regular gasoline, jet fuel and Naphtha prices on the Gulf Coast is similar to the relationship among those same prices on the West Coast." *Id.* at p. 33. Tallett adds that, while whether or not there are comparable margins between the prices of Naphtha and unleaded gasoline has "some relevance," it does not follow that "the margins between finished product prices and whole crude oil prices are relevant to determining the value of Naphtha on the West Coast." *Id.* Furthermore, Tallett claims that neither Ross nor Sanderson present evidence showing that the margins between unleaded regular gasoline prices and Naphtha prices are dramatically different on the West Coast than on the Gulf Coast. *Id.*

497. Tallett notes other evidence that Naphtha margins track gasoline margins, explaining that when O'Brien's and Ross's calculations of the cost of processing Naphtha into gasoline is applied on the Gulf Coast "the resulting values are *below* the actual Gulf Coast prices for Naphtha. . . . [which] shows that Naphtha prices on the Gulf Coast have

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[185] Tallett defines these terms:

> The term "refining margin" or refining "profit margin" is commonly used in the petroleum industry to refer to the difference or "margin" between the value of *all* of the finished products produced by a refinery and the cost of *whole crude oil*. . . . It is also common knowledge in the industry that because prices for gasoline and other finished products are higher on the West Coast than the Gulf Coast, refining margins . . . are higher on the West Coast.

Exhibit No. EMT-133 at pp. 32-33.

maintained their margin vis-à-vis gasoline prices." *Id.* at p. 34 (emphasis in original). He further argues that, based on the contracts discovered during these proceedings, "the increased profitability of gasoline is reflected in higher Naphtha prices on the West Coast." *Id.* at p. 35.

498. While acknowledging the argument that "changed circumstances" raised West Coast gasoline prices although not causing a simultaneous rise in Naphtha's West Coast value, Tallett disagrees and argues that no changed circumstances exist. *Id.* He notes that all of the evidence submitted establishes that there is a balance "between the supply of Naphtha and the demand for Naphtha on the West Coast." *Id.* at p. 36. As a result, Tallett maintains that West Coast Naphtha retains its value as a gasoline and jet fuel feedstock; its value has risen with the price of gasoline. *Id.* at pp. 36-37. He further declares, in response to Ross's allegations, that Naphtha values have not been impacted by severe product requirements on the West Coast, that demand growth has not reduced Naphtha's value, and that operational problems have not reduced demand for West Coast Naphtha nor reduced its value. *Id.* at pp. 37-38.

499. Responding to Ross's singling out of a single contract between Company 13 and Company 41[186] to demonstrate changed circumstances, Tallett asserts that Ross's conclusion is not valid:

> First, there is no evidence that the [Company 13-Company 41] contract was negotiated for this purpose. The [Company 13-Company 41] contract contains a complex series of pricing terms and makes reference to another contract. There could be any number of reasons why the contract was structured in this way. Second, this contract is for full range Naphtha including [Light Straight Run]. As noted above, [Light Straight Run] has not held its value on the West Coast vis-à-vis gasoline prices. This fact could explain the unusual pricing provisions. Finally, this contract is the only one of the close to 300 contracts that have been produced in these proceedings that contains such pricing terms. None of the other contracts contains similar provisions, which tends to suggest that there were reasons other than the one Mr. Ross identified for the structuring of the contract.

Id. at p. 39.

500. Tallett asserts that the West Coast Naphtha contracts produced in discovery

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[186] To maintain confidentiality, the names of some companies engaged in the trading of Naphtha on the West Coast were assigned numbers. The names of these companies are not material or relevant to the issues to be decided in this case. Only the terms of the contracts would be relevant and material, if at all.

demonstrate that West Coast Naphtha prices rose with West Coast gasoline prices from 1999-2001, which supports his regression based proposal. *Id.* As a preliminary matter, Tallett explains how he reviewed the contracts and how he organized the contracts: "I reviewed some 295 contracts in total. Of these, I rejected 89 and retained and applied 206. Several of the 206 contracts comprised term contracts with multiple transactions, e.g., monthly transactions. In these instances, each monthly transaction was separately represented. This resulted in a total of 329 transactions." *Id.* at p. 40. He explained the reason why contracts were rejected as follows:

> In some cases, the contracts were not West Coast contracts; in others the contracts did not involve Naphtha, as when a contract pertained only to LSR. In still other instances, either the pricing information or the timing was not clear or was not legible. In addition, I did not use contracts prior to January 1994 as there were so few produced, nor did I use contracts in 2002, as the price series information was not complete after December 2001.

Id.[187] He described the manner in which he organized the contracts as follows:

> Since the West Coast market moved from a period of relative stability in 1994 through 1998 to a period of widely fluctuating prices in 1999 through 2001, I organized the contracts into these two time periods. In addition, I further separated out for each of the two time periods the contracts that related solely to Heavy Naphtha. I did this because those contracts most closely approximate the Quality Bank Naphtha cut (175º-350ºF).

Id. at p. 41.[188]

501. Comparing the results of his valuation proposal with the Naphtha contract prices, Tallett explains that he plotted the monthly average West Coast Naphtha values against the Naphtha prices for 1999-2001, and he discovered that his approach "generally track[ed] the centerline of the Naphtha contract prices as well as the peaks and troughs in the 1999-2001 period." *Id.* at p. 42. Also, he notes that he compared the average West Coast Naphtha prices he calculated in comparison with the volume weighted average of all of the Naphtha contracts in each of the two periods noted above with the following results: (1) during the 1994-98 period, the values he calculated were 0.5¢/gallon less than the volume weighted contract average (52.7¢/gallon versus 52.2¢/gallon); and (2) for the 1999-2001 period, the price he developed was 1.5¢/gallon less than the volume weighted

[187] *See also* Transcript at pp. 6629-30.

[188] *See also* Exhibit Nos. EMT-140 and EMT-141.

contract average (76.4¢/gallon versus 74.9¢/gallon). *Id.*

502. Tallett also compares the Heavy Naphtha contract prices to West Coast Naphtha prices produced by O'Brien's proposal. *Id.* at p. 43. He reports that this comparison revealed that O'Brien's price exceeded the contract Heavy Naphtha price by 0.6¢/gallon during the 1994-98 period and were below the contract price by 2.1¢/gallon during the 1999-2001 period. *Id.*

503. According to Tallett, Ross's pre-governor methodology "underestimates the Heavy Naphtha contract prices by 2.0¢/gal in the 1994-1998 time frame and by 5.2¢/gal in the 1999-2001 period." *Id.* at pp. 43-44. Were Ross's proposed governor applied, Tallett asserts that, during the 1999-2001 period, when high gasoline prices prevailed, the governor "widens the gap between his Naphtha values and the Heavy Naphtha contract prices from 5.2¢/gal without the governor to 14.4¢/gal with the governor." *Id.* at p. 44.

504. Tallett argues that Ross's suggested governor should not be used because only two of the 295 contracts he reviewed valued Naphtha on the basis of the Gulf Coast price plus a premium and because only the Company 13-Company 41 contract referred to above had anything that arguably was a "governor." *Id.*

505. Most of the contracts, Tallett explains, valued Naphtha using one of three prices:

> (1) West Coast conventional unleaded regular gasoline less a deduct, where the price series was generally OPIS spot pipeline Los Angeles; (2) West Coast CARB unleaded regular gasoline less a deduct, specifically the OPIS CARB spot pipeline Los Angeles price series; or (3) a flat fixed price.

Id. at pp. 44-45.

506. According to Tallett, a comparison of the West Coast Naphtha contracts to published West Coast gasoline prices revealed the following:

> [f]or the period 1994-1998, the West Coast Naphtha contract prices averaged 8.5¢/gal below OPIS spot pipeline conventional unleaded regular prices. For the period 1999-2001, this differential narrowed slightly to 8.4¢/gal. For the July 1996-1998 period, the West Coast Naphtha contract prices averaged 12.0¢/gal below CARB (pricing for which started in July 1996). For the 1999-2001 period, the West Coast Naphtha contract prices averaged 14.4¢/gal below CARB gasoline prices. Differentials versus CARB gasoline for the Heavy Naphtha contract prices narrowed from 15.2¢/gal in 1996-1998 to 9.6¢/gal in 1999-2001.

Id. at p. 45. He suggests that the data demonstrate that during periods of tight supplies and high gasoline prices, Naphtha value relative to gasoline rises. *Id.*

507. As for the alternative proposals proffered by other witnesses, Tallett offers several criticisms. *Id.* Dudley's proposal, he states, "underestimates the West Coast Naphtha contract prices by 9.5¢/gal and the Heavy Naphtha contract prices by 14.3¢/gal." *Id.*

508. When asked what the West Coast Naphtha contracts showed relative to Sanderson and Culberson's assertion that Gulf Coast Naphtha prices should be used to value West Coast Naphtha, Tallett responded that Gulf Coast Naphtha prices should not be used to value West Coast Naphtha because the data demonstrate[189] that West Coast Naphtha prices rise with West Coast gasoline prices and "they can be sustained at values above Gulf Coast Naphtha plus a transportation differential." *Id.* at p. 46.

509. Despite criticisms of the value of the West Coast Naphtha contracts, Tallett defends their utility. *Id.* He declares that they are "the best evidence available regarding the prices at which Naphtha is bought and sold on the West Coast." *Id.* He adds that "[t]he contracts further show that the Naphtha contract prices are fairly constant across a wide range of market conditions, averaging around 12 to 14.4¢/gal off of CARB gasoline prices and 8.4 to 8.5¢/gal off of conventional unleaded regular gasoline prices." *Id.* at p. 47.

510. Addressing Ross's claim that West Coast Naphtha values can't exceed the costs of imported Gulf Coast Naphtha for any length of time, Tallett asserts that both he and O'Brien have proven that West Coast intermediate and finished product prices routinely exceed the cost of Gulf Coast imports. *Id.* at pp. 49-50. Moreover, according to Tallett, Ross fails to consider that there is a balance of supply and demand for Naphtha on the West Coast establishing a trade barrier, and that the Naphtha contracts discovered refute his claim. *Id.* at p. 50.

511. Turning to West Coast VGO prices, Tallett states that he believes that they have shown the same changes in price and volatility that have affected West Coast gasoline prices. *Id.* at pp. 47-48. Defending against Ross's criticism that Tallett's Gulf Coast based VGO Regression formula overvalues West Coast VGO, thus bringing into question the Naphtha regression formula, Tallett answers that Ross's claim is incorrect because, while admitting that he prepared a regression formula to show the reliability of reported West Coast VGO prices, he did not advocate using a regression formula to value the product. *Id.* at p. 48.

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[189] Tallett states that "[i]n the period from 1994-1998, Platt's Gulf Coast Naphtha prices averaged 3.8¢/gal below the average of the West Coast Heavy Naphtha contract prices. For the 1999-2001 period, this gap widened to 16.4¢/gal." Exhibit No. EMT-133 at p. 46.

512. Regarding the West Coast VGO valuation criticisms, Tallett first states that no party disagrees that the appropriate future valuation of West Coast VGO should be based on the OPIS West Coast High Sulfur VGO prices. *Id.* at pp. 8, 52. Several parties maintain, according to Tallett, that this approach should be used for past periods as well. *Id.* Other parties, he notes, oppose using this approach for past periods. *Id.* at p. 52. Ross, according to Tallett, believes that changed circumstances have occurred making West Coast VGO prices reliable. *Id.* Tallett notes, however, that Ross does not specify when the changed circumstances occurred, how the changes have made the OPIS West Coast High Sulfur VGO prices more reliable, nor how the prior prices were unreliable. *Id.*

513. Under cross-examination, when asked whether the Gulf Coast and West Coast petroleum markets were separate, Tallett responded by stating that there was a "global" market "interconnected by transport." Transcript at p. 6692. He added that the Gulf Coast and West Coast markets were "a substantial distance apart." *Id.* at pp. 6692, 6699-6700. After further questioning, Tallett indicated that what he meant by his answer was that the two were "sufficiently and geographically distant from each other so that . . . most people in the industry . . . would not consider them as one market." *Id*. at p. 6694. Later, discussing crude oil, Tallett noted that the world was divided into two markets: (1) the Atlantic basin which consists of "everything from the North Sea and West Africa down across the Atlantic" Ocean; and (2) the Pacific basin which consists of "everything going from basically the Cape of Good Hope east across the Pacific" Ocean and would include the United States's West Coast. *Id.* at p. 6696. According to Tallett, crude oil can flow from the same origin to either the West Coast[190] or the Gulf Coast.[191] *Id*. at p. 6697. Tallett also noted that the cost of transportation can act as a barrier between two markets, i.e., too high a transportation cost can eliminate the flow between two points. *Id.* at pp. 6700-01.

[190] Under re-direct examination, Tallett testified that crude oil on the West Coast comes from the United States (mostly California), the North Slope of Alaska, (a small amount) from the Pacific (Indonesia), some from Mexico and Latin American sources, and an increasing amount from the Middle East as production in California and Alaska decline. Transcript at p. 7160.

[191] At first, Tallett indicated that he wasn't sure whether the price of crude oil depended on to where in the United States it was going. Transcript at p. 6699. Later, after refreshing his recollection, he agreed that the price of Saudi Arabian crude was the same no matter where in the United States was its destination. *Id.* at p. 6788. According to Tallett, only about 100,000 barrels/day of Saudi Arabian crude is imported into the West Coast, while 1,000,000/day or so are imported into the Gulf Coast. *Id.* at p. 7163.

514. Asked about Very Large Crude Carriers, Tallett admitted that they did, in fact, transport crude oil to the West Coast. *Id.* at p. 6701. Tallett pointed out, however, that these large ships cannot dock at West Coast ports, but that their cargoes had to be off-loaded by lighters. *Id*. at p. 6702. He agreed that, from 1996 to 2001, foreign oil imports into California had tripled and that these imports were "replacing ANS crude oil and . . . off-setting the decline in California production." Id. at p. 6702.

515. Discussing the uses of Naphtha, Tallett said that he did not include its use as a petrochemical feedstock because most of the Naphtha which is so used is in the LSR low boiling range rather than the heavy Naphtha boiling range.[192] *Id*. at p. 6703. Therefore, in his analysis, he only considered its use as a reformer feedstock to make reformate and its use to make jet fuel. Id. Under further examination, he amplified Naphtha's use in petrochemical production: "There are two uses of naphtha . . . in the petrochemical market. You have naphtha as a feedstock to ethylene steam-cracking where the main product is ethylene, and you have naphtha as a feedstock for aromatics production, often referred to as BTX, for benzene, toluene, and xylene." *Id.* at p. 6704.

516. Tallett indicated that, in creating his regression formula, he ignored Naphtha's petrochemical use because he was looking for a pricing point:

> I established a flow scheme . . . of taking naphtha into a cat reformer from which the reformate goes into gasoline. And then once I'm in gasoline, I have a pricing point because the gasoline price is published. And then the other part of my flow scheme . . . was the part of naphtha to go into jet [fuel], and that gave me a separate pricing point.

Id. at pp. 6704-05. Under further examination, he described his regression formula and how changes could affect it:

> The regression formula was derived from equating three sets of prices together, naphtha, gasoline and jet fuel. [In d]irect terms, what would change the regression formula would be if one of those series of

[192] Asked how Full Range Naphtha was used in a refinery, Tallett replied:

> It's generally split because the lighter fraction which we've referred to as LSR is not appropriate as a reforming feedstock, whereas the heavier part of the full range naphtha is. You can get an effective boost in the octane by putting the heavier naphtha through a cat reformer.

Transcript at p. 7034.

> prices was different. Supposing the gasoline prices had been higher than they actually were. Then you would have ended up with a different regression equation result. So the question, I think, becomes what would cause the gasoline or the naphtha prices to change.

Id. at p. 6766; *see also id*. at pp. 7093-94.[193] Asked about the relationship between the prices of Naphtha, jet fuel and gasoline, Tallett testified that his regression formula would change if their prices changed. *Id.* at pp. 6768, 6770. Tallett claimed that this was one of the benefits of his approach; i.e., he states that it is simple, but leaves open the opportunity to make changes as conditions change. *Id.* at p. 6768.

517. Later, Tallett was asked whether his West Coast gasoline-jet fuel-Naphtha regression formula reflected an "identical relationship" to that on the Gulf Coast, and he indicated that it did not, but that the formula was the same, and contained the same coefficients, on both coasts. *Id.* at p. 6841. He said the formulas were not identical "in that if you look back at the history of prices on the two coasts and you apply that formula on both coasts . . . you won't get the same naphtha price." *Id*. at p. 6842. Despite this, Tallett agreed that he assumed the "same basic processing, blending relationship" between gasoline, jet fuel and Naphtha on both coasts. *Id*. at pp. 6842, 7025-26.

518. Tallett testified that, in his formula, he multiplied the Platts West Coast unleaded regular mid-value waterborne gasoline price by .653. *Id*. at p. 7195. He further stated that, though there were other West Coast prices, those prices were geographically specific and that the reported price he used was the only general price reported for the West Coast. *Id*. at pp. 7195-96. According to him, the West Coast gasoline price he used is the corresponding price series to Platts Gulf Coast unleaded regular 87 waterborne price. *Id*. at p. 7197. Tallett also testified that the West Coast Los Angeles jet 54 was the only reported waterborne price on the West Coast. *Id*. at p. 7196.

519. According to Tallett, originally, he had not included the price of jet fuel in his analysis, but came to believe that, since refiners had the option of varying the cut-point between Naphtha and jet fuel and because the price of jet fuel, at times, exceeded the gasoline price, "it was appropriate to test whether adding in jet fuel" would increase the reliability of his regression formula. *Id*. at pp. 7094-95. When he did, he states, he found that, instead of leaving 4% of the Naphtha price changes unexplained, only 2% were unexplained.[194] *Id*. at p. 7095.

520. Tallett testified further that the contracts produced in discovery in this proceeding

[193] *See also* Exhibit No. EMT-397.

[194] *See also* Exhibit No. EMT-17.

support his regression formula:

> [The contracts] reinforce the relationship that I derived, . . . which reinforces my belief that the relationship does hold. And that's further reinforced by the discussion a few minutes ago where Dr. Toof took the pure West Coast analysis and took it back to the Gulf Coast, basically doing the reverse of what I did, and was able to show that when you do that, the West Coast relationship provides a good prediction of Gulf Coast [prices].
>
> There you're going [in] the opposite direction because you're taking the relationship that was derived, including a lot of high prices, and taking it back to a region where the price range was somewhat lower on average, and that relationship was a good prediction of Gulf Coast naphtha [prices].

Id. at pp. 7026-27. He added that the processing cost analysis also supported his regression formula and that O'Brien's and Ross's "analyses all tended to reinforce the same levels of naphtha values, again, across a wide range of prices." *Id*. at p. 7027. According to Tallett, in fact, every single way that the relationship between Naphtha, gasoline and jet fuel was analyzed support his regression formula. *Id*. at pp. 7027-28.

521. In Tallett's view, the Quality Bank Administrator, using his regression formula, would "plug in the West Coast unleaded regular [gasoline] price for a particular month, West Coast jet fuel price [for that month], and then do the algebra to get" the West Coast Naphtha price. *Id*. at p. 7094. Also, he suggested that the Quality Bank Administrator revise the regression formula periodically with updated public data. *Id*. at p. 7114.

522. Tallett, in further testimony, admitted that the relationship in his West Coast formula is dependent upon Gulf Coast prices. *Id*. at p. 7201. He admitted further that, were his formula updated by the Quality Bank Administrator, the Administrator "would still have to go back and do a Gulf Coast analysis in order to determine whether the relationship still exists or whether it has changed in any way." *Id*. at pp. 7201-02. In testimony which, although not directly connected, was related, Tallett indicated that, while he preferred a method solely relating to the West Coast, one could establish a West Coast Naphtha price by taking "'the differential between the U.S. Gulf Coast pipeline spot unleaded 87 [price] and [the] U.S. Gulf Coast spot waterborne naphtha from Platts and subtract that differential from Platts L.A. pipeline spot unleaded'" price. *Id*. at pp. 7199-7200. He added that this method, while it was simple, might yield reasonable results over a long period of time, and "seems to yield [results] consistent with" his; but would, on any given month, impose any anomalous Gulf Coast market conditions on the West Coast. *Id*. at p. 7200. However, he admitted that this would average out over a year or more and that, as noted above, his formula was based on Gulf Coast prices. *Id*. at p. 7202.

523. He believed that West Coast Naphtha should be priced on a West Coast basis, Tallett stated. *Id*. at p. 7079. In support, he asserts that, as Heavy Naphtha is used primarily as a gasoline blendstock, its price closely follows the price of gasoline and that the pricing on the Gulf Coast is different than that on the West Coast. *Id*. He claims that the contracts discovered here "reinforce that people in [the] industry who actually undertake these transactions" agree. *Id*. Tallett adds that processing and capital costs on the West Coast tend to be higher than those on the Gulf Coast. *Id*. at p. 7088.

524. According to Tallett, a 10-year (January 1992 through December 2001) analysis of gasoline and Naphtha prices indicates that "over 96 percent of the movements in naphtha prices are explained by gasoline." *Id.* at pp. 6796, 7019. While he conceded that the demands of the petrochemical industry might have some impact on Naphtha prices, he claimed that the impact is "small," as little as 4%. *Id*. at pp. 6796, 7115, 7122-24. However, later, he suggested that, on the Gulf Coast, in addition to the impact which gasoline has on the price of Naphtha, 2% of the "change in [the] reformer grade naphtha price" was caused by the price of jet fuel and the remaining 2% was caused by the demands of the petrochemical market. *Id.* at p. 6838. Tallett noted that there was no petrochemical market on the West Coast to affect the price of West Coast Naphtha. *Id*.

525. Tallett addressed the question of the margin between the price of crude oil and the prices of the finished products derived from it, referred to at the hearing as the "refining margin," and indicated that the West Coast margin was higher than that on the Gulf Coast. *Id*. at pp. 6844, 47-48. He added that, historically, jet fuel prices on the West Coast were about 5¢/gallon higher than on the Gulf Coast and that gasoline prices were about 6.5¢/gallon higher on the West Coast and that CARB gasoline prices were about 10¢/gallon higher than Gulf Coast conventional gasoline, but couldn't state what the differences was between the refining margins on the two coasts. *Id*. at p. 6849. Under further cross-examination, Tallett agreed that not all products were priced higher on the West Coast than on the Gulf Coast. *Id.* at p. 7008.

526. Asked about VGO, Tallett testified that its main use was as a feedstock for the cat cracker "from which . . . a range of products" resulted. Id. at p. 6705. It is used for the same purposes on both the Gulf Coast and the West Coast. *Id*. The difference between the two coasts, according to him, was that the allowable sulfur level on the West Coast required VGO to be "more severely desulfurized." *Id*. at p. 6707. He did indicate that a higher percentage of VGO is used to make CARB gasoline than conventional gasoline on the West Coast. *Id*. at p. 6870. However, Tallett did not agree with the proposition that a higher percentage of VGO is used to make gasoline on the West Coast in comparison with the Gulf Coast. *Id.* at p. 6871.

527. According to Tallett, West Coast VGO prices "closely track" gasoline prices. *Id*. at p. 6874. In other words, he stated "VGO prices rose and fell on virtually all occasions when gasoline prices did." *Id*. at p. 6875. Tallett admitted that there were times when

this was not so. *Id*. at p. 6878.

528. Tallett testified that refiners would pass increases in natural gas costs through to end users. *Id*. at p. 6756. He further stated that the costs would be passed through in the price of the gasoline produced with the more costly natural gas. *Id*. However, Tallett disagreed with the proposition that, when gasoline and Naphtha prices were low, petrochemical users would increase their purchases and drive the Naphtha price up. *Id.* at p. 6793. He noted, too, that jet fuel prices were "counterseasonal" with gasoline prices, i.e., during seasons when gasoline prices were up (the summer),[195] jet fuel prices were down, and vice versa. *Id*. at pp. 6793, 6795. Tallett later added that the price of gasoline tends to pull the price of Naphtha up or push it down. *Id*. at p. 6803. He also suggested that, at times, on both coasts, jet fuel prices exceeded the price of gasoline, including CARB gasoline. *Id*. at p. 6806.

529. Discussing the Gulf Coast and West Coast markets, Tallett agreed that more gasoline and jet fuel is being made as a percentage of crude oil in the latter than the former. *Id*. at p. 6772.

530. Tallett was asked about the Ross governor proposal and stated that he believed that, if it were valid, West Coast Naphtha imports from the Gulf Coast would increase during periods when West Coast Naphtha prices exceed Gulf Coast Naphtha costs plus transportation during periods when West Coast gasoline prices were high. *Id*. at pp. 6993, 7003. He concluded that, as Naphtha was not imported into the West Coast, Ross's theory had no validity.[196] *Id*. at p. 6995. Tallett did admit that, during those periods, Naphtha may have been imported into the West Coast as gasoline.[197] *Id.* at p. 6994.

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[195] Gasoline prices tend to rise in the summer, according to Tallett, because people tend to drive more during that period and the demand for gasoline rises in synch. Transcript at p. 6804.

[196] Tallett is highly critical of the concept behind Ross's governor proposal:

> [Ross is] saying that if the estimated West Coast naphtha price for the month of May exceeds the Gulf Coast price by more than the Gulf Coast price plus transport, then 100 percent of the West Coast Quality Bank naphtha volumes for the month of May should be considered to be capped. That's equivalent to saying in that month of May, supplies will appear from the Gulf Coast and be shipped to the West Coast in order to impact the West Coast market all within that month, which is a physical impossibility.

Transcript at pp. 7051-52.

[197] Tallett opines that importing an intermediate product to the West Coast when

Nevertheless, Tallett believes that Ross's governor proposal is unrealistic because the West Coast and Gulf Coast are too far apart, there are too many difficulties in moving intermediate products from the Gulf Coast to the West Coast, and because "there's too much price risk for potential shippers for the mechanism [which Ross] is talking about to apply." *Id*. at pp. 7051-52.

531. According to Tallett, while able to handle imports of crude oil, the "logistics system" on the West Coast was not established to handle large imports of intermediate products. *Id*. at p. 7029. He stated that there was insufficient tankage and terminal capacity to do so. *Id.* at pp. 7029, 7267-68. Under re-direct examination, Tallett did state that there was an infrastructure on the West Coast to receive imports of jet fuel. *Id.* at p. 7268.

E. BARRY PULLIAM

532. Barry Pulliam ("Pulliam"), a senior economist at Econ One Research, Inc., an economic research and consulting firm, testified on behalf of the Alaska. Exhibit No. SOA-1. Pulliam has been engaged in economic research and consulting, focusing on economic and business valuation issues as well as the operation of markets for crude oil and refined petroleum products, since 1988. Exhibit No. SOA-2.

533. His rebuttal testimony, the only Alaska pre-filed testimony, was offered to support O'Brien's proposal which had been attacked by Sanderson and Ross. Exhibit No. SOA-1 at pp. 1-2. According to Pulliam, his "testimony is based on an analysis of contracts for the sale of naphtha on the West Coast . . . produced by the parties to this proceeding (or their affiliates), and . . . by other West Coast refiners." *Id.* at p. 2. Pulliam begins by summing up his findings as follows:

> My analysis of West Coast naphtha contracts shows that (1) in the majority of cases the contract prices specified are directly linked, or "indexed" to West Coast gasoline prices and (2) the contract prices indicate that the market value of naphtha on the West Coast is substantially higher than the published Gulf Coast naphtha price that Mr. Sanderson advocates.

Id. Referring to Ross's governor proposal, in further summarizing, Pulliam stated:

> [I]n testing [Ross's] hypothesis against actual West Coast naphtha contract

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gasoline prices are spiking high is too risky for refiners because of the time needed for transporting and refining the intermediate product in volatile market situations, that importing a finished product like regular or CARB gasoline, which can be quickly moved to market, is much less chancy. Transcript at pp. 7030-32.

> prices, I find no support for the use of a governor as advocated by Mr. Ross. Moreover, the contract prices indicate that the market value of naphtha on the West Coast is substantially higher than the values that result from use of Mr. Ross's governor over the past 3 years (1999-2001), the period during which his governor has been used most often.

Id. at p. 3. Lastly, Pulliam declares that the contract data he reviewed indicates that O'Brien's proposal is "superior" to the proposals submitted by the other parties. *Id.*

534. Amplifying on his summary, Pulliam states that average Naphtha values derived by O'Brien's proposal are near the contract prices measured over a 1994-2001 period. *Id*. at p. 10. He states that the O'Brien values are within 1.2 to 2.1¢/gallon during this period of time. *Id.* Pulliam opines that "[o]ver the 1994-2001 period, the contract prices are on average closer to the [values derived by the O'Brien proposal] than to the values proposed by" Sanderson and Ross. *Id.*

535. Pulliam asserts that Sanderson understates West Coast Naphtha value, during the period 1994 through 2001, 6.5¢/gallon and by 14.2¢/gallon during the 1999 through 2001 period. *Id.* Under cross-examination, at the hearing, Pulliam stated that the Sanderson/Culberson method "on average" most closely matched the contract results for the 1994-1998 period.[198] Transcript at p. 7449. According to Pulliam, Ross's governor proposal would result in an understatement of West Coast Naphtha values by 10.6¢/gallon "since 1999." Exhibit No. SOA-1 at p. 10. Pulliam concedes that Tallett's proposal results in values which are closest to the contract prices for the 1994-2001 period, but argues that, since 1999, he understates West Coast Naphtha values in a range of from 3.7¢/gallon to 4.1¢/gallon. *Id.* at p. 11; Transcript at p. 7450.

536. At the hearing, in further direct testimony, Pulliam stated that he selected a subset of all of the contracts produced during discovery in this proceeding on which to base his analysis.[199] Transcript at p. 7292. He testified that he reviewed each contract and eliminate those which: (1) were not the equivalent of Quality Bank Naphtha; (2) were not

[198] Pulliam stated that the Sanderson/Culberson methodology resulted in a Naphtha price which was only 1.3¢ under the contract value. Transcript at p. 7449.

[199] Pulliam testified that the contracts listed in Exhibit No. SOA-15 are those for which he had "specifications . . . or for which the name of the product gave [him] information about what type of naphtha it was" and which quality was consistent with Quality Bank Naphtha. Transcript at p. 7294. Exhibit No. SOA-16, he stated, identifies those contracts for which there was insufficient information to determine whether the Naphtha involved was of Quality Bank quality. *Id.* He also indicated that Exhibit No. SOA-17 identifies the contracts which he reviewed, but didn't use. *Id.*

the result of an arm's-length transaction; (3) were not within the appropriate time-frame; (4) were "exchange contracts;" (5) did not contain sufficient information or were illegible; and (6) did not call for a West Coast delivery. *Id.* at pp. 7296, 7298. The remaining contracts, he said, were divided between those which contained sufficient specification and those which did not. *Id.* at pp. 7296-98. Ultimately, Pulliam concluded that only 132 contracts met all of his criteria during the 1994-2001 period and those were the only ones used in his study, 95 of which were in the 1999-2001 period. *Id.* at pp. 7404-05.

537. According to Pulliam, there were several different price terms on the contracts he selected: (1) fixed and flat -- where the price doesn't fluctuate with another index and is set on a date certain;[200] (2) contracts where the price is set at plus or minus the monthly average price of another product;[201] (3) formula priced contract where the price is set at plus or minus the average price of another product over a specific period of time;[202] and (4) formula priced contract where the price is set at plus or minus the average price over a period of time surrounding the unspecified delivery date.[203] *Id*. at pp. 7299-7303.

538. Pulliam testified that, even though the volumes of Naphtha represented by the contracts were as little as 1% or less of the Naphtha processed on the West Coast, the contracts represented "a great majority of the transactions" into which members of the West Coast industry entered. *Id.* at pp. 7324-25. He added that, when reporting services made their assessment, "they sometimes look at a small fraction of the total production of a product." *Id.* at p. 7325.

539. Under cross-examination, Pulliam admitted that 40% of the contract volume occurred between 1994 and 1998, and that 60% occurred during the 1999-2001 period. *Id.* at pp. 7331-32. He further acknowledged that the Naphtha price range (the difference between the highest and lowest prices) during the latter period was greater than the gasoline price range during that same period. *Id*. at pp. 7333-34.

540. Pulliam also admitted that he had no experience in either buying or selling Naphtha. *Id.* at p. 7355. He agreed that, prior to this case, he had not analyzed or done any specific studies of Naphtha's value. *Id.* However, on re-direct examination, Pulliam claimed that, as an economist, he studied the petroleum market "pretty much full-time."

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[200] Exhibit No. SOA-18.

[201] Exhibit No. SOA-19.

[202] Exhibit No. SOA-20.

[203] Exhibit No. SOA-21.

Id. at p. 7573A. He added that, as part of that, on occasion, he analyzed the market value of ANS crude oil sold on the West Coast as well as the Gulf Coast and analyzed the market prices of crude oil produced in other states and in other countries. *Id.* at p. 7573A-74A. Pulliam stated that he recognizes that, on the West Coast, Naphtha supply and demand is almost in balance with no Naphtha exported and little imported. *Id.* at pp. 7356, 7755.

541. According to Pulliam, while he feels that O'Brien's proposal, particularly during the 1999-2001 period, establishes the truest Naphtha price,[204] he is not supporting it or "any particular approach." *Id.* at pp. 7357, 7449. However, it must be noted that, in his Rebuttal Testimony, Pulliam indicated that his testimony responds to Sanderson's and Ross's criticisms of O'Brien's testimony. Exhibit No. SOA-1 at p. 2; Transcript at p. 7590-91.

542. Pulliam claims that he did not study O'Brien's proposal or that of any other witness. Transcript at pp. 7357-59. He claims that his "analysis is simply comparing the end results [of each proposal], the values of naphtha calculated under each approach with [his] contract analysis." *Id.* at p. 7359.

543. In a 1999 study, Pulliam admits, he concluded that California's gasoline prices were higher than that in the rest of the United States because of a lack of competition compounded by the requirement that CARB gasoline be used and the difficulty of bringing CARB gasoline in from outside the State.[205] *Id.* at pp. 7364-71. According to him, he compared the refining margin (the difference between the price of crude oil and the value of the products produced from it) in Houston, Texas, and in Los Angeles, during the 1992 through 1998 period, and found that the Los Angeles refining margin was 4.8¢ higher (13¢ in Los Angeles compared with 8.2¢ in Houston).[206] *Id.* at p. 7372.

544. Pulliam acknowledged that one company, identified in the record as Company 31, on a volume-weighted[207] basis, purchased 83.3% of the Naphtha traded on the West

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[204] By this he meant that it more closely "tracks" the prices reflected in the contracts he included in his study. Transcript at p. 7398.

[205] Exhibit No. WAP-199.

[206] Exhibit No. WAP-199, chart 17.

[207] Pulliam described calculating a volume weighted average as follows:

> What you do is you take the price of each contract, and in coming up with an average, you weight the prices by their respective – the volumes in those respective contracts. So if they had equal weighting, if they both had the

Coast in 2001. *Id.* at p. 7383. However, he indicated that this was of no concern to him. *Id.* at pp. 7383-84. Later in the hearing, Pulliam stated that, for the three year period 1999-2001, he could identify only a total of 8-10 entities purchasing Naphtha and that only a total of 95 contracts (or fewer than 3 per month) were identified as taking place during that same period. *Id.* at p. 7756-57.

545. Under further cross-examination, Pulliam admitted that O'Brien's methodology over-priced Naphtha by about 2¢ during the 1994-2001 period and by 1-2¢ during the 1999-2001 period. *Id.* at pp. 7399-7400. He also agreed that the "best fit" during the longer period and during the period 1994-1998 were the reported Gulf Coast Naphtha price and the O'Brien methodology modified by the Ross governor. *Id.* at pp. 7401-03. During this portion of his cross-examination, Pulliam was asked about Exhibit No. WAP-206 which is a compilation of statistics he collected. *Id.* at p. 7401-02. That document reflects the following in comparison with Pulliam's contract data related to contracts which clearly met Quality Bank Naphtha specifications:

Period	O'Brien	Tallett	Ross	Culberson	Dudley
1994-2001	2.1¢	0.1¢	(3.2)¢	(6.5)¢	(6.5)¢
1994-1998	2.9¢	2.9¢	1.6¢	(1.6)¢	(2.9)¢
1999-2001	0.8¢	(4.1)¢	(10.6)¢	(14.2)¢	(12.1)¢

Exhibit No. WAP-206 at p. 2; Transcript at pp. 7605A-06A. *See also* Exhibit Nos. SOA-24, SOA-25. On re-direct examination, Pulliam indicated that the methodologies using West Coast gasoline prices "performed better relative to the contracts than did those methodologies that were based on the Gulf Coast naphtha quotes" because of a "divergence in gasoline prices" on the two coasts. Transcript at p. 7606A. He added that the reason why the former performed better was because those prices followed the higher West Coast gasoline prices. *Id.* at pp. 7606A-07A.

546. During the course of the hearing, Pulliam was asked for the results of the above

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same volume contract, the average would be 50 percent times one price plus 50 percent times the other price.

If one contract was 75 percent of the volume and the other was 25 percent, it would by 75 percent of the first price and then 25 percent of the second price, and you'd sum those up, and that would be your weighted average.

Transcript at pp. 7628-29.

comparison using Ross's governor. Transcript at p. 7468. That document reflects the following in comparison with Pulliam's contract data which clearly met Quality Bank Naphtha specifications:

Period	O'Brien	Tallett	Sanderson/Culberson	Dudley
1994-2001	(3.2)¢	(3.3)¢	(4.3)¢	(4.1)¢
1994-1998	1.6¢	2.9¢	0.8¢	0.9¢
1999-2001	(10.6)¢	(10.6)¢	(12.2)¢	(11.9)¢

Exhibit Nos. SOA-28, SOA-30; Transcript at pp. 7468-69.

547. Asked specifically about Tallett's methodology, Pulliam admitted that over the 1994-2001 period included in his study, "Tallett's methodology tracks [the contract prices] best." Transcript at pp. 7645A, 7814. He added that his "only concern . . . [was] that in more recent years, it had come in lower than the transactions, so it appeared like maybe there was a trend for lower values there." *Id.* at p. 7645A. Pulliam suggested that the reason why this occurred might have something to do with the influence of jet fuel prices on Tallett's formula. *Id.* at p. 7653A. However, he did admit that Tallett's analysis was developed over a longer period of time than he used. *Id.* at p. 7814.

548. Moreover, Pulliam pointed out that during the 1999-2001 period, on the West Coast, gasoline prices rose much more than jet fuel prices which resulted in lower values being derived by Tallett's formula. *Id.* at 7653A. Pulliam said that, if jet fuel prices were removed from Tallett's formula, the value derived from it might more closely track the contract prices. *Id.* He also noted that the contracts are "typically tied to Los Angeles gasoline prices" and, for that reason, the Naphtha contract prices correlate more closely with that price series than with gasoline prices in other West Coast locations. *Id.* at pp. 7682A-83A. Asked about the 2002 contracts, on re-direct examination, Pulliam testified that, on average, the contract prices were 4.3¢ less than the Los Angeles regular unleaded gasoline price and 6.8¢ higher than the reported Gulf Coast Naphtha price. *Id.* at p. 7830.

549. Under further cross-examination, Pulliam stated that, as an alternative to the proposals made by the parties, valuing West Coast Naphtha at ANS plus $4.00 would systematically undervalue it. *Id.* at p. 7700A. However, he did agree that it might be a way to "deal with the volatility of West Coast gasoline [prices] that had been experienced in [1999] and 2000." *Id.* On re-direct examination, Pulliam asserted that the use of such a formula, while it would protect the seller against gasoline price volatility by "locking in the seller's refining margin," would also protect the buyer's "margin." *Id.* at p. 7831.

550. According to Pulliam, services report prices for three reasons: (1) interested

parties have requested that they be reported; (2) parties are interested in acquiring the data; and (3) "simply because there is a certain volume of product, and it is a relatively easy thing for the assessing companies to cover along with the other products they're covering." *Id.* at p. 7553. He added that the reporting services don't get copies of the actual contracts, but they "try and find out as much about transactions as they can in making their assessments." *Id.* at p. 7559.

551. In connection with that testimony, Pulliam defined a "transparent market" as a market where "interested parties can go and find information." *Id.* at p. 7560. He identified the New York Mercantile Exchange or the stock market as a perfectly transparent market. *Id.* at p. 7562. While he claimed it was not a term he used, Pulliam indicated that an "opaque market" is one where there is "no ability to gather information." *Id.* According to Pulliam, prices may be different in a transparent market as compared with an opaque market because of the ability to gather information. *Id.* at pp. 7562-63. He denied that the West Coast market was opaque stating that people who buy and sell Naphtha can and do gather price information. *Id.* at p. 7623A.

552. Pulliam, under further cross-examination, discussed Exhibit SOA-10, which he explained was his attempt to compare the unleaded regular gasoline price in Los Angeles with the prices on the contracts he used in his study. *Id.* at p. 7643. He reported his findings as follows: (1) with regard to the Naphtha which met Quality Bank specifications, over the 1994-2001 period, the contract prices averaged about 7¢ below the gasoline price; (2) during the 1999-2001 period, the difference narrowed to 4.3¢. *Id.* at pp. 7644-45; Exhibit No. SOA-10. From this, he concluded that value of Naphtha as compared with Los Angeles unleaded regular gas had increased during the latter period as compared with the longer one. Transcript at p. 7645.

553. Discussing imports of petroleum products into the West Coast, Pulliam declared that there was a limited number of storage tanks in California, particularly in the Los Angeles basin, restricting the ability to import "clean" product cargoes, such as Naphtha. *Id.* at p. 7690.

F. CHRISTOPHER ROSS

554. Ross testified on Issue 3, but this portion of his testimony is supported only by BP Exploration and Amoco Production. Exhibit No. BPX-8 at p. 2. He did not "propose a specific base price for West Coast Naphtha," but states that any such price "should reference West Coast gasoline prices since Naphtha's primary use on the West Coast is in gasoline manufacturing." *Id.* at p. 2. Ross argues that, once that is established, "the base price should be capped by a 'governor' that corrects for certain anomalies in the gasoline market that otherwise would distort the value of Naphtha on the West Coast." *Id.* at pp. 2-3. According to Ross, he suggests that a governor be used which recognizes that "the price of Naphtha on the West Coast could never exceed the price of Naphtha on the Gulf

Coast, plus the cost of transporting that Naphtha to the West Coast market." *Id.* at p. 3.

555. He explains that the Gulf and West Coast Naphtha markets are fundamentally different because the Gulf Coast market is defined by a large and highly developed petrochemical feedstock market, attracting a large flow of imports from nearby supply sources in the Caribbean. *Id.* In contrast, he notes, the West Coast has no petrochemical feedstock market and almost no imports. *Id.* Consequently, Ross states, on the West Coast, the primary use of Naphtha is as a feedstock for the reforming process and the resulting approximately 80% volumetric yield of reformate is used as a gasoline component. *Id.* However, on the Gulf Coast, he contends, Naphtha is used both as a petrochemical feedstock and as a component to make gasoline. *Id.* He concludes that "using a Gulf Coast price to value Naphtha on the West Coast not only uses the wrong market, but also relies on the wrong end-use to value West Coast Naphtha." *Id.* at pp. 3-4.

556. Ross asserts that the appropriate method to value West Coast Naphtha must identify the value of Naphtha as it is used on the West Coast. *Id.* at p. 4. Naphtha's primary West Coast use, he claims, is as a feedstock to the catalytic reforming process producing reformate, which is a gasoline blending component. *Id.* However, he notes, there is no reported price for reformate, and, consequently, the Naphtha value should be based on the reported gasoline price, adjusted for the cost of transforming Naphtha into a gasoline component, on the same waterborne basis as other liquid cuts. *Id.*

557. Furthermore, as serious anomalies in West Coast gasoline prices have recently occurred, he argues, an adjustment must be made for the anomalies. *Id.* He contends that if an adjustment is not made for these anomalies, the price of Naphtha will be significantly overstated. *Id.* Concluding, he asserts that, to correct for the potential distorting effect, the value resulting for Naphtha from a "gasoline, minus" calculation must be adjusted to cap the price at a level at which Naphtha from other markets otherwise could be imported into the West Coast:

> If the cost of West Coast Naphtha ever were to exceed the value of the price at which Naphtha from other markets could be imported into the West Coast, Naphtha producers in other markets would seize on this opportunity to achieve greater returns on their product. They would import Naphtha from other sources into the West Coast, reducing the overall price back to the import price. Thus, the alternative "imported value" of Naphtha reflects a realistic cap on the calculated West Coast Naphtha value. This adjustment is essential to ensure a fair valuation of West Coast Naphtha.

Id. at pp. 4-5. According to Ross, his governor represents the Gulf Coast Naphtha price plus the differential cost of shipping Naphtha from a common location (Venezuela) to the Gulf Coast and the West Coast during the January 1994-October 2001 period because there was no history of Naphtha shipments from the Gulf Coast to the West Coast.[208] *Id.* at p. 11. He explains how he established the value of the governor:

> I have established the value of the governor by calculating from 1994 through 2001 the costs of shipping Naphtha from Venezuela's Paraguana Refining Complex (CRP) to Los Angeles and to Houston. I then calculated the difference between these two cost series and calculated the average for the entire period. . . This value is $1.848 per barrel.

Id. at p. 16 (citation omitted).

558. Ross explains that using a pure "gasoline, minus" approach would severely overstate the value of Naphtha as the prices of VGO, butane, and natural gasoline have all fallen out of sync with gasoline prices since 1999. *Id.* at p. 12. In this time period, he continues, finished gasoline prices responded to supply and demand forces caused mainly by interrupted availability of cat cracking and coking capacity and by logistics disruptions. *Id.* Consequently, he asserts, significantly higher prices for finished gasoline resulted. *Id.* At the same time, he adds, higher finished gasoline prices have not resulted in higher prices for the other gasoline feedstock components, VGO, butane, and natural gasoline. *Id.* Concluding, he argues that it would be inappropriate to assume that the value of Naphtha would have risen proportionately to the price of finished gasoline either. *Id.* In order to avoid attributing this anomalous gasoline value to Naphtha, he maintains, a governor should be imposed on the price otherwise calculated under a "gasoline, minus" approach. *Id.*

559. According to Ross, Naphtha and other gasoline feedstock component values do not track gasoline prices during anomalous periods because West Coast gasoline is a complex set of blends affording refiners little flexibility to substitute a component in long supply for another component that may temporarily be in short supply. *Id.* at p. 13. Also, he argues, the specifications governing CARB gasoline are highly complex and under EPA regulations, the ability of refiners to use non-CARB, non-reformulated gasoline as a "sink" for components that cannot be incorporated into CARB or reformulated gasoline pools is limited. *Id.* Ross further suggests that, as the price of Naphtha will follow the rise and fall of gasoline feedstock prices more closely than it will the price of finished gasoline,[209] the "governor is necessary to avoid severely overvaluing Naphtha during period of anomalous gasoline prices. *Id.* at p. 14.

560. The governor, he maintains, will provide reasonable results as it "is a conservative

[208] His calculations appear in Exhibit No. BPX-11.

[209] *See* Exhibit Nos. BPX-12 and BPX-13.

measure." *Id.* at p. 15. However, he admits that few Naphtha imports have occurred, and suggests that, therefore, Naphtha values "have almost certainly not exceeded the cost of imports for any extended period of time." *Id.* Nevertheless, he states, a continuous flow of Naphtha from Caribbean refineries in Venezuela, Trinidad, Aruba, and Curacao to the Gulf Coast exists. *Id.* The quality of Naphtha from Venezuelan crude oil is suitable for reformers, he notes, and the Naphtha used in Gulf Coast petrochemical plants can be used as reformer feedstock on the West Coast. *Id.*

561. In his Answering Testimony, Ross responds to criticisms raised by Exxon, Phillips, Unocal, Williams, and Alaska witnesses. Exhibit No. BPX-27 at p. 2. To begin, he criticizes Tallett's West Coast Naphtha valuations, claiming that it has three fatal flaws. *Id.* at p. 5. As a preliminary matter, however, he notes that he agrees with the use of a waterborne basis in Tallett's valuation. *Id.* The three flaws, he contends, are (1) Tallett's methodology fails to recognize significant changes in the West Coast gasoline market that must be accounted for in any methodology designed to value West Coast Naphtha using a pricing formula based on West Coast gasoline prices; (2) it fails to explain West Coast VGO prices; and (3) it violates the principle that West Coast Naphtha cannot for any extended period of time be above the cost of imports diverted from the Gulf Coast. *Id.* at pp. 5-6.

562. Tallett fails to account for the changed West Coast gasoline market, Ross argues, because the differential between Gulf Coast and West Coast regular unleaded gasoline prices has been more erratic since 1999 than it was from 1994 to 1998. *Id.* at p. 10. Changed circumstances, he maintains, have altered the historic relationship between Gulf Coast gasoline and West Coast gasoline:

> [T]he mean differential between West Coast and Gulf Coast regular unleaded gasoline prices . . . shows that from an initial value of $2.31 per barrel in 1994 the differential remained in a relatively consistent range through 1998 then rose sharply to a peak of $6.39 per barrel in 2000. Over the same time period, the standard deviation of the monthly differential (a measure of its monthly volatility) stayed in a narrow range with values of $1.14 per barrel in 1994 and a similar $1.21 per barrel in 1998, but rose sharply to a peak of $4.41 per barrel in 2000.

Id.; *see also* Exhibit No. BPX-35. These changed circumstances, he believes, are caused by the restrictive gasoline specifications on the West Coast, a growing demand for gasoline combined with "a hostile permitting environment for refinery expansions on the West Coast," and a series of refinery incidents reducing local supply. Exhibit No. BPX-27 at p. 11. However, he asserts, these incidents would not cause West Coast Naphtha prices to rise, rather they would cause a decline in its price because they would have resulted in a lower demand for reformate and, consequently, a lower demand for

Naphtha.[210] *Id.* at p. 12.

563. Ross argues that because of the similar use for West Coast Naphtha and West Coast VGO any method predicting West Coast Naphtha value should also predict West Coast VGO value. *Id.* Tallett's method, Ross claims, does not do so. *Id.* Applying Tallett's data and using his methodology, Ross suggests, overstates actual prices for West Coast VGO by an average $1.56/barrel (3.7¢/gallon). *Id.* at p. 13. Consequently, Ross insists, Tallett's proposed West Coast Naphtha valuation must also be overstated. *Id.* Applying the governor to Tallett's VGO formula, Ross asserts, results in West Coast VGO prices much closer to actual prices.[211] *Id.* at p. 14.

564. Additionally, Ross claims that Tallett's argument that the West Coast Naphtha value can be predicted by referring to the difference between the value of Gulf Coast gasoline and jet fuel and that of Gulf Coast Naphtha is incorrect. *Id.* at pp. 14-15. He states that West Coast finished product prices command greater margins than similar Gulf

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[210] Ross claims to rely on Exhibit No. BPX-37, which shows a time line of refinery and logistics incidents on the West Coast taken from OPIS newsletter reports, along with a graph of gasoline and VGO prices, to demonstrate that most of the refinery incidents involve cat crackers and cokers. Exhibit Nos. BPX-27 at pp. 11-12, BPX-37. He explains:

> In periods after cat cracker incidents (e.g. March-April, June-July 1999, and August September 2001), gasoline prices tend to rise, while VGO prices do not rise in parallel since the demand for VGO as cat cracker feed has been decreased. In periods after coker incidents (e.g. June-August 2001), gasoline and VGO prices rise together, since the supply of coker VGO has been reduced. In both cases, however, the supply of cat gasoline is reduced, so the demand for reformate within the restrictive West Coast specifications is reduced. Lower reformate demand means lower Naphtha demand; lower Naphtha demand means lower Naphtha values. As a result, it is incorrect to state that the anomalies which periodically push West Coast gasoline prices up have also increased Naphtha values.

Exhibit No. BPX-27 at p. 12. He adds that, in fact, Naphtha price might decline under such circumstances. *Id.*

[211] Ross notes that in 2001 the results were different because of several coker incidents reducing VGO supply and driving up VGO prices. Exhibit No. BPX-27 at p. 14. As these incidents only affected VGO supplies, he states, they would not have such an effect on Naphtha values. *Id.*

Coast products.[212] *Id.* at p. 15. According to Ross, this spread increases as the sophistication and complexity of the product increases, and, because gasoline is one of the most sophisticated and complex of the finished products, the relationship Tallett proposes is least applicable for gasoline-based products. *Id.* In further explanation, Ross states:

> [O]n the West Coast, finished product prices contain some marketing margin, while intermediate products have less tendency to inherit the marketing margin of the products of which they are precursors. . . . [T]he differential between the prices of West Coast and Gulf Coast products is greatest for the highest value finished products (which have highest purity and complexity) and least for the lowest value intermediate products. . . . Tallett's Naphtha valuation proposal with the governor is much more consistent with the underlying commodity price relationships for intermediate products than is his ungoverned value. Mr. Tallett and Mr. O'Brien in particular propose Naphtha values that reflect finished product margins. Naphtha is not a finished product - it is an intermediate product. Attributing a finished product margin to the intermediate product significantly overstates its value.

Id.; *See also* Exhibit No. BPX-44.

565. O'Brien's analysis, Ross contends, is also flawed because his Naphtha formula produces values exceeding the principle that West Coast Naphtha values should not exceed the cost of imports diverted from the Gulf Coast as well as attributing some gasoline-marketing margin to Naphtha.[213] Exhibit No. BPX-27 at p. 16.

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[212] *See also* Exhibit No. BPX-44.

[213] Ross explains that O'Brien's values attribute some gasoline marketing margins to Naphtha. Ex. BPX-27 at p. 16. He contends that finished product prices on the West Coast contain higher margins than on the Gulf Coast. *Id.* However, he notes, intermediate products have the same margins on the two Coasts. *Id.* at pp. 16-17. As a result of different conditions in the two markets, he states, West Coast finished products contain higher embedded margins. *Id.* at p. 17. The higher margins, he believes, are specifically related to the finished products and not shared by the lower valued, intermediate products. *Id.* Consequently, he asserts, in order to avoid inappropriately flowing through these margins to the lower valued, intermediate products, these margins should be stripped out of the finished product prices before the intermediate product prices are determined. *Id.* Therefore, O'Brien's analysis, Ross concludes, attributes the higher margins specifically related to finished products to intermediate products. *Id.*

566. As for the contracts produced in discovery, Ross insists they do not support either O'Brien's or Tallett's Naphtha valuations. *Id.* at p. 23. Instead, he believes, these contracts demonstrate that no representative market prices exist for Naphtha on the West Coast. *Id.* This is so, he adds, because there are few transactions, the market is imperfect as buyers and sellers lack market indicators to use in negotiations, and wide disparities exist between contract prices during any given month. *Id.*

567. Ross asserts that there is no observable West Coast Naphtha market price as the contract data prices in no way represent a market price of the type used by the Quality Bank in valuing other cuts. *Id.* at p. 28. According to Ross, at the times when participants are not purchasing Naphtha, their Naphtha value is lower than the price being paid by those that are purchasing Naphtha. *Id.*

568. Regarding Culberson's argument that Gulf Coast Naphtha values are indicative of West Coast Naphtha values, Ross contends that Culberson's arguments are wrong. *Id.* at p. 29. He argues that the sources of Naphtha referred to by Culberson do not exist in sufficient quantity to influence price relationships in the manner Culberson describes. *Id.* This is so, Ross believes, because there are only sporadic movements of Naphtha from Pacific countries to the Gulf Coast and virtually none to the West Coast. *Id.* Additionally, Ross insists, Culberson's transportation cost is less than one half the real cost of moving Naphtha because Culberson failed to adjust his Worldscale 100 freight costs by a market rate for clean products tankers.[214] *Id.* at p. 30.

569. Ross argues that the effective date for any change in value for Naphtha and VGO should be consistent. *Id.* at p. 32. Furthermore, he asserts, any Naphtha and VGO valuation change should be implemented prospectively only. *Id*. He insists that retroactive implementation would unfairly damage parties relying on prior valuations and would be inequitable. *Id.*

570. In his Reply Testimony, Ross answers criticisms raised by various witnesses. Exhibit No. BPX-67 at p. 4. He explains that he is no longer sponsoring a West Coast Naphtha methodology, leaving it to the Commission to choose between the proposed

[214] According to Ross, "clean tankers" are used for light products (gasoline, Naphtha, jet fuel, diesel fuel, low sulfur No. 2 fuel). Transcript at p. 9555. Ross explains that clean tankers are necessary to transport these products as refiners and petrochemical companies will not accept contaminants that may adversely affect the operations of their reformers or ethylene crackers. Exhibit No. BPX-27 at p. 30. Consequently, he notes, the market rate for clean tankers is higher than Worldscale 100 by a factor of two or more, reflecting the higher costs of small tankers used in this trade, and the special characteristics such as multiple stainless steel tanks of these vessels. *Id.* "Dirty tankers are used to transport crude oil and residual fuel oil." Transcript at p. 9555.

methodologies. *Id.* at p. 6. However, he maintains that, in order to ensure that the Quality Bank Naphtha value accurately reflects Naphtha's real value, the final methodology must include a governor correcting West Coast gasoline price anomalies. *Id.*

571. A benefit of his formula, Ross asserts, is that it produces values closely resembling the prices paid by large West Coast independent refiners for Naphtha purchased from asphalt refiners. *Id.* at p. 7. In contrast, he contends, O'Brien and Tallett's values "grossly exceed" actual West Coast contract prices. *Id.*

572. Ross modifies his methodology after reviewing the criticism of other witnesses and finding merit in three of them. *Id.* at p. 8. First, he states, he adjusted the Caribbean to Los Angeles Naphtha transportation cost by 20¢/gallon after understating the cost. *Id.* Second, he agrees that his formula should include a floor as well as a ceiling and, therefore, he sets the floor at the West Coast ANS crude price plus $4.00 per barrel.[215] *Id.* Finally, he corrects a transportation cost calculation error, identified by Sanderson, made by erroneously subjecting the tanker rate multiplier to the Panama Canal charge.[216] *Id.* at pp. 8, 10.

573. Ross adjusted the transportation costs, he explains, because of criticism from O'Brien. *Id.* at p. 8. O'Brien noted, Ross states, that West Coast transportation costs are higher than Ross originally suggested because of the lack of back haul options. *Id.* Adjusting for this fact and based on his own experience, Ross asserts that the appropriate premium for West Coast shipments would be 15 points of Worldscale or 20¢/barrel additional cost for transporting Naphtha from Venezuela to Los Angeles. *Id.* at p. 9.

574. As for the governor floor, Ross contends that many hydrocarbon contracts including price caps also include price floors. *Id.* He explains that the "floor is generally designed to protect the supplier's cost base." *Id.* Acknowledging that one of the contracts discovered in this case had a floor, Ross stated that, while he initially wanted to avoid the "complexity of including a floor," he now agrees with Toof's suggestion that "a formula that includes a ceiling should also include a floor." *Id.* Consequently, Ross suggests that his proposal include a floor of "the value of ANS crude oil on the West Coast plus $4.00 per barrel." *Id.* He adds that "the floor price provision, when applied for illustrative purposes to Mr. Tallett's base Naphtha value, would have been activated in

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[215] Ross states that his "proposal is to hold [the $4.00 floor price] constant indefinitely until such time as the parties decide that it needs to be reviewed." Transcript at p. 9550.

[216] The corrected amounts, as well as the previous corrections, he notes, are found in Exhibit Nos. BPX-70, 71, and 72. Exhibit No. BPX-67 at p. 10.

eleven out of thirty six months, and the cap would have applied in twenty out of thirty six months from 1999 through 2001." *Id.*

575. Ross argues that O'Brien, Toof and Tallett seriously overvalue West Coast Naphtha because they do not take into account gasoline price anomalies. *Id.* at p. 11. Without a governor or "other reality check," he maintains, the resulting methodologies are unsound as fluctuations do occur that are unrelated to Naphtha's value. *Id.* On the other hand, Ross states that he finds the proposal made by Petro Star witness James Dudley "to be interesting and within the bounds of producing reasonable West Coast Naphtha values." *Id.* at pp. 11-12.

576. According to Ross, O'Brien's, Toof's and Tallett's criticisms of his governor proposal fall within six categories, each of which he addresses in turn. *Id.* at p. 12. The first criticism he addresses is that none of the contracts produced in discovery include a cap provision similar to his proposal. *Id.* To this criticism he responds: "In fact, contracts between independent refiners from this first set of contracts and a second set of contracts that the [State of Alaska] produced after the last round of testimony support the results of [his] Naphtha valuation formula and reveal gross overvaluation of Naphtha by the Tallett and O'Brien formulæ." *Id.* Also, he contends, a contract provided by Alaska includes a price cap analogous to the price cap mechanism that he proposed. *Id.* at p. 15. He highlights the importance of this contract,[217] arguing that "[b]ecause the Contract involves a large volume, long term transaction between major, independent players in the relevant market, I believe that it is of particular importance in demonstrating the value of Naphtha on the West Coast." *Id.* He explains that this contract's base price is linked to gasoline minus a discount and has two separate price modifiers countering gasoline price

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[217] Ross explains that this particular contract is important for four reasons:

> First, the Contract is between two independent refiners, so it is not contaminated by issues relating to keeping running an integrated oil production and refining system. . . . Second, the Contract is a long term contract, and therefore reflects the need to establish a formula that remains fair over time to both buyer and seller. Third, the Contract is for substantial volumes of Naphtha which are consistent with the volumes that underlie the waterborne values for the other liquid cuts. Fourth, the Contract was negotiated after it had become clear that West Coast gasoline prices increasingly presented anomalies that needed to be taken into account through some form of "reality check."

Exhibit No. BPX-67 at pp. 17-18. He also points out that most of the previously produced contracts are for spot contracts limited to single delivery dates that, by their nature, would not include a price cap. *Id.* at p. 18.

anomalies. *Id.* at pp. 15-16. Further, he notes, the contract price provisions produce results similar to results he proposes for the Quality Bank. *Id.* at p. 16. He asserts that, absent a governor, a simple gasoline minus formula fails to accurately represent Naphtha's market value. *Id.* at p. 17.

577. Second, he states that Tallett and O'Brien's are just wrong in suggesting that, because the price of West Coast finished products is higher than imports, the price of West Coast unfinished products must also be higher. *Id.* at pp. 12-13. Ross argues that it is invalid because the comparison of imported finished product West Coast prices misstates the price of the imported finished products. *Id.* at p. 19. He explains that different primary destinations for intermediate and finished products create different governor levels which should be applied to analyses of finished products. *Id.* at p. 21. The Gulf Coast, he notes, is the primary market for intermediate products because it holds the largest concentration of refining capacity and draws imports of these products from the Caribbean. *Id.* at p. 20. On the other hand, he asserts, Caribbean finished products are mostly delivered to the East Coast by tanker and compete with finished products from the Gulf Coast delivered by pipeline. *Id.* Different primary destinations for finished and unfinished products, he contends, result in significant cost differences. *Id.* at pp. 22-23.

578. Imports, Ross insists, do cap jet fuel prices most of the time and it is only during particularly overheated market conditions when jet fuel prices exceed the import cap for more than a short period. *Id.* at p. 24. He explains that "the Los Angeles waterborne jet fuel price was beneath the finished products governor for 41 of the 72 months between 1996-2001 (57 percent of the time)."[218] *Id.* For 1996-1998 and 2001, he adds, "the Los Angeles waterborne jet fuel price was beneath the governor for 32 of the 48 months (67 percent of the time)." *Id.* In addition, Ross contends, West Coast gasoline prices exceed the marginal cost of imports, during the 1996-2001 period, in 48 out of 72 months (67% of the time).[219] *Id.* Restrictive West Coast specifications, he contends, result in higher gasoline prices for all gasoline grades. *Id*. He argues that since CARB gasoline is required in California, when supplies are low, its price rises and that, as this condition cannot be ameliorated by import of regular unleaded gasoline, the price will stay high until supplies increase. *Id.* at pp. 24-25.

579. Ross explains that he tested his governor against the prices of finished products and found that jet fuel prices, "except during overheated market conditions are beneath the correctly calculated cost of imports most of the time." *Id.* at p. 25. Ross asserts that,

[218] Exhibit No. BPX-79.

[219] Exhibit No. BPX-80.

because the average West Coast jet fuel prices are below import costs,[220] his governor proposal is proved valid. *Id.* However, he argues, his governor is not invalidated because, although West Coast gasoline prices are above the cost of imports most of the time, West Coast gasoline prices "exhibit changes quite unrelated to the cost of imports." *Id.* Ross claims that, despite the circumstance affecting West Coast gasoline prices, West Coast Naphtha prices are unaffected because there are no CARB or other restrictions limiting imports of Naphtha in the event circumstances drove the price of local Naphtha supplies above import parity. *Id.* at pp. 25-26.

580. The different price formation mechanisms for finished and intermediate products, he insists, are significant for the Quality Bank. *Id.* at p. 26. The West Coast market, he begins, relies on marginal imports of finished products, but, except for exceptional circumstances such as in 2000, the West Coast does not import intermediate products. *Id.* Consequently, he explains, West Coast intermediate product values are mostly below import parity while finished prices are close to import parity. *Id.* Even when unfinished products prices are at import parity, he contends, they are structurally lower than finished products because they are competing with Gulf Coast, rather than higher-valued East Coast, product prices. *Id.* Without some reality check such as the governor, he believes, West Coast Naphtha values would be grossly inflated "when compared to actual prices paid by independent refiners for contract supplies." *Id.* at pp. 26-27.

581. Third, Ross states that Toof errs in claiming that "gasoline imports . . . govern gasoline [prices] and thereby [West Coast] Naphtha values" since that argument is based on the erroneous premise that "Naphtha values move in lock step with gasoline prices." *Id.* at p. 13. He insists that gasoline imports have no impact on Naphtha's value. *Id.* at p. 27. Toof's calculation, Ross believes, is conceptually flawed because movement patterns and price formation mechanisms for finished products are different than those of intermediate products. *Id.* at pp. 27-28. Such a difference, he maintains, causes a finished product's governor to be higher than the Naphtha governor which he proposed. *Id.* at p. 27.

582. Ross recognizes that Tallett also opines that West Coast Naphtha values follow West Coast gasoline prices because there is a high correlation between gasoline precursors and finished gasoline prices on both coasts. *Id.* at pp. 28-29. There are three reasons, according to Ross, why Tallett's analysis fails:

> First, the regression equations are different for the West Coast than for the Gulf Coast at least for VGO and LSR and probably would be for Naphtha as well. Second, applying Gulf Coast equations to the West Coast gives results that are far higher than actual prices of West Coast LSR and VGO,

[220] Exhibit No. BPX-78.

> and would probably do the same for Naphtha. Finally, Mr. Tallett fails to address the evident differences in West Coast and Gulf Coast Naphtha markets.

Id. at p. 29.

583. Applying Gulf Coast equations to West Coast intermediate products, Ross believes, result in values between \$3 and \$10/barrel too high for LSR and from \$2 to \$5/barrel too high for VGO because there are two separate markets. *Id.* at p. 31. Naphtha values on the West Coast, he insists, have a different relationship to gasoline than on the Gulf Coast because the fundamental drivers of the two markets are very different. *Id.* The Gulf Coast, he notes, has a large petrochemical market which does not exist on the West Coast. *Id.* Ross argues that "[w]hen Naphtha is in surplus on the Gulf Coast, the surplus can be absorbed by the petrochemical market. These petrochemical markets, in effect, provide a price support to Naphtha on the Gulf Coast. . . . These drivers are not present on the West Coast, where suppliers and buyers have much less flexibility." *Id.*

584. The West Coast market, he concludes, is not as dynamic or fluid a market as the Gulf Coast.[221] *Id.* at pp. 31-32. When petrochemical demand for imported Naphtha is high, he continues, the differential between Naphtha and gasoline prices tends to be low; but, in the 2000-2001 winter, petrochemical companies captured essentially all Naphtha imports, as extraordinarily high natural gas prices drove up the cost of gas plant products and the Naphtha price differential was very low. *Id.* at p. 31.

585. Fourth, according to Ross, rather than supporting Tallett's claim that the lack of Naphtha imports into the West Coast establishes that West Coast Naphtha values must be higher than imports, it supports his assertion that "the current value of Naphtha on the West Coast most likely is lower than the cost of imports." *Id.* at p. 13. Ross declares that the absence of Naphtha imports when gasoline prices are high demonstrates that Naphtha values are below the cost of imports. *Id.* at p. 32. West Coast gasoline price anomalies, he adds, are likely to reoccur in the future. *Id.* at p. 33. These anomalies, he asserts, result from the fact that the West Coast refining industry cannot fully meet West Coast demand for clean products because product specifications are stringent, demand is growing, and new refinery process plants permitting is difficult. *Id.* Consequently, he insists, the West Coast will increasingly depend on finished product imports and prices

[221] For example, he points to Exhibit No. BPX-83 which, he claims, shows price differentials between Naphtha and regular unleaded gasoline and superimposes Naphtha imports to PADD III. Exhibit No. BPX-67 at p. 31. This Exhibit demonstrates, he states, that Naphtha imports go primarily to refiners in the summer for gasoline use and to petrochemical companies as feedstock in the winter. *Id.*

will be highly volatile as traditional price relationships move towards import parity. *Id.* This situation, he predicts, could last for several years. *Id.*

586. Fifth, Ross declares O'Brien, Toof and Tallett wrong in suggesting that "there might be a time lag between a price increase and the induced import of [a] scarce product." *Id.* at p. 13. Ross answers by stating that the contracts he has reviewed with some governor ceiling provisions are all instantaneous. *Id.* at p. 36. He asserts that accounting for this time lag "is unnecessary" because buyers agree to forego the option of pursuing imports in exchange for having the effect of imports immediately translated into the market. *Id.* More importantly, he contends, this risk of undervaluation must be balanced against the "potential for continuous overvaluation" resulting from a VGO formula similar to that proposed by Tallett for Naphtha. *Id.* at p. 37.

587. Lastly, responding to Toof, Ross declares that "the simplifying assumption of a fixed West Coast-Gulf Coast transportation differential . . . is appropriate in the context of the Quality Bank." *Id.* at p. 13. He argues that such a differential is appropriate because he used a sufficiently lengthy period of time to account for the transportation rate variation over time. *Id.* at p. 38. Concluding, he states that fixing the transportation differential produces a reasonable result and meets the goal of administrative feasibility. *Id.*

588. He disagrees with Sanderson's suggestion that Gulf Coast values are an acceptable substitute for West Coast values. *Id.* at p. 43. Sanderson, Ross reiterates, "presents neither data nor arguments" in support of his opinion that the governor approach does not work. *Id.* As for Dudley's West Coast valuation approach, if the Commission decides that a West Coast based Naphtha approach is necessary, Ross argues, Dudley's approach is reasonable to the extent that it relates West Coast Naphtha value to other intermediate products, but he notes that Dudley's proposal is flawed as the formula is not cost-based. *Id.* at p. 44.

589. Ross testified on Issue 4 on behalf of the Eight Parties concluding that it is appropriate to use the OPIS quotation for high sulfur VGO on the West Coast to value the VGO cut, and that this approach should be implemented on a prospective basis. Exhibit No. BPX-7 at pp. 1-2. Currently, he notes, the Quality Bank uses the Gulf Coast VGO price to value VGO on the West Coast. *Id.* at p. 3. As the intent of the Quality Bank is to measure the relative values of the streams in the markets in which they are used and there is a valid West Coast price available, he argues, that price should be used rather than a Gulf Coast price. *Id.*

590. In the past, he explains, the West Coast VGO market was very thin and subject to possible manipulation. *Id.* at p. 4. Currently, he continues, the market has changed sufficiently to eliminate the manipulation possibility. *Id.* Once the Commission issues an order addressing all the issues in this case, he asserts, then the valuation change for

West Coast VGO should take effect. *Id.*

591. In his answering testimony on Issue 4, Ross explains that all parties agree that it is appropriate to move the West Coast VGO valuation basis from a Gulf Coast basis to West Coast basis using the OPIS high sulfur VGO prices. Exhibit No. BPX-26 at p. 2. However, he notes, the parties still disagree as to the effective date of the change. *Id.* He disagrees with Toof's proposed effective date of June 19, 1994, because he believes the date is unsubstantiated. *Id.* Instead, he proposes that the change should be implemented prospectively. *Id.*

592. In his Reply Testimony on Issue 4, Ross reiterates his insistence that any VGO pricing change should be implemented prospectively only. Exhibit No. BPX-66 at p. 5. Certain changed circumstances, he explains, such as a redistribution of refining assets on the West Coast,[222] negate the original concern that West Coast VGO prices could be subject to manipulation. *Id.* at pp. 5-6. As a result of these changes, he believes, the three major North Slope producers and Tesoro all have direct access to West Coast VGO markets. *Id.* at p. 7. Consequently, he argues, the presence in the market of these parties resolves any concern about market manipulation. *Id.*

593. Ross clarifies his deposition statement that the OPIS West Coast VGO quotation would be appropriate for the period since 1994. *Id.* He explains that he believes that the OPIS West Coast quote has not been manipulated, not that the Quality Bank should use that quote in a retroactive calculation. *Id.* Using the OPIS West Coast VGO quote, he

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[222] Ross explains the changed economics of refining assets on the West Coast:

> In 1999, as part of its agreement with the [Federal Trade Commission] resulting from its merger with Mobil, Exxon sold its Benicia refinery and associated marketing assets in the San Francisco Bay area to Valero. Exxon retained the Mobil Los Angeles area refinery at Torrance, California and related marketing assets. In April 2000, BP Amoco completed its purchase of Arco, thereby acquiring refineries at Carson, California and Cherry Point, Washington, as well as numerous marketing outlets. In September 2001, Phillips acquired Tosco Corporation and as a result now owns refineries in Ferndale, Washington, and in the Los Angeles and San Francisco areas. . . . Since 1994, Tesoro also has developed a significant refining and marketing presence on the US West Coast. Tesoro acquired the Shell Anacortes, Washington refinery in August 1998 and is currently [May 2002] negotiating to complete the purchase of Valero's Golden Eagle refinery in San Francisco.

Exhibit No. BPX-66 at p. 6.

asserts, would be "tremendously unfair to those parties retroactively to change the rules of the game." *Id.*

594. At the hearing, on cross-examination, Ross admitted that he was not an economist, and that he did not have a degree in economics. Transcript at p. 8034. He did claim to have taken a number of economics courses over the course of his working career, but couldn't recall what they were and only that they took place prior to 1978. *Id.* at pp. 8034-35. He did claim to have read excerpts from economics texts submitted as evidence in this proceeding. *Id.* at p. 8035.

595. Ross made it clear that he was not proposing a methodology for calculating a West Coast Naphtha price, but was merely advocating that the Commission select either the O'Brien proposal or the Tallett proposal and modify it by his floor/ceiling proposal.[223] *Id.* at pp. 7898, 8117-18. He also made it clear that he was not advocating a continuation of the use of the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at p. 7898. Ross based his governor on the theory that, "if the price of naphtha [on the West Coast] got too high, that imports would flow capping the price." *Id.* at p. 7926. Although he was not supporting a pricing methodology, Ross admitted that his floor/governor proposal would control the West Coast price of Naphtha, during the 1994-2001 period, over 82% of the time if it modified Tallett's proposal and over 85% of the time if it modified the O'Brien proposal.[224] *Id.* at pp. 8105-06.

596. According to Ross, the ceiling he proposed was Platts Gulf Coast Naphtha price quote plus $1.488.[225] *Id.* at pp. 7918, 9559-60. The $1.488, according to Ross, represents the "transportation differential . . . [he] fixed" as an add-on to the Gulf Coast Naphtha reference price. *Id.* at p. 9551. It was derived, he said, "using Platts [sic] Gulf Coast transportation assessment," i.e., the rates of transportation from the Caribbean to the Gulf Coast. *Id.* at p. 9553.

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[223] Under cross-examination, Ross stated that his problem with O'Brien's proposal was that it took "the higher West Coast finished product gasoline margin and passe[d] it through to the lower valued intermediate product naphtha." Transcript at p. 9541. He also declared that O'Brien's methodology should not be adopted unless it was modified by his governor proposal. *Id.* at pp. 9542, 9545. When asked, Ross further declared that Tallett's proposal, too, while not as much as O'Brien's, overvalues West Coast Naphtha and, therefore, should not be adopted without his governor. *Id.* at p. 9545.

[224] Exhibit No. EMT-437.

[225] *See* Exhibit Nos. BPX-72, BPX-148. Ross would have rounded this to $1.49, if he were using only two decimal places. Transcript at p. 7919. He indicated that, while he had not planned that this figure change, he was amenable to its being updated periodically. *Id.* at p. 9550.

597. Ross also said that the floor he proposed was the monthly average of the high and low in Platts ANS Daily Price[226] plus $4.00. *Id.* at p. 7919. According to Ross, he derived the $4.00 from one of the contracts discovered by the parties during the course of this proceeding, the only contract discovered in this case which contained a floor and ceiling.[227] *Id.* at pp. 7919, 9807, 9814. He states that the $4.00 was intended "to signify a cost base for the supplier," i.e., the cost of producing the Naphtha. *Id.* at pp. 7919, 9828. Further, Ross states that he validated its reasonableness by comparing "the differential between naphtha and West Texas sour which is an analogous grade to ANS on the Gulf Coast," and by another more complicated calculation involving the differential between Naphtha and VGO on the Gulf Coast plus transportation to the West Coast and the differential VGO and ANS on the West Coast. *Id.* at p. 7920.[228] Ross admits, however, that he has no proof that the differential between Naphtha and VGO on the West Coast is the same as the differential between the two on the Gulf Coast. *Id.* at pp. 7924-25. The purpose of the floor is to correct for "sudden dips" in the Gulf Coast Naphtha price, Ross states. *Id.* at p. 9784 He adds "that the floor and the ceiling compliment [sic] each other to produce an equitable answer and deal at least in part with the issue of time lag and risk." *Id.*

598. Asked whether he set the ceiling too low, Ross stated that he set the ceiling at the level which he thought "is appropriate for diverting Caribbean cargoes from the Gulf Coast to the West Coast." *Id.* at p. 7930. He claims to be attempting to connect the price of Naphtha to the point where the supply and demand curves cross. *Id.*

599. According to Ross, there is "no profit built into" his governor. *Id.* at p. 8270. In other words, he assumes that the same profit margin will exist into whatever market the product is taken. *Id.* at p. 8271. Ross admits that this might be a disincentive to attracting the product into a specific market. *Id.* at p. 8270. He also admits that he is assuming the same level of risk in all markets. *Id.* at p. 8271. By this he means that "the risk in going to the East Coast in the case of finished products or the Gulf Coast for intermediate products is not distinctly different than the risk [of] going to the West Coast from Venezuela for either of those types of products." *Id.* at pp. 8271-72.

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[226] Exhibit No. BPX-136.

[227] Because of confidentiality problems, the parties and I have agreed not to identify the parties to this contract. Transcript at p. 7919. However, it should be noted that this contract was included in Tallett's analysis, but not Pulliam's, which resulted in Tallett's volumes being higher than Pulliam's. *Id.* at p. 9895.

[228] *See also* Transcript at pp. 9785-87.

600. Ross suggests that, within the 250,000 barrels of petroleum products imported into the West Coast each day, there is room for some Naphtha to be imported. *Id.* at p. 7995. Despite the fact that almost 200 million barrels of Naphtha are produced on the West Coast each year, he further suggests that two or three 250,000 barrel cargoes of Naphtha year can affect the West Coast Naphtha price. *Id.* at p. 7996. Asked on re-direct examination whether there was "a substantial capability to bring naphtha into the West Coast market," Ross replied that, to him, there was. *Id.* at p. 9617. By "substantial," he said he meant 17 cargoes[229] over a three year period, not in comparison to the total amount of Naphtha used on the West Coast, but only to the amount of Naphtha "traded" on the West Coast, about "5,000 barrels a day."[230] *Id.* at pp. 9617-18.

601. Despite generally approving Tallett's proposal, Ross suggested that a problem with it is that the Gulf Coast Naphtha price which Tallett uses as one of the bases of his formula may be influenced by petrochemical demand.[231] *Id.* at pp. 8118-19. Ross states that he believes that "the presence of petrochemical demand does trim the troughs in naphtha." *Id.* at p. 8120.

602. Under further cross-examination, Ross discussed the problem with fluids having a high Reid Vapor Pressure. *Id.* at p. 8159. He agreed that a high Reid Vapor Pressure caused environmental problems and that Reid Vapor Pressure is more severely restricted on the West Coast than the Gulf Coast.[232] *Id.* Ross also agreed that as a result, on the West Coast, the use of LSR and butane is more restricted in the summer than in the winter. *Id.* at p. 8160. Heavy Naphtha does not have this problem, he stated. *Id.*

603. Ross indicated that an "integrated refiner" uses the cuts resulting from the distillation of its own crude supply to make finished products. Transcript at p. 8475. He added that, if it made a purchase from an outside source, it would be made for a specific reason. *Id.* Such a refinery, he stated, would be designed to keep its finished product flowing to its dealers. *Id.* at p. 8476. Ross did agree that there was always some Naphtha

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[229] The 17 cargoes are "the sum of the fur cargoes of accepted contracts and the 13 cargoes of rejected contracts from the Tallett database." Transcript at p. 9621.

[230] In later re-direct examination, Ross indicated that the 5,000 figure was from Pulliam's analysis, but that Tallett was "more inclusive" and that 8,700 barrels/day were traded in the contracts Tallett accepted. Transcript at p. 9642.

[231] According to Ross, on the Gulf Cost, about 70% of the Naphtha is used to make gasoline and 30% is used by the petrochemical industry. Transcript at p. 9763; Exhibit No. BPX-168.

[232] Exhibit No. BPX-36.

available for sale on the West Coast because asphalt refiners manufacture it, but do not make gasoline. *Id.* at p. 9822.

604. Directed to Exhibit No. SOA-25, Ross was asked to compare O'Brien's proposed method for valuing West Coast Naphtha during the 1994 through 1998 period with and without Ross's governor. *Id.* at p. 9656. He stated that the former better predicted the contract prices as calculated by Pulliam.[233] *Id.* at pp. 9656-57. Ross also agreed that, during that same period, Exhibit No. SOA-25 reflected that the proposal closest to the Pulliam calculated contract prices was the Sanderson/Culberson proposal.[234] Transcript at p. 9657. Directed to page 2 of Exhibit SOA-28, Ross testified that it reflected that each of the competing proposals for valuing West Coast Naphtha was improved by use of his governor. Transcript at p. 9659. Asked why he thought that his governor proposal improved Tallett's and O'Brien's proposals, Ross stated that their formulæ "apply or impose relationships between naphtha values and other product values which are not applicable on the West Coast." *Id.*

605. Ross expressed some concern that the Pulliam contract values did not accurately reflect the price of West Coast Naphtha in a transparent market.[235] Transcript at p. 9660. He said, however, that he is more concerned about the 1999-2001 period than the 1994-98 period because of the gas price anomalies which took place in the former period.[236] *Id.* at pp. 9660, 9665. According to Ross, the gasoline-minus prices in the contracts were less appropriate in the former (1999-2001) period because of these anomalies. *Id.* at p. 9663. Because they were distorted by these gasoline price anomalies

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[233] *See also* Transcript at pp. 9742-44.

[234] Ross stated that, if he had to choose between O'Brien's, Tallett's and the Sanderson/Culberson proposal, each ungoverned, that he would recommend the latter because the other two give "distorted values for naphtha." Transcript at p. 9745. However, he conceded that was not exactly true when Tallett's proposal was viewed over the whole 1994-2001 period. *Id.* at pp. 9745-46. Moreover, Ross conceded that the Sanderson/Culberson proposal undervalued West Coast Naphtha. *Id.* at p. 9948.

[235] Under later re-direct examination Ross stated:

> [A]s you know, I have reservations about the value of the . . . contracts in the sense that they take place in an opaque market and the weighted average values, in my opinion, are not a good indication of what transparent market values would have been."

Transcript at p. 9773; s*ee also id.* at pp. 9802-03.

[236] *See* Exhibit Nos. BPX-129, BPX-159.

occurring in 1999-2001 period, Ross thought that the contract prices during the overall 1994-2001 period also were less reliable than those in the 1994-98 period. *Id.* at p. 9667.

606. When he was asked, inasmuch as there is very little Naphtha trading on the West Coast because refineries produce all they need and use all they produce,[237] where imports would find a market, reluctantly, Ross replied as follows:

> My premise – my supposition is that if there were a published price and if that published price started off at close to where the contract values are, there would be a rush of stuff coming in. People would say heck, this is a real profit opportunity. We can expand our market and possibly expand the amount of naphtha and reformate that is in gasoline.

Id. at p. 9750. He conceded, however, that a refinery's least expensive source for Naphtha would be its own refinery. *Id.* at p. 9751. Ross also agreed that his theory was based upon the likelihood that prices would rise in a transparent market during a time when a major refiner was having a problem in completing the production process of turning crude oil into gasoline. *Id.* at p. 9753.

607. According to Ross, Dudley's proposal has merit. *Id*. at p. 9774. He described Dudley's proposal as follows: "[The Dudley] proposal . . . takes as its reference VGO and LSR prices on the Gulf . . .and the West Coast and . . . applies the differential between those through a formula and then adjusts the naphtha price in the Gulf Coast to get a West Coast price." *Id.* Ross states that he likes the proposal because "it references intermediate products." *Id*. at p. 9775. He disagrees with the 80% VGO/20% LSR ratio Dudley uses because it "doesn't make sense to" him, but says that the proposal has "conceptual merit" because of its use of intermediate products. *Id.* Ross opposes the use of the prices of finished products because "logistics of finished products are different from the logistics of unfinished products." *Id.* at p. 9788. Because of its volatility, Ross is especially criticizes the use of gasoline prices and states that jet fuel and diesel fuel prices are much more stable. *Id.* at pp. 9788-89. He does declare that Dudley's proposal would be more acceptable to him if it was modified by his governor proposal. *Id.* at p. 9816.

G. WILLIAM J. SANDERSON

608. Williams presented Sanderson, president of Purvin & Gertz, Inc., an independent consulting firm specializing in oil and gas processing, transportation and marketing

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[237] Ross agreed that no more than 1-1½% of the Naphtha used on the West Coast is traded and that therefore refineries produce 98½-99% of the Naphtha they need. Transcript at pp. 9751-52.

matters, to testify on Issue 3. Exhibit No. WAP-1 at p. 1. Sanderson concludes that "the Platts Oilgram Price Report ("Platt's") U.S. Gulf Coast spot quotation for waterborne naphtha should continue to be used to value naphtha on both the U.S. Gulf Coast and U.S. West Coast for Quality Bank purposes." *Id.* at p. 3. He explains that it has been used by the Quality Bank since 1993, and that the Platts price is consistent with the Quality Bank Naphtha cut.[238] *Id.* at pp. 3-4.

609. According to Sanderson, the Platts waterborne Naphtha price quotation is a reliable indicator of reforming-grade Naphtha prices on the Gulf Coast because "industry participants rely on the ('Platt's') waterborne naphtha price quotation when an independent assessment of reforming-grade naphtha prices is needed as in the case of the TAPS Quality Bank." *Id.* at p. 4. As for the West Coast, Sanderson argues that he has not been able to "identify any publicly available naphtha price quote for reforming-grade naphtha on the West Coast." *Id.* Additionally, Sanderson states that the lack of a West Coast price quote for reforming grade Naphtha implies that the volume of Naphtha trade is insufficient to capture a reliable West Coat Naphtha price. *Id.*

610. Sanderson argues that using the Platts Gulf Coast waterborne Naphtha price as a proxy for a West Coast Naphtha value for Quality Bank purposes is a sensible solution because it "values naphtha as an intermediate feedstock." *Id.* at p. 5. He claims further that the same crude supplies are available to refiners on both the Gulf Coast and the West Coast and notes that, due to declines in crude production in California and on the Alaska North Shore, West Coast refiners increasingly have purchased volumes of foreign crude. *Id.* Sanderson explains that crude oil imports have increased from an average of 300,000 barrels/day in the mid 1990s to over 700,000 barrels/day currently on the West Coast. *Id.* at p. 6. According to Sanderson, Saudi Arabia, Iraq, Ecuador, and Mexico account for 75% of the increased crude oil imports to the West Coast over the 1994 to 2001 period. *Id.* Additionally, these nations, Sanderson relates, ship significant amounts of crude oil to the Gulf Coast, which is a much larger importer than the West Coast. *Id.*

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[238] Sanderson remarks further,

> [f]or purposes of the Quality Bank, the naphtha cut is defined as naphtha in the 175 to 350^{o} F boiling range. Naphtha in this boiling range is used by refiners as a reformer feedstock. For this reason, naphtha in this boiling range is often referred to as reforming-grade naphtha. Platt's indicates that its spot waterborne price assessments are for reforming-grade naphtha, making the naphtha price quoted by Platt's consistent with the Quality Bank naphtha cut.

Exhibit No. WAP-1 at p. 4.

611. Gulf and West Coast foreign crude oil supplies are linked because "the cost of shipping the same grades of crude oil to the Gulf Coast and West Coast is approximately equal for many of the large crude oil supply sources serving both markets." *Id.* at pp. 6-7. As a result, suppliers are "indifferent as to which market is supplied." *Id.* at p. 7. Since the two crude oil markets are linked, Sanderson posits that "[t]he price competition between the large volumes of crude oil imports analyzed and local supplies of similar quality crude oils means that crude oil prices on the West Coast and Gulf Coast would be expected to be about the same in recent years." *Id.* at p. 9. Sanderson maintains that, currently, crude oil prices have equalized on the West and Gulf Coasts. *Id.* He states that:

> [He] compared the delivered prices of two transparently priced crude oil streams commonly sold in each U.S. market of generally similar quality. ANS crude oil prices delivered to Los Angeles were compared to the price of Isthmus crude oil from Mexico delivered to the Gulf Coast in Houston. Exhibit WAP-7 shows that the average delivered price of ANS to the West Coast was only $0.10 per barrel or 0.2 cents per gallon higher than the delivered price of Isthmus delivered to the Gulf Coast since 1997 when crude oil prices in the two U.S. markets equalized due to the influence of large volumes of imported crude oils to both markets from similar supply locations.[239]

Id. (footnote added).

612. Sanderson states that reforming-grade Naphtha and crude oil prices are related because "[r]efiners on the Gulf Coast and West Coast have the choice of either purchasing intermediate feedstocks like reforming-grade naphtha or producing additional naphtha by processing crude oil streams with a higher content of reforming-grade naphtha." *Id.* at p. 10. He explains that West Coast refiners mostly change their crude oil slates to produce reforming-grade Naphtha.[240] *Id.* Arguing that it is "[t]he ability and

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[239] For the time period from 1994 through 2001, Sanderson states that "[t]he average delivered price of ANS to the West Coast was $0.15 per barrel or 0.3 cents per gallon below the price of Isthmus delivered to the Gulf Coast due to the lower ANS prices on the West Coast prior to 1997 when crude oil prices equalized." Exhibit No. WAP-1 at p. 9. Additionally, Sanderson explains that the crude oil markets changed after 1995 because during 1994 and 1995 "large volumes of crude oil imports to the West Coast from the Middle East and Latin America were not yet required because crude oil supplies were in surplus and crude oil prices were lower on the West Coast than the Gulf Coast." *Id*

[240] Sanderson explains the basis for this conclusion, stating that West Coast refiners mostly use the crude oil slate to produce reforming-grade Naphtha because there

practice of West Coast refiners to substitute crude oils with greater quantities of reforming-grade naphtha for naphtha purchases is the mechanism that maintains the equilibrium between crude oil prices and naphtha prices on both coasts," Sanderson concludes his testimony, stating that

> [s]ince crude oil prices on the two coasts are directly linked and reforming-grade naphtha prices are linked to crude oil in each market through the refiner's ability to substitute crude oils of different naphtha content for naphtha purchases, then naphtha prices also would be linked through the crude oil substitution mechanism.

Id.

613. In his Answering Testimony, Sanderson describes the flaws within Exxon's Naphtha valuation proposal.[241] Exhibit No. WAP-8 at p. 4. He states that "[a] fundamental flaw in this proposal is that the application of the Gulf Coast regression formula to West Coast finished product prices assumes the processing margins between feedstocks and finished products on the West Coast are identical to those on the Gulf Coast." *Id.* at p. 5. According to Sanderson, West Coast refining margins are higher than those on the Gulf Coast. *Id.* In support, Sanderson relies on published refining margins found in the Oil & Gas Journal[242] which he claims indicate that "refinery cash operating margins have been consistently higher on the West Coast than the Gulf Coast, averaging

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are not enough West Coast Naphtha transactions to allow Platts or the Oil Price Information Service to quote West Coast naphtha prices. Exhibit No. WAP-1 at p. 10.

[241] Sanderson characterizes Exxon's proposal as:

> a regression formula developed between two highly priced Gulf Coast finished products, conventional unleaded regular gasoline and jet fuel, and the reforming-grade naphtha feedstock price on the Gulf Coast would be applied to the finished gasoline and jet fuel prices on the West Coast to improperly value West Coast naphtha.

Exhibit No. WAP-8 at pp. 4-5.

[242] Sanderson explains that the data source is "Muse, Stancil & Company ("Muse Stancil"), an international energy consulting firm, [which] publishes refining margins for refining locations around the world in the Oil & Gas Journal, a well-known petroleum industry publication." Exhibit No. WAP-8 at p. 5. He adds that, in that publication, "[m]onthly refining cash operating margins for the U.S. Gulf Coast and U.S. West Coast are available from January 1995 through the present time." *Id.*

$2.87 per barrel or 6.8 cents per gallon higher over the seven-year period the refinery margin data was available." *Id.*

614. Additionally, to bolster his argument that refining margins are higher on the West Coast than the Gulf Coast, Sanderson compares crack spreads[243] "between similar refined product and feedstock prices indicat[ing] . . . price differentials available for refining operations or margins before costs on the two coasts." *Id.* at p. 6. He concludes that

> [t]he 3-2-1 crack spreads are higher on the West Coast than the Gulf Coast on average each year from 1994 through 2001. The difference in the 3-2-1 crack spread between the two coasts (West Coast minus Gulf Coast) varies from a low of 3.6 cents per gallon or $1.51 per barrel in 1998 to a high of 12.0 cents per gallon or $5.05 per barrel in 2000.

Id. at p. 7. The average 3-2-1 crack spread from 1994 to 2001, Sanderson states, is $2.81/barrel higher on the West Coast than the Gulf Coast because of higher West Coast finished product prices. *Id.* The crack spread data, in Sanderson's view, supports the refinery cash margin data from the Oil & Gas Journal indicating that West Coast refinery profitability is greater on the West Coast.[244] *Id.*

615. Sanderson compares the price differential for Los Angeles waterborne

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[243] A "crack spread," according to Sanderson, "is the difference between a refined product price or group of refined product prices sometimes referred to as a 'basket' of prices and a feedstock price." Exhibit No. WAP-8 at p. 6. The appropriate crack spread, in Sanderson's opinion, to use in comparing relative refinery margins before costs on the two coasts is 3-2-1 "because it is sometimes used to approximate the margin before costs for a complex refinery like the hypothetical Quality Bank refinery." *Id.* He explains that an appropriate 3-2-1 crack spread is:

> the difference between three-parts crude oil and the weighted average basket of finished product prices comprised of two-parts conventional unleaded regular gasoline and one-part low sulfur No. 2 fuel divided by three. Stated another way, the weighted average product price basket of two-thirds conventional unleaded gasoline and one-third low sulfur No. 2 fuel oil minus an appropriate crude oil price.

Id.

[244] Sanderson indicates that both Tallett and O'Brien agree with Sanderson's conclusion that refining margins are higher on the West Coast. Exhibit No. WAP-8 at pp. 7-8.

conventional unleaded gasoline minus ANS crude oil with the price differential between Gulf Coast waterborne conventional unleaded gasoline minus the delivered price of Isthmus crude oil on the Gulf Coast and concludes that "[t]he annual average price differentials between conventional unleaded gasoline and crude oil are higher on the West Coast than the Gulf Coast." *Id.* at p. 8.

616. In criticizing Tallett's analysis, Sanderson prefaces his approach by stating that Tallett's analysis is dependent on there being no major changes in the West Coast gasoline market during the period over which Tallett developed his regression analysis. *Id.* at p. 9. However, Sanderson states, there were major changes in the West Coast gasoline markets in 1996, bringing California gasoline specifications in conformance with CARB Phase II reformulated gasoline regulations.[245] *Id.* He adds that the CARB Phase II gasoline regulations do not apply to the Gulf Coast. *Id.* As a consequence of California's actions, Sanderson explains,

> conventional regular unleaded gasoline prices have increased on the West Coast relative to the Gulf Coast. . . . The West Coast waterborne conventional gasoline price averaged 3.4 cents per gallon above the Gulf Coast price from 1992 through 1995. In 1996, the conventional gasoline price differential increased with the West Coast averaging 8.5 cents per gallon over the Gulf Coast from 1996 through 2001.

Id. at pp. 9-10.

617. Also, Sanderson suggests that there is a way to compare relative price differences between other intermediate feedstock prices – of VGO[246] and natural gasoline -- similar to reforming-grade Naphtha on both coasts. *Id.* at p. 10. He explains that the natural gasoline price is relevant to the Naphtha cut because it is used "on the West Coast and Gulf Coast. . . as the basis for valuing the [LSR] cut, the next lower boiling cut to the Quality Bank naphtha cut. The LSR cut is used as an intermediate feedstock for gasoline manufacture on both the West Coast and Gulf Coast." *Id.* Consequently, Sanderson maintains, the West Coast and Gulf price differentials for VGO and LSR can be used to

[245] Sanderson explains that "[i]n March 1996, the California gasoline specifications were changed to comply with the CARB Phase II reformulated gasoline regulations. The CARB Phase II gasoline specifications are very stringent making it the most difficult and expensive gasoline to produce in the country." Exhibit No. WAP-8 at p. 8.

[246] According to Sanderson, "[i]n the case of VGO, all parties in the Quality Bank either have proposed or support the use of the OPIS West Coast spot price for high sulfur VGO for the VGO cut." Exhibit No. WAP-8 at p. 10.

test Tallett's proposed West Coast Naphtha price. *Id.* This is true, according to Sanderson, because the higher refining margins on the West Coast and the price differentials between reforming-grade Naphtha and other intermediate feedstocks on the two coasts (with the same ultimate use) would be more closely related than would the prices of finished products. *Id.*

618. The price differential, according to Sanderson, between high sulfur VGO prices on the two coasts between 1992 and 2001 was 24¢/barrel (6¢/gallon) higher on the West Coast than the Gulf Coast. *Id*. at pp. 10-11. As for LSR prices, Sanderson states that in the same ten year period, the West Coast LSR price averaged $2.27/barrel (5.4¢/gallon) below the Gulf Coast price. *Id.* at p. 11.

619. Sanderson maintains that he expected that the West Coast Naphtha price differential to fall above that for Gulf Coast LSR and below that for Gulf Coast VGO because only LSR with a lower Reid Vapor Pressure can be blended into CARB gasoline in California, while the Gulf Coast is less restrictive. *Id.* Additionally, Sanderson explains why he expects the Naphtha price differential to fall below the VGO differential:

> CARB Phase II gasoline can use less traditional reformate produced from naphtha because of the restrictions on the benzene and aromatics content of CARB gasoline. Reforming increases the octane of naphtha primarily by increasing the aromatics content. Since Gulf Coast gasoline specifications are less stringent, reformate produced from naphtha encounters fewer blending restrictions. In addition, in order to meet the strict CARB Phase II gasoline specifications, alkylate is a very important blending component on the West Coast because it enhances gasoline octane while being very low in the undesirable gasoline properties such as benzene, aromatics, olefins, and sulfur. The feedstock for the alkylation unit comes from VGO processed in the catalytic cracker. VGO not only provides an intermediate feedstock for the catalytic cracker that produces a gasoline component directly, but it also provides the feedstock for the alkylate needed to make CARB Phase II gasoline. Alkylate has a less crucial role in producing the less restrictive gasoline manufactured on the Gulf Coast. Thus, naphtha is a less desirable feedstock than VGO on the West Coast for making the more stringent CARB gasoline. Therefore, the value of naphtha on the West Coast should be lower relative to the Gulf Coast than VGO.

Id. at pp. 11-12.

620. Comparing the predicted West Coast VGO price resulting from applying Tallett's Gulf Coast regression formula with the actual West Coast VGO price, Sanderson claims, results in the Gulf Coast VGO regression formula overvaluing the West Coast VGO price by an average of $1.83/barrel (4.4¢/gallon) over the 1994 through 2001 period. *Id.* at p.

12. The conclusion Sanderson draws from this data is that "the West Coast naphtha value calculated by applying a regression formula developed from Gulf Coast product prices . . . is fatally flawed." *Id.*

621. Sanderson states that since gasoline and jet fuel prices are higher on the West Coast than the Gulf Coast,[247] and since Tallett did not make any adjustments to the coefficients in his Gulf Coast Naphtha regression when applying it to West Coast prices, the result is that Tallett's proposed West Coast Naphtha valuation "is fatally flawed because it inappropriately attributes all of the higher West Coast finished product price to the value of naphtha rather than to the refiner who produces the gasoline and jet fuel." *Id.* at pp. 12-13. Furthermore, Sanderson argues that it is unreasonable to expect that West Coast Naphtha prices could be as high as Tallett's formula suggests because his formula

> consistently exceeds the cost at which West Coast refiners could import naphtha from Venezuela by an average of 3.8 cents per gallon over the 1994 through 2001 period . . . In fact, the West Coast naphtha price exceeded the import cost by 6 to 8 cents per gallon in the 1999 through 2001 period. If the West Coast naphtha price really exceeded the cost of importing naphtha by this magnitude, it is logical to expect that considerable volumes of naphtha would be imported by West Coast refiners.

Id. at p. 13.

622. According to Sanderson, if West Coast Naphtha prices were high enough, California refiners had adequate reforming capacity to process additional supplies.[248] *Id.*

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[247] Sanderson explains that,

> West Coast waterborne unleaded regular gasoline averages 6.5 cents per gallon higher than the comparable Gulf Coast price over the 1992 through 2001 period . . . .The West Coast waterborne jet fuel price averages 5.1 cents per gallon higher than the waterborne Gulf Coast jet fuel price over the same period.

Exhibit No. WAP-8 at p. 12.

[248] Sanderson claims that there is adequate reforming capacity on the West Coast to process additional Naphtha imports. Exhibit No. WAP-8 at p. 13. He relies on the following for this conclusion:

> [t]here are no continuous statistics available regarding reformer capacity utilization. However, the American Petroleum Institute ("API") and the

at p. 14. These Naphtha price comparisons, Sanderson states, demonstrate that Tallett's West Coast Naphtha valuation proposals would result in unjust and unreasonable high values. *Id.* at p. 14.

623. Sanderson states that the proposals valuing West Coast Naphtha using a West Coast gasoline price and subtracting reforming costs suffer from three general flaws: (1) starting with a gasoline price and then subtracting reforming costs "attributes all of the profitability a refiner achieves through the production of gasoline to naphtha, which is only one of a number of gasoline feedstocks;"[249] (2) It would make Naphtha the only cut which is valued using a "finished product price not made almost entirely from the cut a being valued by the finished or intermediate feedstock product price;"[250] and (3) "the use of a subjective formula for the valuation of naphtha is inappropriate when [a] method for valuing naphtha on the West Coast using a reliable and objective methodology currently exists." *Id.* at pp. 15-16.

624. Additionally, Sanderson lists a number of specific criticisms of O'Brien's proposed valuation: (1) the Naphtha values created by his formula "exceed the West Coast gasoline price used in his naphtha formula for nine months in 2000 and 2001;" (2) the Naphtha values created by his "exceeds the price at which West Coast refiners could economically import naphtha supplies from Venezuela, a large-volume supplier of reforming-grade naphtha to the Gulf Coast market by an average of 5.8 cents per gallon despite the availability of excess reforming capacity in California;" (3) "O'Brien's West Coast naphtha valuation is based upon [an] unrealistic three-component blend of

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> National Petroleum Refiners Association ("NPRA") published a report in 1997 that reported the average capacity utilization for major process facilities in the United States by region. As Mr. Tallett disclosed in his answer to BPX Data Request No. 19(e)-(f) and affirmed at his deposition, the API/NPRA report indicated the average capacity utilization for the California refineries surveyed was 66.3 percent of capacity while the capacity utilization for West Coast (PADD V) refineries outside California was 92.3 percent of capacity.

Id. at pp. 13-14.

[249] *See also* Exhibit Nos. WAP-33 at p. 9, WAP-39.

[250] Sanderson also claims that it would be "inconsistent with the proposed resid valuation formulae which price the coker products using Quality Bank intermediate feedstock prices or a regression derived from Quality Bank intermediate feedstock prices for the liquid petroleum products rather than only a finished product." Exhibit No. WAP-8 at p. 15.

reformate, LSR and normal butane to produce a blend of Seattle conventional unleaded regular gasoline;”[251] (4) “O’Brien’s three-component blend of gasoline would not meet the Federal Environmental Protection Agency (‘EPA’) ‘Anti-dumping’ rules for conventional gasoline except possibly from a refinery that produced gasoline from a three-component blend of reformate, LSR, and normal butane;” and (5) since O’Brien valued hydrogen by referring to its purchase from “from an external refinery hydrogen source supported by the full cost of hydrogen manufacture from a hydrogen plant,” its high value “is inconsistent with the simple refinery configuration . . . producing conventional gasoline from a three-component blend of reformate, LSR and normal butane”, referred to by O’Brien in a previous deposition and plays a part in overvaluation of West Coast naphtha in O’Brien’s proposal. *Id.* at pp. 16-22.

625. Concluding, Sanderson states, regarding Ross’s price governor, that it “limit[s] the impact of the severe gasoline price run-ups from being fully and improperly reflected in the value of West Coast naphtha.” *Id.* He argues further that the use of the high West Coast gasoline margin to value West Coast Naphtha results in its “over-valuation” and “favors those streams that contain a naphtha content higher than the TAPS common stream and unduly penalizes those streams containing less naphtha than that contained in the TAPS common stream.” *Id*. For that reason, he asserts, that West Coast Naphtha should continue to be valued on the basis of its published Gulf Coast value. *Id.* at p. 24.

626. In his rebuttal testimony, Sanderson questions the validity of the Naphtha contracts used by several parties in determining Naphtha value. Exhibit No. WAP-33 at p. 5. He explains that he examined the contracts produced by various parties, reviewed the testimony of witnesses Toof, Tallett, Ross, and O’Brien, and examined Ross’s and O’Brien’s work papers, in addition to reviewing Naphtha contracts produced by Alaska. *Id.* at pp. 5-6. According to Sanderson, since the scale of the Naphtha trade on the West Coast is insufficient to support a reliable assessment of West Coast Naphtha prices by an independent pricing service, he was interested in determining “the volumes associated with the naphtha contract transactions and the number of buyers and sellers represented in these transactions.” *Id.* at p. 6.

627. West Coast Naphtha volume within the contracts, Sanderson claims, indicates if there is sufficient robustness in the markets to provide meaningful levels of market price

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[251] Sanderson notes that O’Brien’s three-component blend is not the same as the gasoline produced by the coking refinery configuration agreed upon by all parties as the basis for valuing the Resid cut as it does not include gasoline components produced from the VGO cut and the Resid cut and argues that “[v]aluing naphtha using the three-component blend would be unjust and unreasonable as it would value the naphtha cut using a significantly different refinery configuration than the resid cut.” Exhibit No. WAP-8 at p. 17.

discovery. *Id.* He concludes that the Naphtha contracts do not provide a valid basis for valuing West Coast Naphtha for Quality Bank purposes for the following reasons: (1) "the West Coast naphtha market is not sufficiently robust to allow reliable price determination for purposes of valuing the naphtha cut on the West Coast through the traditional methods of surveying market participants employed by independent price reporting services;" (2) the large majority of the contracts were from the 1999-2001 period when gasoline and crude oil prices were volatile making "it difficult for buyers and sellers of naphtha to properly value West Coast naphtha;" (3) some of the contracts were for truck lots which "are considerably smaller than the waterborne cargo lots on which the Gulf Coast waterborne transaction," which is the current basis for valuation, "is based." *Id.* at pp. 6-7.

628. Sanderson also maintains that the market conditions[252] on the West Coast make the Naphtha contracts unreliable and that the Naphtha contracts produced in this case, he estimates, represent "about 1.7 percent of the Naphtha processed by West Coast refiners on average" from 1994 to 2001. *Id.* at pp. 7-8. He continues, arguing that the extreme volatility of gasoline and crude oil prices on the West Coast make determining West Coast Naphtha value very difficult. *Id.* at p. 9.

629. As for O'Brien's comments on Sanderson's proposal, Sanderson explains that he has

> not stated that refiners vary their crude slates to produce more or less LSR. I have simply used LSR as an example of an intermediate feedstock similar to naphtha in use. In fact, natural gasoline, the similar feedstock used by the Quality Bank to value LSR, is not even produced from crude oil. Natural gasoline is produced from gas processing, an activity unrelated to refining crude oils.

Id. at p. 11. Sanderson adds that the differential between reform-grade Naphtha prices on the West Coast and the Gulf Coast falls between the differentials for LSR and VGO on the two coasts. *Id.* He explains that the West Coast LSR price is below the Gulf Coast

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[252] Unreliable market conditions, Sanderson states, result in

> limited demand for West Coast naphtha [and] limited volumes and sporadic transactions between feedstock suppliers and West Coast refiners. The absence of sufficient naphtha volumes and routine transactions prevents independent pricing services like Platt's, OPIS and others from performing reliable price discovery for West Coast naphtha.

Exhibit No. WAP-33 at p. 7.

price for two reasons: First, LSR has a high Reid Vapor Pressure which make it difficult to blend into the low Reid Vapor Pressure gasoline, such as CARB II, required during the summer months in Arizona and all year in California; and, secondly, "the petrochemical demand for LSR and natural gasoline in the Gulf Coast elevates the Gulf Coast price relative to the West Coast where no significant petrochemical demand exists and eliminates the seasonal oversupply problems encountered on the West Coast." *Id.*

630. Comparing the price relationship changes between reforming grade Naphtha and VGO on the two coasts, Sanderson concludes that "[t]he relationships between the crude oil prices, VGO prices and gasoline prices . . . are fairly stable with the VGO price increasing somewhat relative to crude oil prices in 2000 in response to the very tight U.S. gasoline markets supplied by Gulf Coast refiners." *Id.* at p. 12. He explains that the VGO price differential increased in 2000 because

> [b]y 1999, the West Coast gasoline market had tightened as a result of the very restrictive and unique nature of the gasoline specifications in California (CARB Phase II gasoline) and in Arizona, the inability of gasoline production capacity to keep pace with demand growth and a number of significant gasoline supply interruptions on the West Coast that year due to refinery operating problems."

Id. at p. 12. As a consequence, he declares, West Coast gasoline prices rose dramatically relative to those on the Gulf Coast. *Id.* He adds that finished gasoline and gasoline products were less available in 2000 than in 1999 due to refinery outages and the lower availability of imports of finished gasoline and gasoline components because of the changeover to Federal Phase II reformulated gasoline.[253] *Id.* at p. 13.

631. As a result of the lack of Naphtha imports during 1999 and 2000, Sanderson concludes that "even during periods of extreme gasoline supply shortfalls, the processing of naphtha through reformers was not the vital feedstock needed to produce the incremental gasoline so badly needed on the West Coast during that time." *Id.* at p. 14. Consequently, according to Sanderson, "naphtha values on the West Coast could not have been as high as Mr. Tallett's proposal imputes or refiners would have readily imported naphtha from the Caribbean to produce the gasoline that was in such short supply." *Id.*

632. "[N]o significant West Coast imports of naphtha resulted" in this period, Sanderson states, even though "naphtha supplies can be acquired in the Caribbean and transported to the West Coast for an average of 3.1 cents per gallon over the Gulf Coast price" even though "numerous West Coast naphtha value spikes of 25 cents per gallon or more over the Gulf Coast naphtha price" occurred. *Id.* Consequently, according to

[253] *See* Exhibit No. WAP-44.

Sanderson, Tallett's West Coast Naphtha value is "simply inconsistent with the facts and O'Brien's west Coast naptha value is "unrealistic." *Id.*

633. Sanderson explains that "[t]he 3.1 cent per gallon figure is the average additional cost of shipping naphtha supplies from Venezuela to Los Angeles instead of from Venezuela to the Gulf Coast or naphtha shipping differential over the 1994 through 2001 period." *Id.* at p. 15. According to Sanderson, he determined the 3.1¢/gallon shipping differential by "subtracting the average cost of shipping naphtha from Venezuela to Los Angeles (5.8 cents per gallon) from the average cost of shipping naphtha to the Gulf Coast (2.7 cents per gallon)." *Id.* In Sanderson's view, "[t]he shipping differential is the additional cost a West Coast refiner would have to pay to attract naphtha supplies going to the Gulf Coast from Venezuela to the West Coast." *Id.* Additional costs relating to shipping Naphtha to Los Angeles without back hauls are taken into account, Sanderson states, in determining his 3.1¢/gallon figure:

> In addition to using the Worldscale rates which do not assume a back haul in the voyage from Venezuela to Los Angeles, a review of actual clean tanker fixtures (percent of Worldscale) from the Caribbean to the West Coast was conducted. The average shipping differential of 3.1 cents per gallon reflects actual vessel fixtures for 30,000 dead weight ton clean tankers used to ship clean products and intermediates like naphtha from Caribbean locations such as Venezuela, to the West Coast.

Id.

634. Using actual vessel fixtures for the Caribbean to West Coast voyages, Sanderson relates, "increased the calculated cost of transporting naphtha from Venezuela to Los Angeles slightly from an average 5.4 cents per gallon to 5.8 cents per gallon or 0.4 cents per gallon over the 1994 to 2001 period." *Id.* at pp. 15-16.

635. Addressing Tallett and O'Brien's claim that barriers to entry prevent Naphtha supplies from being brought into the West Coast, Sanderson indicates that there are two barriers to importation of Naphtha into the West Coast: (1) West Coast refiners can't "blend reformate into gasoline due to restrictions in benzene and aromatics content of the stringent CARB Phase II gasoline;"[254] and (2) the lack of sufficient "marine vessels and tankage on the West Coast."[255] *Id.* at p. 16.

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[254] According to Sanderson, O'Brien agrees with him that the ability of West Coast refiners to blend reformate into gasoline is restricted. Exhibit Nos. WAP-33 at pp. 16-17, WAP-47.

[255] *See also* Transcript at pp. 9188-97; Exhibit No. EMT-385.

636. Asked about the comparative contribution of VGO and Naphtha to the production of gasoline, Sanderson states that "[t]here are no statistics available to compare the contributions of the VGO and naphtha cuts, but the relative volumes of gasoline components from each cut can be estimated from available statistics."[256] *Id.* at p. 17. After explaining how he made the calculation, Sanderson estimated that "about 500,000 barrels per day . . . of gasoline components [were] produced from VGO." *Id.* He further estimated that 400,000 barrels/day of gasoline components were produced by reforming Naphtha. *Id.* at p. 18.

637. Sanderson draws several conclusions from comparing the VGO and Naphtha cuts relative to the production of gasoline on the West Coast:

> First, the VGO cut contributed on average at least approximately 100,000 BPD or 25 percent more gasoline components on average to the production of West Coast gasoline than did the naphtha cut for the 1994 through 2001 period.
>
> Second, the capacity of catalytic crackers increased over this period while the capacity of catalytic reformers declined.
>
> Third, the Solomon and Associates surveys indicate that reformer capacity was under-utilized ranging from only 72 to 79 percent of capacity.
>
> Fourth, the analysis indicates that the West Coast less Gulf Coast price differential for naphtha should be below that of VGO.

Id.; Exhibit No. WAP-48. Consequently, according to Sanderson, the relative value of Naphtha on the two coasts should fall between the values of VGO and LSR on the two coasts. Exhibit No. WAP-33 at p. 19.

638. Addressing Tallett's criticism of Sanderson's claim that transportation costs and crude oil prices are similar on both coasts, Sanderson claims that, even though "[t]here are no quoted prices for the same crude oil grade on both the West Coast and the Gulf Coast," he proved that the price of delivering ANS and Isthmus, which he claims have similar qualities, to the Gulf Coast is similar.[257] *Id.* at pp. 19-20. He adds that "as ANS shipments to the Gulf Coast declined in the mid-1990s and West Coast crude oil prices increased," the West Coast ANS quoted price and the Gulf Coast ANS price "nearly converged." *Id.* at p. 20.

[256] *See* Exhibit No. WAP-48.

[257] Sanderson refers to Exhibit No. WAP-7.

639. Faulting Tallett's criticisms of his crude oil transportation analysis, Sanderson states that Tallett makes several incorrect assertions – the first of which is that very large crude carriers cannot deliver crude oil at Los Angeles because there are no lightering[258] operations at the Los Angeles port. *Id.* at p. 20. Sanderson, answering this assertion, claims that *The Drewry Monthly* report indicates that both Chevron and BP use very large crude carriers "to ship crude oil from the Arabian (Persian) Gulf to the West Coast." *Id.* He notes that both use lightering operations to transfer the crude from these large ships to port facilities. *Id.* at pp. 20-21.

640. As for Tallett's claim that Sanderson didn't use the available spot rates for voyages between Saudia Arabia and the West Coast, Sanderson maintains that after reviewing the limited spot rate data and employing the data in his calculations "did not materially change the relative transportation costs from Ras Tanura [Saudi Arabia] to either U.S. coast." *Id.* at p. 21. Despite Tallett's criticism, Sanderson claims that there is no material affect on the relative transportation costs for shipping from Ecuador to the two coasts from using an 80,000 dead weight ton vessel. *Id.*

641. Addressing O'Brien's use of the U.S. Oil & Refining facility in Tacoma, Washington, as a refinery example making O'Brien's three component blend of reformate, normal butane, and LSR, Sanderson states that the three component blend does not comply with anti-dumping regulations for U.S. Oil & Refining. *Id.* at p. 22. He explains,

> [t]he annual average exhaust toxics emissions calculated for Mr. O'Brien's three component blend of 210.8 mg per mile exceed the maximum allowable 1990 baseline exhaust toxics emissions for U.S. Oil & Refining of 121.7 mg per mile due to the high levels of benzene and aromatics in his three-component blend.

Id. at pp. 22-23. As a result, Sanderson argues, "U.S. Oil & Refining would not be able to market Mr. O'Brien's three-component blend as conventional gasoline in the U.S." *Id.* at p. 23.

642. At the hearing, on cross-examination, Sanderson was referred to the Platts Gulf Coast Heavy Naphtha quote effective on February 5, 2003. Transcript at p. 8776. Prior to that date, he testified, Platts quoted price was for Full Range Naphtha with a boiling

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[258] In further direct testimony at the hearing, Sanderson described lighter services as "[w]here you bring a smaller offload, a smaller type on to a larger ship so the larger ship can [offload without having to] go to port." Transcript at p. 8687. He added that the "lightering" takes place in international waters off of Houston and Los Angeles. *Id.*

point of 130°F. to the "high 300s." *Id.* at p. 8777. He added that the Heavy Naphtha quote is for Naphtha with an initial boiling point of 180°F. and ranging up to the high 300s, which is similar to that of Quality Bank Naphtha. *Id.* Consequently, he recommended using this quote rather than the previous one. *Id.*

643. Sanderson also acknowledged that Platts was making a Naphtha + Aromatics adjustment of 0.15¢/gallon to adjust to a standard 40 Naphthenes + Aromatics specification[259] with respect to the Heavy Naphtha quote.[260] *Id.* at p. 8778. According to Sanderson, ANS has a Naphthenes + Aromatics of about 55 which would require an adjustment of "40 to 55 times .15 per point," but he first stated that he was told by an employee of Platts that it only adjusted from "35 up to about 48," and later said that he was told, in a subsequent conversation, that the end result was not so precise. *Id*. at pp. 8778-79, 10534-35. This, he agreed, would make the adjustment 1.2¢/gallon rather than 2.25¢/gallon. *Id.* at p. 8780. Later, Sanderson opined, on being further questioned, that the adjustment could go as high as "50." *Id.* at p. 10535.

644. On further cross-examination regarding the change in the Platts Naphtha quote, Sanderson stated that, in comparison with the Gulf Coast Naphtha price he used in his analysis, the new price "varied between the same price [as he used] and 1 cent per gallon higher." *Id.* at p. 10519. Asked whether the change in the Platts Naphtha quote caused him to reconsider his recommendation that West Coast Naphtha continue to be priced using the Gulf Coast Platts Naphtha quote, Sanderson stated that it did not since "the prices aren't particularly different." *Id.* He added that he continued to be satisfied that the old Platts quote was "reliable," and added that, though the new Heavy Naphtha quote might be better, it did not undermine the reliability of that price. *Id.* at p. 10520.

645. Agreeing that the parties were discussing reformer grade Naphtha, Sanderson also conceded that its primary use, on both the West Coast and the Gulf Coast, is to make gasoline. *Id.* at p. 8817. He further agreed that, on the West Coast, this was "virtually the only use for reformer-grade Naphtha." *Id.* at p. 8818. As a result, Sanderson agreed that "what a refiner would be willing to pay for naphtha is [no more than] its value when made into gasoline, less a margin for [its] processing" costs. *Id.* Therefore, Sanderson conceded, the value of Naphtha on both coasts is "highly correlated" to the price of gasoline. *Id.* at pp. 8818-19. However, he opposes any basis for valuing West Coast Naphtha which is based on West Coast gasoline prices. *Id.* at p. 8939. This, despite the fact that he recognizes that Naphtha is priced on the basis of gasoline because, he claims,

[259] Sometimes referred to as "N+A." Transcript at p. 5692. These relate to the quality of the Naphtha as the amount of "naphthenes and aromatics [in the Naphtha] determine show well it performs inside a reformer making gasoline." *Id.*

[260] *See* Exhibit No. PAI-182.

though "priced" that way, it is not "valued" that way. *Id.*

646. According to Sanderson, the Gulf Coast and the West Coast are "different markets" in that they are "geographically separate" and in that "the supply and demand profiles . . . are different." *Id.* at p. 8819. He also stated that the gasoline markets are different on each coast in that West Coast environmental restrictions re more severe, in particular those in California and large metropolitan areas outside California. *Id.* at p. 8820. Sanderson added that this also affects the supply and price of gasoline, as well as that of gasoline feedstocks and blendstocks on the West Coast. *Id.* at p. 8821. Moreover, Sanderson stated, it is more difficult to build or expand refineries on the West Coast than on the Gulf Coast as a result of these more stringent environmental regulations. *Id.* at pp. 8821-22. Consequently, he said, the West Coast gasoline market is more volatile than that on the Gulf Coast. *Id.* at p. 8822.

647. Sanderson agreed that, "from time to time," the West Coast value of Naphtha exceeded the published Gulf Coast price. *Id.* at p. 8227. He also concurred with the suggestion that Naphtha values will not be identical on both coasts in the future, although he proposes the "over the long haul, the price will be similar." *Id.* at pp. 8827-29. He adds that the "small difference" between the Naphtha values on the two coasts was "within the range that should be tolerable." *Id.* at p. 8830.

648. Discussing the contract data discovered in this case, Sanderson stated that about 80% of them priced Naphtha on a West Coast gasoline minus basis. *Id.* at p. 8862. He added that during the 1994-98 period, the contract prices were close to the Gulf Coast Naphtha price, while in the 1999-2001 period, the West Coast contract prices exceeded the Gulf Coast published price. *Id.*

649. Referred to O'Brien's proposal, Sanderson agreed that "the facilities [O'Brien] considered in calculating the cost of reforming" Naphtha were appropriate. *Id.* at p. 8864. Sanderson believes that Tallett is overpricing Naphtha because his Naphtha values exceed the value of Gulf Coast Naphtha plus the differential[261] between the cost of "transportation from the Caribbean to the Gulf Coast" and that of the cost of transportation between the Caribbean and the West Coast.[262] *Id.* at p. 8873. Later, Sanderson opined that the price of West Coast Naphtha cannot exceed the cost of Gulf Coast Naphtha plus transportation to the West Coast "for a prolonged period of time." *Id.* at p. 9179. He agreed that this does not establish a "value" for West Coast Naphtha, but merely establishes "some sort of a cap." *Id.* at pp. 9179-80. Sanderson declared that the transportation differential between a Caribbean/Gulf Coast voyage and a

[261] Sanderson has calculated the differential as 3.1¢. Transcript at p. 8872; Exhibit No. WAP-33 at p. 14.

[262] *See* Exhibit No. WAP-22.

Caribbean/West Coast voyage is $1.30 or 3.1¢/gallon.[263] *Id.* at pp. 9180-81. Also, he agreed that the cost for a clean tanker would be higher. *Id.* at pp. 9183-84.

650. According to Sanderson, a refiner which desires to alter the volume of Naphtha available in its refinery can either purchase Naphtha from an outside source or alter its crude slate. *Id.* at p. 9024. He adds that "the ability of a refiner to change which crudes [it is] using and hence the quality of the various cuts" connects Gulf Coast and West Coast crudes and feedstocks. *Id.* In other words, Sanderson states, a refiner could choose to use a crude with more or less of a Naphtha content depending on how it wants to alter the quality of its feedstock. *Id.* at pp. 9040, 9055.

651. Sanderson states that, assuming a constant supply, the demands of the Gulf Coast petrochemical market elevate Naphtha's Gulf Coast price. *Id.* at p. 9026. He adds, however, that elements of the demand by the petrochemical industry fluctuates somewhat depending on Naphtha's price. *Id.* at pp. 9026-27. Some petrochemical companies, Sanderson agrees, have an alternative feedstock to Naphtha, "largely in the ethylene cracking aspect." *Id.* at p. 9027. Therefore, he asserts, the demand for Naphtha by the petrochemical industry may be influenced by its price in comparison with these alternatives. *Id.* at p. 9028.

652. On the other hand, according to Sanderson, there is virtually no petrochemical industry on the West Coast. *Id.* Thus, the supply and demand factors on the West Coast are entirely different from that on the Gulf Coast, he claimed. *Id.*

653. Asked about his claim that the crude prices on the Gulf Coast and the West Coast were linked, Sanderson stated that he meant that the "prices were similar or approximately the same." *Id.* at p. 9029. He specifically stated that he was not saying that the prices were the same, nor was he claiming that the crude markets were identical. *Id.* at pp. 9029-30. Sanderson admitted that he only looked at about one-third of the crudes used on each coast and that "many crudes . . . used on the two coasts . . . are different." *Id.* at p. 9030.

654. According to Sanderson, the prices of "intermediate feedstocks track the prices of crude oil." *Id*. at p. 9052. He claims that the feedstocks on both coasts are similar. *Id.* at pp. 9052-53. However, he did not consider all the intermediate feedstocks, but only looked at Naphtha, VGO and LSR. *Id.* at pp. 9061-62. Sanderson admits, however, that his "feedstock equalization theory" does not work for LSR and, in some years, not for VGO. *Id.* at pp. 9062-63. The prices of LSR differ on each coast, Sanderson states, because of a number of factors including the fact that it has a high Reid Vapor Pressure

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[263] *See* Exhibit No. EMT-464.

which restricts its use as a gasoline blendstock on the West Coast.[264] *Id.* at pp. 9068-69. Further, he agrees that VGO does not have the same kind of a problem as does LSR and, as a consequence, the differential between the values of LSR on the West Coast and the Gulf Coast does not serve as a predictor of the differential between the prices of VGO on the West Coast and the Gulf Coast and vice versa. *Id.* at pp. 9071-72.

655. Sanderson also states that the price of crude affects the prices of all products taken from the crude. *Id.* at p. 9056. But, according to Sanderson, there is no rigid relationship, i.e., there is no "set number that is axiomatic that says that naphtha is X dollars a barrel above crude oil." *Id.*

656. Under further cross-examination, Sanderson agreed that VGO contributed more to the Gulf Coast gasoline pool than does either Naphtha, isobutane[265] or MTBE.[266] *Id.* at p. 9091. The latter two, he says, are priced higher on the West Coast than VGO.[267] *Id.* at p. 9092. The Gulf Coast/West Coast differential for MTBE and isobutane are higher than the Gulf Coast/West Coast differential for VGO, Sanderson concurred. *Id.*

657. Referring to a document which his firm created,[268] Sanderson testified that the difference on the Gulf Coast between unleaded regular gasoline and Full Range Naphtha was 5¢/gallon and would be higher on the West Coast. *Id.* at pp. 9142-44.

658. Regarding the West Coast Naphtha contracts discovered in this case, Sanderson asserted the following: "I don't believe that the contract information based on around a thousand barrels a day of naphtha or less than 1 percent of the naphtha processed is reliable." *Id.* at p. 9144. He agreed that he had no other information as "to the actual differentials" on the West Coast. *Id.* at p. 9145.

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[264] Reformate, according to Sanderson, has a lower Reid Vapor Pressure than butane. Transcript at p. 9106.

[265] Sanderson states that isobutane is valuable in making gasoline on the West Coast, but is in short supply, and this accounts for the Gulf Coast/West Coast price differential. Transcript at p. 9093.

[266] While MBTE is valuable in making West Coast gasoline, the Gulf Coast/West Coast price differential, Sanderson asserts, is a factor of the cost of transportation. Transcript at p. 9094.

[267] *See* Exhibit No. PAI-201.

[268] *See* Exhibit No. PAI-214.

659. Turning to the question of barriers to import of Naphtha into the West Coast, among other things, Sanderson referred to "lead time," i.e., once someone from someplace other than the West Coast notices a Naphtha price spike on the West Coast, it needs time to analyze whether that price rise will last long enough for it to acquire a cargo and bring it to the West Coast. *Id.* at pp. 9198-9200. Sanderson did note that, in his opinion, "the largest barrier to entry is the difficulty of blending reformate into the gasoline pool."[269] *Id.* at p. 9218.

660. Adding that "[w]ith some consideration of other market dynamics," Sanderson agreed that Naphtha is "priced on the basis of reformer economics." *Id.* at p. 9341. He also agreed that reformer economics were different in Europe as compared with the United States's Gulf Coast and added that the use of Naphtha was different as well. *Id.* at p. 9342.

661. According to Sanderson, the differential between Naphtha and gasoline is dictated by "the overall value of octane and reformer/refining returns." *Id.* at pp. 9342-43. He agreed that this was also true in Japan. *Id.* at p. 9343. Sanderson added that Naphtha imported into Japan went into the petrochemical industry. *Id.*

662. Sanderson, asked why Naphtha should be treated differently than the other cuts, all of which have a West Coast price,[270] answered that "we're looking for . . . a suitable proxy [because w]e don't know what the price is." *Id.* at p. 10622. He does not think that the price of Naphtha should be affected by West Coast gasoline's "higher refining margin"[271] or, more precisely, that "the additional refining margins that the refiners get by producing gasoline on the West Coast should be attributed to the naphtha prices." *Id.* at pp. 10662, 10674-75. Referring to Exhibit EMT-536, Sanderson submits that, rather than following the price of gasoline, Naphtha follows the price of crude oil. Transcript at pp. 10663-65.

663. Asked about West Coast versus Gulf Coast cost factors, Sanderson admitted that "construction labor" costs were higher in the Los Angeles area than on the Gulf Coast, but did not think that there were significant differences between the Gulf Coast costs and the rest of the West Coast. *Id.* at p. 10683. He agreed that the costs of meeting

[269] Sanderson agreed with his cross-examiner that "[i]f there is a demand at a higher price and it is not being satisfied, it's telling you that there is a barrier to entry." Transcript at p. 9219.

[270] *See* Exhibit No. EMT-531.

[271] By the term "refining margin," Sanderson referred to the differential between the prices of finished products and the price of crude oil. Transcript at p. 10675.

environmental regulations on the West Coast were higher, but suggested that these were "equalizing" as the Gulf Coast regulation became more restrictive. *Id.* at pp. 10683-84. Sanderson also agreed that energy price "spikes" on the West Coast drove those prices higher than similar prices on the Gulf Coast. *Id.* at p. 10684.

664. With respect to the O'Brien proposal, Sanderson submitted that it overvalued Naphtha by about $3.50 per barrel. *Id.* at pp. 10684-86. However, he did not think that this was attributable to any cost factor; rather, he believes that the problem with the O'Brien proposal is his use of a "three-component blend." *Id.* at pp. 10686, 11092. Sanderson argues:

> It isn't the costs narrowly shown on [Exhibit No.] PAI-37 that I criticize. It's the fact that he's producing a three-component blend, calling it conventional unleaded regular. Yet, it ignores the fact that conventional unleaded gasoline on the West Coast is produced by blending all of these other blendstocks produced from all the other cuts that make gasoline.

Id. at pp. 10686-87. He adds later: "Ignoring the contribution of the cat cracker, the hydrocracker[272] and the tankage, the blending and the marketing of gasoline is the problem with that proposal." *Id.* at p. 10688 (footnote added). Sanderson agreed that at least a portion of the differential between gasoline and Naphtha is "cost related," but stated that he did not know to calculate it. *Id.* In any event, according to Sanderson, his problem with O'Brien's proposal is his use of the three-component blend, not his cost calculations. *Id.* at p. 10689-90, 10731. Sanderson clarified his position later, stating: "[T]he three-component blend misvalues reformate. Therefore, the naphtha value is misvalued along with some other things." *Id.* at p. 10730. Sanderson also claims that O'Brien fails to take into account investments a refiner makes into the cat cracker, the hydrocracker and the alkylation unit therefore O'Brien's cost calculations isn't appropriate. *Id.* at p. 11092.

665. According to Sanderson, Platts does not use prices derived from term contracts when they report market prices on the Gulf Coast; they only use spot cash transactions. *Id.* at pp. 10856-57. He agreed that a lot of the prices referred to in this proceeding were term contracts and that "a fair amount" of the Naphtha traded on the Gulf Coast pursuant to term contracts. *Id.* at p. 10857.

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[272] "Hydrocracking is a catalytic cracking process conducted with a high (relative to hydrodesulfurization processes) hydrogen partial pressure." Exhibit No. EMT-544 at p. 2. It is very versatile, but is "expensive due to its high operating pressure and high hydrogen consumption." *Id.* The process is used to produce jet fuel or diesel fuel or for "complete conversion of feed to gasoline and lighter." *Id; See also* Exhibit No. EMT-545 and Transcript at pp. 10765-71 for further information regarding the hydrocracker.

666. Questioned about the relationship between jet fuel and Light Straight Run, Sanderson noted that Naphtha is produced in "fairly broad distillation ranges" by refiners "overlapping and maybe including the Quality Bank [Light Straight Run] cut to overlapping into the light distillate cut, which is ultimately produced to make jet fuel." *Id.* at p. 10868. He did agree that LSR cannot be made into jet fuel or into low-sulfur No. 2. *Id.* at pp. 10868-69.

667. During a discussion of Exhibit No. EMT-559, Sanderson was asked the meaning of the term "Quality Bank penalty" in connection with the operations of a refinery which uses some portion of crude and returns the rest to the TAPS common stream. Transcript at pp. 10893-94. He responded as follows:

> I guess my understanding of that is that when the refinery returns oil that it doesn't extract and retain back to the pipeline, there's an assessment of the – using the Quality Bank prices and the components of each of those materials in the – the volume percents within those Quality Bank definitions, they're charged the difference in value between the passing stream values from the Quality Bank cuts versus what they return, in a very broad sense.

Id. at p. 10894. During redirect examination of Sanderson, Judge Wilson, I, and counsel had a discussion regarding the accounting for the retained stream and, as part of that discussion, the following statement was made by counsel and agreed to by Sanderson:

> If the refinery is going to retain 25 barrels, and to do that, it's going to have to distill 100. What it does is it will enter into an agreement with someone to buy the 25 barrels, and frequently, but not necessarily, with the same party to borrow essentially the 75 barrels, and it borrows them as they come off the pipeline, and then it returns them as they get put back on to the pipeline.
>
> I think the missing thing that's stated here is that as far as the TAPS quality is concerned, what it's looking at are the mixing of the two streams just like at pump station 1. And so the 75 barrels that are going back in will have a lower quality than the common stream, but whoever those belong to at Valdez will get barrels out of the common stream. So the Quality Bank measures that difference in value and assesses an assessment against the return stream.
>
> Correspondingly, the barrels coming down that never went through the refinery suffer a slight diminution in value because they're mixed with the returned barrels. And so the Quality Bank measures that diminution by

> comparing the barrels upstream before they're mixed with the return barrels to the common stream that everybody gets back at Valdez.

Id. at pp. 10957-58. There was general agreement that the real cost of the 25 retained barrels, without considering any processing costs, therefore, was contract price plus the penalty.[273] *Id.* at p. 10958.

668. Also on redirect examination, Sanderson stated that Naphtha, an intermediate product, did not have to be handled as carefully as jet fuel, a finished product, because one has "to be careful not to contaminate the jet fuel . . . [which has] particular sensitivities to having surfactants and water and those sort of things." *Id.* at p. 10947.

669. In response to questions from Judge Wilson, Sanderson indicated that Naphtha is entered into the petrochemical industry in two ways: first, Naphtha is run through a reformer, and the aromatics are extracted from the reformate and used as building blocks for petroleum-based chemicals; and secondly, higher boiling point Naphtha is run through an ethylene cracker producing petrochemicals. *Id.* at p. 11039. Any material left over from one of these processes is then used as a gasoline blendstock, according to Sanderson. *Id.* at pp. 11039-40.

670. Discussing his proposal to maintain the Gulf Coast Platts Naphtha quote as the value of West Coast Naphtha for Quality Bank purposes, Sanderson stated that "one of the strongest arguments for the Gulf Coast Naphtha price is it is a published price in that it's determined by an independent price reporting service." *Id.* at p. 11059. In connection with this discussion, he criticized Tallett's proposal as ignoring the "large differential between the gasoline price and other feedstocks that should be looked at when you price naphtha." *Id.* at p. 11062. According to Sanderson, Tallett errs by using finished products (gasoline and jet fuel) in his formula. *Id.* at pp. 11089-91. To correct this, Sanderson stated that he would substitute a "feedstock element." *Id.* at pp. 11064-65.

671. While criticizing Tallett's proposal, Sanderson found "some merits" in the proposal by Dudley because he "uses VGO and LSR, which are related to naphtha and how they're manufactured into gasoline." *Id.* at p. 11065. Sanderson adds that Dudley's "percentages are based on the supply percentages of LSR and VGO in the crude oil, so they have some logic there." *Id.*

672. Asked about Ross's governor proposal, Sanderson stated that it was needed only because Tallett's and O'Brien's proposals overvalued Naphtha. *Id.* at pp. 11068-69. He

[273] For the complete discussion of the accounting regarding this type of transaction *see* Transcript at pp. 10952-63.

added that he thought that, were Tallett's or O'Brien's proposals adopted, the governor must be used even though he had a problem with the floor proposal. *Id.* at pp. 11069-70.

673. After identifying Isthmus crude as being similar to ANS, Sanderson agreed that it was feasible to apply the differential between the Gulf Coast prices of Mexico's Isthmus crude and Naphtha to the West Coast price of ANS to determine the value of West Coast Naphtha. *Id.* at pp. 11082, 11088. He did declare that, as the prices of Isthmus and ANS were very similar, he preferred to "stick with" Platts Gulf Coast Naphtha quote. *Id.* at p. 11088.

674. During re-cross examination, Sanderson agreed that refiners valued Naphtha on the basis of its value as a gasoline blendstock less the cost of its processing, but added that its value must be compared with the value of other blendstocks. *Id.* at pp. 11109, 11143. He also rejected any manner of valuing West Coast Naphtha based on the price of West Coast gasoline or on the contracts discovered in this proceeding.[274] *Id.* at pp. 11109-10. He reaffirmed that he preferred to continue to use the Gulf Coast Platts Naphtha quote to value West Coast Naphtha even though he recognized that they were different markets. *Id.* at p. 11113.

675. Referring again to the West Coast Naphtha contracts discovered in this case, Sanderson noted that the volumes were very small and, in his opinion, did not reflect Naphtha's market price, "particularly when you consider [ ] that the spot transactions" which he considered as the real indicator are much "smaller than the total volume."[275] *Id.* at p. 11146-47. He opined, therefore, that they were not a reliable indicator of Naphtha's price. *Id.* at p. 11146. Sanderson noted that the volume of Naphtha traded amounted to around 1% of the Naphtha used on the West Coast. *Id.* at p. 11147. According to him, since the amounts are small, the buyers may agree to pay a higher price than they would "if there was a large volume and that was the clearing price of the material." *Id.* at p. 11229.

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[274] Later Sanderson added:

> I think that valuation in those contracts are subject to the problems we have on the West Coast market in that there's no market clearing price for naphtha, so they don't have a yardstick by which to measure themselves, and that's a complication of the West Coast naphtha market.

Transcript at p. 11144.

[275] Referring to the data in Exhibit No. BPX-232, Sanderson indicated that there were only 71 spot transactions during the 1994-2001 period, or less than one per month. Transcript at p. 11253.

H. JAMES A. DUDLEY

676. Petro Star also introduced Dudley, founder of Dudley and Co. Advisors LLC, as a witness. Exhibit No. PSI-5. It asked him to present "a method for determining the value of West Coast Naphtha that does not rely on finished gasoline prices." *Id.* at p. 2. According to Dudley, Petro Star supported continuing to value West Coast Naphtha on the basis of Platts Gulf Coast Naphtha quote. *Id.* at p. 3; *see also* Transcript at p. 10038. However, Dudley states, if a change must be made, it can be done with reference to market prices which are already used in the Quality Bank calculations. Exhibit No. PSI-5 at p. 3.

677. According to Dudley, LSR,[276] Naphtha and VGO[277] are all used, after processing, to make gasoline blendstocks. *Id.* at p. 4. He also notes that LSR boils at a lower temperature than Naphtha and that VGO boils at a higher temperature than Naphtha. *Id.* Dudley concludes that "[u]sing LSR and VGO as pricing references thus brackets the cut for which we must develop a reasonable price mechanism." *Id.*

678. Dudley proposes calculating the differentials between West Coast and Gulf Coast prices for LSR and VGO and then applying the differentials to the Gulf Coast Naphtha price to determine the proper surrogate price for West Coast Naphtha. *Id.* According to Dudley, his methodology results in a reasonable valuation of West Coast Naphtha because it is accurate inasmuch as it uses "fractions whose boiling ranges bracket the Naphtha cut" and because it uses data already used in Quality Bank calculations. *Id.* at p. 5.

679. Dudley explains the steps in his methodology as follows:

> As the first step, the price differential between the Gulf Coast and the West Coast is calculated for the LSR cut. The West coast price for LSR is subtracted from that of the Gulf Coast to find the region-to-region LSR differential.

* * * *

[276] According to Dudley, LSR is used primarily as a gasoline blendstock or as an isomerization unit feedstock although there are other lesser uses and it is used similarly on both the Gulf Coast and the West Coast. Transcript at pp. 10153-54, 10169.

[277] According to Dudley, VGO is used as a feedstock for the FCC unit (sometimes called a cat cracker) both on the West Coast and the Gulf Coast. Transcript at pp. 10153-54.

> The second step follows the same sequence as the first, except that here the price differential between the Gulf Coast and the West Coast is calculated for the VGO cut. The West coast price for VGO is subtracted from the Gulf Coast price for VGO, giving the region-to-region VGO differential.
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> * * * *
>
> In steps 1 and 2 we have found the region-to-region price differentials for LSR and VGO, which bracket the Naphtha cut for which we are seeking a price. The methodology determines a single differential to apply to the Naphtha cut by weighting the LSR and VGO differentials. The weighting factors are found using the volume percentage of the LSR and the VGO that are contained in the ANS crude oil as it is delivered to Valdez for shipment. In step 3, the LSR factor is found by dividing the LSR volume percent figure by the sum of the volume percentages for LSR and VGO. Subsequently, the VGO factor is found by dividing the VGO volume percent figure by the sum of the volume percentages for LSR and VGO. The two factors thus total to 1.00, and represent the relative amounts of the two cuts that are used in refineries that are processing the ANS crude oil.
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> * * * *
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> [The fourth step] yields the final region-to-region differential, the one for Naphtha. It is derived from the LSR and VGO differentials and their respective weighting factors, and will be applied to the Gulf Coast Naphtha price to calculate the surrogate West Coast Naphtha price. For this calculation, the differential for each of the cuts is multiplied by the weighting factor for that cut. The two products thus determined are then added together. The resultant sum is the weighted differential to be used for the West Coast Naphtha price determination.
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> * * * *
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> For the last calculation, the surrogate region-to-region Naphtha differential from step 4 is subtracted from the Gulf Coast Naphtha price. The figure thus derived is the surrogate West Coast Naphtha price for use in the TAPS Quality Bank system.

Id. at pp. 6-7; *see also* Exhibit No. PSI-7. [278] An additional benefit of his proposed methodology, Dudley maintains, is that the West Coast Naphtha valuation would be consistent with other West Coast Quality Bank cuts valuations. Exhibit No. PSI-5 at p. 8.

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[278] The numbers used in Exhibit PSI-7 were updated in Exhibit PSI-14 although there was no change in Dudley's proposal. Transcript at p. 10042.

680. In his rebuttal testimony, Dudley answers Toof's assertion that his proposal had no basis in fact, stating that his "methodology states the obvious," that is, it answers the question of how different the West Coast intermediate cut prices are from those on the Gulf Coast. Exhibit No. PSI-11 at p. 1. He explains how his methodology determines this:

> LSR, Naphtha, and VGO all are feedstocks for process units that produce blendstocks for gasoline. In addition, LSR, like Naphtha, enjoys a substantial petrochemical market on the Gulf Coast but not the West Coast. Therefore, it is reasonable to expect that price differences for LSR and VGO between the Gulf and West Coasts provide good evidence of what the price difference between the Coasts is for Naphtha. My methodology looks to the known price differences between LSR and VGO on the Gulf and West Coasts to estimate the difference between the Gulf Coast Naphtha price and the West Coast Naphtha price. LSR and VGO prices indicate how different the West Coast market is from the Gulf Coast market, and the West Coast Naphtha price can then be calculated by applying this difference to the Gulf Coast Naphtha price.

Id. at pp. 1-2.

681. Dudley also responds to Toof's claim that his methodology does not account for the value of gasoline from which, Toof claims, Naphtha receives 90% of its value first asserting that he relies on Sanderson's, Ross's, and Culberson's testimony attacking the use of a finished product like gasoline to value an intermediate product like Naphtha. *Id.* at p. 2. His proposal, Dudley claims, was intended to, and does, avoid those problems as well as being simple and, in addition, "relies exclusively on data already used by the Quality Bank." *Id.* While conceding that the price of gasoline impacts the decisions of refineries involving LSR, VGO and Gulf Coast Naphtha, he contends that his proposal assumes that the price of gasoline already has been taken into consideration to determine the five prices he uses in his formula. *Id.* Dudley further argues that, "[i]f West Coast Naphtha were valued based on finished gasoline prices, it would be valued under a totally different methodology than the other four cuts on the West Coast and all five cuts on the Gulf Coast." *Id.* at p. 3.

682. Conceding that West Coast Naphtha must be treated differently than other West Coast cuts because there is no published price, Dudley argues that his proposal "minimizes [this] special treatment by using the valuations of other Quality Bank cuts and the two prices that are available for the West Coast, as well as by avoiding the subjective decisions that use of finished product prices entails." *Id.*

683. Addressing the criticism that his methodology is not used by anyone in the petroleum industry for valuation purposes, Dudley answers by stating that his

methodology addresses a unique question so there should be no surprise that no one in the petroleum industry uses such a methodology. *Id.* at pp. 3-4. He also declares that no one in the industry uses any of the methods proposed by any of the other witnesses. *Id.* at p. 4. Dudley maintains that the core of the issue "is the relationship of LSR and VGO prices on the Gulf Coast to LSR and VGO prices on the West Coast." *Id.* He adds: "No matter what Gulf Coast LSR and VGO prices are in absolute terms, if West Coast LSR and VGO prices are higher, my methodology will calculate a West Coast Naphtha price that is correspondingly higher than the Gulf Coast Naphtha price." *Id.*

684. During cross-examination, Dudley conceded that there is no direct relationship between a cut's boiling point and its relative value. Transcript at p. 10054. He also agreed that LSR, because it has a high Reid Vapor Pressure, was less valuable on the West Coast than on the Gulf Coast. *Id.* at p. 10056. Moreover, Dudley conceded that Naphtha did not share this problem, although he did not agree that this was relevant. *Id.* Dudley further agreed that the economics affecting VGO were different than those affecting Naphtha. *Id.* at p. 10057.

685. Challenged because he admitted that he did not do an analysis comparing the Gulf Coast and West Coast gasoline economics, Dudley stated:

> I've decided to use this methodology because I believe it provides an accurate indicator of the naphtha price, and as I said before, I wasn't trying to produce a naphtha price that was greater than VGO. I was simply trying to reflect what I know about gasoline making economics, and I believe my methodology does that.

Id. at p. 10065.

686. Dudley agreed, "in general industry terminology," that the relative amounts of VGO and LSR in the ANS common stream had little to do with the value of West Coast Naphtha, but believes that they are useful because "in a confined refinery operation, the refinery planners have to produce blended pools of gasoline that meet finished specifications [a]nd they have to essentially balance the refinery in one way or another." *Id.* at p. 10068.

687. Asked why he chose LSR and VGO to derive the value of Naphtha, Dudley stated:

> I picked LSR and VGO after reviewing both the product characteristics, the usage in refineries and the Quality Bank data. When I looked through the nine cuts, the two fractions there that had similar characteristics to the naphtha cut were the LSR and the VGO. There were factors about the other cuts that I thought made them inappropriate for use in this valuation.

Id. at pp. 10096, 10101. He further stated that there were no cuts whose prices bracketed Naphtha. *Id.* at p. 10097.

688. Dudley testified that his proposal could be verified by comparing the Gulf Coast series of prices to the West Coast series of prices monthly for 10 years. *Id.* at p. 10102. When he did that, he claims, a situation never arose where the West Coast Naphtha price was out of line. *Id.* at p. 10103. He declared that none of the results reflected bias in his proposal. *Id.*

689. Asked whether he still believed that VGO was an appropriate indicator for the value of West Coast Naphtha, Dudley responded in the affirmative noting that it shares "the characteristics of being a crude oil boiling fraction," was "primarily processed in a refinery for the purpose of enhancing gasoline production," and that it was processed through a cat cracker. *Id.* at p. 10145.

I. S. FRANK CULBERSON

690. The Union Oil Company of California produced Culberson, president and chief operating officer of Rimkus Consulting Group, Inc., an engineering consulting firm, to testify. Exhibit No. UNO-1 at p. 1. He begins by asserting that the current method of valuing the Naphtha cut for ANS crude oil deliveries to the West Coast is just and reasonable and should not be changed. *Id.* at p. 2. Were the Commission to decide to change the Naphtha cut valuation method for West Coast deliveries, he adds, then such a change should be prospective only. *Id.*

691. Culberson argues that, although the West Coast and Gulf Coast Naphtha markets may be separate submarkets, the two Coasts are linked by the ability to move and divert product between them. *Id.* He believes that "[t]his linkage prevents the prices for naphtha in one submarket from diverging to any great degree from the prices in the other," and adds that in view of this "market prices for naphtha established in the Gulf Coast submarket do not undervalue naphtha in the West Coast market." *Id.*

692. He explains that there are no published prices for West Coast Naphtha because there are few trades of Naphtha on the West Coast and "[p]ricing services do not report prices when there are only isolated trades or transactions." *Id.* at p. 5. According to Culberson, only a few cargoes of Naphtha have been imported by West Coast refineries in the past several years, and, he concludes, there is little demand for Naphtha on the West Coast beyond that produced by West Coast refineries for their own use. *Id.* at p. 6.

693. In Culberson's view, the value of West Coast Naphtha is restrained by the Gulf Coast Naphtha value. *Id.* He theorizes that, although there are few imports of Naphtha to the West Coast, there are some imports. *Id.* From this Culberson concludes that these

imports show that there are no structural barriers[279] to West Coast imports. *Id.* He also argues that "if naphtha commanded a higher price on the West Coast than it does on the Gulf Coast, there would be significantly larger shipments of naphtha into the West Coast market." *Id.* Culberson suggests that the absence of Naphtha sales does not indicate that there are trade barriers to its import, but rather reflects lack of demand. *Id.* In contrast, Culberson notes, the Energy Information Agency reports that substantial imports occur for the Gulf Coast of a number of petroleum products, as well as little imports for the West Coast. *Id.* at p. 7.

694. Imports for the Petroleum Administration for Defense Districts III and V,[280] he reports, are reported by the Energy Information Agency in two different formats. *Id.* The first, he explains, is Special Naphtha,[281] and the second is Naphtha for Petrochemical Feedstock.[282] *Id.* According to Culberson, in a three year period, District III imported on average of both types of Naphtha over 2,700,000 barrels/month, but imports for District V average only 32,000 barrels per month. *Id.*

695. He notes that the Energy Information Agency (sometimes "EIA") Special Naphtha and Naphtha Petrochemical Feedstock categories do not include all imports of Naphtha as other products that could be used to manufacture gasoline are reported to the Agency

[279] By the term "structural barrier," Culberson says he means physical limitations such as unavailable tankage, port congestion, geographic limitations. Transcript at pp. 12064-66. He also used the term "risk factors" barriers, by which he means the risk that prices will change while a cargo is in-transit. *Id.* at p. 12066.

[280] Culberson explains the Petroleum Administration for Defense District III "comprises the States of Texas, Alabama, Mississippi, Louisiana, Arkansas and New Mexico. This is an area where over 30% of the U.S. petroleum refining capacity and some 75% of petrochemical capacity is located." Exhibit No. UNO-1 at p. 7. The Petroleum Administration for Defense District V, he adds, "includes the states of California, Oregon, Washington, Arizona, Nevada, Alaska and Hawaii." *Id.*

[281] Special Naphtha, Culberson notes, is a finished product within the Naphtha boiling range, usually about 125°F to 400°F, used for thinners, cleaners, and solvents. Exhibit No. UNO-1 at p. 8. This type of Naphtha, he contends, cannot be used for gasoline blending as "[i]t could not be used as a catalytic reformer feed for upgrading reformate for gasoline production." *Id.*

[282] Naphtha for Petrochemical Feedstock, according to Culberson, is "naphtha derived from petroleum used in the manufacture of chemicals/petrochemicals, synthetic rubber and plastics." Exhibit No. UNO-1 at p. 8. This type of Naphtha, he asserts, can be used to blend gasoline. *Id.*

under different categories. *Id.* at p. 9. Unfinished Oils, he explains, is a catch all category that "can include Naphtha for gasoline blending or for processing through a reformer. Naphtha can technically be considered an Unfinished Oil and is sometimes reported to EIA as such." *Id.*

696. According to Culberson, imports of Naphtha and Unfinished Oils flow "from the Far East and the western side of South America to the Gulf Coast, with small volumes delivered to the West Coast." *Id.* at p. 11. Also, he asserts, there are more movements of Naphtha and Unfinished Oils from the Caribbean and eastern South America to District III, as well as movements from the Caribbean and eastern South America to the West Coast. *Id.* He concludes that "Naphtha on the high seas originating in the Pacific could be shipped more cheaply to the West Coast than to the Gulf Coast, and could be diverted to the Gulf Coast or West Coast, respectively, if prices dictate." *Id.* at p. 12.

697. In Culberson's view, the lack of significant Naphtha imports to the West Coast cannot be explained by the West Coast's self sufficiency in Naphtha. *Id.* at p. 13. If Naphtha, he contends, "were more valuable to West Coast refineries, they would be willing to pay a price higher than Gulf Coast naphtha prices to attract supply." *Id.* He explains why West Coast Naphtha imports are so small:

> Petroleum product demand on the West Coast, on average, is heavily tilted toward gasoline and jet fuel because of significant commuting by car and long distance flights. The available crude oil slate is heavier than for most other parts of the U. S. This combination has lead to the installation of high-conversion, complex refineries on the West Coast. These refineries employ disproportionate amounts of cat cracking, hydrocracking and coking, producing relatively large quantities of naphtha and achieving a balanced product slate. In other words, West Coast refineries are able to satisfy their own demand for naphtha from internal sources, and do not require imports of naphtha to produce gasoline.

Id.

698. Culberson begins his rebuttal and answering testimony[283] by stating that he will reply to criticisms of his West Coast Naphtha approach before addressing Exxon's prospective adjustments. Exhibit No. UNO-7 at p. 1. He first reiterates his belief that the current Quality Bank method for valuing West Coast Naphtha should be continued. *Id.* at p. 2. According to Culberson, using the Platts Gulf Coast waterborne price for valuing West Coast Naphtha is reasonable because the Gulf Coast price does not undervalue West Coast Naphtha. *Id.*

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[283] According to Culberson, his Answering Testimony also is supported by OXY USA, Inc. Exhibit No. UNO-7 at p. 1.

699. Culberson responds to Toof's claim that he did not present any data to support his position by first asserting that his background and experience make him an expert. *Id.* at p. 3. In addition, Culberson claims that he discovered additional data supporting his contention that Gulf Coast Naphtha prices do not undervalue West Coast Naphtha. *Id.* at p. 3. He describes that information as follows:

> The most significant additional data concerns the evidence we obtained from interviewing traders who actively trade naphtha. Astra Oil Trading is a major refined products trader, and we interviewed Erik Kotula of Astra . . . . Mr. Kotula indicated that there was a steady surplus of naphtha produced in Alaska that is usually sent to Japan. He also stated that occasionally naphtha was sent to the Gulf Coast. In the past seven years, he has sent five or six cargoes from the West Coast to the Gulf Coast, and that the netback West Coast price for this naphtha was below the Gulf Coast price. He also stated that he had brought a cargo of naphtha from Ecuador to the West Coast in December. Although he stated that West Coast naphtha value on average might be slightly higher than Gulf Coast, he indicated that using Gulf Coast prices to value West Coast naphtha was conservative and not excessive.

Id. at pp. 3-4.

700. Toof and Tallett, Culberson suggests, misconstrue his testimony as equating West Coast and Gulf Coast Naphtha prices. *Id.* at p. 4. Instead, he maintains, the Gulf Coast and West Coast Naphtha markets operate as separate submarkets for the same product and are linked by the ability to move product between each and by the ability to divert product destined from one to the other. *Id.* He adds that his testimony is "not that naphtha prices on the Gulf Coast were equal to naphtha prices on the West Coast, but rather that Gulf Coast naphtha prices <u>do not undervalue</u> West Coast naphtha." *Id.* (emphasis in original).

701. Clarifying further, Culberson explains that Gulf Coast prices best represent West Coast Naphtha value because the Naphtha prices are more or less the same, but adds that this does not mean that the Gulf Coast and West Coast Naphtha prices are equal at all times. *Id.* at p. 5. As for Toof's, Tallett's, and O'Brien's reliance on separate price series for unleaded gasoline, VGO, jet fuel, fuel oil, and LSR to demonstrate that the two markets are distinct, Culberson answers that the prices on the two coasts do not match exactly, but, "in the absence of a published West Coast price, the continued use of the Gulf Coast price provides a fair and more than adequate value for West Coast naphtha." *Id.*

702. The separate price series for the various refined products referred to by Toof,

Tallett and O'Brien, he maintains, does not undermine his conclusions. *Id.* at p. 5. Culberson explains:

> First, let's distinguish between the finished products and the intermediate products. The Gulf Coast and West Coast price series for finished gasoline do not provide a valid point of comparison for relative naphtha values. The West Coast gasoline market is not workably competitive. Demand for gasoline is high and growing. The market is dominated by a small number of large refiners with significant market power. The CARB requirements impose market entry barriers for potential new entrants to the market. . . . [P]articularly since 1997, West Coast gasoline prices have remained substantially above Gulf Coast prices, with a West Coast/Gulf Coast differential exceeding 15¢/gallon for extended periods. But naphtha is not a finished product like gasoline. It is an intermediate product. So the separate price series and West Coast/Gulf Coast price differentials for gasoline are really not relevant to naphtha.
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> The intermediate products for which separate price series have been identified by Mr. Tallett and Mr. O'Brien are VGO and LSR. West Coast vs. Gulf Coast price differentials for these products show different patterns than those for gasoline. Gasoline shows a sustained differential of some significant amount in excess of zero. . . . This means that, on average, West Coast gasoline prices are higher than Gulf Coast prices. By contrast, West Coast/Gulf Coast differentials for VGO and LSR straddle zero, with VGO being slightly above zero . . . and LSR being below zero.
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> * * * *
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> Both VGO and LSR, along with naphtha, are used in the manufacture of gasoline. It is therefore reasonable to conclude that naphtha will be valued similarly to these other two intermediate products. One would expect that West Coast/Gulf Coast price differentials for naphtha would fall between those for VGO and LSR, centering on zero. . . . Hence, if published prices for West Coast naphtha were available, the average West Coast/Gulf Coast differential for naphtha would be zero or less than zero. This would indicate . . . that while West Coast and Gulf Coast naphtha prices on any given day might not be equal, use of the Gulf Coast naphtha price would not undervalue West Coast naphtha. . . . Gulf Coast naphtha prices may indeed be higher due to the petrochemical demand for naphtha on the Gulf Coast. In this regard, naphtha is more like LSR, which has a lower West Coast value.

Id. at pp. 6-7.

703. Culberson characterizes Toof's, Tallett's, and O'Brien's criticisms about the West and Gulf Coast markets as being inconsistent and contradictory. *Id.* at p. 7. He notes that on the one hand, Tallett argues that gasoline prices on both coasts are not equalized, but on the other hand, maintains that trade in gasoline imposes a Naphtha price governor. *Id.* at pp. 7-8. Also, Culberson points to an inconsistency where Toof states that gasoline imports to the West Coast surge when West Coast gasoline price spikes, but Tallett argues that, when West Coast gasoline prices are high, gasoline imports increase and thus moderate the rise in West Coast gasoline prices. *Id.* at p. 8. Furthermore, Culberson asserts, the evidence produced by Toof, Tallett, and O'Brien on the separate price series and gasoline trades support his position:

> Toof shows import surges, ranging from 1,012 barrels to 2,498 barrels in months when the West Coast gasoline price spikes [and]. . . . the price spikes disappear or reverse following months in which import surges are reported. . . . These data tend to prove my point that the Gulf Coast prices will discipline West Coast prices, even in the less than fully competitive gasoline market. . . . Tallett explicitly agreed with my testimony that Gulf Coast and West Coast markets are connected by transportation, and that a West Coast refiner could take advantage of favorable naphtha prices by diverting a cargo in transit to land it on the West Coast. Mr. Tallett agreed with my testimony that such naphtha purchases could be accommodated by making changes in the refinery's crude slate, and that the time required for diverting naphtha in transit is only two or three weeks.

Id. at p. 9.

704. Responding to Tallett's and O'Brien's contention that the West Coast and Gulf Coast price differentials remain above the cost of transportation into the West Coast market for long periods of time, thereby making moderating price differentials ineffective, Culberson states that he disagrees. *Id.* He first asserts that the gasoline market is distinguishable from the intermediate product market. *Id.* Next, he argues that the price differentials remain at high levels for short periods only and that upward spikes are followed by downward spikes. *Id.* According to Culberson,

> [t]his indicates, in a workably competitive market, that a significant nontransitory increase in price produces a competitive response in the form of an increase in supply, either through imports or increased production from existing market participants. Over time, the differentials should average out. For finished products, the average differentials are above zero due to the lack of effective competition, but for intermediate products, the

> average differentials are near or below zero. If the price differentials average near zero, then the market prices are roughly equivalent.

Id. at pp. 9-10.

705. This analysis is true, Culberson asserts, despite Tallett's claim that, from 1999 through 2001, VGO was 4.3¢/gallon higher on average on the West Coast because this time period is atypical. *Id.* at p. 10. He notes that if one averages the VGO differential for a longer period such as 1992 through 2001, the differential is 0.6¢/gallon, much closer to zero. *Id.* Also, Culberson maintains that Tallett overlooks the LSR differential which averages 5.4¢/gallon lower on the West Coast vs. the Gulf Coast over the 1992-2001 time period. *Id.*

706. The 1999 through 2001 period, Culberson contends, is atypical for a number of reasons:

> • Revised, more stringent, CARB gasoline standards caused California refiners to make significant expenditures to meet the new standards. The refiners, in turn, significantly raised prices to try to recover these expenditures quickly.[284]
>
> • Gasoline, jet fuel and diesel fuel prices increased as a result of the introduction of ultra low sulfur level requirements for all California refined products.
>
> • Natural gas prices spiked starting in 2000 and reached $20 per MCF in 2001.[285] As hydrogen [a component element used in refining fuels] costs are directly tied to natural gas prices, the ultra-high natural gas and hydrogen prices raised refining costs.
>
> • Industrial electricity rates climbed drastically as a result of high natural gas prices, deregulation, "the electricity market manipulations of energy traders such as Enron," and low supply.

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[284] Culberson asserts that "[t]his distorted the margin between intermediate and finished products, especially gasoline, not only in California, but also to some extent in contiguous states." Exhibit No. UNO-7 at p. 11

[285] Culberson states: "California refineries have the highest level of conversion facilities in the world, and they use more fuel, and in particular consume more hydrogen, than other refineries." Exhibit No. UNO-7 at p. 11.

- Several long and significant outages at West Coast refineries limited gasoline production from cat cracking and related alkylate production, which compounded the lower allowable use of reformate in California because of CARB gasoline restrictions.

Id. at pp. 10-12. As a result of these anomalies, Culberson continues, finished product prices rose to unprecedented levels in California from 1999 through 2001, but, he adds, as some of these conditions have diminished, prices have been returning to normal levels in 2002.[286] *Id.* at p. 12.

707. Intermediate product prices, Culberson relates, did not follow gasoline prices and other finished product prices because gasoline prices became disconnected from other refined product prices in the 1999 through 2001 period. *Id.* Gasoline is different, he asserts, because even as gasoline prices rose, the prices were moderated by gasoline imports. *Id.* According to Culberson, a report prepared for the California Energy Commission indicates that the California gasoline market is unstable and supply constrained because the CARB gasoline requirement limits imports, and that this may result in future shortages. *Id.* Additionally, he states, jet fuel and diesel fuel imports increased although there "are limited supplies of jet fuel available on the world market, and not much ultra low-sulfur diesel is available either." *Id.* at pp. 12-13.

708. During the same period, Culberson explains that West Coast LSR prices declined because CARB gasoline Reid Vapor Pressure restrictions severely limit its use, particularly during the summer when the use of LSR is almost totally eliminated. *Id.* He further notes that even though VGO imports increased, the volume of imports were limited by availability, and VGO prices increased, but not at the same rate as gasoline prices. *Id.*

709. Culberson states that, because there are no reliable published prices for West Coast Naphtha, it is difficult to state what happened to West Coast Naphtha prices during this same period. *Id.* He opined, however, "that West Coast naphtha prices showed relatively little change," and supports his opinion by asserting that since Naphtha imports did not increase, it stands to reason that prices did not increase. *Id.*

710. Regarding Tallett's contention that Energy Information Agency data reflects that there were no imports of Naphtha into PADD V for the months where Ross's governor would be applied, Culberson responds that Tallett's test actually supports Ross's position because, if West Coast Naphtha were valued higher than Gulf Coast Naphtha, Naphtha would be imported into PADD V. *Id.* at p. 14. Addressing Tallett's and O'Brien's

[286] *See also* Transcript at pp. 12081.

argument that market entry barriers[287] prevent Naphtha imports into the West Coast, Culberson maintains, first, that reformers at California refineries are not operated at capacity.[288] *Id.* at p. 15. If not for the CARB gasoline limitations, Culberson asserts, refiners could change their crude slates and make less Naphtha internally, thus taking advantage of the lower Caribbean Naphtha price to import substantial amounts of naphtha. *Id.*

711. Responding to O'Brien's contention that West Coast refiners couldn't accommodate a crude oil shift because they purchase significant quantities of crude under long term contracts, and altering the crude oil slate would be very expensive, Culberson states:

> O'Brien claimed that more than 50% of crude slates were subject to long term contracts, but he could not define how much of the crude oil purchases were under long term contracts. In fact, in today's market, many coastal refiners purchase 30-50 percent of their crude oil on the spot market, and they study their options daily and weekly to take advantage of discrepancies in price, such as those we are discussing related to naphtha. They do not have to rethink their options starting from scratch, or order new shipments from the Persian Gulf under long-term contracts in order to take advantage of spot market purchases.

Id. at pp. 15-16. Culberson does admit that there would be a time lag between the time a refiner noticed cheaper Naphtha and the time to deliver it of, at most, three weeks, and perhaps as little as several days for a diverted shipment. *Id.* at p. 16. Additionally,

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[287] Culberson explains that O'Brien and Tallett's market barriers include the contention that West Coast refiners have their reformers full from the crude oils that they run. Exhibit No. UNO-7 at pp.14-15. Also, Culberson continues, the barriers include the claim that importers from areas such as the Caribbean would have no backhauls, and that only 25% of tankers would be interested in shipping Naphtha to the West Coast. *Id.* at p. 15.

[288] Culberson states:

> Data produced in discovery . . . show that California reformers are running about 65%-70% of capacity, versus a percentage in the low 90's on the Gulf Coast. It is true that the production of CARB gasoline has imposed limits on aromatics and limited reformate in gasoline, and this is an extremely low utilization rate.

Exhibit No. UNO-7 at p. 15 (citations omitted).

Culberson contends, under O'Brien's method, that West Coast Naphtha prices could stay at levels above Gulf Coast Naphtha and Caribbean Naphtha long enough to bring in shipments.[289] *Id.*

712. Addressing the claim that there can be no backhaul and that the limited availability (25%) of clean tankers imposes severe restrictions on the ability of the market to divert or ship Naphtha to the West Coast, Culberson responds that clean tankers travel frequently from the Caribbean to the East Coast and back without any backhauls. *Id.* at p. 17. Also, he continues, tankers routinely travel from western South America to the Gulf Coast without return hauls. *Id.* He argues, "[i]f a significant percentage of the 25% of clean tankers were pressed into service hauling naphtha from Mexico and the Caribbean to the West Coast, approximately 25,000 barrels per day of naphtha could be moved to the West Coast." *Id.* Finally, according to Culberson, no market barriers prevent Naphtha imports in the event that Naphtha values spike, rather, he asserts, it is easier to import Naphtha into the West Coast than it is to import gasoline because surplus Naphtha of the appropriate quality is produced by refineries in Mexico, the Caribbean, and South America, while CARB gasoline production outside of California is severely limited. *Id.*

713. As for O'Brien's contentions regarding Steven Laino's ("Laino")[290] statements made to Culberson, he answers that O'Brien misinterprets Laino's statements. *Id.* at pp. 17-18. More precisely, Culberson stated:

> While Mr. Laino did say that only about 25% of commercially available vessels will travel to the West Coast due to a lack of return cargoes, I

[289] Culberson states:

> O'Brien's naphtha method produces West Coast naphtha prices that average 7.5¢/gallon higher than Gulf Coast naphtha prices over the period 1992-2001. In some cases far higher differentials are in effect for 6 months, which is much longer than the time of 2-3 weeks to get a naphtha shipment to the West Coast from the Gulf Coast area. . . . [T]he O'Brien West Coast price differential provides more than sufficient incentive to recover the cost of transporting naphtha to the West Coast. The absence of any significant West Coast naphtha imports during these periods shows that the O'Brien method overvalues naphtha.

Exhibit No. UNO-7 at pp. 16-17.

[290] Steven Laino is a ship broker working for Odin Marine, a ship brokering and marine consulting firm, based in Stamford, Connecticut, with offices in Europe, Singapore and Korea. Exhibit No. UNO-9 at p. 5.

> understood him to be referring to times of normal demand for shipping. He also stated that rates may drop to 70% of Worldscale or lower when there is excess shipping capacity, and that at this time, there is a surplus of tankers for clean products and rates are at or slightly below Worldscale 100. He said that, if naphtha were needed on the West Coast, "it would not be difficult to arrange spot shipments of naphtha to the West Coast in these vessels. The outlook for the foreseeable future is for an ample supply of tankers with no expected increase in rates."

Id.

714. Responding to Tallett's claim that there are no West Coast imports of Naphtha because West Coast refiners are self-sufficient in Naphtha, Culberson asserts that West Coast refiners could choose to buy Naphtha rather than make it themselves. *Id.* at p. 18. He adds,

> [t]hey could accommodate this choice by substituting cheaper crude oils that produce lower naphtha fractions. . . [I]f West Coast naphtha were more valuable, refiners would be willing to pay a price higher than Gulf Coast prices to attract naphtha supply. Both are necessary to explain the lack of naphtha imports. Conceivably, if West Coast refiners could not meet their demand with internally generated naphtha, there would be imports even with prices on the Gulf Coast and West Coast being in parity. But where the West Coast refiners are capable of meeting their own demand, the lack of naphtha imports says something about the West Coast naphtha price. It indicates that the West Coast price is not significantly above the Gulf Coast price. That is not self-contradictory.

Id. at pp. 18-19.

715. Regarding Tallett's argument that intermediate product prices follow gasoline prices, Culberson attacks Tallett's reliance on Exhibit No. EMT-89 to graphically demonstrate his conclusions. Exhibit No. UNO-7 at p. 20. He claims that the exhibit is incomprehensible and unreadable, " [t]he longitudinal axis, representing time, spans the period of January 1992 through December 2001 . . . [and] is so shortened in the graph that the curves are all bunched together. This has the effect of masking the substantial price differences between and among the various products." *Id.* Culberson maintains, based on the prices of Vacuum Gas Oil and Light Straight Run, that intermediate product prices do not follow gasoline prices. *Id.* at p. 21. He further declares that, even were it possible to plot West Coast Naphtha against West Coast gasoline prices and even were it shown that West Coast Naphtha prices followed Vacuum Gas Oil prices, it does not follow that West Coast gasoline prices should be used to value Naphtha. *Id.*

716. Culberson responds to Toof's contention that Tallett's approach to valuing West Coast Naphtha is better than Culberson's by stating that Tallett's method is fundamentally flawed because, even though Tallett contends that the West Coast market is distinctly different from the Gulf Coast market, "he inconsistently uses a correlation between finished products (gasoline and jet fuel) and an intermediate product (naphtha) based on Gulf Coast product prices to establish a West Coast product price." *Id.* 25.

717. Culberson says that he disagrees with O'Brien's argument that his approach to valuing West Coast Naphtha is inconsistent with the price spreads of other products and that only O'Brien's method is fully consistent with the approaches taken with respect to the valuation of other cuts. *Id.* He argues:

> [O'Brien's] approach is <u>not</u> consistent with the approaches taken with respect to other cuts, and should be rejected because it would grossly overvalue the naphtha cut. In fact, if you correct the arbitrary assignment of an elevated reformate value in his calculations, his cost-based approach produces a result that is <u>below</u> the value of Gulf Coast naphtha. Therefore, a proper cost-based analysis supports my argument for retaining Gulf Coast prices.

Id. at pp. 25-26 (emphasis in original). Culberson also attacks O'Brien's proposal stating that he agrees with Ross and Sanderson in their criticism. *Id.* He further states:

> [T]he most fundamental error lies in [O'Brien's] arbitrary assignment of value to the intermediate product, reformate, which like naphtha has no published West Coast price. This involves a two-step process. . . . [where] O'Brien back-calculates a value of $26.02 per barrel for reformate based on a published gasoline price of $24.05 per barrel. His assumption is that, because you can blend gasoline from three products, LSR, N-butane and reformate, and there are published prices for LSR and N-butane, you can back calculate the value of reformate by weighting the percentage of each constituent in the blend, using the feedstock prices for LSR and N-butane, and algebraically calculating a value for reformate to produce a $24.05 value for the blend. The problem with this argument is that it assigns a finished product value to reformate, a blendstock, while retaining feedstock values for LSR and N-butane, thereby transferring all of the value of the gasoline blend to reformate and none to LSR and N-butane. If this blending process were actually used to any great degree, the values of LSR and N-butane would immediately rise until they approached the price of gasoline.

Id. at pp. 26-27.

718. Regarding the Naphtha contracts produced in this proceeding, Culberson states that the Naphtha contracts produced by Company 31 were not impressive in number, Naphtha volume, or objectivity. *Id.* at p. 29. He notes that only 70 contracts were produced covering the December 1993 to February 2002 period, that 59 were for West Coast delivery (including one to Anchorage (AK) and three to Hawaii), that 10 were for delivery to a foreign port, and that nine involved an intra-company transfer. *Id.* Culberson claims that, of the 50 West Coast contracts not involving an intra-company transfer, O'Brien only referred to 33 which is an average of one every three months over the 99-month December 1993 to February 2002 period. *Id.* at p. 30. He also asserted that the total volume of the 33 contracts is about 2.8 million barrels, or about 1,000 barrels/day; compared with 170,000 barrels/day of Naphtha produced from ANS, or less than 0.6%. *Id.* Lastly, Culberson notes, two-thirds of the entire volume represents four contracts which took place during the 1999-2001 anomalous period. *Id.*

719. Discussing the contracts submitted by Phillips, Culberson notes that the vast majority represented truck lots of around 200 barrels. *Id.* at p. 33. Eliminating these small truck lots, Culberson claims, leaves only 24 contracts, of which three can be eliminated because of duplication, and an additional six can be eliminated because the material did not meet Quality Bank standards. *Id.* at pp. 33-34. The remaining 15 contracts involved about 800 barrels/day, or 0.5% of the ANS-based Naphtha, were all from the anomalous 1999-2001 period and had prices which were below, at or slightly above the Gulf Coast Platts Naphtha quote. *Id.* at p. 34.

720. Referring to contracts submitted by Company 41, Culberson declared that all but 23 could be eliminated for the same reasons as contracts were eliminated in other analyses.[291] *Id.* at p. 36. The total volume involved in these 23 contracts amounted to about 0.4% of the total volume of Naphtha produced from ANS. *Id.* at p. 37.

721. Culberson declares that his analysis of the contracts submitted by Alaska reflected that only 201 contracts were discovered which took place during the 120-month period July 1992 through May 2002 and that this amounts only to 1.7 contracts/month and that, of those, almost 50% were made during the anomalous 1999-2001 period. *Id*. at p. 39. Culberson also notes that the total volume covered by the contracts was about 3,100 barrels/day in comparison with 170,000 barrels/day produced by ANS or 1.8% of the total Naphtha volume produced from ANS. *Id.* at pp. 39-40.

722. After his review of the contracts, Culberson concluded:

> [The contracts] have provided no compelling evidence that the ANS

[291] The exclusion criteria are listed in Exhibit No. UNO-47. Transcript at p. 10188.

> naphtha cut destined for the West Coast should be valued higher than Gulf Coast naphtha prices. They have reaffirmed my opinion that the ANS naphtha cut destined for the West Coast should continue to be valued at Gulf Coast naphtha prices.

Id. at p. 41.

723. On further direct examination, at the hearing, Culberson stated that, following submission of his pre-filed testimony, he received information regarding the contract analyses.[292] Transcript at p. 10188. He testified that his updated analysis reflected that, during the 1993-98 period, on a straight average basis, the West Coast Naphtha price was about 0.9¢/gallon higher than that on the Gulf Coast. *Id.* at p. 10191. On a volume-weighted average basis, he said that the West Coast Naphtha price was about 2.51¢/gallon higher than that on the Gulf Coast. *Id.* In 2002, Culberson claimed, the West Coast Naphtha straight average price exceeded the Gulf Coast price by 1.9¢/gallon. *Id.* at p. 10192. Culberson opined that, while the West Coast Naphtha price may have exceeded the Gulf Cost price by a "penny or two a gallon," he did not consider it significant or unusual. *Id.* at pp. 10192-93.

724. According to Culberson, Platts does not use term contract data to report prices; rather, it uses cash contract data only. *Id.* at p. 10193. He added that, according to Platts, Gulf Coast contracts often vary from the reported prices by a penny or two. *Id.* at p. 10194.

725. Under cross-examination, Culberson agreed that eight of the nine Quality Bank cuts have both a Gulf Coast and a West Coast reference price.[293] *Id.* at p. 10207. Culberson was asked whether this was so because the values of these cuts were different on each coast and he replied: "I would say it's because there's good data available in those cuts to other prices." *Id.* at pp. 10207-08. He added that he didn't think that the prices necessarily would be different and said "[t]hey might be the same at various times." *Id.* at p. 10208.

726. Culberson agreed that West Coast and Gulf Coast Naphtha values were different, but asserted that there was no "good data" regarding West Coast Naphtha values. *Id.* He admitted that, were a West Coast Naphtha value higher than that on the Gulf Coast, it

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[292] The updated information is reflected in Exhibit UNO-20. Transcript at pp. 10188-89.

[293] The eight cuts referred to include VGO which, in this proceeding, the parties have agreed will have both a Gulf Coast and a West Coast reference price. Transcript at p. 10207.

would be detrimental to his client. *Id.* at p. 10211. On re-direct examination, Culberson agreed that Phillips would be benefited by the higher West Coast Naphtha values resulting from O'Brien's proposal, were the Commission to adopt it. *Id.* at p. 11492. He further stated that Exxon would benefit were Tallett's proposal to be adopted by the Commission. *Id.*

727. According to Culberson, there is a higher demand for Naphtha on the Gulf Coast than on the West Coast. *Id.* at p. 10332. He agreed that this could drive the Gulf Coast Naphtha price up. *Id.* at p. 10333. Culberson also stated that the Gulf Coast had the greatest concentration of refineries as well as the largest number of petrochemical plants in the United States. *Id.* He also declared that more Naphtha is produced on the Gulf Coast than on the West Coast and that more is imported. *Id.* Furthermore, Culberson agreed that there was a higher demand for Naphtha on the Gulf Coast than on the West Coast, but he added that West Coast supply and demand was in balance. *Id.* at pp. 10333-34.

728. Culberson testified that, based on a Quality Bank common stream volume of 1.1 million barrels/day, a range of 100,000-150,000 barrels/day of ANS Naphtha is produced. *Id.* at p. 11326. He agreed that, taking this volume into consideration, "a cent per gallon over a sustained period of time" was a significant amount. *Id.* at pp. 11326-27. In addition, Culberson agreed that, during some periods of time, it was reasonable to price good quality Naphtha[294] at the CARB unleaded regular gasoline price less 8¢ and poor quality Naphtha[295] at the CARB unleaded regular gasoline price less 15¢.[296] *Id.* at pp. 11327-28. He said that this formula was "correct" for the 1999-2001 period, but not for all contracts which took place during the 1993-1998 period. *Id.* at p. 11328.

729. When asked whether he had any "empirical data" which suggests that "Gulf Coast Naphtha prices are a good representation of West Coast" Naphtha values, Culberson said that he had only his "knowledge of the way refineries and chemical plants operate" and his knowledge of the "trends in these industries over the last 30-plus years." *Id.* at pp. 11408-09. Questioned further, Culberson admitted that he could point to no record evidence supporting the proposition. *Id.* at p. 11409.

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[294] According to Culberson, good quality Naphtha "has a reasonable N plus A number [somewhere in the 50 range], and it's good reforming quality naphtha." Transcript at p. 11330.

[295] Culberson stated that poor quality Naphtha would have a low N+A or "could also be outside the boiling range of normal naphtha." Transcript at p. 11330.

[296] *See also* Exhibit No. UNO-9.

730. According to Culberson, while it is appropriate to make an N+A adjustment for Gulf Coast Naphtha, the same is not true of Naphtha on the West Coast. *Id.* at pp. 11409-10. He said that Naphtha with an N+A of 40 and Naphtha with an N+A of 55 has the same value on the West Coast. *Id.* at p. 11410.

731. Discussing the 1999-2001 period which Culberson identified as "atypical,"[297] he stated that imports of petroleum products rose significantly[298] on the West Coast. *Id.* at pp. 11449, 11500. However, under further questioning, Culberson admitted that the increase in VGO was minimal and that the major imports were gasoline and gasoline blendstocks. *Id.* He later agreed that "nobody is importing naphtha on a regular basis to California." *Id.* at p. 11476.

732. Summing up why he believed that the Gulf Coast Naphtha price should continue to be used to value West Coast Naphtha, Culberson made the following points: (1) there has been high refining margins on the West Coast which were not captured at the refinery, but at other levels; (2) using West Coast gasoline retail or wholesale prices mistakenly attributes some of the value of the captured refining margin to the Naphtha; and (3) this value should not be attributable to the value of Naphtha because the cost of making it out of crude oil doesn't change "anywhere near what happens in the marketplace." *Id.* at pp. 12056-57. Culberson also reiterated his claim that, if the value of West Coast Naphtha surpassed that on the Gulf Coast, West Coast refiners would switch their crude oil slates so they would make less Naphtha and import the cheaper Naphtha. *Id.* at p. 12057.

733. During later examination, Culberson admitted that there are limitations as to how much a refinery could change its slate: "You can change crude oil slates quite a bit, but if you have an existing plant that's already geared up to use southern crude oil, there are limitations on how far you can adjust from that balancing point or starting point." *Id.* at p. 12070. He does insist, however, that even though a plant could not change its whole slate, it could make some adjustments.[299] *Id.* Culberson claims:

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[297] According to Culberson, during this period "there was an unusual large number of refineries with outages, from various things like fires, explosions and equipment problems which caused a lot of refinery outages and some product shortages." Transcript at p. 11500.

[298] Asked to define what he meant by "significant," Culberson replied: "They doubled or tripled in some cases." Transcript at p. 11449.

[299] Culberson agreed with suggestions that refiners could change the cut points (boiling points) in crude units or in cokers (to some degree), or change the cut point between distillate and hydrocrackate in the hydrocracker. Transcript at pp. 12088-89.

> What they would do is go to a heavier crude oil and process that, run their conversion units, cat crackers, hydrocrackers and cokers at full capacity, as high as they could get, and they would be making less naphtha out of the reduced crude oil they're bringing in suddenly and importing naphtha then to bring the balance there.

Id. at p. 12071. While he did not feel that this would impact ANS sales, Culberson further admitted that it would have to be mixed with the heavier crude, and that not every refiner would move to the heavier crude. *Id.* Also, he did not believe that this would change the slate of finished products made from the crude. *Id.* at pp. 12071-72.

734. Under further examination, Culberson noted that there were two grades of Naphtha: (1) reformer grade which can be used "either for gasoline manufacturing and refining or aromatics manufacturing, benzene[,] xylene and toluene which is [sic] feedstocks for a lot of products we enjoy at home and appliances and whatever;" (2) a lighter Naphtha, "which comes in primarily through the Gulf Coast," used for making ethylene[300] in cracking furnaces. *Id.* at pp. 12067-68. He also stated that both types could not be used to make CARB gasoline because the LSR portion of Naphtha requires further processing (isomerization) before it can be used. *Id.* at pp. 12068-69.

735. Culberson agreed that "there's no real way for anyone to determine the actual market value of West Coast naphtha because there's so little naphtha traded on the West Coast."[301] *Id.* at pp. 12074-75. He claimed that all of the proposals had "deficiencies" and maintained that Platts Gulf Coast price was the "best reference." *Id.* at pp. 12078-79. According to Culberson, he could "live with" Ross's proposed floor price of ANS plus $4.00. *Id.* at pp. 12076-77. Of the remaining three options, with or without Ross's governor, Culberson indicated that he favored Dudley's proposal without the governor, but still thought that Ross's floor proposal of ANS plus $4.00 was the best alternative were the Commission to move away from Platts Gulf Coast Naphtha quote. *Id.* at pp. 12078-79.

736. During questioning about the manufacture of CARB gasoline, Culberson indicated that a refinery's reformer would have to be run "at a higher severity to make CARB

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[300] This is used to make garbage bags, bottles and like items. Transcript at p. 12068.

[301] According to Culberson, only about 1,000 barrels/day of Naphtha were traded during the 1994-2001 period, while about 5,000 barrels/day of VGO were traded during the 1996-2001 period. Transcript at p. 12126.

gasoline."[302] *Id.* at p. 12106. He indicated that this was done "to make octane"[303] because CARB gasoline requires a higher octane than regular unleaded gasoline. *Id.* at pp. 12106-07. However, he noted that, were a reformer run at a lower severity, the octane level might be increased by use of a blendstock such as MTBE or Ethanol. *Id.* at pp. 12107-08.

J. JAMES A. BOLTZ

737. Besides Dudley, Boltz testified on the Naphtha issue on behalf of Petro Star. Exhibit No. PSI-1 at p. 1. Addressing the appropriate valuation method for West Coast Naphtha issue,[304] Boltz explains that Petro Star believes that there should be no change to the current methodology. *Id.* at p. 4. Alternatively, Boltz continues, were the Commission to determine that a West Coast reference price must be used, then he suggests Dudley's methodology would be appropriate. *Id.* at p. 4. According to Boltz, if the methodologies proposed by the various parties in this proceeding had been effect in the past, Petro Star's financial performance would have been significantly undermined and a substantial portion of Petro Star's net income would have been used to fund the methodologies' assessment. *Id.* at pp. 4-5. He states

> [g]iven the nature of Petro Star's operations, the magnitude of these impacts demonstrates why using finished gasoline as the pricing basis for West Coast Naphtha is inaccurate and unfair. Essentially, using a finished

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[302] According to Don Jeffrey Sorenson: "Severity is usually referred to in degrees of Fahrenheit. We think about the temperature of the reactor. The higher the temperature, we refer to that as being higher severity." Transcript at p. 13224. He also noted that, while higher severity results in a higher octane, it also results in a lower volume of liquid produced. *Id.*

[303] According to Culberson, "[t]he higher the severity, the higher the octane." Transcript at p. 12106.

[304] According to Boltz, a high Naphtha Quality Bank valuation would have a significant affect upon Petro Star because

> Petro Star does not manufacture gasoline. However, we retain a portion of the higher boiling range Naphtha to use in jet fuel manufacture. Consequently, our return oil is lean in Naphtha relative to the TAPS common stream, and a high Quality Bank valuation of Naphtha increases our Quality Bank assessments.

Exhibit No. PSI-1 at p. 4.

> gasoline-based valuation for West Coast Naphtha would unfairly shift the value that is added by refiners in the refining process to crude oil producers.

Id. at p. 5.

738. During cross-examination, Boltz stated that he agreed with the testimony of some previous witnesses that the price of finished products, like gasoline, should not be used to value West Coast Naphtha. Transcript at p. 11592. However, he did not disagree with the statement that "the value of naphtha on the West Coast is related to the value of gasoline." *Id.* at p. 11593. Addressing Dudley's proposal for valuing West Coast Naphtha, Boltz stated that Petro Star has never used that method to compute the value of Naphtha nor, to his knowledge, has anybody else in the industry. *Id.* at p. 11594. On re-direct examination, Boltz also stated that he was not aware of any of the proposals made in this proceeding being used to value Naphtha. *Id.* at p. 11612.

739. Boltz denied that Petro Star was being inconsistent in asserting that Naphtha should be continued to be valued using Platts Gulf Coast quote while positing that the remaining eight cuts be valued on a West Coast waterborne basis. *Id.* at p. 11595. In support, Boltz notes that there is no West Coast published Naphtha price. *Id.*

K. KARL R. PAVLOVIC

740. Pavlovic was called to the stand to identify and authenticate Exhibit No. EMT-488. Transcript at p. 12184. He stated that it contained a series of emails between him, officials of the Energy Information Agency and others "regarding various classifications of naphtha and [his] understanding of [how] reformer grade naphtha would be reported, both to the administration and in their statistics." *Id.* During cross-examination on this point, it became apparent that it was an attempt by Pavlovic to get an understanding as to what was meant by "reformer grade naphtha." *Id.* at pp. 12185-89. He stated that he believed that "a reformer grade naphtha is a naphtha irrespective of its initial and ending boiling point, that has a high enough N plus A to be useful as reformer feedstock." *Id.* at p. 12189. Despite this, he claimed that the EIA does not use a reforming Naphtha classification. *Id.* Pavlovic admitted, under further cross-examination, that he did not know how to classify Naphtha which could both be used in a reformer or to make petrochemicals. *Id.* at pp. 12190-92.

L. THE JUNE 2003 HEARING

1. INTRODUCTION

741. At the hearing, on February 27, 2003, counsel for the Quality Bank Administrator (sometimes "Administrator") advised us that that day the Administrator was filing for a

change in the manner in which Naphtha was being valued.[305] *Id.* at pp. 9491-92. Heretofore, the Administrator had used the Platts Gulf Coast Waterborne Naphtha assessment, counsel stated, but Platts had announced that it was going to add a Heavy Naphtha quote to that previously published. *Id.* Inasmuch as the Administrator believed that the Heavy Naphtha quote referenced a product which was closer in kind to Quality Bank Naphtha, he was proposing that it replace the quote previously used. *Id.* at p. 9492.

742. As there was opposition to the Administrator's proposal, while the Commission accepted it, it suspended the tariff and set the matter for hearing, consolidating it with the ongoing proceeding. *BP Pipelines (Alaska), Inc.*, 102 FERC ¶ 61,345 (2003). Subsequently, the parties agreed that evidence on this issue was to be presented in June 2003.

2. JAMES THOMAS MITCHELL

743. First, Mitchell addressed the possibility that someone would publish a West Coast Naphtha assessment. *Id.* at p. 13169. He stated that he contacted both Platts and OPIS and provided them with some of the evidence presented in this case indicating that there was some Naphtha trading being done on the West Coast. *Id.* at pp. 13169-70. Mitchell stated that the Platts employee indicated that, while such an assessment was under consideration, it did not have a high priority. *Id.* at p. 13170. The OPIS employee with whom he spoke told him, Mitchell said, that her boss asked her to investigate the matter. *Id.* at p. 13171. By the time of his testimony, Mitchell has not heard anything further from either reporting service. *Id.*

744. Next, Mitchell went on to discuss his February 2003 filing. Transcript at pp. 13171-72. He said that, until Platts announced it, he was unaware that it was contemplating publishing both a Gulf Coast Naphtha and a Gulf Coast Heavy Naphtha assessment. *Id.* at p. 13172. After speaking with Robert Sharp ("Sharp"), an employee of Platts, he "decided to adopt the heavy naphtha assessment to value the naphtha component" for the following reason: "Given without a doubt the heavy naphtha assessment, the properties upon which that was based more closely related to the properties of the Quality Bank naphtha component, I felt that was an appropriate price to use." *Id.* at p. 13173-74. In a conversation about a week before he testified, Mitchell says he was told by Sharp that Platts had "plenty of transactions" and "had no trouble assessing a [Heavy Naphtha] price." *Id.* at p. 13175.

745. Mitchell was asked to address the question of Naphthenes + Aromatics as regards the Heavy Naphtha assessment. *Id.* at p. 13175. He indicated that Sharp told him that he would adjust the Full Range Naphtha data by 0.15¢/N+A percent/gallon up to an N+A of

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[305] The filing is attached to the record at Exhibit No. PAI-222.

50 with a maximum adjustment of 1.5¢/gallon.[306] *Id.* Asked whether he would adjust Platts Heavy Naphtha assessment by 1.5¢/gallon, as suggested by some parties, to account for the higher N+A in ANS, Mitchell stated that he considered and rejected it because he lacked the authority to do so. *Id.* at p. 13176. Saying that he had no position on whether the Commission should order such an adjustment, he indicated that it was administratively feasible if the Commission chose to do so. *Id.*

746. He was asked to describe how his office handled the third party price assessments, Mitchell said that his office used the published version of the prices rather than the electronic version, and that his analyst check any anomalous prices with the reporter. *Id.* at p. 13179. Mitchell added that his office used the "daily highs and lows for all of [the] pricing for what we call quote days, those days in which the prices are quoted" except for West Coast natural gas liquids which are quoted on a weekly basis. *Id.* at pp. 13180-81.

3. DON JEFFREY SORENSON

747. Don Jeffrey Sorenson ("Sorenson") was called to testify by Phillips. Transcript at p. 13208. He is an "advising engineer in the business analysis group at the [Phillips] Los Angeles refinery." *Id.*

748. Sorenson testified that Phillips has three West Coast refineries: (1) Ferndale (WA); (2) San Francisco Area (which consists of two plants, one in Rodeo and the other in Santa Maria); and (3) Los Angeles (which also consists of two plants, one in Wilmington and the other in Carson). *Id.* at pp. 13211-12. The primary product, he stated, produced at the Los Angeles refinery is CARB gasoline. *Id.* at p. 13212. According to Sorenson, CARB II contained MTBE as an oxygenate,[307] but that the State of California ordered that MTBE be removed effective January 2004 and so CARB III was created without the additive. *Id.*

749. After prefacing his remark by indicating that he has worked with gasoline blending and in Naphtha purchasing, Sorenson said that refiners value Naphtha[308] with a

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[306] According to Mitchell, the Platts employee with whom he spoke indicated that he did not believe that there was enough Naphtha with an N+A above 50 to make it "worth making a correction," but the employee claimed not "[to be aware that] ANS naphtha is considerably above that." Transcript at pp. 13197; *see also id.* at p. 13333.

[307] MTBE was removed to meet environmental concerns. Transcript at p. 13213.

[308] Sorenson defines Naphtha as a material with a boiling range of 70°F to 400°F. Transcript at p. 13214. He also said that the term Light Naphtha refers to material in the lower part of the boiling range, that the term Heavy Naphtha refers to material in the heavier range, and that the term "Full Range Naphtha" refers material in the entire

55 N+A[309] more than Naphtha with a 40 N+A. *Id*. at p. 13213. He states the following regarding aromatics:

> Aromatics are very high octane. Aromatics in the gasoline pool increase the octanes. Aromatics in the naphtha feed to the catalytic [reformer's] aromatics in the naphtha to make it easier for the catalytic reforming process because catalytic reforming produces aromatics to increase the octane of the gasoline so if the aromatics are already there, the reformer doesn't have to work as hard to increase the octane.

Id. at pp. 13218-19. Sorenson claims that this is significant because higher octane[310] material sells for a higher price than low octane material. *Id.* at p. 13219. According to Sorenson, refiners favor material with a high N+A because, as N+A increases, "the yield of gasoline or the volume of gasoline that can be made from a barrel of feed increases." *Id.* at p. 13220. Sorenson noted that Naphthenes make it easier to reform Naphtha to reach a given octane level. *Id.* at pp. 13221-22. He stated, too, that ANS has a high N+A. *Id.* at p. 13239. Asked whether his refinery would be willing to pay more for a crude with a 55 N+A than for a crude with a 40 N+A, Sorenson answered in the affirmative. *Id.* at p. 13242.

750. According to Sorenson, CARB gasoline regulations restrict the use of aromatics and benzene in gasoline. *Id.* at p. 13238. Despite that, he states, because a higher N+A increases yields, the value of a high N+A has not diminished. *Id.* However, according to Sorenson, ANS not only has a high N+A, it also has a high benzene level. *Id.* at p. 13239. He notes that, because restrictions on benzene use will be increased under the CARB III standards, refineries must purchase equipment to remove it. *Id.* at pp. 13238-39.

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boiling range. *Id.* Sorenson also noted that Quality Bank Naphtha refers to material which boils in the 175°F to 350°F range. *Id.* at pp. 13214-15.

[309] Sorenson reminds us the term "N+A" refers to the volume percent of Naphthenes plus the volume percent of Aromatics. Transcript at p. 13215. He notes that when a material is referred to as having a 40 N+A, it means that "40 percent of the material is naphthenes and/or aromatics." *Id.* at p. 13216. Sorenson states that the most fundamental of the Naphthenes are benzene, toluene and xylene. *Id.* at p. 13218.

[310] According to Sorenson, octane "is a measure of how the fuel burns, about how quickly it would ignite." Transcript at p. 13219. He adds: "If the fuel ignites too quickly, your car would knock and that's the knocking you hear if you're running [on] too low [an] octane." *Id.*

751. Sorenson testified that the volume of ANS going to California refineries has declined and that more ANS goes to the Pacific Northwest than to California. *Id.* at p. 13240. He didn't believe that the decline of ANS deliveries to California had anything to do with its benzene level, but thought that it had more to do with the declining ANS production. *Id.* at pp. 13240-41. Sorenson states that the California refineries are more able to process heavy, high sulfur crudes than the Pacific Northwest refineries and, thus, the latter were outbidding the former for the smaller ANS production. *Id.* at p. 13241.

752. On cross-examination, Sorenson was asked whether all Naphthas with an "N+A of 55 were equal with respect to being run through a reformer" and responded in the negative. *Id.* at p. 13260. According to him, a factor which would affect the ease with which Naphtha could be reformed is its benzene content. *Id.* He also indicated that Naphtha with a higher ratio of aromatics to naphthenes is easier to reform. *Id.* at p. 13261.

753. During re-direct examination, Sorenson stated that he believed that a material with an N+A of 55 provides more value to a refiner than a material with an N+A of 40, which is the standard N+A used by Platts. *Id.* at p. 13335. He declared that this would be true whether the refiner was making CARB II or CARB III. *Id.*

4. DAVID I. TOOF

754. Exxon called Toof to the stand to testify. *Id.* at p. 13337. Toof began his testimony by stating that he supported the Administrator's proposal to use the new Platts Gulf Coast Heavy Naphtha quote because the specification for that material more closely matches that of ANS Naphtha. *Id.* at p. 13339. He added:

> I believe that the cost differentiation, the approximately 1.5 cents per gallon that the Quality Bank administrator [sic] discusses, Platts' understanding of the difference, is borne out both by the data that we see since February [2003], and also, I believe you can generate, alternatively, that same sort of price differential going back in time.

Id.

755. Toof also stated that he believed that it was appropriate to adjust the Gulf Coast Heavy Naphtha quote by 1.5¢/gallon to account for the 55 N+A of ANS. *Id.* at p. 13340. He also suggested that the N+A adjustment would be consistent with adjustments being made for other Quality Bank cuts, referring in particular to the ".5 cent per gallon adjustment that's currently being made with regard to [the] light distillate cut and the 1.1 cent per gallon adjustment that's been proposed with regard to the heavy distillate cut for

the logistics adjustment."[311] *Id.*

756. During cross-examination, Toof stated that "generally the higher the N+A, the higher the volume of reformate at the same octane level." *Id.* at p. 13410. He further said that "the higher the severity [at which the reformer is run], the higher the octane and the concomitant reduction in the yield of reformate." *Id.* at pp. 13410-11. Toof, in addition, indicated that he understood that the purpose of a reformer was to make Aromatics and that, therefore, "aromatics pass through as aromatics." *Id.* at p. 13411.

5. WILLIAM J. SANDERSON

757. Williams called on Sanderson to testify on this point. *Id.* at p. 13476. He testified that the Administrator's decision to use the new Platts Heavy Naphtha quote did not cause a change requiring an N+A adjustment. *Id.* at p. 13483. Sanderson gave the following reasons in support of his position: (1) both Platts Full Range Naphtha quote and the new Heavy Naphtha quote are based on an N+A of 40; (2) he is not aware that the Platts assessment ever has been adjusted for N+A; and (3) it would be inconsistent to adjust the Naphtha value for N+A, but not adjust other cuts in a similar fashion. *Id.* As to the latter, he asserted that: "Once you make an adjustment for N+A and naphtha that we're talking about, I think that would open the door to make adjustments for the other products that are similar [to] naphtha, like light straight run, VGO and others." *Id.* at p. 13486. The cuts which Sanderson believes also may need adjustments are: LSR, Light Distillate, Heavy Distillate, VGO, and Resid. *Id.* at p. 13498.

758. According to Sanderson, in a conversation with Sharp, the same employee of Platts with whom Mitchell spoke, he was told that N+A was not routinely adjusted down to 40 N+A and that 0.15¢/N+A was "an industry rule of thumb." *Id.* at p. 13499. He also was told, he said, that specifications other than N+A were considered when making price assessments although he was not told what those other specifications were. *Id.* Sanderson also claimed that he was told that the N+A adjustment cutoff point was 48 and not 50 because "48 was a naphtha that was routinely traded in the Gulf Coast called El Chaure naphtha." *Id.* at p. 13500.

759. During cross-examination, asked about this conversation with Sharp, Sanderson indicated that he did not ask him about the conversation to which Mitchell referred.[312] *Id.*

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[311] Toof summarized his conclusions in a document attached to the record as Exhibit No. EMT-640. Transcript at p. 13341.

[312] Sanderson said that he asked Sharp "if the transaction you're looking at and considering has an N+A different than 40, do you make a .15 cent per N+A adjustment?" Transcript at p. 13564.

at p. 13564. Sanderson also stated that Sharp told him that the other factors he took into consideration were Reid Vapor Pressure, API gravity and total sulfur or mercaptans. *Id.* Sharp refused to provide him with "rules of thumb" for those factors, Sanderson related. *Id.* at p. 13564-65. However, Sharp did tell Sanderson, he stated, that the 0.15¢ N+A adjustment was an "industry rule of thumb." *Id.* at p. 13609. According to Sanderson, before this proceeding, he had never heard of this "rule of thumb." *Id.* at p. 13610.

760. Sanderson, also under cross-examination, agreed that a higher N+A allows a refiner to operate the reformer at a lower temperature and, therefore, at a lower operating cost. *Id.* at pp. 13555-56. He added that, with a higher N+A, a refiner can get the same octane operating the reformer at the lower temperature and also increase its yield. *Id.* at p. 13557.

761. Asked whether he agreed that "naphthenes are easily converted to aromatics by the catalytic reforming process typically found in refineries," Sanderson said he did. *Id.* at p. 13568. Also, he generally agreed that reformate was high in aromatics and was, therefore, an excellent gasoline blendstock, but said that it depended on the market. *Id.* at pp. 13568-69. Sanderson further agreed, in general, that makers of gasoline preferred Naphtha with a high (40+) N+A content, and that N+A is "one of the most important qualities sought by a gasoline or aromatics producer." *Id.* at p. 13569.

762. According to Sanderson, he did not believe that either the Gulf Coast or the West Coast Naphtha values should be adjusted for N+A because such an adjustment was inconsistent with the Quality Bank. *Id.* at p. 13570. Assuming that it was consistent with the Quality Bank, Sanderson thought that it might be appropriate to make such an adjustment on the Gulf Coast, but not the West Coast, because of the nature of ANS crude and its N+A content. *Id.* at p. 13571. He opined, however, that, were such an adjustment to be made on both coasts, the Gulf Coast adjustment would be higher because it "has a home for the benzene, toluene and xylene." *Id.* at p. 13571. Sanderson theorized that any N+A adjustment on the West Coast might be offset by a penalty for benzene content. *Id.* at pp. 13571-72.

763. On re-direct examination, Sanderson was asked whether, on the West Coast, a refiner would prefer a refiner would prefer a Naphtha with a 55 N+A which has a high benzene and benzene precursor content or with a low benzene, low benzene precursor, content and indicated that it would prefer the latter because there are benzene control requirements on the West Coast. *Id.* at p. 13614. He added that controlling benzene removes any benefit received from the 55 N+A. *Id.* at p. 13615. Sanderson also indicated that, as benzene was not tightly controlled on the Gulf Coast, it was less of a problem there for gasoline producers. *Id.* However, he noted that Gulf Coast producers of petrochemicals would favor the higher benzene content because they seek to produce benzene. *Id.* at pp. 13615-16. Sanderson agreed that there is no petrochemical industry on the West Coast. *Id.* at p. 13616.

764. According to Sanderson, removing MTBE from gasoline makes it more difficult for a refiner to meet restrictions on benzene and aromatic. *Id.* at p. 13618. He added, referring to CARB III gasoline to which MTBE is not added: "octane comes from aromatics from the reformer, and to accommodate the refiner's ability to make gasoline, particularly premium gasoline, the cap spec for aromatics and CARB phase III was increased and it goes to this issue." *Id.*

6. MICHAEL SARNA

765. Michael Sarna ("Sarna"), an employee of Purvin and Gertz, was called next by Williams. *Id.* at p. 13621. He testified that benzene content is not desirable if a gasoline producer has to meet the standards for CARB gasoline. *Id.* at p. 13628. Sarna stated that benzene is a known carcinogen. *Id.* at p. 13629. In addition, Sarna claimed that "removing one gallon of benzene from gasoline is the equivalent of removing 28 gallons of other aromatics." *Id.* at pp. 13634-35. He later clarified this comment stating: "the whole concept is taking a gallon of benzene out of the gasoline, you're allowed to put in 28 gallons of aromatics." *Id.* at p. 13815. Sarna said that this allows a refiner to "cut the reformate at a higher end point . . . among other things." *Id.* He agreed that this means that "the more benzene that you extract, the more flexibility you have in making gasoline." *Id.* at pp. 13815-16.

766. Sarna also noted that Gulf Coast refiners which have a BTX[313] operation value benzene and toluene. *Id.* at p. 13782. According to him, too, C_{10} aromatics are undesirable to California refiners because they have a high boiling point and are not good for blending CARB gasoline, because some of them convert to benzene, and because they tend to form coke on the catalyst in the reformer which shortens the life of the catalyst and results in a shut down of the reformer to replace or regenerate it. *Id.* at pp. 13628-29.

767. Not all aromatics are undesirable, according to Sarna. *Id.* at p. 13632. He suggests that high octane aromatics are desirable as a CARB gasoline blendstock.[314] *Id.* Sarna states that, trying to remove benzene and benzene precursors, a refiner loses Toluene and Toluene precursors, the highest octane material. *Id.* at p. 13633. Later, he stated that "in California, refiners are interested in the C_7 and C_8 aromatics in gasoline, owing to the CARB specifications." *Id.* at p. 13782.

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[313] BTX refers to benzene, toluene and xylene which are aromatics used to make plastics. Transcript at pp. 13218, 13782-83. No California refiners reform BTX aromatics. *Id.* at p. 13789.

[314] In connection with this comment, Sarna mentions Toluene (120 research octane), xylene (115), C_9 (110), and C_{10} (108). Transcript at pp. 13632-33.

768. Sarna states that the octane for premium CARB gasoline is 91 R+M/2 and for regular CARB gasoline it is 87 R+M/2. *Id.* at p. 13647. He said that, typically, California refiners operate semi-regenerative reformers in a range of 95-98, although "one or two refiners . . . operate higher than that." *Id.*

769. Asked whether, at a constant octane, an increased N+A provides an increased yield of reformate, Sarna agreed that it did. *Id.* at p. 13676. He also agreed that, when reforming to a constant octane, if "the higher the N+A, the lower the severity at which the unit can be operated" and that the lower severity resulted in cost savings. *Id.* at p. 13682.

770. According to Sarna, the making of CARB gasoline makes it "necessary that the refiners know what the C_6s, C_7s, C_8s, and C_9s are in" Naphtha and LSR because the refiners "need to know how much benzene and benzene precursors they have in the naphtha, and also how much toluene, xylene and C_9s because they all affect the gasoline pool." *Id.* at pp. 13836-37. He added that they need this information because of the specifications for CARB gasoline. *Id.* at p. 13837.

M. THE OCTOBER 2003 STIPULATION

1. INTRODUCTION

771. On June 18, 2003, the Quality Bank Administrator filed an additional "Notice . . . Regarding Proposed Replacement Product Price to Value Naphtha Component on the U.S. Gulf Coast and the U.S. West Coast" ["Notice"]which was accepted by the Commission subject to refund and to the outcome of this proceeding. *Trans Alaska Pipeline System, et al.*, 104 FERC ¶ 61,201 (2003). In addition, the Commission consolidated the issues raised with those pending in this proceeding. *Id.*

772. In his "Notice," the Administrator indicated that Platts had begun publishing two Gulf Coast waterborne assessments for Heavy Naphtha: one referred to as "Heavy Naphtha" reflect its assessment of transactions involving a ship's cargo (volumes up to 250,000 barrels) and the second referred to as "Heavy Naphtha Barge" reflects its assessment of barge cargoes (volumes up to 50,000 barrels). *Id.* at p. 61,705. The "Notice" further reflects that, as the two assessments split what previously had been one, he must propose a replacement and that he proposes the following: "the replacement price for the Naphtha component on both the Gulf Coast and the West Coast be the arithmetic average of the average monthly price for Gulf Coast Waterborne 'Heavy Naphtha' and Gulf Coast Waterborne 'Heavy Naphtha Barge' as reported to Platts." *Id.* at pp. 61,705-06.

773. After the Commission's Order, I held a pre-hearing conference on August 26, 2003, in order to determine how the parties wanted to make an evidentiary record

regarding this new issue. *Order Scheduling Prehearing Conference* (August 19, 2003). At the conference, the parties agreed to hold a short hearing starting on October 28, 2003. Transcript at p. 13876, *Hearing Notice* (September 23, 2003). However, on October 10, 2003, the parties submitted a "Stipulation . . . Regarding Hearing on Proposed Replacement Product Price to Value Naphtha Component on the U.S. Gulf Coast and U.S. West Coast Effective August 17, 2003." In that document, the parties agreed that, were certain documents admitted into evidence, there was no need for a hearing. In view of the above, on October 17, 2003, I issued an *Order Canceling Hearing and Accepting Evidence into the Record.* The evidence is discussed below:

2. THE OCTOBER EVIDENCE

(a) EXHIBIT NO. TC-19

774. Exhibit No. TC-19 is the Administrator's June 18, 2003, "Notice," which previously has been discussed.

(b) EXHIBIT NO. TC-20

775. Exhibit No. TC-20 consists of a two-page memorandum memorializing Mitchell's thought process regarding the June 18, 2003, "Notice." With regard to a conversation he had with Sharp, an employee of Platts, Mitchell states:

> [Sharp] confirmed that he is now assessing the prices in two separate markets. He feels that this is more representative of how the market actually functions. The assessment noted as "Hvy Naphtha" is, in fact, an assessment of cargo transactions. He has also bifurcated the full range naphtha assessment into cargo and barge transactions. He stated that barge transactions are typically for 50,000 barrels while cargoes are up to 250,000 barrels. He said that there are numerous transactions for both full range and heavy naphtha in both barge and cargo lots, although for heavy naphtha, barge transactions may slightly predominate. He was unable to provide any detailed breakdown of the transactions.

Exhibit No. TC-20 at p. 1.

776. In addition, Mitchell opines, based on experience at the hearing on this matter, that all interested parties agree that "heavy naphtha is the correct product to be used for valuation of the naphtha component." *Id.* He goes on to state that he has learned from Platts that there are numerous transactions for both barge and ship cargoes lots and that "both are representative of the market for heavy naphtha on the Gulf Coast." *Id.* at p. 2. Mitchell then asserts that he is unaware of any way in which to calculate either "a volume or a transaction weighted average of the assessments." *Id.* Consequently, he suggests

using "an arithmetic average of the average monthly price for Hvy Naphtha and Hvy Naphtha Barge as the price for the naphtha component on both the Gulf Coast and the West Coast." *Id.*

(c) EXHIBIT NO. TC-21

777. Exhibit No.TC-21 consists of one-page memorandum memorializing a telephone conversation which Mitchell had with Sharp following the August 2003 prehearing conference. In that conversation, Mitchell asked Sharp whether the Heavy Naphtha assessment effective from February through April 2003 was "an overall assessment for Heavy Naphtha on the Gulf Coast or was meant to be strictly a cargo assessment?" According to Mitchell, Sharp told him that, to make that assessment, both cargo and ship lots were taken into consideration. When questioned further, Mitchell states that Sharp told him that, while the assessment was weighted towards cargo lots, it "was not exclusively one or the other." When asked about the new assessments, according to Mitchell, Sharp indicated that the Heavy Naphtha assessment was strictly an assessment of cargo lots and that the Heavy Naphtha – Barge "is based solely on barge deals."

(d) EXHIBIT NO. TC-22

778. Exhibit No. TC-22 consists of a two-page memorandum memorializing a conference call between Mitchell, Sharp, Toof and Stephen Jones.[315] The memorandum reflects that Sharp stated as follows: "[P]rior to the addition of a heavy naphtha barge quote, the heavy naphtha assessment was intended to reflect a cargo basis and that the old number weighted barge a lot less and was therefore considered primarily a cargo number." Exhibit No. TC-22 at p. 1. Sharp also informed the conferees that, because "customer feedback had encouraged a minimization of barge quotes since it was used for cargo contract pricing . . . he considered the old heavy naphtha quote basis to be consistent with the current cargo assessment." *Id.*

779. Despite the above, Sharp repeated his previous comment to Mitchell that the old heavy naphtha quote "was not exclusively a cargo assessment" and included some, but not all, barge deals. *Id.* However, Sharp also said that "he sometimes used barge transactions for the high for the day and cargo transactions for the low." *Id.* at p. 2.

(e) EXHIBIT NO. TC-23

780. Exhibit No. TC-23 is an eight-page document consisting of the February 13, 1998, "Notice of TAPS Quality Bank Administrator Regarding Proposed Replacement Product Price to Value Gas Oil on the U.S. Gulf Coast and U.S. West Coast." Exhibit No. TC-23

[315] Stephen Jones is not further identified.

at p. 1. In the document, the Administrator notes that he discovered in February 1998 that, beginning January 1, 1998, OPIS was separating out its single price range for Gulf Coast High Sulfur VGO into separate reports for barge and cargo size lots. *Id.* at p. 3. He further states: "The barge assessments are for 50-75,000 barrel shipments delivered to Houston, Texas, while the cargo sales represent shipments of up to 250,000 barrels delivered anywhere on the Gulf Coast." *Id.*

781. In discussing this matter with employees of OPIS, Mitchell said that he was told that, while neither Gulf Coast market for High Sulfur VGO was "highly liquid, . . . the barge market is more liquid than the cargo market." *Id.* He also was told that, because there were many weeks in which no cargo transactions took place, OPIS "decided to report the cargo market separately because the occasional cargo transactions would tend to distort the price range reported for a particular day." *Id.* Mitchell was also told that it was believed that "over the course of a year, the barge price assessment would probably be more representative of High Sulfur VGO market value on the Gulf Coast." *Id.* at p.

ISSUE NOS. 5 (RETROACTIVITY) AND 9 (REPARATIONS)

A. JAMES A. BOLTZ

782. Boltz was the first witness to testify on these issues. His testimony was presented on behalf of Petro Star, which he believes would be prejudiced by retroactive application of proposed changes in the Quality Bank methodologies. Exhibit No. PSI-1 at pp. 1-2. As a preliminary matter, Boltz describes how the TAPS Quality Bank impacts Petro Star and explains which parties receive payments based on the assessments against Petro Star's return oil:

> At the Golden Valley Electrical Association ("GVEA") Connection (where the return stream is a commingled stream consisting of return oil from the Williams and Petro Star refineries) and the Petro Star Valdez Refinery ("PSVR") Connection, the Quality Bank calculates the value difference between the refinery return streams and the streams formed by commingling the return streams with the TAPS common stream. Petro Star's crude oil supplier pays Quality Bank assessments based on the differences between the value of Petro Star's return streams and the commingled streams, and Petro Star reimburses its supplier.
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> * * * *
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> Petro Star reimburses its crude oil supplier, which is a shipper on TAPS, for paying the assessments on Petro Star's return oil. Other shippers, typically North Slope crude oil producers, receive the actual payments from the Quality Bank. Three parties to this proceeding, Phillips, BPX, and Exxon

> Mobil account for 83% of North Slope production and are the largest beneficiaries. The State of Alaska has a royalty interest in 12.6% of North Slope production and has economic interests similar to those of producers. To a small extent, Petro Star's parent [Arctic Slope Regional Corporation] benefits, too, as a North Slope royalty owner. Under the Native Claims Settlement Act, [Arctic Slope Regional Corporation] shares this benefit with the other Alaska Native Regional Corporations.

Id. at pp. 3-4.

783. Regarding the retroactive application of the revised values issue, Boltz insists that any revised values should be applied prospectively only. *Id.* at p. 5. He states that "retroactive application of valuation methodologies effectively bars Petro Star from mitigating the effects of a redetermined valuation." *Id.* at pp. 5-6. Boltz explains that, while Petro Star's options are limited, it can adjust its product slate to "react to changes in the Quality Bank methodology." *Id.* at p. 6. He adds that, within environmental limitations, Petro Star can "select which petroleum fractions [to] . . . retain for use as refinery fuel, or withdraw from specific markets if it becomes "uneconomic to produce a particular fuel," or close. *Id.* He argues that, were the proposed changes in the Quality Bank methodology placed into retroactive effect, it would be too late for Petro Star to do anything to mitigate their impact. *Id.*

784. Boltz argues further that, had Petro Star "cut back its production based on a mistaken prediction that a new Quality Bank methodology would be imposed retroactively, it would have needlessly incurred losses that it has no means to recover." *Id.* at p. 7. He adds that withdrawing from markets on the basis of a party's shifting litigation position "would not have been prudent."[316] *Id.* at pp. 7-8. Additionally, Boltz suggests that, except for one customer with whom Petro Star has a long-term contract, it would not be able to recover these costs and would have to absorb them. *Id.* at p. 8.

785. According to Boltz, were the valuations were imposed retroactively, the impact on

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[316] Boltz also states that if the Commission

> or the courts find that the mere filing of an appeal or a complaint can trigger a serious danger of retroactivity, an aggressive competitor . . . could attempt to compel its rivals to cut production or withdraw from the market merely by filing a complaint or an appeal. If successful, this tactic would be anti-competitive and ultimately harm the consumer.

Exhibit No. PSI-1 at p. 8.

Petro Star would be "catastrophic."[317] *Id.* at p. 9. He argues that "the magnitude of the impact, when compared to the impact of the valuation methodology supported by all of the other Quality Bank participants, is evidence of the unfairness of the Exxon Mobil/Tesoro methodology."[318] *Id.* at p. 10. Furthermore, Boltz points to the diversity of interest of the parties opposing the Exxon proposals as evidence of the reasonableness of the current methodologies[319] and that "the compensation demanded by [Exxon] is excessive." *Id.* at p. 11.

786. During cross-examination, asked why Petro Star would agree to a Heavy Distillate methodology retroactive to February 2000 while at the same time suggesting that changes

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[317] According to Boltz, were Exxon's proposals for the remand cuts made retroactive for the period December 1993 though the end of 2001, the impact on Petro Star would total $20.8 million as compared with its net income, for the same period, of $36.81 million. Exhibit No. PSI-4. During cross-examination, Boltz claimed that, were the Exxon Resid valuation adopted, the change was significant enough, perhaps, to shut Petro Star down. Transcript at pp. 11746-48.

[318] Boltz states:

> If the remand cut valuations advocated by [Exxon] were imposed retroactively to December 1993, it would require a total payment from Petro Star that is approximately twenty times higher than the amount that would be required if the valuation methodology advocated by Mr. O'Brien were [sic] imposed retroactively.

Exhibit No. PSI-1 at p. 9.

[319] Boltz expands on this point stating,

> [a]lthough all of the participants in the Quality Bank would receive more from the refiners if the Exxon Mobil/Tesoro proposal were adopted, none of the other participants support it. Moreover, except in the special case of Heavy Distillate, none are seeking the retroactive application of any valuation of the remanded cuts. Other than Exxon Mobil, the parties that the Quality Bank compensates for the impacts of the refinery return streams accept as fair the prospective-only application of the O'Brien Resid valuation as a reasonable balancing of their diverse interests. This is compelling evidence that it *is* fair, and that the compensation demanded by Exxon Mobil is excessive.

Exhibit No. PSI-1 at p. 11 (emphasis in original).

in the Quality Bank methodology only should be prospective, Boltz replied that the former was an unusual circumstance because "the price was discontinued and frozen in its last price, so we know that the price that's being used for heavy distillate is incorrect, and all the parties have agreed to within a penny as to what that price is going to be." Transcript at p. 11709. Later, he added that Petro Star has not made any change in its operation as a result of the change in the Heavy Distillate methodology because the new price would be very similar to the old one. *Id.* at p. 11726.

787. After agreeing that Petro Star would be allowed a more competitive position were any changes to be prospective rather than retroactive, Boltz also agreed that the method used by the Quality Bank to value Resid was significant to Petro Star's profitability because its "return streams have a higher proportion of resid that does the" common stream. *Id.* at p. 11710. When the gravity method was replaced with the distillation method, for example, Boltz said that one of the things Petro Star did was to change fuel types and product mix. *Id.* at pp. 11714-15. He also stated:

> One of the other things that we've done is as we have gone along, our general approach to optimizing the refineries has been one of maximizing the jet fuel cut and also maximizing our throughput. We could have gone in a completely different direction here, and we could have maximized the diesel fuel and minimized throughputs and concentrated on efficiencies. Because of the way the Quality Bank has been during this period of time, the optimum position for us was to increase capacity.

Id. at p. 11715.

788. Asked about how Petro Star responded to a 1997 change in the Resid valuation, Boltz indicated that, because the Resid valuation was lowered, Petro Star continued to expand its refineries and its throughput. *Id.* at p. 11716. He noted that "[i]n the case of the Valdez refinery, in 1993, we were operating at 30,000 barrels a day of throughput. Today, we operate as high as 50,000 barrels a day of throughput." *Id.* Boltz, agreeing that the change lowered the value of Resid indicated that, despite that fact, Petro Star took the action it did because the change was not "significant enough to have [it] change [its] overall scheme of optimization." *Id.* at p. 11725.

789. During re-direct examination, Boltz testified that lowering the value of Resid in the Quality Bank would increase Petro Star's payment into it. *Id.* at p. 11735. In turn, that impacts its ability to sell its products because it would have to charge a higher price for them. *Id.* Under further examination, Boltz agreed that Petro Star was advantaged when the value of cuts in its return stream was more valuable than the cuts it retained. *Id.* at p. 11743.

B. J. DANA DAYTON

790. Phillips called Dayton back to testify on the retroactivity issue. Exhibit No. PAI-22 at p. 1. She notes that her testimony is also supported by Amoco, BP, OXY, Petro Star, Alaska, Unocal, and Williams. *Id.* at p. 2. Her general position on the issue is that there should be no retroactive application of the revised values to the various cuts. *Id.*

791. Dayton argues that, because the Commission held that retroactive relief was not available to aggrieved parties when the gravity-based Quality Bank was replace by the current distillation methodology in December 1993 "despite the fact that hundreds of millions of dollars of overpayments had been made into the Quality Bank by the impacted parties," no retroactive relief should be granted here. *Id.* at p. 3. She notes that "if changes to the distillation methodology are required to be made retroactive to December 1993, the same parties who made substantial overpayments prior to 1993 for which no reimbursement is possible would be required to make additional payments to the same parties who received substantial overpayments prior to December 1993." *Id.*

792. After describing the TAPS,[320] and discussing the "history of the Quality Bank litigation,"[321] Dayton admits that her argument is equitable in nature. *Id.* at p. 10. She then explains that, to support her argument, she estimated the refunds which would have been due aggrieved parties for the January 1, 1990, through November 30, 1993, period.[322] *Id.* at p. 11. Dayton states that she also "estimated the refunds that would be owed for the entire period of January 1, 1990, through December 31, 2001, if the Modified Nine-Party Settlement were made retroactive for the entire period." *Id.* She notes that she distinguishes between two distinct Quality Bank determination points for the purposes of her comparison (Pump Station No. 1 and the downstream refinery connections) because, she claims, the equitable issues are different between the producers at each locale. *Id.* at p. 11.

793. According to Dayton, with regard to the Pump Station No. 1 Quality Bank, light petroleum shippers benefited from the gravity methodology used prior to December 1, 1993, because the natural gas liquid blending resulted in an artificially high API gravity. *Id.* at pp. 11-12. As a result, she states, they received larger payments from the Quality

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[320] Exhibit No. PAI-22 at pp. 4-5.

[321] Exhibit No. PAI-22 at pp. 6-10.

[322] In later discussions with Judge Wilson, Dayton indicated that the earlier period could be said to begin in 1986 when the "major NGL blending at Prudhoe Bay started up." Transcript at p. 12663.

Bank "than they should have been due," while heavy petroleum shippers made "correspondingly higher payments into the Quality Bank." *Id.* at p. 12. Dayton states, further, that even though the change to a distillation-based method "corrected" the natural gas liquid blending problem, the "light petroleum shippers [still] have benefited from the various changes to the distillation-based methodology that have been instituted since December 1, 1993." *Id.*

794. Dayton declares that the refineries benefit from no retroactivity in either time period. *Id.* She states that the issue involving them is different and describes it as follows:

> TAPS is the only source of crude oil for the three online refineries. They must make operational decisions within their refineries to optimize operations. Within differing limits, a refinery can vary its operating parameters, its choices of fuels, and its product slate to reflect the impacts of the TAPS Quality Bank on its economics. Under some circumstances, Quality Bank considerations may even make it economically unreasonable for a refinery to participate in a given fuel market. Had a different methodology been in place in the past, the online refiners would have optimized past operations in light of that different methodology.

Id. at p. 13. Dayton argues, since these operators cannot go back and conform their operations to new conditions, i.e., they cannot mitigate the impact of retroactivity, it would not be fair to make the proposed changes retroactive. *Id.*

795. Summarizing her analysis, Dayton states that "shippers of lighter petroleum at Pump Station No. 1 benefited considerably more from the gravity methodology in the First Period [January 1, 1990, through November 30, 1993] than they have lost in the Second Period [December 1993 through December 31, 2001]." *Id.* at pp. 13-14. She concludes that, even though the Commission has determined that there should be no refunds for the first period, lighter petroleum shippers nonetheless benefited more during the first period than heavier petroleum shippers benefited in the second period. *Id.* at p. 14. Consequently, she maintains, it would be inequitable to "require retroactive application of changes in the Second Period when no retroactivity is possible for the First Period." *Id.* at p. 15.

796. Before describing the results in detail, Dayton explains her methodology. *Id.* She states that she "calculated the amount of refunds that would have been due each year if the Modified Nine-Party Settlement had been used for that entire year instead of whatever Quality Bank methodology actually was used for that year." *Id.* Dayton used the values contained in the Nine Party Settlement for Light and Heavy Distillate, both of

which, she states, were approved by the appellate court.[323] *Id.* For the Resid value, which is one of the remand issues, according to Dayton, she used O'Brien's value. *Id.* at pp. 15-16.

797. Dayton described the data she had, what she was missing and how she compensated for it, any adjustments and corrections she made, and how she accounted for consolidation of ownership and changes in equity interest. *Id.* at pp. 16-21. She then described Exhibit No. PAI-28 on which she presented estimated refunds or required payments for the major crude oil streams flowing into Pump Station No. 1 for the 1990 through 2001 period. Exhibit No. PAI-22 at pp. 21-22. Dayton described Exhibit No. PAI-29 as showing the same information broken down by producer. Exhibit No. PAI-22 at pp. 21-23. In addition, she described Exhibit Nos. PAI-30 and PAI-31 as following "the same format but includ[ing] the effects of the refinery connection Quality Banks." Exhibit No. PAI-22 at p. 22.

798. Based on these exhibits, Dayton concludes the following:

- Heavier petroleum shippers would receive refunds totaling $385 million for the 1990-1993 period, but would only owe $46 million for the 1994-2001 period.[324]

- Heavy petroleum shippers would benefit even more from the refinery connections as they would have received refunds of about $435 million for the earlier period and would owe refunds of only about $43 million for the latter period.

Id. at pp. 23-24. Dayton adds that her calculations do not include interest, about which she claims: "If interest were added, the refunds due in the First Period to the shippers of heavier petroleum would exceed the refunds due shippers of lighter petroleum by even more." *Id.* at p. 25.

799. In Reply Testimony, Dayton calculates the impact of Exxon's cut proposals on the other parties, using the same model and data used in her prior retroactivity calculations.

[323] *See Exxon,* 182 F.3d 30.

[324] Dayton argues that "[t]he impact on these shippers of not being compensated for the overpayments they made in the First Period will be exacerbated if refunds are ordered for the Second Period." Exhibit No. PAI-22 at p. 23. Such an occurrence, Dayton claims, will make the heavier petroleum shippers "double losers." *Id.* Concomitantly, light petroleum shippers, she asserts, "would receive a double windfall." *Id.*

Exhibit No. PAI-47 at p. 2. She explains that she performed three calculations,

> [f]irst, I have performed a calculation of the "remand" refunds, *i.e.,* the retroactive application back to December 1, 1993 of [Exxon's] Resid value, as well as of the Heavy and Light Distillate values adopted by the Commissions in 1997. . . . Second, I have added to that first calculation the retroactive application to July, 1994 of [Exxon's] proposed cut values for the Naphtha and VGO cuts. [Exxon] proposes an effective date of June 19, 1994. My analysis slightly underestimates the impacts of the effective date, by using a July 1 effective date. . . . In order to allow the Commission to evaluate the Naphtha and [Vacuum Gas Oil] retroactive claims separately, I have shown each impact calculation separately. I have not included the calculation of refunds for the proposed February 2000 effective date for the Heavy Distillate valuation as that effective date and the application of refunds to that date are not in dispute.

Id. at pp. 2-3. For the purpose of these calculations, Dayton notes, she used Exxon's proposed Quality Bank cut valuation formulas, correcting only for incorrect OPIS VGO prices in the Exxon Resid formula and the VGO retroactive calculations. *Id.* at p. 3. Also, Dayton states, interest is not reflected in her analysis, but "[t]he impact of showing interest in most instances would be to cause those parties shown as owing refunds to have their refund requirement increased, while those parties who are shown as receiving refunds to have their refund receipts increased." *Id.*

800. However, Dayton claims that there are several flaws in Exxon's refund calculations presented by Pavlovic. *Id.* As a preliminary matter, Dayton asserts that, since Pavlovic's calculations depend on flawed cut values proposed by other Exxon witnesses, the resulting values also are flawed. *Id.* at pp. 3-4. Even if Exxon's cut values were accepted, she claims, there still exist a number of flaws in Pavlovic's analysis. *Id.* at p. 4.

801. First, Dayton argues, Pavlovic incorrectly bases his calculations on the TAPS Carriers's invoices of number of barrels of crude shipped by Exxon which includes not only barrels of crude in which Exxon holds an interest, but also includes "royalty in value" barrels[325] and barrels purchased by Exxon from other parties.[326] *Id.* at p. 4.

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[325] These are "associated with the State of Alaska's royalty interest in various fields." Exhibit No. PAI-47 at p. 4. With regard to these barrels, Dayton states, Quality Bank credits and debits are passed through Alaska. *Id.* at p. 5.

[326] According to Dayton, Exxon "does not bear the impact of the Quality Bank credits and debits associated" with these barrels. Exhibit No. PAI-47 at p. 4. She adds, "[a]ny sales of crude for shipment through TAPS should include a passthrough to the

According to her, and, as a consequence, Exxon's damages are overstated. *Id.* Dayton notes that Pavlovic agrees that his calculations would overstate Exxon's damages, were the Quality Bank credits and debits included in them. *Id.* at pp. 6-7.

802. Another problem with Pavlovic's testimony, according to Dayton, is that Pavlovic never addresses damages suffered by Tesoro. *Id.* at p. 7. Also, Dayton states, Pavlovic failed to use Exxon's proposed processing cost deduction in calculating, and consequently overstates the Heavy Distillate impacts. *Id.* at pp. 7-8.

803. Dayton lists a number of other what she termed "errors or misstatements" contained in Exxon's presentation:

> • Exxon witness Toof, while claiming that Quality Bank values for Heavy Distillate and VGO were used, used the LA Low Sulfur Pipeline No. 2 value less 4.3¢/gallon to determine the value of Resid while the applicable price for Heavy Distillate was 0.5% Sulfur Waterborne Gas Oil until February 2000.
>
> • Toof also used the West Coast VGO value for the period December 1993 forward even though Exxon is not proposing this application until June 19, 1994.
>
> • The OPIS VGO prices used by Dr. Pavlovic and Dr. Toof are in error as they apparently have not considered corrections that OPIS periodically made to reference prices for a given month or otherwise have misinterpreted the data OPIS publishes which resulted in Toof running his regression on the wrong set of numbers.

Id. at p. 8.

804. Dayton explains that, in part, the purpose of her second Reply Testimony is to respond to "Pavlovic criticism of [her] testimony regarding the retroactive application of the Resid cut valuation." Exhibit No. PAI-71 at p. 1. According to Dayton, Pavlovic claims that there are five flaws in her analysis:

> (1) the heavy petroleum producers/shippers were not the unwitting victims of NGL blending; (2) [she] did not use shipper invoice volumes in [her] calculation of refunds; (3) [she does] not have TAPS distillation yield data for the 1990-93 time period; (4) [she has] overvalued Resid in [her]

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seller of the Quality Bank debits and credits." *Id.* at p. 5. Unless it does not, Exxon should not be able to claim credits for these barrels, according to Dayton. *Id.* at p. 6.

> calculations; and (5) [her] conclusions regarding the refiners are based on two false premises.

Id. at pp. 3-4.

805. Addressing the first of Pavlovic's claims, that heavy petroleum producers knew of the natural gas liquid blending, and, consequently, there are no equitable considerations, Dayton declares that "Pavlovic obviously has no knowledge of the approval process within the producing areas ("Units") on the North Slope."[327] *Id.* at p. 4. She adds that only Prudhoe Bay owners (producers of light oil) had a vote and that the heavy oil producers did not participate. *Id.* Moreover, while she agrees with Pavlovic that the heavy oil producers were aware that natural gas liquids were being blended, Dayton claims that the heavy oil producers did not acquiesce

> to the Quality Bank treatment of the NGL blending at Prudhoe Bay. . . . [T]hese producers expressed concerns that the then existing gravity-based quality bank would not result in an equitable accounting of the crude values once significant volumes of NGLs were being blended into the Prudhoe Bay stream.

Id. at pp. 4-5.

806. Dayton declares that, whatever the heavy producers knew about natural gas liquid blending, it would not be equitable to require producers of heavy oil to pay refunds for the latter period when they did not receive refunds for the 1990-93 period "when they were making overpayments into the Quality Bank." *Id.* at p. 6. She declares that refunds should be available for the entire period, from 1990 forward, or not at all. *Id.* Dayton adds, "[s]ince refunds cannot be ordered for 1990-93 as a matter of law, they should not be required at all." *Id.*

807. As for Pavlovic's criticism that she did not use shipper invoices in her calculations, Dayton responds that shipper invoices are not publicly available. *Id.* at p. 6. Also, she states that, contrary to Pavlovic's claim, the field allocations[328] used in her

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[327] Dayton also declares that Pavlovic apparently is unaware that BP is the sole operator of the Prudhoe Bay Unit and the Central Gas Facility as he claimed that Phillips was a joint operator of the two. Exhibit No. PAI-71 at p. 5.

[328] On re-direct examination, at the hearing, Dayton claimed that the data she used was "audited, accurate data." Transcript at p. 12635. She added that it is the same data used to allocate production among specific producers and to calculate royalty payments to be made to Alaska. *Id.*

calculations are more appropriate to use than shipper information because "shipper invoices include barrels shipped by one party where the economic impact of the Quality Bank is contractually passed on to the State of Alaska or to some third party."[329] *Id.* Dayton claims that, therefore, her calculations "provide an accurate picture of the actual impact of the Quality Bank methodology as applied at Pump Station No. 1 and any changes made to that methodology." *Id.* at p. 7.

808. Asserting that the impacts at the refinery connections are more difficult to accurately determine, Dayton claims, her calculations of the refiners's payments at the refinery connections are accurate. *Id.* She adds, though not all producers sell to the refiners, "the calculated payments to the producers at these connections assume a proportionate sale to the refiners from all producers and the State of Alaska." *Id.* Accordingly, Dayton admits that her testimony does not accurately reflect the actual impact on individual producers. *Id.* Dayton declares that, should the Commission order refunds, shipper invoices should be used "to determine who should receive the initial payments from or make payments to the TAPS Carriers," but adds that, were that to happen, "[t]he provisions of royalty agreements with the State of Alaska and of contracts with third parties would then govern any further allocation of Quality Bank debits and credits." *Id.*

809. According to Dayton, the purpose of her testimony was to present "the actual financial impacts of the retroactive application of the Quality Bank methodology," not to calculate the initial refunds were the Commission to order them paid. *Id.* at pp. 7-8. She asserts that, in her "opinion, the actual financial impacts are more relevant to the Commission's consideration of the equities involved in considering [Exxon's] retroactivity and damages claims than are shipper payments and receipts derived from shippers' invoices." *Id.* at p. 8.

810. Dayton declares that, whether Pavlovic's calculations or hers are accepted, "the equities" do not change because the refunds owed by Exxon for the earlier period dwarf the refunds which would be owed to Exxon in the later period. *Id.* She suggests, further, that, if she had used shipper invoices, the amount of overpayments which Exxon received during the 1990-93 period would have exceeded the $84.3 million that she calculated. *Id.* Dayton maintains that regardless of the exact Quality Bank impacts, "[h]owever the calculation is performed, it cannot obscure the central equitable point that it would be unfair to require refunds for only part of the litigation period at issue here." *Id.* at pp. 8-9.

811. Noting Pavlovic's criticism that her 1990-1993 calculations should be rejected

[329] Dayton explains that "[b]y contrast, the field production allocations that [she] use[s] represent the barrels owned by a producer at Pump Station No. 1 that are subjected to the Quality Bank impacts." Exhibit No. PAI-71 at pp. 6-7.

because the TAPS does not have sufficient distillation yield data for that period, Dayton states:

> There is a significant amount of data available regarding Prudhoe Bay quality and [natural gas liquids] blending levels, and I have assays of the various streams from the same time 1990-93 period. . . . I have the data available to make reasonable adjustments that account for each of the changes in crude quality mentioned by Dr. Pavlovic. Dr. Pavlovic has presented no testimony attacking the reasonableness of any such adjustment.

Id. at p. 9 (citations omitted).

812. Asked about the status of her equitable argument were the Commission not to accept the Eight Parties position on the value of Resid, Dayton declares:

> It would take significant adjustments to the Eight Party proposal before the amount of payments owed after 1993 would outweigh the overpayments from the 1990-93 time period. If the Commission were to require changes to the Eight Parties' Resid proposal, I would recommend that the Commission permit me to rerun my calculations based on the Resid value established by the Commission so that the equities of requiring retroactive changes for only part of the litigation period can be appropriately weighed.

Id. at p. 10. Moreover, Dayton asserts that Pavlovic is incorrect in claiming that, if Exxon's Resid value were adopted, the refund amounts owed to Exxon in the first period would exceed the amount of refunds Exxon owes in the second period. *Id.* at p. 11. She adds, applying interest to Pavlovic's refund claims reflects that the amount in refunds plus interest which Exxon owes for the first period exceeds the amount in refunds plus interest it would receive for the later period. *Id.*

813. Dayton also addresses two other criticisms Pavlovic makes regarding equitable considerations. *Id.* at p. 12. She claims Pavlovic mischaracterizes her testimony when he asserts she states that the refiners were entitled to rely on the assumption that there would be no retroactivity. *Id.* According to Dayton, she does not assert that the refiners were entitled to rely on the existing methodology but that "it is the refiners' ability to optimize their operations based on the methodology in effect that gives rise to the inequity in requiring refunds." *Id.*

814. Next, Dayton answers Pavlovic's contention that, since the refiners were aware that the methodology was in dispute, they should have optimized their operations to account for the probability that the methodology would change. *Id.* at p. 13. Although she agrees with Pavlovic's contention that, if the refiners had the ability to hedge risk,

they should have done so, she disagrees that the refiners actually could hedge their risk. *Id.* Dayton declares that refiners did not have the ability to hedge their risk because of an "uncertainty about what, if any, changes might be made for a long period of time." *Id.* at p. 14. She adds that the varying claims in the pending litigation would have resulted in differing impacts upon the refiners and, as a result, the refiners could not "define, much less hedge, what the risks might be." *Id.* Moreover, according to Dayton, "[e]ven if the risks could be defined, however, they could not necessarily have been hedged in a way that would put the refiners in the same position as if the change in methodology had been implemented in 1993." *Id.* at pp. 14-15. Consequently, Dayton asserts, the refiners could not optimize operations to be indifferent to which Quality Bank methodology is in place. *Id.* at p.16.

815. During additional direct testimony at the hearing, Dayton re-asserted that her testimony, as pertinent to these issues, is intended to present the Commission with calculations related to the question of whether it would be equitable to place into retroactive effect its determination on the cuts remanded by the Circuit Court in *OXY*.[330] Transcript at p. 11755. She also notes that the question she discusses involves two separate periods of time: (1) January 1990 through November 1993, when the original litigation took place and for which the parties affected by the ruling were not granted retroactive effect; and (2) from December 1993 forward. *Id.* at pp. 11755-56. Dayton states that she is comparing the retroactive impact during each period. *Id.* at p. 11756. Besides the retroactivity issue, Dayton states that her testimony addresses Exxon's damages (reparations) claim. *Id.*

816. When asked, during cross-examination, whether whatever action or inaction which refiners took with regard to the existence of a particular Quality Bank methodology, they ought to be free from paying refunds, Dayton responded as follows:

> I think that really simplifies what I said. What I said is I do not believe that the – the position [we've] taken is that we shouldn't have refunds, and the reason with regard to the refiners is that I believe it would be inequitable to have refunds as they would have made different decisions had different methodologies been in place, and therefore, the refunds that would have been assessed to them, I assume that they're smart businessmen, but those refunds that would have been assessed against them would have been significantly less had they been – and maybe none.
>
> I think they have been very successful in optimizing their operations around whatever methodologies are in place to minimize what those

[330] These cuts are Light Distillate, Heavy Distillate, Fuel Oil and Resid. Transcript at p. 11825.

> payments are, and I would expect them to do that.

Id. at p. 11903. Dayton explains, in response to further questioning, that all of the decisions which the refiners are making regarding their operations are economic in nature and that their decisions regarding the Quality Bank are "part and parcel of how they make their decisions day to day and long-term." *Id.* at p. 11904.

817. She was asked whether the products made by a refiner and the size of its refinery were influenced by the price of crude oil, and Dayton answered affirmatively. *Id.* at p. 11907. Dayton further agreed that, as to the refiners involved here, the price they were paying for crude oil was influenced by the value of Resid. *Id.* She further agreed that, were the price of Resid "in flux," the refiners could not be certain of the price they ultimately paid for the crude. *Id.* at pp. 11907-08.

C. CHRISTOPHER ROSS

818. BP called Ross back to the stand to testify on these issues. With regard to Quality Bank West Coast VGO, he stated that, as the market has changed since 1994, he now supports the use of the OPIS West Coast High Sulfur VGO to value it. Exhibit No. BPX-7 at p. 4. He also supported it being implemented prospectively *Id.* Ross also indicated that, were the Commission to change the manner in which West Coast Naphtha is valued, this change also should be implemented prospectively. Exhibit No. BPX-8 at p. 5.

819. In later testimony, Ross indicated that he agreed with Toof that a change in the value of West Coast Naphtha and West Coast VGO should be implemented on the same day, but does not agree with him that they should be implemented effective June 19, 1994. Exhibit No. BPX-26 at pp. 2-3. According to Ross, there are no facts which support such an early implementation for VGO, especially as the current value became effective in May 1994, barely a month before Toof suggests that the new value be effective. *Id.* at pp. 3-4. In other testimony, he adds, in opposition to Toof's suggested June 19, 1994, effective date for any change in the West Coast Naphtha value:

> Since the valuation approaches to Naphtha and VGO must be consistent to avoid mis-valuation of one cut relative to the other, it follows that Naphtha change must also be implemented prospectively. Further, the valuation of the Naphtha cut has never been remanded by the Court of Appeals. Therefore, prudent business practice would reasonably have led companies to rely on the prior Gulf Coast Naphtha valuation basis in taking now irreversible business decisions. Retroactivity in implementation would unfairly damage parties that had relied on the prior valuation basis for taking rational decisions in the past that would have been different under the changed valuation, and such retroactive implementation would clearly be inequitable.

Exhibit No. BPX-27 at p. 32.

820. Addressing the Quality Bank West Coast VGO valuation again in later testimony, Ross stated that, while he would have been satisfied in using the OPIS West Coast VGO price in 1994, the Commission was not. Exhibit No. BPX-66 at p. 5. He indicated that, since then, refining assets on the West Coast have been redistributed which should alleviate the Commission's concern that the "West Coast VGO price could be subject to manipulation." *Id.* at pp. 5-6.

821. At the hearing, during cross-examination, Ross reiterated his position that both West Coast Naphtha and West Coast VGO should be valued prospectively on a West Coast basis.[331] Transcript at pp. 12139, 12167-68, 12171-72. On re-direct examination, asked again for his views on retroactive application of changes in the Quality Bank methodology, Ross stated:

> I believe actually since the mid-'70s, that retroactivity ought to be avoided in any commercial arrangement because business people make decisions based on the best assumptions available, and changing those assumptions retroactively causes damages to those business people which are irreparable, so I have a very strong belief that retroactivity is just a bad thing.

Id. at p. 12173. He agreed that businesses could make a risk analysis, but added that he did not believe that, with regard to VGO, before this proceeding and the parties's agreement, there was a "low probability" that the Commission's 1993 ruling would be overturned. *Id.* at p. 12174. As to Naphtha, according to Ross, "whatever the probability of it being overturned, there wasn't anything else, any other price you could use." *Id.* Noting that "the 1993 settlement had been overturned" and characterizing the Tesoro proposal as without sense, Ross declared that there was no way of making a risk analysis. *Id.* at pp. 12174-75.

[331] In later testimony, asked why any change in the valuation of VGO and Naphtha should be effective on the same date, Ross stated: "They are products that are used both in gasoline manufacture. They're important components in the Quality Bank. I can't think of any reason at all – I think that treating them on a different basis would lead to more inequities than treating them on the same basis." Transcript at pp. 12179-80.

822. In later testimony addressing the justification for rejection a West Coast VGO price in earlier proceedings now has been alleviated, Ross asserted:

> The manipulation concern, to my mind, has been alleviated by a better alignment between people who own the refineries and trade in the VGO and other markets and the major participants in this proceeding. In 1994, there was a big gap in the sense that BP was not represented in the West Coast refining industry, yet it was one of the major producers.

Id. at p. 12178. He added that, now, BP was an active participant in the West Coast VGO market and that this only occurred in "the last two or three years." *Id.* According to him, "the last puzzle piece to fall in place was the acquisition by Tesoro of the Golden Eagle refinery which was completed in San Francisco in May 2002." *Id.*

D. KARL R. PAVLOVIC

823. Pavlovic testified for Exxon on the subject of refunds and damages. Exhibit No. EMT-68 at pp. 3, 6. Over several pages of testimony he detailed how he calculated, and the amount of those, damages.[332] *Id.* at pp. 7-14.

824. In his Answering Testimony, Pavlovic addressed Dayton's criticism of his earlier work. Exhibit No. EMT-102 at p. 21. As noted above, Pavlovic found five flaws in her thesis:

- The Heavy Petroleum producers/shippers were not unwitting victims of natural gas liquid blending. *Id.* at p. 25. According to Pavlovic, natural gas liquid blending has occurred at every major Alaska North Slope field. *Id.* He claims that the owners of these fields must have been aware of this and, as they are "sophisticated companies well-positioned to analyze the financial impact of significant operational changes, were well aware of the impact of NGL-blending on the Quality Bank." *Id.*

- Dayton's estimated producer/shipper volumes are based on the ownership of fields of ANS streams which does not take into account "transactions prior to Pump Station No. 1 or Royalty in Kind payments to the State by producers/shippers." *Id.* at p. 26. He further declares that "Quality Bank invoice barrel volumes for each shipper should be used" instead. *Id.* Pavlovic adds, "[a] proper calculation requires the number of

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[332] I don't consider this testimony significant because, as I noted on several occasions at the hearing, it will be the responsibility of the Quality Bank Administrator to calculate damages, if any, after the Commission rules.

barrels of each stream actually shipped by each party in each invoice period, because that is the basis upon which each party's original invoice credits and debits for the period were calculated by the Quality Bank." *Id.* at pp. 26-27. According to him, Dayton's methodology produced "significant errors." *Id.* at p. 27.

• Because Dayton used the average Quality Bank distillation yields over the May 1, 1994, through April 30, 1995, period to estimate monthly yields, her analysis is "not sufficiently sensitive" to the impact of a given stream on Quality Bank credits and debits. *Id.* at p. 28. Pavlovic suggests that significant changes during the 1990 to 1995 period, particularly in 1993 and early 1994, occurred in the ANS petroleum streams. *Id.* He notes that "five new streams came on line during this straddle period,"[333] while Prudhoe Bay crude and condensate was in decline and Natural Gas Liquid production was increasing. *Id.* Conceding that Dayton stated that she made adjustments to take all of this into account, Pavlovic indicates that the adjustments are not sufficient:

> Because the credits and debits are a function of the composition of each stream relative to the compositions of the other streams, small differences between estimated and actual distillation yields for the streams can have very large impacts on the refunds calculated for the streams and the parties shipping the streams.

Id. at p. 29.

• Dayton used a modified Nine-Party Settlement methodology to value Resid even though it produces a "significant[]" overvalue for Resid. *Id.* at p. 30. He adds that, consequently, "Dayton's calculations are biased in favor of heavier petroleum streams and shippers of heavier petroleum streams." *Id.* Accordingly, Pavlovic opines, Dayton overstates the refunds for the January 1, 1990, through November 30, 1993, period and understates them for the period beginning in December 1993. *Id.* at pp. 30-31.

• Dayton's position is based on two false premises: first, refiners/shippers were entitled to rely on a distillation methodology which would not be modified retroactively; and, secondly, that refiners/shippers

[333] Point McIntyre, West Beach, North Prudhoe Bay, Niakuk and the Petro Star Valdez refinery return stream. Exhibit No. EMT-102 at p. 28.

> have no way of optimizing their operation to "insulate them from retroactive application of a different distillation methodology." *Id.* at pp. 32-33. Pavlovic believes that the refiners/shippers had the ability to and should have "hedge[d] that risk." *Id.* at p. 33.

825. In his Rebuttal Testimony, Pavlovic admitted to certain errors in his calculations, which were pointed out by Dayton, and corrected them. Exhibit No. EMT-194 at pp. 5-8. Aside from that, Pavlovic takes issue with Dayton's claim that he erred in using Exxon's "shipped barrels as developed from [its] Quality Bank invoices." *Id.* at p. 9. He claims that, were Exxon to be successful, the Quality Bank Administrator would have to use Quality Bank invoices, which are based on shipped barrels, to calculate Exxon's damages. *Id.*

826. Pavlovic adds, responding to two matters raised by Dayton which, she asserted, diminish the damages he claimed: (1) that Exxon did not purchase barrels of crude from third parties; and (2) that only about 5.5% of Exxon's shipped barrels represent Royalties in Kind and that, therefore, only that amount "would be the maximum potential portion of the damages as to which State of Alaska might have a claim via any passthrough provisions in [Exxon's] royalty agreements with the State." *Id.* at p. 11.

827. On further direct examination at the hearing, Pavlovic updated the calculations he had performed during the pre-trial stages of this proceeding. Transcript at pp. 12193-12211, 12219-31. Under cross-examination, at the outset, Pavlovic admitted that Exxon did not appeal the Commission's decision not to use the VGO and Naphtha values contained in the 1993 settlement. *Id.* at p. 12233. He also agreed that, in its 1997 offer of settlement, Exxon did not seek to alter the West Coast VGO value based on the Platts Gulf Coast VGO assessment. *Id.* at p. 12263.

828. During further examination, Pavlovic explained that, when he suggested that refiners could "optimize" their operation, he wasn't referring to the manner in which they operated their refinery, but to "the entire panoply of business operations." *Id.* at p. 12311. He expanded on this thought:

> I'm talking about the totality of their business operations, that is what they do in order to – which is what all businessmen do to deal with the downside risk in their operations. For refiners, some of what they do has to do with the way they operate their refinery.
>
> Other things that businesses do all the time are to make provisions of various kinds to deal with future downside risk. I mentioned in my testimony, and I'll mention now, that, knowing that the methodology could change, I believe the refiners should have looked at what the possible changes were. And they knew what the possible changes were, quantified

> what the potential impact of those things might be on their operation, assess the probability of the change, and on that basis, take appropriate action to deal with future risk.

Id. at p. 12312. According to Pavlovic, the refiners could have assessed the largest amount which was at risk and established a reserve fund or negotiated a protective contract with their suppliers and/or customers. *Id.* at pp. 12312-13, 12319-21. He, also, opined that his suggestions were realistic, but agreed that the likelihood that a supplier would agree to a long-term protective agreement "is very small." *Id.* at pp. 12313-14. In later cross-examination, Pavlovic agreed that he was suggesting that refiners could hedge their risk and that hedging was not cost-free. *Id.* at p. 12322.

E. DAVID TOOF

829. Exxon presented Toof as it next witness. The revised value for Resid, Toof argues, should be made retroactive to December 1, 1993, because there never has been a just and reasonable Resid rate. Exhibit No. EMT-1 at p. 21. Additionally, Toof alleges that "[a]ll parties have been on notice since the inception of the distillation methodology in 1993 that the prevailing rate for the Resid cut was challenged as not just and reasonable." *Id.* Toof asserts that the financial impacts are significant and that Dr. Karl Pavlovic has calculated that Exxon is owed as much as $86,558,958. *Id.* at p. 22.

830. The valuation of the Heavy Distillate cut, according to Toof, has been frozen at the October 1999 Platt's West Coast price for Waterborne Gas Oil reduced by 1¢/gallon[334] since November 1, 1999. *Id.* at p. 23. Toof states that "[w]hile all of the parties have agreed that Platt's West Coast LA Pipeline Low Sulfur No. 2 price should be the new benchmark, there has not been agreement as to the appropriate price adjustment to reflect the processing costs required to take account of the low sulfur content of the proxy product." *Id*. Since the new proxy product has a low sulfur content (.05%), Toof argues that an appropriate adjustment would be 4.3¢/gallon. *Id.* at pp. 23-24. He also argues that the effective date should be February 1, 2000, 60 days after Platts stopped publishing a new assessment. *Id.* at p. 24.

831. As for the Naphtha cut, Toof begins, "[b]oth Gulf Coast and West Coast Naphtha . . . are valued as the Gulf Coast product using Platt's U.S. Gulf Coast spot quote for Waterborne Naphtha." *Id.* However, Toof argues that the current valuation fails to value West Coast Naphtha reliably. *Id.* at p. 25. He explains that the two products – gasoline and jet fuel – produced from Naphtha determine the value of the Naphtha stream and concludes that "[t]he prices for West Coast Gasoline and Jet Fuel exceed by a substantial

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[334] According to Toof, the price is adjusted to reflect the costs incurred in reducing the sulfur content from .57% to .5%. Exhibit No. EMT-1 at p. 23.

martin [sic] comparable prices for Gulf Coast Jet Fuel and Gasoline." *Id.*

832. In his Answering Testimony, Toof indicates that he disagrees with Dayton's conclusion that the Commission cannot order changes to the distillation methodology to be made retroactive to December 1, 1993, as such a change would be inequitable and a windfall for several parties. Exhibit No. EMT-76 at p. 36. Dayton's conclusion, he notes, is based on certain values proposed by O'Brien and Ross, incorporating the flaws in their analysis. *Id.* at pp. 36-37. If the Commission should adopt any of the Exxon methodology, Toof contends, Dayton's conclusion would be undermined. *Id.* at p. 37. Additionally, Toof points out that the rates paid by Exxon during the January 1990 through November 1993 period were just and reasonable rates approved by the Commission. *Id.* He argues further that "[t]he refunds that [Exxon] now seeks are the result of delays arising from the imposition of two contested settlements which have been rejected by the Court of Appeals. *Id.*

833. Toof states that even though there is no disagreement with Exxon's position that West Coast VGO should be valued on the basis of the OPIS West Coast high sulfur VGO price, Ross argues that the change should be applied only prospectively, while Exxon believe that the change should be made retroactive to June 1994. Exhibit No. EMT-123 at pp. 36-37. He notes that Ross concedes that the OPIS West Coast High Sulfur VGO price is a reasonable price for the entire period. *Id.* at p. 37*;* Exhibit No. EMT-128 at p. 2.

834. In addition, Toof finds fault with Boltz's claim that retroactive implementation of the Resid value would place an "onerous burden" on Petro Star. Exhibit No. EMT-123 at pp. 43-44. Toof asserts that Petro Star was on notice, as early as late 1993, that Exxon opposed the revised Resid values, that it had requested a stay in implementation of the tariff, and "that the Commission has indicated in denying that stay that it could remedy any error of law by refunds." *Id.* at p. 44. He further argues that Petro Star should have established a reserve fund on the chance that this would occur. *Id.*

835. In further direct testimony at the hearing, Toof took issue with Dayton's updated testimony. Transcript at pp. 12360-62. Regarding her testimony, he states: "I don't think that calculating a potential credit or payment in a prior hypothetical period, using a hypothetical rate structure and hypothetical data, and then comparing that to a proposed methodology is a fair comparison." *Id.* at pp. 12362-63. He also stated that he did not believe that "a measure of equity or fairness would be to take a look at what happened – to try and go back and rewrite history as to what might or might not have happened in some previous period and somehow offset activities in future periods by taking account of those prior periods." *Id.* at p. 12379.

836. Addressing the steps which a refiner could have taken to protect itself against the possibility that there may be refunds ordered here, Toof suggested that it could structure

its sales contracts or crude purchase contracts to provide protection. *Id.* at p. 12392. He admits that it might be difficult to do in the case of sales contracts, but, pointing to one discussed by Petro Star's witness, indicated that this was possible. *Id.* at pp. 12392-93. Toof indicates that there is no evidence that refiners took any steps to protect themselves. *Id.* at p. 12393. He also discussed the possibility that refiners could have optimized their operations to avoid refunds. *Id.* at pp. 12394-96.

837. Toof argues that there were points in time when "refiners knew – not just should have known, but did know – what sort of liability they were incurring and what the basic price points were that would induce that liability." *Id.* at p. 12397. He cites, for example, 2000 when refiners "put their settlement model on the table and did their coker feedstock methodology." *Id.* Asked to cite to specific points in time which had nothing to do with proposals being put forward, Toof pointed to Judge Leventhal's and Judge Wilson's decisions as notifying the parties that there was going to be a new Quality Bank methodology, the 1993 settlement proposal and the Commission decision modifying it, the Exxon February 1994 request for a stay and the Commission's denial of that request, the Circuit Court's *OXY* decision, the 1997 contested settlements, and the *Exxon* and *Tesoro* Circuit Court decisions. *Id.* at pp. 12400-02. He admits that he cannot point to a single event which should have generated "action to alleviate" the risk, but suggests that in this "continuum" the refiner should have continually re-evaluated his position and taken action to protect itself. *Id.* at pp. 12402-04.

THE QUALITY BANK ADMINISTRATOR

838. The TAPS Carriers also presented a witness, James T. Mitchell ("Mitchell"), to testify on the administrative feasibility of all of the proposed changes to the TAPS methodology. Exhibit No. TC-1 at p. 1. Mitchell is employed by Mitchell & Mitchell as a "consultant specializing in the downstream aspects of the petroleum industry." *Id.* In addition, he is the Quality Bank Administrator (sometimes "Administrator") for TAPS and has been since 1994.[335] *Id.* at p. 3. According to Mitchell, "[his] mission . . . is to produce accurate, reliable, and timely adjustment invoices in accordance with the [Quality Bank] Methodology Tariff and any orders of the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska (Commissions)." *Id.*

[335] Mitchell states that, actually, Mitchell & Mitchell is the Quality Bank Administrator and that he is the Quality Bank Administrator's representative, but that he is "generally referred to as the Quality Bank administrator [sic]." Transcript at p. 13094. He also serves as Quality Bank Administrator for the Kuparuk Transportation Company and the Endicott Pipelines, both of which feed into TAPS and "share use of some assay results with TAPS." *Id.* at pp. 13094-95; Exhibit No. TC-1 at p. 5.

839. He explains the TAPS Quality Bank operations as follows:

> During the course of each month, continuous samples of the petroleum streams of interest to the QB are collected at nine locations on TAPS by Alyeska Pipeline Service Company (APSC) personnel. At the end of the month composite samples are transferred to sample cylinders and shipped to the ITS Caleb Brett laboratory in Houston. ITS Caleb Brett technicians perform the laboratory tests necessary to develop an assay for each stream in accordance with ASTM test methods. The assay gives a breakdown of the stream into the nine components specified in the QB Methodology Tariff: propane, isobutane, normal butane, light straight run, naphtha, light distillate, heavy distillate, gas oil, and resid. These assays are transferred to the QBA for analysis. In some cases more than one assay is required for a given stream and the QBA must decide which to use for the stream value determination.
>
> Mitchell & Mitchell develops the component values based on publicly available information and adjustments specified in the QB Methodology Tariff. These values and the assay are then used to calculate the QB value for each stream.
>
> Shortly after the end of each month APSC provides the QB data processing firm, Resource Data, Inc. (RDI), with the quantity of each stream shipped by each shipper on each of the Carriers. Using these quantities and the stream values, RDI runs the software that calculates the QB adjustments and creates the shipper invoices. The shippers send their payments to Wells Fargo Bank, which then disburses funds to shippers having credit balances.
>
> All of the steps are computerized, the transfer of data is electronic, and there is extensive quality assurance at each stage.

Id. at pp. 3-4.

840. After noting that the TAPS shippers pay an administration fee for the TAPS Administrator with the fee deducted from the adjustment funds every month, Mitchell states that his specific duties as the Quality Bank Administrator are to

> [develop] the component values that are used to calculate the QB values for each stream. In addition, I provide general supervision and coordination of APSC, ITS Caleb Brett, RDI, Wells Fargo, and the firms transporting the sample cylinders. Finally, the QB Methodology Tariff provides that I am to perform certain other functions, such as investigating the validity of a

> sample if certain criteria are met, proposing replacement product prices, and resolving unanticipated implementation issues.

Id. at pp. 4-5.

841. Mitchell explains the purpose of his testimony is to comment on the administrative feasibility of the proposals made by the parties in this dispute. *Id.* at p. 5. He indicates that by "administrative feasibility" he means the following:

> [T]hat a proposal can be implemented using data that is readily available to the QBA, that the proposal can be accomplished using sample quantities currently available to the QB, and that it will not result in excessive delay in completing each month's QB. In addition, the methodology set forth in the proposal must be clear and unambiguous. Finally, it is necessary that intrastate and interstate shipments be treated identically.

Id. at pp. 5-6. In preparation for his submission, Mitchell states that he examined all of the parties's proposals, sought clarification where needed, and circulated a draft of his pre-filed testimony "to all of the parties to be sure that [he] described each of their proposals correctly." *Id.* at p. 5.

842. According to Mitchell, because crude oil is transported through TAPS in a commingled stream, the quality of the crude a shipper receives downstream is affected by the quality of the other crude transported. *Id.* at p. 6. Therefore, Mitchell states, "quality adjustments need to be made for all petroleum transported in the pipeline on the same basis." *Id.* Noting that that the Quality Bank is a "zero-sum game," Mitchell asserts that, less administrative fees, all payments made to the Quality Bank must equal the payments made by the Quality Bank. *Id.*

843. Mitchell declares that, as he understand them, all of the proposals are administratively feasible. *Id.* at p. 7. However, he believes that all of them would require additional costs "including a modest one-time cost to reprogram the QB system." *Id.* Also, he suggests, proposals requiring a retroactive payment adjustment will require a one-time cost for "computer programming, data processing and quality assurance." *Id.* Mitchell states that he should be allowed sufficient time to correctly compute any retroactive payments, and that the Commission specifically define how such payments, including interest, are to be made.[336] *Id.* He requests that any prospective changes be

[336] Mitchell suggests a "two-step process" for calculating these retroactive payments: (1) the revised values are calculated and published to the parties; and (2) after differences are resolved, the adjusted calculations will be made and invoices issued. Exhibit No. TC-1 at p. 7.

made effective on the "first day of the first month after the" Commission's Order becomes effective. *Id.* at p. 8.

844. Describing his understanding of each party's Resid proposal Mitchell finds each of them administratively feasible. *Id.* at pp. 10, 12. As to the Exxon proposal, Mitchell suggests that the Administrator be given the authority to retest when "he has reason to believe that a significant change may have occurred in" the common stream. *Id.* at p. 15. He suggests annual retesting as a minimum. *Id.*

845. Mitchell notes that the parties have agreed that West Coast Heavy Distillate is to be valued using Platts Low Sulfur Diesel assessment as the base price effective February 1, 2000. *Id.* at p. 16; Transcript at pp. 13119-21. He finds this proposal is administratively feasible as he does the different proposals for adjustment submitted by the parties. Exhibit No. TC-1 at pp. 16-17.

846. After discussing his understanding of each party's Naphtha proposal, Mitchell finds each administratively feasible. *Id.* at pp. 17-20. With regard to Petro Star's proposal, Mitchell finds that it "would result in a delay in finalizing the pricing each month" which "could cause a problem for some producers" and Alaska. *Id.* at p. 20. He admits, however, that Petro Star's witness has suggested a means of alleviating this problem. *Id.* at p. 21.

847. Mitchell notes that the parties have agreed that West Coast VGO is to be valued using the OPIS West Coast High Sulfur VGO weekly assessment. *Id.* He further notes that the Eight Parties have suggested that this change be prospective only and that Exxon has suggested that it be retroactive to June 19, 1994, and finds that each is administratively feasible. *Id.* at p. 22.

848. Noting that Exxon suggests that changes in the valuation of Light Distillate, Heavy Distillate and Resid be made retroactive to December 1, 1993, while the Eight Parties support a prospective change, Mitchell finds each administratively feasible. *Id.* at p. 22.

849. During further direct testimony at the hearing, using Exhibit No. TC-14, Mitchell discussed changes in the parties's Resid proposals which occurred during the course of the hearing. Transcript at pp. 13099-13119. In particular he noted that, under these modified proposals, the Administrator would be required periodically "to take samples and measure the properties of Resid." *Id.* at pp. 13100-01. He notes that such a change would require that the Administrator make "decisions on several points that would be necessary for the [Administrator] to make such adjustments prospectively into the future."[337] *Id.* at p. 13101.

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[337] These are thoroughly described on Exhibit No. TC-14 and in the transcript.

850. Discussing the possibility of retroactive application of a Resid proposal, Mitchell states that he would need to know "what properties or yields" to use. *Id.* at p. 13105. He notes that, while he has no samples for the retroactive period by which to make an assessment of stream quality, data made available through this proceeding and perhaps other data, including assays, might enable him to make the appropriate adjustments. *Id.* at pp. 13105-06.

851. While he believed that all of the Naphtha proposals were administratively feasible, Mitchell indicated that he had a problem with the suggestion that the new methodology be retroactively effective. *Id.* at pp. 13121-24. As to the latter, he indicated that he did not believe that it was feasible "to either collect Quality Bank debits or pay Quality Bank credits to anyone other than the TAPS shippers."[338] *Id.* at p. 13124. Explaining, Mitchell noted that while he had information related to these shippers, he did not have sufficient data regarding these other shippers. *Id.* He added: "Even if we were given the data as part of this proceeding, we wouldn't have any way of knowing whether the other party to such agreements agreed that the shippers' interpretation of such an agreement is, in fact, their interpretation." *Id.* Mitchell also theorized that, even were he able to calculate such a payment and send an invoice, he would have trouble collecting. *Id.* at pp. 13124-25.

852. Asked to describe the Nelson-Farrar index, Mitchell stated:

> The Nelson-Farrar index is a refinery operating cost index that's published in the Oil and Gas Journal once a month, and it's used under the previous settlement agreement that was put into effect in February 1998, which included for the first time some cost adjustments to three of the products. It's used in conjunction with those to update those cost adjustments annually.

Id. at pp. 13127-28. He requests that, were the Commission to require its use as to any of the cuts at issue here, the Commission "specifically state how it would be applied." *Id.* at p. 13128. He recommends that it be used in the same manner as currently, that it be used annually and that it be applied at the same time as those for which he currently uses it.[339]

Transcript at pp. 13101-04.

[338] Mitchell states that no "shippers of record" have disappeared, i.e., have no successors. Transcript at pp. 13125-27.

[339] Mitchell stated that he currently calculates the Nelson-Farrar adjustment in January of every year based on the number published in the first weekly edition in that month of the Oil and Gas Journal. Transcript at p. 13128. He notes that there is a time lag in the publication of the numbers, and that the data published in January is that for August or September of the previous year. *Id.* at pp. 13128-29. Mitchell states that the

Id.

853. During cross-examination, Mitchell stated that, while it was true that the Quality Bank calculations at each location (Pump Station No. 1, Golden Valley, Petro Star and Valdez) were "zero sum," that the Valdez Quality Bank was on a different basis than the other three. *Id.* at p. 13135.

854. Asked about the procedure he would follow when he believed that a new assay was needed, Mitchell stated that he had not thought the details through, but that, if the shippers wanted to be notified beforehand, he would do so or would notify them when "a change was being made in the valuation formula." *Id.* at p. 13136. He agreed that any sampling done needs to be "representative of all the streams of TAPS at that time." *Id.* at p. 13137.

855. Under further examination, Mitchell stated that neither Resid proposal was more objective than the other and that neither would cost more than the other. *Id.* at pp. 13161-62. He also indicated that none of the Naphtha proposals would require that he "exercise subjective actions each month." *Id.* at p. 13162. However, he asserted that any of the proposals changing the manner in which West Coast Naphtha was valued would be more costly. *Id.* at pp. 13162-63.

SUMMARY OF PARTIES'S ARGUMENTS AND RULINGS

ISSUE NO. 1: WHAT IS THE APPROPRIATE METHOD FOR VALUING THE RESID CUT?

A. LEGAL STANDARD AND BURDEN OF PROOF

856. In November 1993, Exxon explains, the Commission rejected the Resid valuation proposal within the parties's 1993 Settlement Agreement arguing that only "unadjusted quoted market prices" could be used in valuing Quality Bank cuts.[340] Exxon Initial Brief at p. 10. The Resid valuation proposed in the 1993 settlement rejected by the Commission, Exxon states, involved the use of adjusted market prices. *Id.* In its place, the Commission used Platts West Coast waterborne FO-380 price, without adjustment, to value West Coast Resid, and the Platts Gulf Coast waterborne 3% sulfur No. 6 fuel oil price, without adjustment, to value Gulf Coast Resid. *Id.*

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calculations are put into effect in February of each year. *Id.* at p. 13129.

[340] *Trans Alaska Pipeline System*, 65 FERC ¶ 61,277, at p. 62,289 (1993).

857. On rehearing, Exxon notes, the Commission modified this valuation methodology, directing that all Resid above 1050°F on both coasts be valued using the Platts West Coast spot price for waterborne FO-380 without adjustment in order to more accurately value it.[341] *Id.* at p. 11. After reviewing the Commission decisions, Exxon explains, the Circuit Court rejected the Commission's policy of requiring that all Quality Bank cuts be valued on the basis of unadjusted quoted market prices as being "arbitrary and capricious" and contrary to "reasoned decisionmaking."[342] *Id.* The Circuit Court ruled that the proxy prices used by the Commission, Exxon contends, lacked an adequate foundation. *Id.*

858. On remand, Exxon states, the Commission abandoned the use of unadjusted market prices. *Id.* at p. 12. Instead, Exxon asserts, the Commission adopted a contested settlement proposal advanced by nine parties,[343] adjusting the two Resid proxy prices it had initially adopted by deducting from each a fixed 4.5¢/gallon as an approximation of the cost of processing Resid into the higher quality products represented by the selected proxy prices.[344] *Id.*

859. Again, after reviewing the Commission's order on remand, Exxon states, the Circuit Court rejected the Resid valuation methodology as arbitrary and capricious holding that the Commission failed to present evidence showing that the adjusted market prices represented a reasonable proxy for Resid's market value.[345] *Id.* at pp. 12-13. Consequently, Exxon explains, the Commission ordered a hearing to determine a valuation methodology for the Resid cut valuing it on both the Gulf and West Coasts.[346] *Id.* at p. 13. Subsequently, Exxon notes, the parties have agreed on a number of issues, narrowing the areas of disagreement to be resolved. *Id.*

860. According to Exxon, in addressing the Resid valuation, the Commission must decide each disputed issue on the basis of the evidence in the record in order to produce a

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[341] *Trans Alaska Pipeline System*, 66 FERC ¶ 61,188 at pp. 61,419-20 (1994).

[342] *OXY,* 64 F.3d at pp. 693-94.

[343] *Trans Alaska Pipeline System*, 81 FERC ¶ 61,319 at pp. 62,460, 62,464 (1997).

[344] Exxon explains that the Commission adopted the Platts West Coast FO-380 price less 4.5¢/gallon to value the Resid cut on the West Coast, and the Platts Gulf Coast waterborne 3% sulfur No. 6 fuel oil price less 4.5 cents per gallon to value the Resid cut on the Gulf Coast. Exxon Initial Brief at p. 12.

[345] *Exxon,* 182 F.3d at pp. 41-42.

[346] *Trans Alaska Pipeline System*, 97 FERC ¶ 61,150, at p. 61,651 (2001).

just and reasonable resolution of the particular issue.[347] *Id.* at pp. 13-14. It states that, although the Commission may take into consideration its resolution of similar issues pertaining to other Quality Bank cuts, it cannot base its decision on a global view of a reasonable overall result.[348] *Id.* at p. 14. Finally, Exxon maintains, the Commission must not be influenced by the fact that a position may be supported by a larger number of parties, or may be the product of a compromise among the parties.[349] *Id.* As for the burden of proof, Exxon explains, each party has the burden of supporting its own position.[350] *Id.*

861. On reply, Exxon notes, the parties agree that there has not been a "final decision" as to a just and reasonable valuation of Resid since the implementation of the distillation method. Exxon Reply Brief at p. 11. It also suggests that the parties agree that what is sought here is a proxy which is rationally related to Resid's actual value. *Id.* Exxon also suggests that the parties agree that each carries an identical burden of proof. *Id.* It argues that any decision on the issues must be based on record evidence and accuses the Eight Parties of offering, as proof, "one of [the] Four Horsemen: Subjectivity, Typicality, Consistency, and [Exxon] Economic Self-Interest." *Id.* at p. 12.

862. In their Reply Brief, the Eight Parties suggest that, while they agree with Exxon regarding the burden of proof issue, they do not agree that the Commission needs to decide discrete issues, such as location factor, coker gas plant, automatic deheading, etc., but suggests that the Commission only needs to decide "which overall approach replicates a proxy for the Resid component that bears a rational relationship to the actual value of Resid." Eight Parties Reply Brief at p. 4.

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[347] See *Northern States Power Co. (Minnesota) v. F.E.R.C.*, 30 F.3d 177, 180 (D.C. Cir. 1994); *Cook Inlet Pipe Co. v. Alaska Pub. Utils. Comm'n*, 836 P.2d 343, 348 (Alaska 1992).

[348] *See National Treasury Employees Union v. Horner*, 854 F.2d 490, 499 (D.C. Cir. 1988); *Tarbox v. State, Alaska Transp. Comm'n*, 687 P.2d 916, 921 & n.10 (Alaska).

[349] *See Exxon,* 182 F.3d at p. 50; *NorAm Gas Transmission Co. v. F.E.R.C.*, 148 F.3d 1158, 1164-65 (D.C. Cir. 1998); *Laclede Gas Co. v. F.E.R.C.*, 997 F.2d 936, 946 (D.C. Cir. 1993).

[350] *See* 5 U.S.C. § 556(d)(2000) ("the proponent of a rule or order has the burden of proof").

B. STIPULATED MATTERS AND AREAS OF DISPUTE

863. The Eight Parties point out that the applicable standard for any methodology is that it must be just and reasonable; specifically, it must bear a rational relationship to Resid's value.[351] Eight Parties Initial Brief at p. 10.

864. Exxon and the Eight Parties explain that they have stipulated, first, that the Resid cut should be valued as a Coker feedstock based on the before-cost value of the products produced by the Coker, reduced by the costs of coking the Resid, as adjusted over time by the Nelson Farrar Index. Exxon Initial Brief at p. 15; Eight Parties Initial Brief at p. 9.

865. Second, Exxon continues, the parties agree that the Coker products that are produced by running ANS Resid through a Coker are Propane, Butane, Isobutane, LSR, Naphtha, Heavy Distillate, VGO, Coke, and Fuel Gas. Exxon Initial Brief at pp. 15-16. According to Exxon, a portion of the Fuel Gas cut consists of Hydrogen Sulfide, which the parties agree to value as part of the Fuel Gas cut at 1¢/barrel. *Id.* at p. 16, n.11. Additionally, Exxon notes, the parties agreed that the yields for the nine Coker products will be calculated using PIMS. *Id*. at p. 16.

866. Third, Exxon states, the parties agree that Coker products will be valued using Quality Bank values, except for coke and Fuel Gas for which no Quality Bank values are available. *Id.*

867. Fourth, according to Exxon, the parties agree that Fuel Gas will be valued at the *Natural Gas Week* monthly average California South (Los Angeles) delivered-to-pipeline natural gas spot price, plus a 15¢/MMBtu transportation charge, which represents the cost of transporting the gas from the pipeline at the Arizona-California border to the refinery gate of a refinery in Los Angeles. *Id.* Exxon explains that this 15¢ transportation charge is added to the pipeline spot price because Fuel Gas produced in the coking process at the refinery is used by the refinery to avoid purchasing Fuel Gas the refinery would otherwise have to purchase and deliver to the refinery gate in Los Angeles. *Id.* Consequently, Exxon states, the parties agree that Fuel Gas produced in the coking process is to be valued at the refinery gate. *Id.*

868. Fifth, Exxon adds, the parties agree that coke will be valued based on the mid-point monthly quote from *PCQ* for West Coast Low Sulfur (above 2% Sulfur) Petroleum Coke, and on the Gulf Coast at the mid-point monthly quote from *PCQ* for Gulf Coast High Sulfur (above 50 HGI) Petroleum Coke. *Id.* at p. 17. The parties disagree, however, Exxon explains, over the adjustments required in order for these prices to accurately reflect the value of the coke to the refiner. *Id.*

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[351] *See Exxon,* 182 F.3d at p. 42; *Trans Alaska Pipeline System*, 65 FERC ¶ 61,277, at p. 62,286 (1993).

869. Sixth, Exxon notes, the parties agree that the before-cost value of the Coker products will be determined by multiplying the Coker product yields calculated using PIMS times the values of each of the Coker products. *Id.*

870. Seventh, according to Exxon, the parties agree that coking costs include the capital costs of the Coker and certain downstream processing units, as well as the fixed and variable operating costs of the units. *Id.* However, Exxon notes, the parties have not agreed on what the coking costs should be, and they disagree on whether the coking costs on the Gulf Coast need to be adjusted for use on the West Coast to reflect higher West Coast costs. *Id.*

871. Eighth, Exxon explains, the parties agree that the value for the base year will be adjusted for other years using the ratio of the Nelson Farrar Index for the year in which the value is being determined to the Nelson Farrar Index for the base year. *Id.* However, according to Exxon, the parties disagree as to the proper base year, with the Eight Parties proposing a base year of 1996 and while Exxon proposes a base year of 2000. *Id.*

872. On reply, all Exxon states is as follows: "The parties are in substantial agreement as to the identity of stipulated matters and areas of dispute." Exxon Reply Brief at p. 14.

873. In their Reply Brief, the Eight Parties take issue with one comment made by Exxon in its Initial Brief: "Accordingly, by agreement of the parties, Fuel Gas produced in the coking process is to be valued at the refinery gate." Eight Parties Reply Brief at p. 8. Acknowledging that Exxon rightfully cited to O'Brien's testimony for this comment, they argue that the Joint Stipulation does not provide support for it. *Id.* The Eight Parties, citing Joint Stipulation at p. 2, state that "it only provides: 'plus 15¢/MMBtu for transportation from the Arizona-California Border,'" and noted that "O'Brien testified that the 15¢ would be to a refinery gate, but he never identified an actual specific refinery in the Los Angeles area." *Id.*

C. BEFORE-COST ISSUES

1. C_5 Cut Point

874. Exxon begins by addressing the three areas of disagreement regarding before cost issues. Exxon Initial Brief at p. 18. In Exxon's view, the net effect of the disagreements on the before-cost value of Resid is, on average, 98¢/barrel of Resid for the period from 1992 through 2001. *Id.* According to Exxon and the Eight Parties, these disputed areas are:

> (1) the temperature that should be used for the C_5[352] cut point so that the PIMS yields will be accurately apportioned among the Quality Bank cuts for coker products; (2) which assays should be used in calculating the PIMS yields on a going-forward basis and for past periods; and (3) whether, in order to reflect the value of the coke to the refiner, the published free on board ('FOB') vessel price of the coke needs to be adjusted to reflect the substantial coke transportation and handling costs incurred between the refinery and the point of sale reflected in the FOB price.

Exxon Initial Brief at p. 18; Eight Parties Initial Brief at p. 13 (note added).

875. According to the Eight Parties, the C_5 cut point issue involves trying to identify which of two proposed formulæ best matches an ANS Coker Naphtha distillation curve in order to value the Coker Naphtha from the PIMS Delayed Coker as part of the pre-cost portion of the Coker Resid valuation formula. Eight Parties Initial Brief at p. 13. The Eight Parties explain that, unlike the actual breakdown of components in the TAPS Quality Bank, the Coker Naphtha from a Delayed Coker has a boiling range of C_5 to 390°, meaning that it overlaps three Quality Bank components - LSR, Naphtha, and Heavy Distillate. *Id.* at pp. 13-14.

876. Consequently, the Eight Parties state, the issue is translating C_5 into a numerical boiling point to determine what portion of the Coker Naphtha yield is valued as LSR and what portion of the yield is valued as Naphtha. *Id.* at p. 14. Both Exxon and the Eight Parties agree on the appropriate formulæ to use in determining yield, yet disagree on whether 60°F or 100°F is the appropriate cut point.[353] Eight Parties Initial Brief at p. 14;

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[352] The Gary & Handwerk textbook explains that the petroleum industry uses a shorthand method of listing lower-boiling hydrocarbon compounds which characterize the materials by number of carbon atoms and unsaturated bonds in a molecule. *Petroleum Refining, Technology and Economics* (4th ed. 2001) at p. 5. For example, propane is C_3. *Id.*

[353] All parties agree that the following formulae are to be used in determining yield (where the variable x is either 60°F or 100°F):

C_5 -175°F LSR Yield = ((175-100)/(390-x))* C_5 -390 yield

175-350°F Naphtha Yield = ((350-175)/(390-x))* C_5 -390 yield

350-390°F H. Distillate Yield = ((390-350)/(390-x))* C_5 -390 yield.

Eight Parties Initial Brief at p. 14; Exxon Initial Brief at p. 19.

Exxon Initial Brief at p. 19. None of the parties in the proceeding, the Eight Parties note, have any distillation curves for ANS Coker Naphtha because companies with such information did not wish to share it. Eight Parties Initial Brief at p. 14.

877. The C_5 cut point, Exxon begins, is the initial boiling point at which the heavier C_5 products begin to boil off, separating, for Quality Bank purposes, the heavier C_5 products from the lighter C_4 products (like Butane) produced by the Coker. Exxon Initial Brief at p. 18. This issue arises, Exxon asserts, because adjusting the PIMS model yields is necessary in order for them to correlate with the Quality Bank's cuts for Coker products. *Id.*

878. According to Exxon, PIMS divides the total liquid Coker product yield into three boiling range cuts, that are set forth on a "true boiling point" basis:[354] Naphtha (C_5-390°F), Distillate (390°-650°F), and Gas Oil (650°+F). *Id.* at pp. 18-19. These cut ranges, Exxon notes, differ from the true boiling point ranges used by the Quality Bank, which are LSR (C_5-175°F), Naphtha (175°-350°F), Light and Heavy Distillate (350°-650°F), and VGO (650°-1050°F). *Id.* at p. 19.

879. As the cut points differ, Exxon states, the yields produced by PIMS must be apportioned among the Quality Bank cuts. *Id.* Such apportionment, according to Exxon, is accomplished by "linear interpolation," pursuant to which the yields for the PIMS C_5-390°F cut are assumed to be linearly distributed among the LSR, the Naphtha, and the front end of the Heavy Distillate cuts used by the Quality Bank. *Id.* The parties, Exxon notes, agree that this apportionment needs to be made, and agree on all aspects of the methodology to be used in making the apportionment except for the C_5 cut point. *Id.* Exxon supports a 60°F cut point while the Eight Parties propose a 100°F cut point. *Id.* The difference between the two cut points, Exxon contends, results, on average, in an

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[354] Exxon explains true boiling point:

> True boiling point or "TBP" is the temperature at which a material evaporates or boils off in a true boiling point or "TBP" distillation. A TBP distillation refers to a laboratory distillation performed in a fractionating column, resulting in fractionation similar to that found in a refinery, and resulting in a distillation curve corresponding to that produced by ASTM Method D-2892. True boiling points contrast with ASTM boiling points, which are the temperatures at which percentages of a material evaporate during a different type of laboratory distillation procedure, *not involving fractionation*, which is easier and less expensive to run, such as ASTM Method D-86.

Exxon Initial Brief at pp. 18-19, n.12 (emphasis in original; citations omitted).

11¢/barrel reduction in the before-cost value of Resid for the period from 1992 through 2001. *Id.* at p. 20.

880. According to Exxon, the evidence supports a 60°F cut point while the Eight Parties assert that 100°F is the appropriate cut point. Exxon Initial Brief at p. 20; Eight Parties Initial Brief at p. 15. 60°F, Exxon notes, is the undisputed boiling point separating the C_5 materials from the lighter C_4 materials. Exxon Initial Brief at p. 20. Additionally, Exxon states, the 60°F cut point is supported by the testimony of Gary, co-author of the Gary & Handwerk text. *Id.*

881. Gary explained that, according to Exxon, unlike the distillation of virgin crude, the C_5 material produced by a Coker include pentenes as well as pentanes. *Id.* Consequently, Exxon notes, while a C_5 cut point of 82°F (the initial boiling point for iso-pentane) might be appropriate for virgin crude, the C_5 cut point for the Coker products should be between 31°F (the boiling point for normal butane) and 68°F (the initial boiling point for iso-pentene). *Id.* at pp. 20-21. Gary concluded, Exxon states, that the C_5 cut point for Coker material should be in the low 60s. *Id.* at p. 21.

882. Additionally, Exxon asserts, the evidence demonstrates that 60°F is the standard C_5 cut point used in the petroleum industry, and that it is consistent with cut points actually used in assays.[355] *Id.* at p. 21. The Eight Parties's own evidence, Exxon insists, supports the 60°F C_5 cut point:

> O'Brien presented a distillation curve for a coker naphtha, which he claimed supported his 100°F cut point. However, Mr. O'Brien erroneously presented his coker naphtha distillation curve on an "ASTM[356] boiling point basis" rather than on a "true boiling point basis." It was undisputed that the PIMS model as well as the assays in this case are presented on a true boiling point basis. And when Mr. O'Brien's coker naphtha distillation curve was converted to a true boiling point basis, the evidence clearly showed that the use of 60°F as the C_5 cut point produces a closer fit than the 100°F C_5 cut point proposed by Mr. O'Brien.

Id. at p. 22 (footnote added).

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[355] The assays used in this case, Exxon relate, use either 60°F or 70°F as the C_5 cut point. Exxon Initial Brief at p. 21. Furthermore, Exxon contends, O'Brien and Dayton admit that 60°F is closer to the C_5 cut point used by the Quality Bank for crude oil, which is 70°F. *Id.* at pp. 21-22.

[356] The American Society for Testing and Materials. Exxon Reply Brief at p. 24.

883. Exxon accuses the Eight Parties of not providing any substantial evidence in support of their proposed 100°F C_5 cut point. *Id.* at pp. 22-23. Indeed, Exxon claims, O'Brien admits that the true C_5 cut point is 60°F and that 60°F represents the best initial boiling point for C_5. *Id.* at p. 23. According to Exxon, the principal support for O'Brien's 100°F C_5 cut point contention is that it provided a closer fit to the Coker Naphtha distillation curve he presented than did the 60°F cut point proposed by Tallett. *Id.* After the conversion described above, Exxon argues, the evidence demonstrated that the 60°F C_5 cut point produced a closer fit. *Id.* at pp. 23-24.

884. As for O'Brien's reliance on a 96°F cut point provided with the PIMS model documentation to support his position, Exxon explains that the reliance was unwarranted. *Id.* at p. 24. The reference to a 96°F cut point, Exxon argues, was prepared for demonstration purposes based on generic technology and was not intended to represent a standard cut point. *Id.* Also, the documentation, Exxon contends, was based on stale data prepared before current reformulated fuels altered U.S. refiners's fractionation practices, and Aspen Technology neither sells nor stands behind the data in that documentation. *Id.* O'Brien, Exxon states, admits his inexperience with both operating PIMS as well as the documentation provided with the PIMS model. *Id.* at p. 25.

885. The Eight Parties respond by pointing out that the logical place to find an appropriate cut point is the PIMS model itself. Eight Parties Initial Brief at p. 15. According to the Eight Parties, Tallett admits that PIMS uses a C_5 cut point for Coker Naphtha of 96°F on a true boiling point basis. *Id.* Furthermore, the Eight Parties relate, Tallett confirmed that the cut point for LSR in PIMS was 96°-180°F and that ANS is one of the crudes in the PIMS model. *Id.*

886. According to the Eight Parties, the Gary & Handwerk textbook indicates that the LSR cut point for typical crude oil fractions is 90-190°F on a true boiling point basis. *Id.* at p. 16. This 90°F initial boiling point used in the textbook, the Eight Parties continue, is on both an ASTM and TBP basis. *Id.* The Eight Parties assert that Tallett testified that the lowest boiling point for C_5 is 82°F, which is the boiling point for Isopentane, the heaviest Pentane. *Id.* This boiling point, the Eight Parties note, is confirmed by Gary. *Id.*

887. On Reply, Exxon argues that the record supports a 60°F C_5 cut point. Exxon Reply Brief at p. 15. Citing the Transcript at p. 1248, it claims that O'Brien agreed to that fact. Exxon Reply Brief at p. 15. It notes, in addition, that despite the Eight Parties's claim that Gary, and his treatise, support the use of at least an 82°F Naphtha cut point, Gary testified "that the C_5 cut point for Coker material should be in the 'low 60s.'" *Id.* at p. 17.

888. Exxon argues that O'Brien's testimony supporting a 100°F cut point was based on an ASTM boiling point basis while the PIMS model and the assays used in this case are based on a true boiling point basis. *Id.* at p. 19. It asserts that a 60°F cut point most accurately reflects the point separating the C_4 material from the C_5 material and is closer to the cut point used by the Quality Bank than that proposed by the Eight Parties. *Id.* at p. 20.

889. In their Reply Brief, the Eight Parties claim that Exxon misreads O'Brien's testimony and that O'Brien clearly supports a 100°F C_5 cut point. Eight Parties Reply Brief at p. 9. According to the Eight Parties, PIMS uses a 96°F C_5 cut point and Tallett confirmed this. *Id.* They conclude that, as O'Brien's suggested C_5 cut point of 100°F is closer to the PIMS cut point of 96°F, it is more acceptable than Tallett's proposal that a 60°F cut point be used. *Id.* at p. 12.

2. Assays

890. A dispute also exists over which ANS assays should be used with PIMS, Exxon notes, to calculate the product yields resulting from running ANS Resid through a Coker, for the past period at issue in the case. Exxon Initial Brief at p. 25. Exxon argues that an average of all reliable assays should be used, while the Eight Parties believe that three of the ten assays in dispute should be used in evaluating the past period – two assays produced by Caleb Brett, one in 1996 and the other in 2001, and a 1994 Exxon assay. *Id.* at pp. 25-26.

891. As for the future period, Exxon states, all parties agree that the 2001 Caleb Brett assay should be used as a starting point and that the two new assays taken in April/May 2003 and April/May 2004 will also be used in this proceeding. *Id.* at pp. 26-27. The new assays, Exxon explains, are necessary as the qualities of the TAPS common stream have changed over time because of the new Alpine and Northstar fields and because of declines in the older fields's production.[357] *Id.* at pp. 27-28. Also for these reasons, Exxon recommends that new assays be taken on an annual basis or whenever the Quality Bank Administrator has reason to believe that there may have been changes to the common stream. *Id.* at p. 29.

[357] Exxon explains that, if the new assays and the 2001 Caleb Brett assay are deemed by the Quality Bank Administrator to be consistent, the newest assay should be used. Exxon Initial Brief at p. 28. However, Exxon continues, if the new assays and the 2001 Caleb Brett assay are deemed by the Quality Bank Administrator to be inconsistent, the Quality Bank Administrator should attempt to determine why the assays are inconsistent, and determine which assay should be used. *Id.* Finally, Exxon states, if the Quality Bank Administrator cannot determine the cause of the differences, he should use an average of the assays. *Id.* at p. 29.

892. Exxon additionally argues that, on a going forward basis, the carbon residue content of the Resid be measured using the Microcarbon Residue ("Microcarbon") test rather than the Conradson Carbon Residue ("ConCarbon") test. *Id.* According to Exxon, the evidence demonstrates that the Microcarbon test is an improved method of measuring carbon residue equivalent to the ConCarbon test but more accurate with a higher level of repeatability and reproducibility. *Id.* at pp. 29-30. The Microcarbon test, according to Exxon, is the industry standard for testing carbon residue, especially for heavy fractions like the Resid at issue in this proceeding. *Id.* at p. 30. Answering the Eight Parties's argument that the ConCarbon test is the one related to the PIMS model, Exxon argues that the American Society for Testing and Material has found that the two methods are alike although the Microcarbon test is more precise. Exxon Reply Brief at p. 24. It further suggests that Dayton agrees that PIMS works as well with the Microcarbon test as with the ConCarbon. *Id.* at p. 25.

893. Regarding the past periods, Exxon asserts that the 10 assay average, adjusted to reflect the weight-blending approach advocated by the Eight Parties, is the most reasonable method of measuring the common stream's qualities. Exxon Initial Brief at p. 31. According to Exxon, this 10 assay average of the ANS Resid results in an average carbon residue content of 23.07%. *Id.* The Eight Parties, Exxon relates, support a three assay average resulting in an average carbon residue of 22.60%. *Id.* at p. 32. Exxon claims that the 10 assay average is strongly supported by the record because none of the assays are without flaws and the carbon residue content of 23.07% proposed by Tallett was near the lower end of the range of possible results, while Dayton's 3-assay average represented the lowest extreme of that range. *Id.* at pp. 32-33. Using all available, reliable assays, Exxon contends, "reduces the chance that a single assay, or the manner in which a single lab has produced a particular assay or performed a particular test, will unduly skew the average." *Id.* at p. 34.

894. Exxon accuses the Eight Parties of an effort to avoid the "obvious superiority" of the 10 assay average. *Id.* at p. 35. The criticisms presented by the Eight Parties, Exxon believes, are without merit. *Id.* According to Exxon, the procedures used by Haverly in making the assays are all standard industry practice. *Id.* Addressing the Eight Parties's contention that three of the ten assays should be disregarded because they had Resid volume percentages either higher or lower than the range of monthly Quality Bank assays for the year in which the sample was taken, Exxon insists that the Eight Parties are mistaken. *Id.* at p. 36. Dayton's comparison of assays, Exxon explains, was taken on a single day with a monthly average sample while the monthly Quality Bank assays were based on a continuous sample drawn over a month-long period. *Id.* Such a comparison, Exxon maintains, was "plainly an apples-to-oranges comparison." *Id.*

895. According to Exxon, the 10 assay average is the most reasonable put forth, while the 3 assay average advocated by the Eight Parties is at the extreme low end of the range of possible carbon residue values, consequently producing the highest Resid value. *Id.* at

p. 39. Additionally, Exxon notes that, when the 3 assay average is computed on the basis of the Microcarbon test rather than on the basis of the mix of methods used by Dayton, the results clearly validate the reasonableness of the values proposed by Tallett.[358] *Id.* at p. 40.

896. For prospective periods, the Eight Parties agree with Exxon that an average of the 2001 Caleb Brett assay and assay(s) taken in the future should be used. *Id.* at pp. 27-28; Eight Parties Initial Brief at p. 19. As for the retroactive period, the Eight Parties maintain that a three assay average should be used. *Id.* at p. 20. According to the Eight Parties, seven of Exxon's proposed ten assays have a serious flaw. *Id.*

897. Four Haverly/Chevron assays used by Tallett, the Eight Parties begin, have Resid ConCarbon measurements taken from cuts other than the 1050°+ cut, to wit: 1005°F, 1065°F, 1000°F, and 650°F.[359] *Id.* at pp. 20-21. The problem, the Eight Parties explain, is that, in order to use measurements taken from cuts with these cut points to determine the qualities of the Quality Bank 1050°+ Resid cut, it is necessary to extrapolate data based on a single data point, which is not possible. *Id.* at p. 21. The Eight Parties point out that Tallett agrees with their concerns regarding measuring ConCarbon at a cut differing significantly from the 1050°+. *Id.*

898. Three assays, the Eight Parties assert, reported Resid yields outside of the range of Resid volume yields in the assays taken each month of the year by the Quality Bank Administrator. *Id.* at p. 22. The Eight Parties explain that the Quality Bank Administrator's assays do not show the Resid qualities needed to be input into the PIMS model, but do show how much Resid each sample contains by volume. *Id.* at pp. 22-23. According to the Eight Parties, assays should not be used if their Resid volume yields were higher or lower than all of the monthly Resid volume percentages in the Quality Bank Administrator's assays for the year in which the assay sample was taken. *Id.* at p. 23.

899. The Williams/BP assay is the last disputed assay, according to the Eight Parties, and it is faulty, they say, because the vacuum distillation procedure used is D-2892, which, they claim, is not the appropriate method. *Id.* at p. 24. According to the Eight Parties, everyone agrees that the test referenced in the assay is the wrong test and, unless

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[358] Exxon explains that the evidence shows that the carbon residue value for the 3-assay average using the Microcarbon test is 23.29%. Exxon Initial Brief at p. 40. The carbon residue content test, Exxon insists, confirms the reasonableness of the 10-assay average. *Id.*

[359] The Eight Parties explain that the Quality Bank Resid cut is defined as the crude components that have not boiled off at 1050°F (referred to as "1050°+"). Eight Parties Initial Brief at p. 20.

it can be shown that the correct test was performed, this assay must be discarded. *Id.* at pp. 24-25. Thus, the Eight Parties maintain, Tallett's proposed 10 assay average is unsupportable because seven of the ten assays are invalid. *Id.* at p. 25.

900. As for implementing changes in assays to be used for Resid valuation, the Eight Parties advocate that once the Commission determines the appropriate assays to use as well as the C_5 cut point issue, the Quality Bank Administrator should be ordered to recalculate using yields equivalent to the most recent version of PIMS. *Id.* at p. 26.

901. On reply, Exxon declares that the assay question has two components: which assay(s) should be used on a going-forward basis (i.e. from the date of the final order in this proceeding), and which assay(s) should be used for the period from December 1, 1993, through that date. Exxon Reply Brief at p. 20. Other than suggesting that the parties do not agree on whether the Microcarbon or the ConCarbon test should be used, "the parties agree that, if the Resid valuation is to be done on the basis of the common stream, then current assay data should be used to account for recent changes in" its composition. *Id.* at pp. 20-21 (note omitted). It adds that the 2001 Caleb Brett assay is a starting point, that it would not be prudent to rely solely on it, and that it should be tested against assays the parties agree should be taken in 2003 and 2004. *Id.* at p. 21. Exxon declares that it now has no objection to use of an average of the 2001 Caleb Brett assay and the new ones if "the Quality Bank Administrator deems the results of the 2001 assay and the new assays to be consistent." *Id.* at p. 22. It also suggests that the Quality Bank Administrator should recheck common stream values on a periodic basis. *Id.*

902. Addressing the going-forward period, the Eight Parties claim that Exxon posits that the 2001 Caleb Brett "assay should not be used unless it differs significantly from the 2003 and 2004 assays."[360] Eight Parties Reply Brief at p. 13. They suggest that there are problems with the 2003 assay and that, if those problems cannot be resolved, this assay should not be used. *Id.* The Eight Parties add that the "2004 assay should only be used if all the parties agree that the [2004] assay is representative of all the input streams and free of analytical problems." *Id.* at p. 14.

903. Acknowledging that the Microcarbon test is newer, the Eight Parties do not agree that Dayton suggested it was more precise. *Id.* Rather, they state that, were the ConCarbon test preformed by an "experienced lab technician" who performs multiple tests, it is just as accurate as the Microcarbon test. *Id.* at p. 15. Further, the Eight Parties note, Mitchell testified that when both test were performed, the Microcarbon test "gave almost universally higher carbon residue results than the" ConCarbon test. *Id.* Therefore, they argue, the question is not which test is more precise, "but whether a test

[360] Exxon's position is not accurately described by the Eight Parties. See the discussion above.

should be used that reaches consistently higher carbon residue results." *Id.* The answer, according to the Eight Parties, is that the ConCarbon test should continue to be used as "it is the test that the PIMS yields were based upon." *Id.*

904. Turning to the past period, Exxon states that the parties disagree on whether a 10-assay average should be used, as suggested by Tallett, or a 3-assay average, as suggested by Dayton. Exxon Reply Brief at p. 26. In making their argument, Exxon explains, the Eight Parties ignore the impact of which carbon test results should be used. *Id.* Should the Microcarbon test results be used, Exxon asserts, "Tallett's proposed 10-assay average is far more reasonable than Ms. Dayton's proposed 3-assay average." *Id.* at p. 27.

905. Exxon also defends Tallett's use of certain assays against the Eight Parties's attack. *Id.* at pp. 28-33. It begins by acknowledging that the four Haverly/Chevron assays "employed an assay manger computer program to recut the assay data and [that they] did not always use the 1050°F cut point used by the Quality Bank." *Id.* at p. 29. However, it argues that this is not a reasonable basis for dismissing these four assays because they have a quality rating of good and accurate carbon residue numbers. *Id.* Exxon adds:

> Moreover, the evidence shows that the Haverly/Chevron assays were performed in accordance with the widely-accepted procedure of taking small incremental cuts of about 10°F, examining the qualities of each cut, and then taking the industry-standard mathematical interpolation procedures to reconcile and balance quality results and to state the qualities of cuts specifically matching the Quality Bank cuts.

Id. at pp. 29-30.

906. Next, Exxon turns to the three assays which Dayton claimed should be disregarded because the percentage of Resid was "either higher or lower than the range of monthly Quality Bank assays for the year in which the sample was taken." *Id.* at p. 30. According to Exxon, it is unfair to compare assays of samples taken on a single day with assays of samples taken over a full month. *Id.*

907. The last assay addressed by Exxon is the one performed by Caleb Brett in 1995 for BP and discovered in the files of Williams. *Id.* at pp. 31-32. Exxon argues that, although the assay reflects that the vacuum distillation method used was D-2892, which Dayton claims is not appropriate, Tallett testified that the results reported could not by reached by the D-2892 methodology and that the results only could be reached if the correct vacuum distillation method, D-5236, was used. *Id.* at p. 32.

908. According to Exxon, Tallett's 10-assay average is reasonable "when viewed against the many possible assay combinations that were presented at the hearings." *Id.* at p. 33. It states that the various combinations produce carbon residue averages ranging from a low of 22.48% to a high of 24.3%[361] and argue that Tallett's carbon residue content of 23.07% "is conservative and near the lower end of the range of possible results." *Id.* at pp. 33-34.

909. In their Reply Brief, the Eight Parties acknowledge that all parties agree that different assays should be use for the going forward period than for the retroactive period. Eight Parties Reply Brief at p. 12. Referring to the 2001 Caleb Brett assay, the Eight Parties note that Exxon did not believe it should be used "unless it differs significantly from the 2003 and 2004 assays." *Id.* at p. 13. They claim that Exxon fails to state any reason why this should be so, and argue that it should be used whether it is consistent or not. *Id.*

910. The Eight Parties next turn to the 2003 ANS Valdez assay and assert that, while they initially agreed that it should be used, they have now seen the results from it and believe that there are problems "both with respect to the testing that was performed and with the samples that were taken." *Id.* They state that the parties are discussing (as of November 2003) whether the samples can be retested and, if not, the Eight Parties submit that the 2003 ANS Valdez assay cannot be used. *Id.* With regard to the 2004 assay, the Eight Parties state: "Given the problems with the 2003 assay, [they] believe that the ANS Valdez assay to be taken as part of the agreed suite of 2004 assays should only be used if all the parties agree that the assay is representative of all the input streams and free of analytical problems." *Id.* at p. 14.

911. Turning to which assays should be used for the retroactive period, the Eight Parties begin by asserting that seven of the 10 assays in the record should not be used because they are unreliable for one or more of the following reasons: (1) the carbon residue test was based on a different cut than the 1050°F Resid cut point used by the Quality Bank; (2) "the volume of Resid included in the assay was outside the range of the Quality Bank assays for the entire year in which the assay was taken;" and (3) "the wrong test was used to determine the qualities of the Resid cut." *Id.* at p. 16. For this reason, the Eight Parties find fault with Exxon's suggestion that all 10 assays be used. *Id.* They further note that Tallett, Exxon's witness, agreed with Dayton's criticism of these seven assays. *Id.* at pp. 16-17.

912. In defense of the two Caleb Brett assays, which it claims Exxon attacked, the Eight Parties note, they were performed by the same laboratory which performs assays on

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[361] According to Exxon, other combinations produce carbon residue averages of 22.60%, 23.41%, 23.51%, 23.53%, and 23.77%. Exxon Reply Brief at pp. 33-34.

behalf of the Quality Bank Administrator. *Id.* at pp. 17-18. They suggest, too, that, at the hearing, Tallett withdrew his criticism of the two assays. *Id.* at p. 18.

3. Coke Value

913. Exxon explains that the parties agree that the coke produced by the coking process should be valued on the basis of the free on board ("FOB") vessel prices for fuel grade coke published in the *PCQ*. Exxon Initial Brief at p. 40. Specifically, Exxon notes, the parties agree that the published coke prices to be used are: (1) on the West Coast, the mid-point monthly quote from *PCQ* for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke; and (2) on the Gulf Coast, the mid-point monthly quote from *PCQ* for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke. *Id.* at pp. 40-41; Joint Stipulation p. 2.

914. The only disputed issue remaining, Exxon states, is whether the FOB vessel prices must be adjusted to reflect transportation, handling, storage, and reselling costs incurred by the refiner when shipping the coke from the refinery gate to the point of sale reflected in the FOB vessel price. Exxon Initial Brief at p. 41. The Eight Parties's failure to make such an adjustment, Exxon argues, results in an overstatement of approximately 65¢/barrel in the before-cost value of the coke produced from the ANS Resid over the period from 1992 through 2001. *Id.*

915. In Exxon's view, to properly reflect Coke's value to the refiner, the FOB vessel price must be adjusted. *Id.* Exxon explains:

> Both of the stipulated *PCQ* Coke prices are export prices quoted on an FOB vessel basis, and it is well established that an FOB vessel price means that the product (*i.e.*, Coke) is to be delivered and loaded by the seller at no expense to the buyer. This means that in order to realize the FOB vessel price, the refiner must incur all of the costs required to get the Coke from the refinery to the dock and onto the vessel, the point of sale reflected in the FOB vessel price. Accordingly, in order to reflect the value of the Coke to the refiner, the FOB vessel price must be adjusted to account for the substantial costs incurred by the refiner to move the Coke from the refinery to the vessel.

Id. at pp. 41-42 (emphasis in original; citations omitted).

916. While the published *PCQ* FOB vessel prices for coke are the appropriate starting point for determining the value of coke to the refiner, Exxon insists, those prices do not represent the value of the coke to the refiner. *Id.* at p. 42. To realize the FOB vessel price, Exxon explains, the refiner must move the coke from the refinery to the vessel and, the costs associated with transporting, handling, storing, and loading the coke constitute a

substantial percentage (about 61% on average on the West Coast) of the reported price for Coke. *Id.*

917. Consequently, Exxon argues, the value of the coke to the refiner on the West Coast is, on average, only 39% of the quoted FOB vessel price. *Id.* Furthermore, according to Exxon, the costs of moving coke from the refinery to the vessel are sometimes so high that the coke is sold at a net loss by the refiner because coke cannot be practicably stored for any length of time by the refinery while continuing refinery operations. *Id.* Coke produced from ANS Resid, Exxon believes, will be radically overvalued unless the FOB vessel price is adjusted to account for the costs that must be incurred by the refiner to get the coke to the point of sale reflected in the FOB vessel price. *Id.* at pp. 42-43.

918. Exxon notes that the estimated cost of shipping coke from the refinery gate to the point of sale is at least $6.00/short ton on the Gulf Coast and at least $10.75/short ton on the West Coast, and claims that these cost estimates are undisputed. *Id.* at p. 43. Additionally, Exxon states, the Eight Parties agree that coke's value to the refiner is determined by the "net-back" value a refiner can earn from coke produced in the coking process, and that this net-back value is the *PCQ* FOB vessel price less the costs of moving the coke from the refinery to the vessel. *Id.* Consequently, Exxon argues, without adjusting the quoted FOB vessel price for costs of moving coke from the refinery to the vessel, "the FOB vessel price will substantially overstate the value of the coke to the refiner." *Id.* The Eight Parties admit, Exxon asserts, that, without Bartholomew's adjustment, the Resid cut would be overvalued by approximately $10.82 million for every 100 million barrels of ANS crude passing through TAPS. *Id.* at pp. 43-44.

919. As for the Eight Parties's objections to Exxon's coke value adjustment proposal, Exxon asserts that they are without merit. *Id.* at p. 44. Their argument that the adjustment is inconsistent with using unadjusted waterborne prices for other liquid Quality Bank cuts, Exxon insists, is baseless. *Id.* To begin, Exxon explains, coke is the only solid among the Quality Bank products. *Id.* Consequently, Exxon states, the magnitude of the costs of transporting, handling, storing, and reselling the coke are far higher than the corresponding costs for other Quality Bank products and these costs are of a different order of magnitude than the transportation and handling costs associated with the other Coker products. *Id.* The result, Exxon argues, is that the shipping and handling costs for coke represent, on average, more than 60% of its value, while corresponding costs for other Coker products represent only about 2% to 8% of their value. *Id.* at p. 44-45.

920. According to Exxon, although coke accounts for only 4% of the ANS common stream, coke bears over 17% of the total logistics costs (an overly disproportionate amount) for all Quality Bank products while VGO, which accounts for 36% of the ANS common stream, bears only 31% of the total logistics costs. *Id.* at p. 45.

921. The only logical place for valuing coke, Exxon believes, is the refinery gate. *Id.* All parties stipulated to valuing Fuel Gas at the refinery gate, Exxon notes, because there is no Quality Bank reference price for Fuel Gas. *Id.* Consequently, Exxon explains, the parties agreed that Fuel Gas will be valued at the *Natural Gas Week* monthly average California South (Los Angeles) delivered-to-pipeline natural gas spot price, plus a 15¢/MMBtu transportation charge, which represents the cost of transporting the gas from the pipeline at the Arizona-California border to the refinery gate of a refinery in the Los Angeles basin. *Id.* at pp. 45-46. The 15¢ transportation charge is added to the pipeline spot price, Exxon asserts, because Fuel Gas produced in the coking process at the refinery is used by the refinery to avoid purchasing Fuel Gas that the refinery would otherwise have to purchase from the pipeline at the Arizona-California border and pay to have delivered to the refinery gate in Los Angeles. *Id.* at p. 46. The same reasoning, Exxon argues, applies to coke valuation as it is the only other Coker product for which there is no Quality Bank reference price. *Id.* at pp. 46-47.

922. Exxon also objects to the Eight Parties's attempt to introduce the value of calcined coke as an issue at the hearing for the first time. *Id.* at p. 47. According to Exxon, calcined coke is a higher quality coke made by processing of higher grades of unprocessed or "green" Coke. *Id.* Exxon notes that the parties have stipulated that coke should be valued on the basis of the *PCQ* quoted prices for fuel grade or green coke for the purposes of this case. *Id.* Coke made from 1050+°F Resid, Exxon relates, is a poor quality coke unsuitable for calcination due to its concentration of metals, carbon residue, and sulfur. *Id.* Consequently, Exxon states, the Eight Parties argued, in an earlier phase of the proceeding, that a cut point of 1050°+F for the Resid cut, as opposed to 1000°F, was justified because the coke was to be valued on the basis of a coke price equal to that of the lower valued fuel coke, *not* that of coke used for calcinating. *Id.* at pp. 47-48. As a result, Exxon argues, the Eight Parties are estopped from claiming they are entitled to a higher Resid value based on the higher price of calcined coke. *Id.* at p. 48. This is so, Exxon believes, because were the *PCQ* quoted price for calcined coke used instead, the cut point for the Resid cut would have been lower (1000°F), and the VGO yields would be smaller. *Id.*

923. Additionally, Exxon insists, it is much more expensive to produce calcined coke because there are significant additional costs that must be incurred to process green coke into calcined coke. *Id.* Therefore, Exxon explains, "[i]f the higher price of calcined Coke were used to value the Coke in this proceeding, the proxy price for Coke would have to be adjusted to account for the significantly higher costs of producing calcined Coke." *Id.* at p. 48.

924. Most important, Exxon asserts, is that the Eight Parties have not produced any evidence as to how the price of calcined coke would be adjusted to reflect additional processing costs, and there is no evidence in the record to support the Eight Parties's

attempt to introduce the value of calcined coke into this proceeding. *Id.* at pp. 48-49. Finally, Exxon notes that, because the *PCQ* quoted price for calcined coke is also an FOB vessel price, further adjustments reflecting costs incurred by the refiner to ship calcined coke on a vessel would be necessary. *Id.* at p. 49. Exxon concludes:

> [T]he evidence is overwhelming that in order fairly to value the Coke produced by a refiner in the coking process, the FOB vessel prices for Coke must be adjusted to account for the disproportionately high additional costs that the refiner must incur in order to move the Coke from the refinery to the vessel in order to obtain the FOB vessel Coke price to which the parties have stipulated. For this purpose, the Commission[] should use $10.75 per short ton cost for the West Coast, and $6.00 per short ton cost for the Gulf Coast.

Id.

925. The Eight Parties view is that consistent valuation of Quality Bank cuts is essential in order to achieve just and reasonable valuations, and adopting Exxon's proposal would create "an unacceptable and unnecessary inconsistency" in Resid valuation. Eight Parties Initial Brief at p. 27. According to the Eight Parties, Resid is the heaviest of the five liquid Quality Bank cuts and, once generated from the distillation tower, it is processed in a Coker, creating Coker products. *Id.* Coke, the Eight Parties continue, is one of the eight salable Coker products resulting from the Resid coking process. *Id.* at p. 28. Although all parties agree that the base coke price on the West and Gulf Coasts will be derived from waterborne quotes in the *PCQ*, the Eight Parties state, they disagree whether those price quotes should be adjusted. *Id.* at pp. 27-28.

926. Exxon's proposal to value coke at the refinery gate, the Eight Parties argue, is inconsistent with the current and proposed prices for other liquid products as the coke prices are already on a waterborne basis. *Id.* Additionally, the Eight Parties maintain, valuing coke at an unidentified refinery gate, while other products are valued elsewhere, will create inconsistencies between the coke values and other product values. *Id.* at p. 28. The Eight Parties insist that waterborne prices are the most appropriate basis for valuing liquid products because they represent cargoes of products at their source or destination harbor and are the largest available parcels and include the lowest marketing margins. *Id.* In the case of coke, the Eight Parties contend, the waterborne prices are published by *PCQ* and should be adopted. *Id.*

927. According to the Eight Parties, consistency is sought by all parties in the proceeding as well as the Commission. *Id.* Bartholomew states, the Eight Parties note, that the *PCQ* prices coke at a waterborne location as it is a consistent location. *Id.* at p. 29. Further, the Eight Parties claim that they rely on the Circuit Court's opinion in *OXY* in which it stated that "the [Commission] must accurately value all cuts - - not merely

some or most of them - - or it must overvalue or undervalue all cuts to approximately the same degree." *Id.* (quoting *OXY*, 64 F.3d at p. 693).

928. The Eight Parties argue that Exxon's arguments about the importance of a transportation and handling adjustment are untenable. *Id.* Exxon's position that there currently is no consistency in valuing various Quality Bank cuts, the Eight Parties assert, is wrong because the four gas plant products are consistently valued at the largest quantity available for the products (pipeline basis on the Gulf Coast and truck/rail basis on the West Coast) while the liquid products for the Gulf Coast are consistently valued on a waterborne basis. *Id.* at pp. 29-30. As for West Coast Naphtha, Light Distillate, and VGO, the Eight Parties contend, these are also valued consistently on a waterborne basis. *Id.* at p. 30. The remaining two West Coast liquid cuts (Heavy Distillate and Resid), the Eight Parties believe, should also be valued on a waterborne basis. *Id.* Should the Commission adopt the Eight Parties's proposal, they argue, all liquid products on both coasts will be valued on a consistent waterborne basis. *Id.*

929. Exxon's argument that the coke transportation and handling adjustment is a substantial portion of coke's value, but only a minor portion of other products values, the Eight Parties contend, is flawed. *Id.* Exxon does not acknowledge, the Eight Parties argue, that "on a whole barrel of ANS crude basis, the impact of the [Coke adjustment] . . . on the value of Resid . . . is actually less than the impact a similar, consistent adjustment would have if it were made to VGO and Heavy Distillate." *Id.* Furthermore, the Eight Parties maintain, a comparable Naphtha adjustment would have a similar impact as the proposed coke adjustment. *Id.* at pp. 30-31. Such a result exists, the Eight Parties explain, because the yield of coke from the Coker is small, and, when multiplied by the yield of Resid in ANS, the disproportionate effect does not exist. *Id.* at p. 31. Consequently, the Eight Parties argue, no reason exists to treat coke differently from other liquid products. *Id.*

930. Additionally, the Eight Parties contend that, were the Commission to value coke at the refinery gate, then similar adjustments would be necessary to value every other Quality Bank product, but, the Eight Parties maintain, there is no evidentiary basis to make such adjustments. *Id.* Also, the Eight Parties question which refinery gate would be used for any adjustments. *Id.* at p. 32. Any determination, the Eight Parties assert, would require further litigation, prolonging the ultimate resolution of this case. *Id.*

931. The Eight Parties also believe that Exxon's support for a transportation adjustment only for coke is inconsistent and supported only because it benefits Exxon's economic position. *Id.* According to the Eight Parties, Pavlovic admits that, if all of the transportation cost adjustment he developed were applied to the other products, Exxon's total refund claim would be decreased by 4 or 5%. *Id.*

932. Finally, the Eight Parties argue that Exxon's proposed adjustment of $10.75/ton is merely a guess and is not rooted in any systemic study. *Id.* They point out that Bartholomew did not perform a study of coke transportation rates, nor did he produce any documents related to his analysis. *Id.* Instead, the Eight Parties relate, he testified that his $10.75 was comprised of $2.00 for transportation, $6.75 for handling, and $2.00 for sellers's commissions; without any variation over time. *Id.* at pp. 32-33.

933. On reply, Exxon argues, the "facts" requiring an adjustment to the FOB vessel price of coke are "undisputed." Exxon Reply Brief at p. 35. It then argues that coke, being a coal-like solid,[362] must be transported from the refinery to the vessel and that, as a result of the cost of doing that, the value of coke to a refiner is only 39% of its FOB vessel price. *Id.* It further asserts that, upon occasion, the cost of transportation has been so high that coke had a negative value to the refiner. *Id.*

934. Answering the Eight Parties claim that coke should be valued on a waterborne basis for consistency, Exxon points out that the parties have agreed that Fuel Gas is to be valued on a landborne basis and declares that, therefore, there is no inconsistency in valuing coke on the same basis. *Id.* at p. 39. It also notes that, contrary to the Eight Parties's claim that Fuel Gas is not a "salable product," the Fuel Gas price is based on a published market price. *Id.* at pp. 39-40. Exxon further declares that coke, though only 4% of the common stream, "bears over 17% of the total logistics costs for all Quality Bank products." *Id.* at p. 41.

935. The Eight Parties's challenge to its suggestion that the cost of transporting, handling and selling coke is $10.75, Exxon claims, is without merit. *Id.* at p. 42. It notes that the Eight Parties offered no evidence to counter the testimony of its witness that this was the cost, and that Ross, the Eight Parties's witness, admitted that he had no basis on which to challenge Exxon's evidence. *Id.* As to the Eight Parties's challenge of its witness's calculations, Exxon notes that its witness "described in detail how he did his calculations, which were based on many years of course-of-business dealings with refineries, transportation and storage companies and Coke traders, as well as cost studies done for clients in 1991-92 and 1995." *Id.* at p. 43.

936. In their Reply Brief, the Eight Parties indicate their disagreement with Exxon's contention that the matter in dispute is whether and how the reported coke price should be adjusted. Eight Parties Reply Brief at p. 21. Rather, according to them, the issue is "whether it is appropriate to value one of the eight saleable coker products on a refinery gate basis, as [Exxon] suggests, when none of the other saleable coker products or any of the Quality Bank cuts are valued on that basis." *Id.* The Eight Parties say no. *Id.*

[362] Exxon declares that it disputes the Eight Parties assertion that coke is a liquid product. Exxon Reply Brief at p. 39.

937. Claiming that there is no need to adjust the coke waterborne price, the Eight Parties declare that doing so would create an inconsistency in the Quality Bank valuation. *Id.* at pp. 21-22. They point out that Exxon's own witnesses testified in support of consistency in the valuation of all of the ANS cuts. *Id.* at p. 22.

938. Responding to Exxon's claim that coke is physically different from other products and accordingly should be treated differently, the Eight Parties, while acknowledging the physical difference, state that, as the amount of coke produced from a barrel of ANS is small in comparison with other products produced from the barrel, "the impact of the proposed adjustment . . . is actually less than the impact a similar, consistent adjustment would have if it were made to VGO or Heavy Distillate." *Id.* at pp. 22-23.

939. Regarding Exxon's assertion that setting the price of coke at the refinery gate would be consistent with the manner in which Fuel Gas is treated, the Eight Parties state that Fuel Gas is used internally by a refinery, and therefore is not a marketed product. *Id.* at p. 23. According to the Eight Parties, because it is used internally by the refinery, its value is the same as the refinery's avoided cost of purchasing natural gas. *Id.*

940. The Eight Parties also assert that, while Ross, their witness, did not directly dispute Exxon's witnesses testimony regarding the cost of moving the coke from the refinery to a ship, he "did not agree or even opine as to their accuracy." *Id.* at p. 24. In addition, the Eight Parties state that Ross did not estimate that, unless the coke price was adjusted as Exxon requested, "the Resid cut would be overvalued by approximately $10.82 million for every 100 million barrels of ANS crude." *Id.*

D. COKER COSTS

1. Overall Approach

941. The parties disagree, Exxon explains, over the cost of coking the Resid cut. Exxon Initial Brief at p. 49. Such costs, Exxon notes, are incurred to refine Coker products into products meeting specifications used by the Quality Bank to value the other ANS cuts. *Id.* Exxon presents a cost study demonstrating that the coking cost for ANS Resid is $5.75/barrel on the Gulf Coast and $6.97/barrel on the West Coast in Year 2000 dollars; while the Eight Parties present cost curves to estimate a cost of $4.60/barrel in Year 2000 dollars ($4.30/barrel in Year 1996 dollars) to coke the ANS Resid on both Coasts. *Id.* at pp. 49-50.

942. According to Exxon, Jenkins submitted a line item cost study identifying direct or inside battery limits ("ISBL") costs for all the major equipment required for the Coker and the related downstream refinery units necessary to process Coker products and bring them up to the quality specifications of the Quality Bank reference products. *Id.* at p. 50.

Jenkins next, Exxon states, adds offsite or outside battery limits ("OSBL") Coker costs, fixed and variable operating costs, and related financing costs. *Id.* Finally, Exxon notes, in order to convert his capital cost estimates from Gulf Coast costs to West Coast costs, Jenkins used West Coast location factors. *Id.* Following the cost estimation procedures recommended in the Gary & Handwerk treatise, Exxon relates, Jenkins itemized storage facilities, steam systems, and cooling water systems costs and then provided for the remaining OSBL costs by using a factor of 25% of the ISBL cost of the Coker and related processing units. *Id.* at p. 51.

943. Exxon points out that Jenkins's overall capital cost estimates compared favorably with Coker cost estimates provided in several treatises, as well as with actual costs for several recent Coker construction projects. *Id.* at p. 52. In contrast, the Eight Parties, Exxon states, presented a conceptual cost estimate based on proprietary conceptual cost curves without any supporting documentation. *Id.* at p. 54. Furthermore, Exxon contends, the Eight Parties did not include a West Coast location factor, although they did admit that capital costs are higher on the West Coast than the Gulf Coast. *Id.* According to Exxon, O'Brien essentially concedes that his conceptual approach is subjective and that he could get any result he wanted from the cost curves by adjusting certain constants in the underlying cost curve equations. *Id.* at pp. 54-55. Exxon asserts that the Eight Parties's approach is a "black box," making the evaluation of coker costs "exceedingly difficult, if not impossible." *Id.* at p. 55.

944. Additionally, Exxon contends that cost curves are an unreliable way of calculating Coker costs. *Id.* at p. 56. According to Exxon, the Meyers Handbook states that using cost curves for Delayed Cokers is not practicable because of the differences in the quality of feedstock and the differences in facilities required. *Id.* Also, Exxon states, Gary testified that he was surprised cost curves were being used to estimate Coker costs. *Id.*

945. According to Exxon, cost curves are, at best accurate only to about ±25 to ±30%. *Id.* Even O'Brien's consulting firm, Baker and O'Brien, Exxon relates, recommend an allowance of at least 20% to cost curves in order to capture unidentified but real costs. *Id.* at p. 57. O'Brien, Exxon notes, does not include any contingency allowance for his cost curves. *Id.*

946. Exxon insists that O'Brien's approach to estimating downstream processing units costs was defective. *Id* at pp. 57-58. O'Brien assumes that processing can be done in larger units serving the entire refinery, Exxon states, and, consequently, assigns only incremental costs of such costs to the Coker. *Id.* at p. 58. He also, Exxon contends, ignores the Coker gas plant costs and makes no attempt to separate the costs for storage, steam systems, or cooling water systems from his overall OSBL cost estimate. *Id.* The ultimate result, Exxon argues, is that O'Brien's estimates for OSBL and downstream processing units costs are black boxes that "[can] not be analyzed or validated." *Id.* Finally, O'Brien's Coker cost estimate, Exxon asserts, is below Coker cost estimates

found in the most widely accepted petroleum engineering texts. *Id.*

947. The Eight Parties state that the Coker cost issue is about defining the costs of operating a Delayed Coker at the "Quality Bank Refinery" in order to complete the formula to calculate the Quality Bank Resid component on the Gulf and West Coasts. Eight Parties Initial Brief at p. 33. O'Brien's West Coast cost figure, the Eight Parties relate, is $4.30/barrel in Year 1996 dollars and $4.62/barrel in Year 2000 dollars; while Exxon's figure for the West Coast is $6.97/barrel in Year 2000 dollars and $5.75/barrel on the Gulf Coast. *Id.* at pp. 33-34.

948. The difference between the parties, the Eight Parties claim, results from the different approaches adopted as well as Exxon's inconsistent approach designed to allow the cost curves in valuing certain components to be higher or lower as needed to skew the valuation, thus benefiting Exxon's interests. *Id.* at p. 34. O'Brien's approach, the Eight Parties explain, assumes a typical large West Coast coking refinery with an assumed coking capacity of 40,000 barrels/day because Resid processing costs vary from refinery to refinery. *Id.* Furthermore, the Eight Parties note, O'Brien not only determines the processing costs at a typical coking refinery to coke Resid, but also determines the costs of processing the Coker product cuts into Quality Bank quality products so they could be valued consistently using Quality Bank reference prices. *Id.* at pp. 34-35. O'Brien, the Eight Parties explain, divides his processing cost calculations into three categories: (1) capital costs; (2) fixed costs; and (3) variable costs. *Id.* at p. 36.

949. According to the Eight Parties, Exxon's approach is an attempt to determine the costs of adding a Coker to an existing refinery utilizing efficient units and focuses on design rather than actual operations. *Id.* at pp. 36-37. They claim it represents the results of a "skewed engineering exercise" that fails to answer the fundamental question of what costs do West Coast refiners incur in processing Resid in a Delayed Coker. *Id.* at p. 37. In the Eight Parties's view, Jenkins does not adhere to standard industry practice because he does not use cost curves to develop estimates of capital costs, but, instead, creates a detailed capital cost estimate for an unknown site, using the Los Angeles area as a proxy. *Id.*

950. Such an approach, the Eight Parties believe, allows Exxon to craft its desired result – an entirely subjective, high cost estimate driving down Resid's value.[363] *Id.* at p.

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[363] According to the Eight Parties, Exxon's approach has numerous flaws:

> Jenkins' faulty detailed cost estimate approach . . . make[s] highly subjective factored estimates from phantom vendor quotes. These already high costs were then subjected to an endless series of subjective multiplication factors. Mr. Jenkins then added additional high capital costs for steam generation, unnecessary new tankage . . . , plus the high-end

38. In comparing Exxon's distillate hydrotreater and Delayed Coker capital cost bases, the Eight Parties note, many inconsistencies exist that would result in inconsistent valuations for heavy distillate and Resid. *Id.* at p. 39. According to the Eight Parties, these inconsistencies include the following:

> [B]ecause Exxon desires a lower capital cost for the Distillate hydroheater in order to have a higher Heavy Distillate value, Mr. Jenkins in this instance elected to use his company Jacobs' cost curve instead of using the detailed estimate approach used for the delayed coker cost. Or stated another way, Mr. Jenkins elected not to use the Jacobs' cost curve for developing his delayed coker costs. Similarly, for the Distillate hydroheater, the factor Mr. Jenkins applies to ISBL costs to determine OSBL costs was 20%, compared to the 25% that he used for the delayed coker. He similarly applied owner's costs of only 6% for the Distillate hydrotreater versus 10% for the delayed coker.

Id. at pp. 39-40 (internal citations and notes omitted). The result, the Eight Parties assert, of the inconsistent valuation is that Exxon has developed two dissimilar methodologies allowing them to skew the Heavy Distillate value higher. *Id.* at p. 40.

951. On reply, Exxon reiterates that the parties differ on the amount of the costs involved in coking ANS Resid and refining the Coker products into products which meet Quality Bank specifications. Exxon Reply Brief at p. 44. Exxon adds that its "overall capital cost estimates compared favorably with the coker cost estimates provided by several well known independent industry benchmarks, including the Gary & Handwerk treatise and the Myers text, as well as with the actual costs reported for several recent coker construction projects." *Id.* at p. 47.

952. Exxon also attacks the Eight Parties's "depiction" of their "cost curve approach as a straight-forward objective application of a 'standard industry' approach to calculating the costs of a 'typical' West Coast refinery." *Id.* at p. 48. It claims that cost curves "are

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> range of a factor for other "offsites." . . . Mr. Jenkins continued the multiplication factor frenzy by multiplying the costs by a location factor of approximately 130%, then by a further 110% for "owners costs," and finally, assuming the worst case scenario of borrowing funds for construction rather than using equity funds to finance construction, he justified a multiplier of 104.3% on top of all of the others. Thus, there is no wonder that [Exxon]'s cost estimate is about 50% higher than the Eight Parties' estimate.

Eight Parties Initial Brief at p. 38.

not a reliable way of calculating coker costs" and, in support, cites to the Meyers textbook and Gary's testimony. *Id.* Exxon also criticizes the Eight Parties for failing to use a West Coast location factor when, it claims, it is undisputed that West Coast construction costs are higher than those on the Gulf Coast. *Id.* at p. 49.

953. Lastly, Exxon attacks the Eight Parties's approach as "subjective." *Id.* at p. 50. In support, it points to their own witness's testimony and, in particular, Exxon quotes O'Brien as stating that his cost curve approach was "'conceptual' or a 'hypothetical construct,' . . . conced[ing] that [his approach is] 'subjective to the extent that it's conceptual' . . . [and] acknowleg[ing] that all changes to his conceptual cost curves . . . were 'subjective.'" *Id.* Exxon also accuses O'Brien of admitting that he could, by "adjusting the value of certain constants in the equations underlying his cost curves" get any result he wanted. *Id.*

954. The Eight Parties begin the discussion of this issue in their Reply Brief by noting that the parties have not altered their positions: they still support O'Brien's cost curve approach for determining the ISBL cost of major equipment for both the Delayed Coker and any related downstream refinery units, while Exxon continues to support Jenkins's line item analysis. Eight Parties Reply Brief at p. 26. They claim that the result is that O'Brien estimated a cost, in Year 1996 dollars, of $4.30/barrel and that Jenkins estimated, in Year 2000 dollars, a cost of $5.75/barrel on the Gulf Coast and $6.97/barrel on the West Coast. *Id.*

955. Answering Exxon's complaint that O'Brien's $107.4 million Coker cost estimate was significantly below the $175 million estimate in the Gary & Handwerk Treatise, the Eight Parties note that, in 2000, Jenkins, using his company's cost curve, estimated the cost of a Coker to be $111 million, which they allege is near O'Brien's estimate. *Id.* at p. 27.

2. Capital Costs

956. According to Exxon, the parties agree that the capital costs of the Coker consist of:

> (1) the direct, or Inside Battery Limits ("ISBL"), costs of the coker itself and the related downstream refinery units (*e.g.*, hydrotreaters, sulfur plant) that are required to process the coker products to bring them up to the quality specifications of the Quality Bank reference price; (2) the costs of the other facilities (referred to as "Outside Battery Limits," or "OSBL," facilities) that are required to support the major refinery processing units, such as storage facilities, steam generation systems, electric power distribution facilities, fuel oil and fuel gas facilities, cooling water systems, and waste water treatment and disposal facilities; and (3) various financing costs, such as capital recovery costs, owner's costs, and interest during

construction.

Exxon Initial Brief at pp. 59-60; Eight Parties Reply Brief at p. 28. After adjusting the capital costs by an appropriate location factor, Exxon explains, the costs are combined with fixed and variable operating costs producing a total cost for coking ANS Resid. Exxon Initial Brief at p. 60.

a. ISBL Coker Costs[364]

i. Approach

957. Exxon explains that Jenkins's cost study assumed that a Coker would be added to an existing refinery, that it would have a 40,000 barrels/stream day of ANS Resid capacity, and an 87% annual utilization rate. *Id.* Additionally, Exxon notes, Jenkins concluded that four drums would be necessary, as well as automatic deheading equipment, a modern coke handling system, and a Coker gas plant.[365] *Id.* at pp. 60-61.

958. To derive total installed ISBL costs, Exxon states, Jenkins next applied installation factors based on the particular classes of equipment, which included individual factors for all of the major installation cost components. *Id.* at p. 62. These installation factors, Exxon asserts, were derived by Jacobs Consultancy from a book written by Kenneth Guthrie, and were modified over the years by Jacobs Consultancy, and were reviewed for reasonableness by personnel at Jacobs Engineering. *Id.* Finally, according to Exxon, Jenkins used a West Coast location factor of 1.26 to end up with $173 million in Year 2000 dollars on the West Coast for the ISBL capital cost. *Id.* at pp. 62-63.

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[364] ISBL costs, Exxon states, are the direct costs for acquiring and installing the equipment required by the particular refinery processing unit. Exxon Initial Brief at p. 60.

[365] To develop the costs for each item, Exxon explains, Jenkins used cost estimation formulæ developed by his employer, Pace/Jacobs Consultancy, and its parent company, Jacobs Engineering, from public data and vendor quotations. Exxon Initial Brief at p. 61. For specialty equipment, for which no general cost formulæ were available or appropriate, Exxon states, Jenkins used vendor quotes from other projects that Jacobs Consultancy had worked on or quotes obtained specifically for this project from vendors. *Id.* Next, Exxon continues, the bare costs were reviewed for reasonableness by employees of Jacobs Engineering, and where cost estimation formulæ were used, Jenkins confirmed the reasonableness of his estimates against the lowest acceptable actual vendor quotes for equipment of the particular type or size using vendor quotes from other projects that his firm had worked on, or quotes specifically obtained for this cost study. *Id.*

959. According to Exxon, Jenkins's estimate for the ISBL costs of the Coker is more reasonable than O'Brien's estimates:

> [T]he evidence shows that Mr. Jenkins' assumption that a 4-drum coker would be used to coke 40,000 barrels/day of ANS Resid is more reasonable than Mr. O'Brien's assumption that a 2-drum coker would be used, and that Mr. Jenkins's assumption that the coker would have automatic deheading equipment, a modern coke handling system, and a gas plant are far more reasonable than Mr. O'Brien's assumption that the coker would have none of these features (or in the case of the gas plant, that the costs would be covered by his OSBL factor).

Id. at p. 65. In comparing Jenkins's and O'Brien's cost estimates, Exxon contends, for the items both included in their estimates, Jenkins's cost estimates are lower. *Id.* The result, Exxon argue, is that when the equipment O'Brien concluded are inappropriate or unnecessary are removed from Jenkins's estimate so that the two Coker cost estimates include only the same equipment, Jenkins's Coker cost estimate is $12 million lower than O'Brien's estimate. *Id.* at p. 66.

960. Beginning, the Eight Parties state that O'Brien's assumptions include: (1) a 2-drum Coker sufficient to coke 40,000 barrels/day of ANS Resid, (2) manual deheading, (3) standard coke handling equipment, and (4) including the Coker gas plant in OSBL costs. Eight Parties Initial Brief at p. 41. Furthermore, the Eight Parties note, O'Brien checked his cost curve results against estimates using data in publicly available textbooks – Gary & Handwerk, Meyers, and Maples. *Id.*

961. The Eight Parties explain that, although he found significant variation, when making adjustments, the result was that O'Brien's own cost estimate of $145.0 million fell between the low end, represented by Maples at $111.2 million, and the high end, represented by Meyers at $256.8 million. *Id.* According to the Eight Parties, Jenkins also prepared a cost curve valuation, using his firm's cost curves, which were close to O'Brien's estimate ($111 million in 1997 dollars as compared to $107 million in 1996 dollars). *Id.* at p. 43. In the Eight Parties view, the sole reason for not using Jenkins's cost curve approach is that Exxon would benefit from a low Resid value. *Id.* at pp. 43-44.

962. Additionally, the Eight Parties argue, Jenkins does not have particular technical expertise with Delayed Cokers sufficient to create a detailed cost estimate for these Cokers and he has never previously prepared a detailed cost estimate for Delayed Cokers. *Id.* at p. 45. According to the Eight Parties, Jenkins and Dickman did not spend the time necessary to develop a detailed cost estimate. *Id.* at p. 46. They note that Gary had stated that a lot of engineering manpower is necessary in order to get a detailed Delayed Coker

cost estimate, requiring that equipment is specified in sufficient detail that adequate costs can be found. *Id.* Jenkins and Dickman, the Eight Parties point out, spent approximately three weeks doing this work. *Id.* Also, the Eight Parties assert that Jenkins did not follow the steps[366] Gary said were necessary for a detailed estimate even though Jenkins repeatedly used the Gary & Handwerk textbook to support his detailed estimate and resulting Delayed Coker capital cost. *Id.*

963. Another criticism, the Eight Parties relate, is that Exxon ignored the PIMS operating parameters in its design of the Delayed Coker while at the same time retaining the PIMS yields even though the two are directly linked. *Id.* at p. 48. The Eight Parties contrast Exxon's actions with O'Brien's decision, correct in their view, to retain the PIMS operating parameters in his Delayed Coker design. *Id.* According to the Eight Parties, Exxon's explanation for this is that the PIMS operating parameters were not tied to yields. *Id.* However, the Eight Parties explain, the operating parameters cells in PIMS are dead cells or place holders, but the operating parameters given are comments corresponding to the yields the parties agreed to use. *Id.* Exxon's position, the Eight Parties assert, is necessary to justify its need for a higher cost four-drum Coker rather than a two-drum Coker to process 40,000 barrels/day of ANS Resid. *Id.* at p. 49.

964. On reply, Exxon notes that the difference in Coker ISBL estimates between it and the Eight Parties is around $20 million in Year 1996 dollars.[367] Exxon Reply Brief at p. 51. It claims, however, that the Eight Parties failed to include, in their $107.4 million estimate, the costs of "automatic deheading equipment, certain coke handling facilities necessary to meet West Coast environmental regulations, and a coker gas plant." *Id.* at p. 52. Exxon adds that the Eight Parties's estimate only includes the cost of a 2-drum Coker when a 4-drum Coker is required. *Id.*

965. Moreover, Exxon asserts that the Eight Parties's cost curve is not supported by documentation and that O'Brien could not identify one project underlying his cost curves. *Id.* at p. 55. Nor could he detail what specific equipment is included. *Id.* Exxon adds that O'Brien "admitted that there is simply no way for anyone else to validate his cost curves." *Id.* at p. 56.

966. Answering the Eight Parties's charge that Jenkins, Exxon's witness, failed to

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[366] These failings, the Eight Parties explain, include not getting any vendor quotes or getting quotes for an insufficiently detailed Delayed Coker. Eight Parties Initial Brief at p. 46. Another failed step, the Eight Parties relate, is not performing any heat and material balance. *Id.* at p. 47.

[367] Exxon's estimate is about $127 million and the Eight Parties's estimate is about $107.4 million, according to Exxon. Exxon Reply Brief at p. 51.

follow the common industry practice of using cost curves to estimate project costs, Exxon asserts that, while cost curves may be used to estimate the cost of "simple types of processing units . . . where there are no significant variations in equipment design or cost," using a "general cost curve for a delayed coker is not a reliable approach." *Id.* at p. 57. It also notes that O'Brien's estimate of $107.4 million is "below the Gary & Handwerk estimate ($175.0 million) and below the entire broad range of estimates set forth in the Myers text (ranging from $109.5 million to 219.1 million)." *Id.* at p. 58. Exxon adds that, O'Brien, faced with that evidence, deducted certain costs from them which he claimed were not included in his estimate, but still wound up with a Gary & Handwerk estimate of $137.5 million, well above his $107.4 million estimate, and a Myers text range of $99.5 million to $205.5 million, whose midpoint ($150 million) is well above his estimate. *Id.* at p. 59.

967. On reply, the Eight Parties assert that Jenkins's "line item estimate is fatally flawed." Eight Parties Reply Brief at p. 28. Claiming that Jenkins failed "to adhere to strict detailed design requirements," they elucidate as follows: "[Jenkins's cost estimates] are totally lacking in foundation, particularly for a refinery adding a delayed coker to run ANS crude oil. Moreover, the factors Mr. Jenkins used were old and error-prone." *Id.* at pp. 28-29.

968. The Eight Parties accuse Jenkins of running up the costs in his 2002 line item estimate, and in support they note that his 2000 estimate, based on a cost curve, was lower. *Id.* at p. 29. They note further that his 2002 line item approach is inconsistent with the cost curve approach he used to estimate the capital cost for the Heavy Distillate cut. *Id.*

969. Detailing some specific errors they allege are contained in Jenkins's line item estimate, the Eight parties note the following: (1) Jenkins applied installation factors, but could not state whether they had anything to do with a Delayed Coker; (2) referring to Exhibit No. WAP-81, Jenkins admitted that all of the numbers in the "total column on the installation factors" were incorrect;" (3) Jenkins could not "state with certainty where the factors he used originated;" and (4) the installation factors which Jenkins used were old, i.e., they were based on a 1970s era textbook and Jenkins had no idea as to whether they had been updated. Eight Parties Reply Brief at pp. 30-34. The Eight Parties also assert that Jenkins failed to "do the work necessary to size the equipment to obtain vendor quotes for his detailed cost estimate for the delayed coker." *Id.* at pp. 34-35.

970. Continuing to attack Jenkins's cost estimate, the Eight Parties claim that the vendor quotes Jenkins used were not related to a 40,000 barrels/day Delayed Coker, as envisioned in this proceeding. *Id.* at p. 35. Moreover, they allege that neither Jenkins nor Dickman, who aided Jenkins on this project, were able to present vendor quotes to support their testimony. *Id.* at pp. 36-39.

971. The bottom line, according to the Eight Parties, contrary to Exxon's assertion that none of Jenkins's line item estimate was challenged, is that they challenged it in its entirety and it was "shown to be lacking." *Id.* at p. 39. In comparison with Jenkins's faulty line item estimate, the Eight Parties claim that O'Brien's cost curve approach is sound and based upon a database which has been "compiled, correlated, and updated . . . for over twenty years." *Id.* at p. 41. Finishing this portion of their argument, the Eight Parties state as follows:

> [B]oth Baker & O'Brien and Jacobs [Jenkins's employer] have cost curves for delayed cokers. Both have developed the data from various sources over the years. Both do not maintain the underlying supporting documentation and data. Both Mr. O'Brien and Mr. Jacobs could not identify any particular coker project data included in their respective cost curve data. Most importantly, both Mr. O'Brien and Mr. Jenkins used their respective delayed coker cost curves in 2000 and calculated a cost that was within a couple of million dollars of each other's calculations. The only difference now is that Mr. O'Brien followed the typical industry practice and used a cost curve to calculate his delayed coker cost while Mr. Jenkins did not. As a result of this variance in approach, Mr. Jenkins has increased significantly the ISBL cost difference from a couple of million dollars to $66 million ($173 million, less $107 million).

Id. at p. 43.

ii. Two Drum or Four Drum Coker

972. Exxon insists that a 4-drum Coker is necessary to process 40,000 barrels/day of ANS Resid, while contending that O'Brien's 2-drum Coker, operating in a 14 hour cycle time, is unsupportable and unreasonable. Exxon Initial Brief at p. 66. According to Exxon, O'Brien admitted that 4-drum Cokers could be used for lower feed rates. *Id.* at p. 67. Also, Exxon states, O'Brien acknowledged that he did not know how many 2-drum Cokers were used in his firm's 2-drum cost curve; nor did he know the coke drum sizes used in deriving the 2-drum cost curve. *Id.* Exxon asserts that O'Brien's assumptions do not fare well when compared with real world Coker capacity and that his assumption that a refiner would construct a 2-drum Coker to process 40,000 barrels/day is unreasonable. *Id.*

973. According to Exxon, the evidence demonstrates that a Coker processing 40,000 barrels/day of ANS Resid will have four drums and that the crossover point between a 2-drum and a 4-drum Coker is within the 25,000 to 35,000 barrels/stream day.[368] *Id.* at

[368] O'Brien defined "stream day" as follows:

> Stream day is the amount that a refinery can run in one 24-hour

pp. 67-68. Furthermore, Exxon relates, 4-drum Cokers within the United States are used to process amounts as low as 17,500 barrels/stream day. *Id.* at p. 68. Only one existing 2-drum Coker, Exxon states, was found to have the capacity for processing 40,000 barrels/day of Resid and that that Coker, the CITGO Petroleum Coker in Corpus Christi, Texas, exists on the Gulf Coast and produces shot coke.[369] *Id.* Exxon adds that this Coker was originally built in 1982 to process 22,500 barrels/day, and, since then, significant enhancements have been added to increase the Coker's capacity. *Id.* at p. 69. Such enhancements, Exxon contends, are not included in O'Brien's Coker cost calculations. *Id.* The newest and largest 2-drum Coker on the West Coast, Exxon relates, has only a 26,000 barrels/stream day capacity and no other existing 2-drum Coker, beside the CITGO Corpus Christi Coker, processes more than 35,500 barrels/stream day. *Id.* Finally, Exxon argues, two of the four 4-drum West Coast Cokers process merely 28,000 barrels/stream day (Valero/Ultramar's Wilmington refinery) and 22,000 barrels/stream day (Phillips/Tosco's Rodeo refinery), respectively. *Id.*

974. Consequently, Exxon concludes, O'Brien's assumption that a 2-drum Coker can process 40,000 barrels/day is not reasonable. *Id.* According to Exxon, O'Brien did not estimate a typical Coker's cost. *Id.* at pp. 69-70. Instead, Exxon insists, he assumed that a Coker could push its maximum possible capacity at optimal operating conditions in order to achieve the assumed results. *Id.* at p. 70. O'Brien additionally admits, Exxon notes, that his proposed 2-drum Coker would be unable to process 40,000 barrels/day of a crude producing heavier coke than that produced by ANS Resid, such as the coke produced by California crude. *Id.*

975. Exxon argues that O'Brien's drum size assumptions are inconsistent, unclear, and unreasonable. *Id.* at pp. 70-72. In order to process 40,000 barrels/day of ANS Resid, Exxon states, O'Brien asserts that the largest size drums manufactured today must be used. *Id.* at pp. 70-71. Exxon notes that O'Brien changed his position several times regarding the actual specifications for the proposed drum size. *Id.* at p. 71. At various points in his testimony, Exxon states, O'Brien proposed the following measurements for his drums: (1) drums with a 29 foot diameter and an overall length of 120 feet, (2) drums that were 28.5 feet in diameter and 120 feet in height, and (3) that his conceptual cost

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> period when it's operating under optimal conditions. Calendar day is when it can run under a period of a year or more on a continuous basis. It has to shut down periodically for maintenance and other unexpected problems.

Transcript at p. 852.

[369] Shot coke, Exxon notes, is easier to remove from coke drums as compared to the sponge coke produced by ANS Resid, and also employs automatic deheading equipment to reduce cycle time. Exxon Initial Brief at p. 68.

curve makes no drum size assumption. *Id.* at pp. 71-72.

976. According to Exxon, the evidence demonstrates that O'Brien's coke drums would not be able to process 40,000 barrels/day of ANS Resid based on reasonable operating assumptions. *Id.* at p. 71. Exxon insists that a coke drum processing 40,000 barrels/day of ANS Resid in a 2-drum Coker with the drum diameter initially assumed by O'Brien -- 27.5 feet -- and reasonable assumptions regarding cycle time would be 148 feet, which is far larger than any coke drum manufactured today. *Id.*

977. Additionally, Exxon notes that, even if O'Brien's coke drums had 29- or 30-foot diameters, the resulting vapor velocity would exceed acceptable limits. *Id.* at p. 72. Finally, Exxon contends that O'Brien's 2-drum Coker design has no spare capacity and, consequently, no operating flexibility. *Id.*

978. Exxon contends that O'Brien's cycle time assumptions are not reasonable because his assumed 2-drum Coker would require a 14 hour cycle time. *Id.* O'Brien, Exxon notes, admits that his cost curve does not contain cycle time information and that the 14 hour cycle time is not typical for a 2-drum Coker. *Id.* at p. 73. Upon investigating the Solomon Associates data used by O'Brien in assuming a 14 hour cycle time, Exxon states it discovered that the data was based on erroneously reported cycle times and the correct data had a corrected average cycle time of approximately 16 hours. *Id.* O'Brien, Exxon relates, admits that he did not verify the accuracy of the Solomon Associates data and that a 16 hour cycle time would mean that his proposed 2-drum Coker would have insufficient capacity to process 40,000 barrels/day of ANS Resid. *Id.*

979. Solomon Associates reported operating cycle times, Exxon explains, rather than design cycle times. *Id.* According to Exxon, the witnesses agreed that when estimating Coker construction costs, one should use design rather than operating cycle time. *Id.* Virtually all new Delayed Cokers, Exxon states, are designed for cycle times between 16 and 24 hours and no Coker operating today was designed to operate in less than 16 hours cycle time. *Id.* at pp. 73-74. Although Coker operating cycle times can be reduced beneath the design cycle time, Exxon insists such reductions involve extra expenses for "modifications, revamping, and debottlenecking;" none of which are included in O'Brien's cost estimates. *Id.* at p. 74. O'Brien fails, Exxon relates, to include modern coke handling systems such as automatic deheading equipment and automatic chutes necessary to achieve short cycle times.[370] *Id.* Finally, Exxon insists, a 14-hour cycle time

[370] Another problem, Exxon explains, is that O'Brien's large diameter coke drums are difficult and time-consuming to decoke because, as drum diameter increases, the water pressure in the stream of water used to decoke coke drums drops as the distance from the central cutting head increases. Exxon Initial Brief at pp. 74-75. When the coke is shot coke, Exxon notes, this is not a problem as it falls in balls out of the bottom of the Coker drum. *Id.* However, Exxon relates, it is a problem when the coke is sponge coke,

would materially shorten the life of the coke drum because of additional drum stresses due to rapid temperature cycles and this fact is ignored by O'Brien. *Id.* at p. 75.

980. According to Exxon, another problem with O'Brien's 2-drum Coker is that it would have excessive vapor velocity that would carry over coke particles ("coke fines") into the fractionator, causing poor operation and, ultimately, unit shut down. *Id.* at p. 76. In Exxon's view, vapor velocity is the design limiting factor for a Coker using Resid feed with a ConCarbon of 23 and operating at 15 psig and the problem can be avoided by either reducing the Coker fresh feed rate below the 40,000 barrels/day or by moving to a 4-drum coker. *Id.*

981. To avoid this problem, Exxon notes, O'Brien proposed that his Coker would operate with zero recycle[371] thus avoiding the vapor velocity problem. *Id.* Even though O'Brien claimed that his Coker would be assumed to operate with zero recycle because the PIMS model assumed zero recycle, Exxon explains that zero recycle has varied meanings and can refer to recycle varying from zero up to 5 percent. *Id.* at pp. 76-77. Additionally, Exxon contends, the PIMS model is inconsistent with true zero recycle because it does not produce extra heavy Coker gas oil, which would be produced under conditions of true zero recycle. *Id.* Another problem, Exxon states, is that O'Brien's Coker did not factor in the costs of operating with true zero recycle and if they had, the capital costs would be at least one million dollars greater. *Id.*

982. Exxon argues, in contrast to O'Brien's unreasonable assumptions, Jenkins's 4-drum Coker is reasonable. *Id.* Four-drum Cokers, Exxon explains, are used to process anywhere from 17,000 to 80,000 barrels/day of Resid and virtually all Cokers processing 40,000 barrels/day have four drums. *Id.* at pp. 77-78. Additionally, Exxon contends, assuming a 16-hour design cycle time is reasonable, and Jenkins's design did not have vapor velocity problems. *Id.* at p. 78. Although Jenkins's assumptions regarding outage -- the distance between the top of the coke in the coke drum and the top of the drum -- were challenged on the ground that some Cokers have been operated with smaller outages, Exxon states, Jenkins's Coker cost estimates were appropriately based on a reasonable outage for which a Coker would be designed. *Id.* Exxon insists that Jenkins properly designed a contingency thus allowing the operator flexibility should problems

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like that produced from ANS crude. *Id.*

[371] As to zero recycle, O'Brien states as follows: "Zero recycle means effectively, [that] all the material coming into the coker, the coking drum – only goes through the coking drum once and there's no material being brought back and sent through the drum twice." Transcript at p. 1019. He adds: "If you have recycle in the drums, then that material is being coked twice and it will reduce the yields of the liquid products and increase the yields of the coke." *Id.* at p. 1020.

arise when decoking the other drum. *Id.* at p. 79. These design contingencies, Exxon notes, are often used in designing refineries. *Id.*

983. As to the question of two or four drums, the Eight Parties believe that only a 2-drum Coker is necessary and the difference between the two proposals is approximately $13 million in ISBL costs. Eight Parties Initial Brief at pp. 49-50. According to the Eight Parties, Jenkins, calculating the difference solely on the cost of coke drum sizes, concluded that the difference in ISBL costs between two drums and four drums is approximately $25 million on a Gulf Coast basis and $32 million on a California basis. *Id.* at p. 50.

984. O'Brien explains, the Eight Parties state, that his firm uses three different cost curves for developing estimates of Coker costs, depending on whether the Coker is 2-drum, 4-drum, or a 6-drum Coker, and the break even point between using two drums or four drums for a Coker is very near, but slightly above, where 40,000 barrels/day of ANS Resid falls. *Id.* at pp. 50-51. Despite Exxon's contention that a 2-drum Coker would be inadequate, the Eight Parties insist that there are 2-drum Cokers in the United States capable of processing 40,000 barrels/day of ANS Resid. *Id.* at p. 51. The Eight Parties note that three such refineries exist: the Citgo Corpus Christi refinery, the Flint Hills/Koch Saint Paul/Rosemont refinery, and the Marathon Garyville refinery. *Id.* at pp. 52-53. Additionally, the Eight Parties state, the 4-drum Orion Good Hope/Norco refinery has an 80,000 barrels/stream day or 75,000 barrels/calendar day capacity. *Id.*

985. Discussing Dickman's contention that the 2-drum Corpus Christi refinery should be disregarded because it produces shot coke instead of sponge coke that is easier to remove which shortens cycle time, the Eight Parties's argue that a coke drum containing shot coke is subject to hot spots making it *more*, not less, difficult to cut the shot coke out of the drum, thus increasing cycle times. *Id.* at p. 54. As for Dickman's testimony that 24 hour cycle times are typical, the Eight Parties disagree, arguing that Cokers operate on 14-16 hour cycles because the economics of coking encourages operating at maximum capacity and shorter cycle times. *Id.* at pp. 54-55.

986. The Eight Parties point out that Dickman's testimony about 24 hour cycle times is inconsistent with Jenkins's proposed 16 hour cycle time used in Exxon's Coker design cost estimate. *Id.* at p. 55. Furthermore, the Eight Parties state, cycle times below 16 hours are supported by numerous industry articles regarding cycle times, and the Meyers textbook states at page 10 that that cycles of 14 to 16 hours are typical. *Id.*

987. Regarding the vapor velocity issue, the Eight Parties note that there is no absolute vapor velocity limit recognized in the industry; but, instead, the limit used by a refinery depends on the refinery's tolerance with respect to the amount of coke fines that carry over into the fractionator, which has to be traded off against the greater capacity achievable with higher vapor velocity. *Id.* at pp. 55-56. The Eight Parties explain that

O'Brien did not assume any particular vapor velocity for his conceptual design, but did calculate a vapor velocity of 0.72 feet/second for his design, which is within limits acceptable to most refiners. *Id.* at p. 56. Dickman's assertion that the vapor velocity limit applicable to a Coker processing ANS is 0.625 feet/second, the Eight Parties insist, is incorrect. *Id.* No industry standard, the Eight Parties relate, exists on the subject and refineries do operate with vapor velocities higher than what Exxon suggests. *Id.* at p. 57.

988. As for Dickman's spreadsheet Coker drum calculations, the Eight Parties argue it does not support Exxon's assertions. *Id.* The Eight Parties explain that Dickman developed the spreadsheet allowing different parameters to be input into the spreadsheet, allowing the inputs to calculate the height of the Coker drum or vapor velocity. *Id.* It was used, the Eight Parties continue, to calculate other operating parameters of a Coker, such as tons of coke processed per day. *Id.* The Eight Parties contend that,

> In presenting various scenarios modeled by his spreadsheet, Mr. Dickman varied the spreadsheet's base assumptions to favor the result that he wanted to achieve for that particular application, rather than using uniform assumptions across the different scenarios that he considered. What is more, Mr. Dickman did not mention these variations in his testimony, instead leaving it to others to uncover how the scenarios differed and how those differences affected the results.

Id. at pp. 57-58.

989. The Eight Parties also question Dickman's conclusions regarding his calculations for tons of coke processed. *Id.* at p. 58. Dickman's testimony, the Eight Parties relate, asserts that O'Brien's approach would not allow a 2-drum Coker to process the necessary 2,400 tons/day of coke required to process 40,000 barrels/day of ANS Resid based on Dickman's calculations. *Id.* However, the Eight Parties point out, Dickman admits that he changed O'Brien's exact assumptions. *Id.* Dickman in his coke tons calculations, the Eight Parties relate, assumed a 16 hour cycle time rather than O'Brien's 14 hour cycle time, assumed a 30-foot outage instead of a 25-foot outage, and assumed a drum outlet temperature of 850°F instead of the 805°F shown on PIMS and a drum pressure of 25 psig instead of the 15 psig shown on PIMS. *Id.* at p. 58-59.

990. Consequently, the Eight Parties contend, as O'Brien's key assumptions were altered, Dickman's spreadsheet underestimates the amount of capacity available in the coker drums. *Id.* at p. 59. A similar altering of assumptions, the Eight Parties continue, impacted Dickman's vapor velocity calculations because he changed the assumptions in the spreadsheet from those he used in the coke tons calculations, increasing the calculated vapor velocity above what it would have been under the assumptions in the coke tons calculations. *Id.*

991. The Eight Parties also claim that Dickman, after using Jenkins's assumed 25 psig drum pressure in his coke tons calculations, "switched to the 15 psig found in PIMS and assumed by Mr. O'Brien in the Vapor Velocity Calculations." *Id.* at p. 60. They further state that Dickman agrees that switching from 25 psig to 15 psig "increases the resulting calculated vapor velocity and makes it harder for the design to stay within maximum limits." *Id.* The Eight Parties add:

> Ironically, Mr. Dickman defended his decision to use 15 psig in the Vapor Velocity Calculations instead of 25 psig that he used in the coke Tons Calculations on the grounds that increasing the pressure changes the coker yields from what was shown in PIMS. That argument is inconsistent with [Exxon's] argument . . . that it was appropriate for Mr. Jenkins to use the PIMS yields notwithstanding that Mr. Jenkins assumed a Drum Pressure of 25 psig.

Id. at p. 60 (internal citations omitted).

992. Another change, the Eight Parties note, between the coke tons calculations and the vapor velocity calculations was in the natural recycle assumption. *Id.* Dickman employed the 0% recycle assumption appearing in PIMS in his coke tons calculations while using a 5% recycle in his vapor velocity calculations, thus causing the calculated vapor velocity to increase. *Id.*

993. To demonstrate the results under O'Brien's assumptions, the Eight Parties state, Phillips modeled several scenarios using Dickman's spreadsheet and concluded that O'Brien's model can handle the 2,400 tons/day of coke required to process 40,000 barrels/day of ANS Resid.[372] *Id.* at p. 61. According to the Eight Parties, Dickman

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[372] The Eight Parties explain how, under O'Brien's assumptions, his 2-drum coker can handle the required amount of coke:

> [Exhibit No. PAI-141] shows that, under these assumptions, the two-drum coker can handle 2,403 tons/day of Coke . . . which means that it can handle the necessary 2,400 tons/day of Coke required to process 40,000 barrels/day of ANS Resid. The vapor velocity shown is 0.71 feet/ second.
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> * * * *
>
> [Exhibit No.] PAI-142 shows what happens if all of the assumptions in [Exhibit No.] PAI-141 are held constant, except that Mr. Jenkins's assumed operating pressure of 25 psig were [sic] used. This exhibit shows that, under this assumption, the two-drum coker could process 2,403 tons/day of Coke with a lower vapor velocity of 0.53 feet/ second.

agreed that their calculations accurately reflected the results of putting O'Brien's assumptions into his spreadsheet and agreed that those results indicated that the 2-drum Coker could process 40,000 barrels/day of ANS Resid. *Id.* at p. 62.

994. The Eight Parties argue that Jenkins made two errors in calculating drum size with the result that his 4-drum Coker can process far more than 40,000 barrels/day of ANS Resid. *Id.* at p. 63. Jenkins testified, the Eight Parties relate, that his Coker drum cost estimate was based on two inputs: the drum's diameter and the drum's height. *Id.* According to the Eight Parties, he used a drum diameter of 27 feet and then performed a calculation based on the 60,034 cubic feet of coke produced by 40,000 barrels/day of ANS Resid to determine the necessary drum height. *Id.* The Eight Parties state that Jenkins calculated 60,034 cubic feet of coke would fill a 27-foot diameter drum up to 51 feet and he added 25 feet to account for outage. *Id.* at p. 64. Summing these numbers, the Eight Parties continue, results in a calculated drum height of 76 feet, which was the height Jenkins used to get a price quote for the cost of the drum. *Id.*

995. The two mistakes, the Eight Parties point out, include first his underestimation of the amount of coke going into the cone and bottom head extension at the bottom of his coke drum -- instead of 1,801 cubic feet assumed by Jenkins, he should have used 9,335 cubic feet. *Id.* Second, the Eight Parties claim, he misapplied his calculation of the 25-foot outage by failing to calculate the outage from the top of the flange as is industry practice and by improperly calculating the outage from the top of the tangent. *Id.* Jenkins admits, the Eight Parties assert, that he was effectively using a 35-foot outage instead of a 25-foot outage and that he only needed to add 15 feet to the tangent length to account for a 25-foot outage. *Id.*

996. These two mistakes, the Eight Parties contend result in an overly high price quote for the Coker drums. *Id.* According to the Eight Parties, Jenkins design only requires Coker drums with only 59 feet of tangent length, which is the sum of the 44 feet taken by the coke, plus 15 feet necessary to account for the outage. *Id.* at p. 65. Jenkins, the Eight Parties state, admitted to this error at hearing. *Id.*

997. According to the Eight Parties, they've devised a method to quantify the cost impact of Jenkins's errors. *Id.* at p. 66. Beginning with Dickman's admission that the 4-drum Coker can process 50,000 barrels/day of ANS Resid instead of the 40,000 barrels/day it was designed for, the Eight Parties state, the cost impact can be quantified by allocating Jenkins's total capital costs to the 50,000 barrels/day of ANS Resid that it can actually process instead of the 40,000 barrels/day used in Jenkins's calculations. *Id.*

Eight Parties Initial Brief at pp. 61-62.

998. Dividing the total costs, the Eight Parties explain, by 50,000 barrels instead of 40,000 results in cost per barrel of capacity of $7,692 instead of $9,616, which translates into net capital recovery cost per barrel/day of $3.62 on a West Coast basis. *Id.* at p. 67. Such costs, the Eight Parties point out, are over $1/barrel lower than the equivalent net capital recovery cost per barrel/day of $4.64 when assuming 40,000 barrels/day of capacity. *Id.*

999. On reply, Exxon reiterates its position that a 2-drum Coker is not feasible where it was necessary to process 40,000 barrels/day of ANS Resid. Exxon Reply Brief at p. 61. Regarding the Eight Parties suggestion that a 2-drum Coker was sufficient, Exxon finds a disparity between their position that their cost curves represent a typical Coker and what Exxon claims is a lack of evidence that a 40,000 barrel/day 2-drum Coker is typical. *Id.* at p. 62. To the contrary, according to Exxon, the record does not indicate that there are any 2-drum Cokers on the West Coast with a capacity exceeding 26,000 barrels/day and that there is only one 2-drum Coker in all the United States with a 40,000 barrels/stream day capacity.[373] *Id.* Moreover, Exxon asserts that "O'Brien's coker" pushed the maximum limits of a 2-drum Coker operated under optimal conditions and could not, therefore, be determined to be typical. *Id.* at pp. 62-63.

1000. In contrast with its assertions regarding O'Brien's 2-drum proposal, Exxon declares that a 40,000 barrel/day Coker almost always has four drums. *Id.* at p. 63. It adds that "the cross-over between a 2-drum coker and a 4-drum coker is in the range of 25,000 to 35,000 barrels per stream day." *Id.*

1001. In their Reply Brief, the Eight Parties allege that a Coker for a 40,000 barrel/day refinery processing ANS is on the boundary between being able to use a 2-drum Coker and requiring a 4-drum Coker. Eight Parties Reply Brief at p. 43. They claim that O'Brien determined that it was "possible" for a 2-drum Coker to process this amount of ANS. *Id.* In support, the Eight Parties claim that the record reflects that at least four existing 2-drum Cokers are capable of so performing, that the drum sizes imagined by O'Brien are well within the sizes available to the industry, that the less than 16-hour cycle times imagined by O'Brien "are commonly achieved by many refineries," that it is not relevant that sponge coke, not shot coke, is produced by ANS Resid, and that the vapor velocity imagined by O'Brien is within industry standards. *Id.* at pp. 44-45.

1002. Claiming that Exxon suggests that many of its proposals are based on design criteria even when refineries can be operated at more efficient levels, the Eight Parties

[373] According to Exxon, the 2-drum Coker is operated by CITGO in Corpus Christi, Texas, and uses automatic deheading equipment to lower the cycle time. Exxon Reply Brief at p. 64. It further notes that the Eight Parties's proposal does not include use of such equipment. *Id.*

argue that the issue is not how much it would cost to install a new Coker in a refinery, but "how much it costs to process Resid into the various products for which there are published prices that are used to establish the value of Resid." *Id.* at pp. 45-46.

iii. Automatic Deheading

1003. According to Exxon, automatic deheading equipment should be included in the Coker's cost because it is used to improve safety and reduce Coker cycle time. Exxon Initial Brief at p. 80. All the Cokers built within the past ten years, Exxon notes, have automatic deheaders. *Id.* Jenkins's model, Exxon states, includes automatic deheading and the ISBL cost of automatic deheading equipment on the West Coast would be about $12.7 million – a number unchallenged by O'Brien. *Id.* at p. 81. Instead, Exxon states, O'Brien assumed that manual deheading could be used to save costs and the automatic deheading equipment costs would be avoided. *Id.* Using automatic deheading equipment, Exxon asserts, shortens cycle times by from 35 minutes to an hour. *Id.* at p. 82.

1004. Exxon notes that O'Brien admits that automatic deheaders improve cycle time, that his firm has never recommended that a Coker be built without automatic deheading equipment, and that building a Coker without automatic deheading would endanger worker safety. *Id.* Regarding the cost of automatic deheading equipment, Exxon explains that Jenkins relied on a Year 2000 vendor quote installed at a CITGO refinery in Lake Charles, Louisiana. *Id.* at p. 83. On the other hand, Exxon asserts, the Eight Parties did not present direct testimony on this issue. *Id.*

1005. As to the question of automatic deheading equipment, the Eight Parties insist that such equipment is not necessary. Eight Parties Initial Brief at p. 69. O'Brien testified, the Eight Parties state, that this equipment is sometimes added to Cokers to improve safety, especially when producing shot coke. *Id.* He also testified, the Eight Parties note, that ANS produces sponge coke, that automatic deheading equipment is not used in all modern Cokers, and, while automatic deheading is an available safety feature for shot coke, the safety issue is lessened for sponge coke. *Id.* at p. 70.

1006. Even if automatic deheading is included, the Eight Parties argue, Jenkins's estimates included flawed and inflated assumptions. *Id.* According to the Eight Parties, Exxon did not produce a single vendor quote in support of Jenkins's testimony regarding automatic deheading and instead presents an estimate for an automatic deheading device.[374] *Id.* Additionally, the Eight Parties contend, Jenkins's estimate includes a

[374] The Eight Parties further question Jenkins's assumptions, noting that the estimate was derived from a summary sheet obtained by Dickman from Citgo's Lake Charles Refinery but never physically provided to Mr. Jenkins. Eight Parties Initial Brief at p. 70. According to the Eight Parties, Dickman testified that this estimate was based

number of escalators or multipliers to his bare cost estimate of $5,800,000 to account for higher West Coast coasts resulting in a $12,716,575 total cost; but nowhere does Exxon substantiate why automatic deheading equipment would cost more on the West Coast. *Id.* at p. 71. The Eight Parties assert that the only record evidence for a vendor quote for a West Coast automatic deheading system is the Hahn & Clay system at the BP Carson Refinery in California. *Id.* at p. 72. Jenkins's estimate, the Eight Parties point out, exceeded the Hahn & Clay cost by more than $10,000,000 ($12,716,575 - $2,616,810) [Hahn & Clay estimate scaled to a four-drum coker in Year 2000 dollars.][375] *Id.*

1007. On reply, Exxon notes that its estimate assumes that automatic deheading equipment would be used, while the Eight Parties's assumed that it would not. Exxon Reply Brief at p. 77. According to Exxon, contrary to the Eight Parties's assertion, automatic deheading equipment is used "not only for safety reasons (including to enhance safety in the production of sponge coke), but also to improve efficiency and reduce cycle times in the production of all kinds of Coke." *Id.* at pp. 77-78. It notes that, over the last 10 years, all Cokers built have included automatic deheaders. *Id.* at p. 78. Moreover, Exxon claims, that to reach the short cycle times assumed by both its and the Eight Parties's witnesses, automatic deheading equipment would have to be used. *Id.*

1008. According to the Eight Parties, in their Reply Brief, it was not necessary for O'Brien to discuss automatic deheading equipment because he used "conceptual cost curves to model a typical, economic and efficient refinery." Eight Parties Reply Brief at p. 49. They further note that such curves are "supported by a number of projects, which include varying pieces of equipment." *Id.* at p. 50. Declaring that there is no evidence in the record supporting Exxon's assertion that, for the last 10 years, all Cokers built have had automatic deheading equipment, the Eight Parties assert that, even were it true, it would mean nothing because the record is not clear as to the type of automatic deheader to which Jenkins referred in his testimony. *Id.* at pp. 51-52.

The Eight Parties submit that, even were automatic deheaders required, they would only be needed on the bottom heads. *Id.* at p. 52. Therefore, they claim, Jenkins estimate for

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upon a vendor quote, which was not competitively bid. *Id.* The Eight Parties note the estimate was for a more expensive retrofit of an existing drum rather than the less expensive building of new drums. *Id.* Jenkins, the Eight Parties continue, also assumed top and bottom automatic deheading, but admits that the preponderance of automatic deheading systems are bottom systems and not top systems. *Id.* at pp. 70-71.

[375] Furthermore, the Eight Parties reiterate, Jenkins's estimate included both top and bottom deheading and, even if the top deheading is removed from the calculation, Jenkins's estimate exceeds the Hahn & Clay estimate by approximately $6,400,000 [Hahn & Clay estimate scaled to a 4-drum Coker in Year 2000 dollars]. Eight Parties Initial Brief at p. 72.

the cost of automatic deheading equipment was excessive inasmuch as he included automatic deheading on both the top and bottom heads. *Id.*

iv. Coke Handling Equipment

1009. In Exxon's view, Coker costs should include the cost of appropriate coke handling facilities meeting West Coast environmental requirements. Exxon Initial Brief at p. 84. These facilities include, Exxon relates, the coke pit and crane, chutes and conveyor system, and covered storage used to move and store coke and to meet environmental requirements. *Id.* Although Jenkins includes these costs in his ISBL coker costs, Exxon notes, O'Brien asserts that these costs are not necessary and that all that is necessary is a coke pad and front end loader. *Id.* at p. 85. West Coast environmental standards, Exxon states, can only be met with a coke pit and crane, chutes and conveyor system, and covered storage. *Id.* Exxon explains:

> Coke is a very dirty, dusty product analogous to coal. Environmental requirements designed to prevent the release of coke dust into the atmosphere are stringent . . . . To meet these requirements, the Coke is cut into a coke pit, and a clamshell crane is then used to pick it up and put it into a hopper where it is crushed and screened. The Coke is then conveyed to a storage barn, from which it is later loaded into trucks using a smaller conveyor system. For environmental reasons, all of these operations must be enclosed to minimize the release of coke dust into the atmosphere. Indeed, even the loaded trucks must be washed down to minimize the release of dust before they leave the refinery.

Id. According to it, O'Brien's suggested alternative – the coke pad and front end loader – would not be acceptable under West Coast environmental requirements. *Id.* Because of these requirements, Exxon contends, no West Coast refinery uses a coke pad and front end loader to handle coke. *Id.*

1010. Addressing the coke handling issue, the Eight Parties state that it is handled in varied ways and that coke handling costs will be covered in the various costs curves that companies have developed over the years for Delayed Cokers. Eight Parties Initial Brief at p. 73. The Eight Parties note that O'Brien's cost curves include coke handling as part of the ISBL costs for Delayed Cokers and any other equipment taking coke outside of the battery limits is included in O'Brien's OSBL number. *Id.* According to the Eight Parties, because O'Brien's cost curve is underpinned by numerous projects with varied equipment and at various locations, the curve provides an objective method to cost coke handling. *Id.* at p. 74.

1011. Jenkins's cost approach, the Eight Parties insist, involves a state of the art, and highly expensive, coke handling system which is "neither consistent with nor typical of the West Coast refining industry." *Id.* The Eight Parties believe that Exxon improperly compares the Shell Martinez system to a typical West Coast refinery. *Id.* at p. 75. This refinery, the Eight Parties assert, is world class. *Id.* According to the Eight Parties, Jenkins admits that of the West Coast refineries of which he is aware, not one of the refineries installed all of the coke handling equipment his detailed cost estimate includes. *Id.* Additionally, the Eight Parties relate, Exxon did not produce a single vendor quote or other evidence supporting Jenkins's cost for coke handling.[376] *Id.* at p. 76. The Eight Parties note that Jenkins escalates his bare cost for coke handling from $2.7 million to $5,919,785 through a number of multipliers but failed to establish that Jenkins's estimate is typical of the West Coast coking industry. *Id.* at pp. 76-77.

1012. According to Exxon, the Eight Parties wrongly defend O'Brien's failure to include storage costs in his ISBL calculations by suggesting that O'Brien included the costs in his OSBL calculations. Exxon Reply Brief at p. 85. In response, Exxon notes that O'Brien agreed that his OSBL estimate did not include the costs of storage. *Id.*

1013. The Eight Parties, in response to Exxon's assertion that O'Brien conceptualized a simple coke pad and front end loader to handle the coke, argue that, relying on "conceptual cost curves" O'Brien calculated "costs for a typical, economic and efficient delayed coker at a refinery" which may have, to handle coke, pits and cranes or pads. Eight Parties Reply Brief at pp. 56-57. Further, the Eight Parties attack Exxon's evidence regarding the need for coke handling equipment beyond a coke pit and front end loader in order to meet West Coast environmental standards, noting that Exxon failed to place evidence that such standards exist into the record. *Id.* at pp. 57-58.

1014. According to the Eight Parties, O'Brien included the costs of coke handling equipment in both his ISBL and OSBL cost estimates. *Id.* at pp. 58-59. They claim that Exxon wrongly suggested, in its Initial Brief, that coke handling must be in the Coker's ISBL costs, and that Exxon wrongly relies on the Gary & Handwerk textbook for that claim. *Id.* at p. 59. Moreover, the Eight Parties suggest that Exxon's coke handling proposal is "world class" rather than typical and that Jenkins's proposed costs for it are therefore excessive. *Id.* at pp. 60-61.

v. Coker Gas Plant

1015. According to Exxon, Coker ISBL costs should include the cost of a Coker gas plant, which is used to process gases produced in coking Resid. Exxon Initial Brief at p. 87. Exxon explains that Jenkins includes the cost of the Coker gas plant in these costs,

[376] The Eight Parties characterize Dickman's research into conveyor systems as "a discussion with a vendor that was not reduced to a quote, estimate or even a note or memorandum." Eight Parties Initial Brief at p. 76.

while O'Brien does not, even though he admits that allowances for processing Coker gas should be made. *Id.* at p. 88. O'Brien's claim that the Coker gas plant should be included in the OSBL costs, Exxon insists, must be rejected. *Id.* He admits, Exxon points out, that the Gary & Handwerk text costs out the Coker gas plant as part of ISBL costs. *Id.*

1016. Additionally, Exxon contends, O'Brien's OSBL cost was not large enough to include the Coker gas plant in addition to all the other costs included in his OSBL factor. *Id.* According to Exxon, the Coker gas plant cost alone would consume almost 40% of O'Brien's OSBL allowance. *Id.* at pp. 88-89. Furthermore, Exxon states, O'Brien's claim that the Coker gas plant should be included in the OSBL costs is inconsistent with other O'Brien positions. *Id.* at p. 89. O'Brien's positions for downstream hydrotreater units and the Coker sulfur plant, Exxon claims, are costed out separately on an ISBL plus OSBL cost basis. *Id.* In addition, Exxon argues, O'Brien's approach for the Naphtha gas plant differs as well because he includes ISBL costs for the hydrotreater, catalytic reformer, and the gas plant. *Id.*

1017. Alternatively, Exxon asserts, Jenkins's estimate for the Coker gas plant cost was reasonable because he estimated cost as a function of the horsepower requirement, which, in turn, was determined by the volume and composition of the gas stream coming off the Coker. *Id.* Exxon explains that, for the purposes of determining the split of the gases coming off the Coker, Jenkins used information from the Gary & Handwerk treatise. *Id.* An alternative was suggested at hearing, Exxon notes, but it insists it would have increased the gas plant cost:

> Jenkins could instead have used the PIMS model to derive the gas yields at the battery limits of the coker and worked backward to determine the gas yields at the off-gas compressor, [but] this approach would have *increased* the cost of the gas plant. Specifically, the evidence showed that if Mr. Jenkins had so used the PIMS yields, the cost of the gas compressor would have *increased* by nearly a million dollars and the total cost of the project would have *increased* by nearly four million dollars, because the amount and composition of the gas stream produced by the PIMS model would have required the use of a compressor with substantially greater horsepower.

Id. at pp. 89-90 (emphasis in original).

1018. In addressing the Coker gas plant, the Eight Parties assert, O'Brien does not consider the gas plant to be part of ISBL Coker equipment, and instead considers the gas plant as part of his OSBL factor of 35% of ISBL costs. Eight Parties Initial Brief at p. 77. Jenkins, the Eight Parties state, includes a gas plant in his ISBL calculation designed to process only Coker gases.[377] *Id.* O'Brien explains, according to the Eight Parties, that it is inappropriate to include the Coker gas plant as part of the ISBL costs because the gas plant is not part of the Coker, but is a separate unit entirely, and thus is not inside the battery limits of the Coker. *Id.* at p. 78. Also, the Eight Parties point out, the gas plant is shared among several units in the refinery, primarily the cat cracker and the Coker, and, consequently, it is inappropriate to assign its entire cost to the Coker as an ISBL cost. *Id.*

1019. In its Reply Brief, Exxon states that the "coker gas plant is used to process the gases produced in the coking of the Resid." Exxon Reply Brief at p. 86. According to it, O'Brien failed to include its cost in his ISBL estimate, but claimed that it was included in his OSBL estimate. *Id.* Exxon, challenging the Eight Parties's defense of O'Brien's failure to include such costs in his ISBL estimate because they claimed that the gas plant would serve both the Coker and the cat cracker unit, declares that O'Brien admitted that, if the refinery did not have the latter unit, it would still have to build a gas plant. *Id.* at pp. 86-87. Acknowledging the Eight Parties claim that a gas plant would not be inside the battery, Exxon asserts that Coker gas plants are located as close as possible to the Coker fractionator because the heat from the latter is used in the gas plant to minimize costs. *Id.* at pp. 87-88. Exxon also rejects the Eight Parties's claim that the Gary & Handwerk textbook supported placing the Coker gas plant costs in the OSBL as totally unsupported: "Gary directly addressed this argument and flatly rejected it." *Id*. at p. 89. Lastly, Exxon posits that O'Brien's OSBL costs were insufficient to have included the costs of a Coker gas plant in addition to the other costs which O'Brien claims he included there. *Id.* at p. 90.

1020. In their Reply Brief, the Eight Parties begin by declaring that Exxon is wrong in suggesting that the Gary & Handwerk textbook agrees with Jenkins that the Coker gas plant should be costed out as part of the ISBL. Eight Parties Reply Brief at p. 61. They note that Jenkins testified to this and that the text does not list it as part of the Coker gas plant. *Id.* The Eight Parties also assert that the Gary & Handwork textbook indicates that a refinery "will have a single gas plant that supports a number of processes, including the coker, the cat cracker, the hydrocracker and the reformer." *Id.* According to them, also, O'Brien assumed that a portion of the costs of a gas plant were included in the Coker's OSBL costs and Jenkins erred in assigning 100% of its cost to the coking unit. *Id.* at p. 62.

[377] The Eight Parties explain that Jenkins did not provide a West Coast cost for this gas plant, but used his Gulf Coast cost estimate of $14 million, then applied a 30% West Coast location factor resulting in a West Coast ISBL cost of $18.2 million. Eight Parties Initial Brief at p. 77. After the OSBL, the Eight Parties continue, interest during construction, and owner's cost adders, the total Coker gas plant cost is approximately $26 million. *Id.*

1021. Next, the Eight Parties argue that Exxon erred in suggesting that O'Brien was being inconsistent in developing ISBL and OSBL cost estimates for the hydrotreaters, but only treating the gas plant as part of the OSBL costs.[378] *Id.* According to them, the Gary & Handwerk textbook treats the gas plant as a process which is indirectly involved, i.e., supports, but isn't directly engaged in, the production of hydrocarbon fuels. *Id.*

1022. Acknowledging Exxon's attack on O'Brien's testimony that a refinery would not build an "inefficiently-sized gas plant just for its Coker, but instead would integrate its gas plant into the refinery and use it to process gases produced from a number of process units," the Eight Parties claim that it is without merit. *Id.* at p. 63. They state that O'Brien's testimony is supported by Gary & Handwerk. *Id.* According to the Eight Parties, Exxon's further claim that O'Brien testified that the gas plant would be integrated with the gas plant used by the catalytic cracking unit is without merit. *Id.* at pp. 63-64. Rather, they say, he testified "that he assumed 'an integrated efficient refinery for all of [his] calculations.'" *Id.* at p. 64. In other words, the Eight Parties claim, O'Brien assumes "that the gas plant would be shared by the several processes, including the coker, added to the base refinery in a typical West Coast refinery." *Id.* at p. 65.

1023. Lastly, the Eight Parties find fault with Exxon's claim that the gas plant must be located close to fractionator of the Coker. *Id.* They say the gas plant's location is irrelevant. *Id.* at pp. 66-67.

b. OSBL Coker Costs

i. Approach

1024. According to Exxon, all the parties agree that the OSBL facilities include electric power distribution systems, fuel oil and fuel gas facilities, water supply systems, waste water treatment and disposal systems, plant air systems, fire protection systems, flare, drain and waste containment systems, plant communications systems, roads and walks, railroad facilities, fences, buildings, vehicles, product and additives blending facilities, and product loading facilities. Exxon Initial Brief at p. 92. However, Exxon states, the parties disagree over whether the Coker gas plant should be treated as part of the OSBL costs or separately costed out as an ISBL unit, and how certain OSBL facilities - storage facilities, cooling water systems, and steam generation systems - should be costed out for purposes of estimating the cost of the Coker. *Id.*

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[378] The Eight Parties also state that it wasn't inconsistent for O'Brien to cost out a gas plant in the Naphtha reforming process because that was a saturated gas plant as compared with the *unsaturated* gas plant associated with a coker. Eight Parties Reply Brief at pp. 62-63.

1025. Exxon explains that only Jenkins presented a reasonable estimate of OSBL Coker costs in accordance with the procedures described in the Gary & Handwerk text, concluding with total OSBL costs for the Coker and related processing units of $118.3 million in Year 2000 dollars on the West Coast and $91 million in Year 2000 dollars on the Gulf Coast.[379] *Id.* at pp. 93-94. O'Brien's estimate, Exxon contends, "unreasonably low, incomplete, and impossible to verify" because he failed to quantify any specific costs in his OSBL cost estimate and, instead, merely applied a single OSBL factor of 35% to the ISBL costs of the coker, for a total OSBL cost of $37.6 million. *Id.* at p. 95.

1026. According to Exxon, O'Brien's factor was a black box "whose lack of transparency severely limited any meaningful analysis of his OSBL cost estimate." *Id.* at pp. 95-96. This estimate, Exxon notes, is based on O'Brien and his staff's experience and judgment, with no documentation supporting any part of the estimate. *Id.* at p. 96. Additionally, Exxon points out, O'Brien could not explain why he included no OSBL costs with respect to the downstream hydrotreaters estimate, or why he used a different OSBL factor for the sulfur plant cost estimate. *Id.*

1027. Addressing OSBL Coker costs, the Eight Parties explain that they used the typical industry practice in expressing OSBL costs as a percentage of ISBL costs and used 35% of the ISBL costs because O'Brien includes steam and cooling water facilities as OSBL costs. Eight Parties Initial Brief at p. 80. Jenkins, the Eight Parties note, agrees that the Eight Parties's approach is typical in the industry. *Id.* However, the Eight Parties relate, Jenkins adopts the Gary & Handwerk textbook approach, thus increasing capital costs $57 million for steam generation, cooling water, and storage.[380] *Id.* at p. 81. The Eight Parties characterize Jenkins's approach as an "inconsistent patchwork" resulting in a higher OSBL cost. *Id.* at pp. 81-82.

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[379] Exxon relates that Gary explained the appropriate procedures for estimating refinery costs. Exxon Initial Brief at pp. 92-93. According to Exxon, Gary recommends estimating the costs of the major processing facilities to be built or added in addition to costs of major supporting facilities, such as related storage facilities and any related steam generation facilities and cooling water systems. *Id.* Next, Exxon states, the cost estimator applies a percentage factor to cover the other OSBL support facilities costs and adds this to the costs of the process units, storage facilities, steam systems, and cooling water systems. *Id.* at p. 93.

[380] According to the Eight Parties, this amount includes $26.8 million in costs for Jenkins's economies of scale on a West Coast basis and $20.5 million in costs after economies of scale on a Gulf Coast basis. Eight Parties Initial Brief at p. 81. If Jenkins followed typical industry practice, the Eight Parties insist, any cost for storage tanks would have been included in the offsite factor. *Id.*

1028. In addition, Exxon claims that the Eight Parties's OSBL estimate of $37.6 million is too low. *Id.* Exxon breaks out the "undisputed" cost of a Coker gas plant, which O'Brien claims to have included, of $14 million and declares that the $23.6 million remainder[381] would have to cover all the other costs. *Id.* at p. 94-95. It also noted that O'Brien included no monies for storage costs. *Id.* at p. 95. Further, according to Exxon, O'Brien failed to separate out the cost of the steam and cooling water facilities, a minimum of $13.5 million according to it, which further diminishes the $23.6 million remainder. *Id.* Exxon concludes that O'Brien's $37.6 million OSBL estimate is wholly inadequate. *Id.*

1029. In their Reply Brief, the Eight Parties declare that O'Brien's cost curve methodology followed standard industry practice, while Jenkins's itemized approach strays from it and allows Exxon "to accumulate unrealistically high OSBL costs." Eight Parties Reply Brief at p. 66. They add that, contrary to Exxon's claim, Jenkins did not follow the Gary & Handwerk procedure in making his estimations of the cost of the Coker and the related downstream equipment. *Id.* Rather, the Eight Parties state that Jenkins used a "Jacobs . . . based detailed line item cost estimate." *Id.* at p. 67. The Eight Parties further charge that "Jenkins engaged in a selective patchwork approach that enabled him to increase substantially the costs he calculated." *Id.* at pp. 66-67.

ii. Coker Gas Plant

1030. Exxon believes that the Coker gas plant costs should be included as part of the ISBL costs for the Coker because the Coker gas plant is an integral part of the processing units for the Coker and, consequently, should be costed out in the Coker's ISBL costs. Exxon Initial Brief at p. 97. O'Brien concedes, according to Exxon, that the Gary & Handwerk text suggests that Coker gas plant costs should be separately costed out in the ISBL costs. *Id.* Additionally, Exxon insists, economic reasons exist for locating the gas plant within the battery limits of the Coker, putting it in close proximity to the Coker fractionator. *Id.* at p. 98.

1031. O'Brien's credibility regarding his claim that the gas plant costs were included in his OSBL cost estimates for the Coker, Exxon states, is undermined because O'Brien was unable, in discovery, to identify the gas plant when listing the equipment included in his OSBL costs. *Id.* Additionally, Exxon asserts, by failing to include Coker gas plant costs in ISBL costs, O'Brien fails to include a corresponding share of OSBL costs for the gas plant. *Id.* at p. 99. Such an amount, Exxon insists, is not trivial. *Id.*

1032. Noting that the Gary & Handwerk text "explains that the gas plant supports *all* of

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[381] Exxon erroneously states the remainder as $23 million. *See* Exxon Reply Brief at p. 95.

the refineries processing units," the Eight Parties suggest that Exxon's gas plant estimate needs to be "allocated among *all* the refinery's processing units and not just the coker." Eight Parties Initial Brief at p. 83 (emphasis in original). They add that, once that is done, Exxon has no support for claiming that O'Brien's $37.6 million estimate is insufficient. *Id.*

1033. In its Reply Brief, Exxon reiterates that "the coker gas plant is an integral part of the coker and should be separately costed out as a part of the coker's ISBL costs, not merely lumped into the coker's OSBL costs." Exxon Reply Brief at p. 96. It further claims that the record is "undisputed" that the Gulf Coast cost of a gas plant, in Year 1996 dollars, is at least $14 million. *Id.* According to Exxon, the Gary & Handwerk textbook places Coker gas plant costs in ISBL costs. *Id.*

1034. Addressing the Eight Parties's argument that the gas plant services processing units other than the Coker, principally a cat cracker, and that only a portion of the $14 million should be placed in OSBL costs, Exxon declares that O'Brien testified that the Quality Bank refinery he had in mind did not have a cat cracker. *Id.*

1035. Exxon also states that the Eight Parties ignored Gary's testimony in making their claim. *Id.* In connection with this assertion, Exxon declares that O'Brien admitted that he misread the Gary & Handwerk textbook and, therefore, mistakenly included the Coker gas plant in OSBL costs. *Id.* It further states that the Gary & Handwerk textbook "indicates that the coker gas plant should be separately costed out as an ISBL cost," as Exxon's witness did. *Id.* at pp. 96-97.

1036. Lastly, Exxon challenges the Eight Parties's claim that O'Brien included the cost of a Coker gas plant in his OSBL estimate. *Id.* at p. 98. It asserts that, deducting the $14 million cost of the gas plant from his OSBL estimate would leave "the amount remaining for all other OSBL costs [as] no more than $23 million, or about 21% of ISBL costs, an amount that is plainly not sufficient." *Id.* Exxon also claims that the Eight Parties's failure to include the Coker gas plant in its ISBL cost leads to a "double undercount" because they also have "failed to include a corresponding share of OSBL costs for the gas plant." *Id.* The result, Exxon asserts, is that the Eight Parties underestimated the cost of the Coker by "$14 million for the ISBL cost, plus $3.5 million for the OSBL cost." *Id.*

1037. In their Reply Brief, the Eight Parties assert that the gas plant is a support facility which should not be included in the Coker ISBL costs. Eight Parties Reply Brief at p. 70. They say that the Coker gas plant is properly accounted for in the OSBL costs as it is a shared facility and only a portion of the costs should be attributed to the Coker. *Id.*

iii. Storage Costs

1038. According to Exxon, OSBL costs must also include appropriate storage costs for storing the Resid as a Coker feedstock and for the storage associated with downstream units. *Id.* at pp. 99-100. Jenkins, Exxon states, includes additional tank costs in his OSBL costs, but O'Brien does not include any storage costs. *Id.* at p. 100. Instead, Exxon contends, O'Brien argues that the Coker could merely use existing storage tanks that are already part of an assumed Quality Bank base refinery. *Id.* Exxon insists that such an assumption is clearly wrong and notes that O'Brien concedes that "if the addition of a coker to a refinery required additional storage, the costs of adding that additional storage should be treated as a cost of the coker." *Id.* at pp. 100-01.

1039. Additionally, Exxon asserts, O'Brien's claim that Coker storage costs are recovered through the prices of other Quality Bank cuts is incorrect because a refinery without a Coker blends Resid directly into fuel oil, which has very different storage requirements. *Id.* at p. 101. Consequently, Exxon explains, no intermediate storage would be necessary. *Id.* However, Exxon states, in a refinery with a Coker, intermediate storage would be needed both for the Resid and for the Coker products to protect the Coker from having to shut down due to a shutdown of a downstream processing unit, and to protect the downstream processing units by making product available in the event of a shutdown of the Coker. *Id.*

1040. O'Brien's contention, according to Exxon, that existing storage tanks can be used to store Resid is incorrect because Resid storage tanks must be heated to around 500ºF and insulated in order to keep the material in a liquid state. *Id.* at p. 102. Crude oil and other refinery product storage tanks, Exxon notes, must be maintained at temperatures below 212ºF. *Id.* Also, Exxon points out, the Coker storage tank's heating process uses open flames and, consequently, these tanks are segregated in a separate area of the refinery away from the tank farm used for other refinery products. *Id.* Concluding, Exxon maintains that even if no additional storage was required to be built, the Coker should still bear a share of costs for the existing storage facilities it uses because the costs of common facilities used to support a group of refinery products should be attributed to all those products. *Id.* at pp. 102-03.

1041. According to Exxon, Jenkins's estimate of the magnitude of the storage costs is reasonable. *Id.* Jenkins testified that Coker feed tanks would require 15 days of storage capacity. *Id.*; Exhibit Nos. EMT-37 at p. 48, EMT-56, EMT-289. This estimate, Exxon explains, was based on Dickman's knowledge that an average Coker experiences downtime of about 45 to 48 days every year, including downtime of about 7 days to decoke the Coker heaters, as well as downtime associated with power failures, foam-overs, and other equipment failures.[382] Exxon Initial Brief at p. 103. Dickman, Exxon

[382] Exxon further explains that, based upon Dickman's determination that the Coker feed tank would normally be filled to approximately 50% of capacity in order to provide protection against both a shutdown of the upstream vacuum unit and a shutdown of the downstream Coker, he next determined that about 13.5 days of usable storage

contends, confirmed the reasonableness of his estimates by comparing them to storage capacity installed at existing refineries. *Id.* at p. 104.

1042. Exxon points out that Jenkins's Coker feed tank cost estimates - $24.1/barrel on the Gulf Coast and $31.5/barrel on the West Coast, - are below the $60 to $80/barrel benchmark set forth in the Gary & Handwerk treatise. *Id.* Additionally, Exxon insists, Jenkins's estimates for propane and butane storage tanks are reasonable as they are based on recommended per barrel costs presented in the Gary & Handwerk textbook, and the tanks are properly sized for the Coker gas plant. *Id.* Similarly, Exxon contends, Jenkins's hydrotreater storage tanks are properly sized given the Coker yields. *Id.* at pp. 104-05. Concluding, Exxon states that Jenkins's cost estimates for the storage facilities required by the Coker are reasonable and appropriate. *Id.* at p. 105.

1043. Regarding storage, the Eight Parties argue that its costs are captured in the Quality Bank reference price. Eight Parties Initial Brief at p. 83. Consequently, the Eight Parties contend, it is improper to charge Resid a storage cost as storage is not a processing cost. *Id.* The Eight Parties explain, however, that Jenkins does charge the Quality Bank Resid component with a storage cost. *Id.* Moreover, the Eight Parties relate, the number of tanks Jenkins includes in his cost estimate is unrealistic, resulting in excessive costs. *Id.* According to the Eight Parties, even if storage were a factor in determining the processing costs of Resid, it is unnecessary to add new tanks simply because a Delayed Coker is added to the base refinery. *Id.* at p. 84. The Eight Parties point out that an integrated refinery producing fuel oil would have vacuum Resid tanks necessary to operate the Coker as well as product storage tanks. *Id.* Further, the Eight Parties relate, such a refinery does not have dedicated Coker intermediate product storage. *Id.*

1044. Exxon's argument that it is not proper cost allocation to use existing tankage because the cost is not charged back to the Resid cut, the Eight Parties contend, is correct on a total refinery accounting basis, but is incorrect for the purposes of this case. *Id.* Here, the Eight Parties explain, the exercise is to define the costs of processing Resid and not to perform a refinery cost allocation analysis. *Id.* Jenkins, the Eight Parties argue, failed to investigate whether refineries added new tankage as part of their Coker construction projects or utilized existing storage. *Id.* at p. 85. According to the Eight Parties, he admitted that a number of refineries either did not add storage tanks or modified existing tanks.[383] *Id.* Despite his admissions, the Eight Parties state, Jenkins

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would be required. Exxon Initial Brief at pp. 103-04. He further determined that in order to provide 13.5 days of usable storage, the Coker feed tank should be sized to provide 15 days of storage, Exxon relates, because three feet of "heel" at the bottom of the tank would be unusable and an additional foot of "free board" at the top of the tank would be unusable except to protect against overflow. *Id.* at p. 104.

[383] The Eight Parties further explain that,

uses costs related to new tanks "regardless of whether the tanks are new, existing or modified." *Id.* at pp. 86-87.

1045. Another problem with Jenkins's approach, the Eight Parties assert, is that he oversized his storage tanks, thus increasing their cost. *Id.* at p. 87. Assuming that the addition of new tanks is appropriate, the Eight Parties believe, Exxon failed to support Jenkins's cost estimate. *Id.* According to the Eight Parties, Jenkins's tank calculations are highly subjective and excessive. *Id.* at p. 88. No single source, the Eight Parties argue, defines Jenkins's days of inventory for his various tanks. *Id.*

1046. For the Coker feed tank, the Eight Parties explain, Jenkins estimate is based upon a conversation Dickman had with a contact at a refinery indicating a Coker feed tank volume corresponding to 15 days of coker throughput. *Id.* Furthermore, the Eight Parties continue, Jenkins based his Coker feed tank costs on costs derived from a conversation Dickman had with a tank vendor, basing the entire cost estimate on this one conversation without further investigation. *Id.* They point out that the industry average for Coker feed tank volumes is 5.5 days of storage, rather than the 15 days of storage assumed by Jenkins. *Id.* at pp. 88-89.

1047. The Naphtha, Distillate, and Gasoil intermediate tank costs, the Eight Parties explain, were developed based upon a spreadsheet Jenkins created for this litigation, which is based on approximately twenty data points of tank information in Jacobs Consultancy's files. *Id.* at p. 89. They point out that Jenkins based his intermediate storage numbers on 15 days of inventory for the Coker feed tank before making additional subjective adjustments. *Id.* According to them, Jenkins admits that refiners generally run their Coker Naphtha, Distillate, and Gasoil directly to the processing units without passing through intermediate storage. *Id.* The Eight Parties argue that Jenkins failed to present any support for the need to add intermediate product storage. *Id.* at p. 90.

> Jenkins admitted that with regard to the Shell Deer Park Refinery, both Maya 1 and Maya 2 projects, that no new tanks were added nor were modifications made to the existing tanks . . . Mr. Jenkins agreed that the Phillips Sweeney Refinery used existing tanks with some possibly being modified . . . Similarly, Mr. Jenkins agreed that at the Valero Texas City coker project, a refinery with which Mr. Jenkins was familiar existing tanks were used and refurbished . . . Finally, Mr. Jenkins acknowledged that at the PACC Port Arthur Refinery[,] tanks 108 and 109 referred to as "new crude storage tanks" were on a drawing dated 4-18-74.

Eight Parties Initial Brief at pp. 85-86 (citations omitted).

1048. In its Reply Brief, Exxon begins by noting that, while it included the total costs of storage in its OSBL estimates,[384] the Eight Parties failed to include any storage costs at all. Exxon Reply Brief at p. 99. It notes that O'Brien claimed that the Coker could use existing storage. *Id.*

1049. Claiming it to be "absurd on its face," Exxon notes that one argument made by the Eight Parties is "that coker storage costs are covered by the Quality Bank reference prices." *Id.* at p. 100. First stating that the parties agreed that "in order to calculate the value of Resid, coker costs must be calculated, including coker OSBL costs," Exxon then itemized the other costs the parties agreed should be included in OSBL costs. *Id.* Declaring that all Quality Bank cuts incur these OSBL costs and that no one has suggested that these costs could be ignored, Exxon exclaims that, for the same reason, storage costs should not be ignored in determining the cost of a Coker. *Id.* at pp. 100-01.

1050. Exxon adds that it is unreasonable to assume that the storage requirements of a refinery with a Coker would be the same as that of a refinery without a Coker. *Id.* at p. 101. According to it, without a Coker, a refinery would blend the Resid with Fuel Oil eliminating the need for an intermediate storage. *Id.* Exxon then states:

> By contrast, in a refinery with a coker, intermediate storage would be needed both for the Resid and for the coker products to protect the coker from having to shut down due to a shutdown of a downstream processing unit, and to protect the downstream processing units by making product available in the event of a shutdown of the coker.

Id. at pp. 101-02. Moreover, Exxon says, storage for the Resid is necessary so that the crude unit would not have to shut down in the event of a Coker shutdown. *Id.* at p. 102.

1051. Exxon, noting the possibility that Coker products could be run straight into a hydrotreater, indicated that intermediate storage would still be necessary to protect the Coker from having to shut down as a result of the shutdown of a downstream processor. *Id.* Further, disputing the Eight Parties's claim that Coker products could be held in the virgin product tanks, Exxon states that, to avoid contamination, refiners do not like to intermingle lower quality products, such as those produced by a Coker, and higher quality virgin products. *Id.*

1052. In their Reply Brief, the Eight Parties declare that, under the Quality Bank methodology, no single product is charged for storage. Eight Parties Reply Brief at pp.

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[384] Exxon states that the total for storage in Year 2000 dollars, was $34.1 million on the West Coast and $26.2 million on the Gulf Coast. Exxon Reply Brief at p. 99.

70-71. Rather, according to them, "any cost of storage is captured in the Quality Bank reference price." *Id.* p. 71. They note that O'Brien testified that, with regard to Resid, the only processing costs involved are those which are required to turn it into Quality Bank quality. *Id.* The Eight Parties further claim that, were storage costs considered for coker products, "an inconsistency will be introduced into the Quality Bank methodology." *Id.*

1053. Acknowledging Exxon's attack on O'Brien's suggestion that, were a Coker added to an existing refinery, a refiner would use existing storage, the Eight Parties assert that even Jenkins testified to facts which support that claim.[385] *Id.* at p. 73. They submit, further, that even were new tanks needed, Jenkins's estimate does "not even come close to replicating a typical West Coast refinery." *Id.* at p. 74. The Eight Parties assert that there is no "objective or verifiable" evidence supporting Jenkins's "wildly inflated estimate that refiners install fifteen days of vacuum Resid inventory when adding a delayed coker to an existing refinery." *Id.* Instead, they submit, "the average storage is 5.5 days" which is "much closer to the 6.8 days . . . Jenkins gave as a corrected answer on re-direct than the completely unsubstantiated 15 days that he actually used." *Id.* at pp. 75-76 (footnote omitted).

1054. Attacking Exxon's claim that Jenkins's $31.50/barrel West Coast estimate for storage was conservative because the Gary & Handwerk estimate ranged from $60/barrel to $80/barrel, the Eight Parties assert that the Gary & Handwerk estimate related to "an entire tank farm not a single feed tank." *Id.* at p. 76. They add that, from their perspective, Exxon offered nothing to support Jenkins's estimate. *Id.* at p. 77. Contrariwise, they claim that Boltz obtained quotes from two vendors for an 80,000 barrel storage tank and that those estimates were $12.35/barrel and $9.70/barrel. *Id.*

1055. Further, the Eight Parties note that Exxon cites to a report by the California Energy Commission that includes a $31.00/barrel estimate for storage tanks, but claim that its confidence that the report support Jenkins's estimate is misplaced. *Id.* at pp. 77-78. According to the Eight Parties, the California Energy Commission's quote

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[385] The Eight Parties state:

> The fallacy of this argument is shown in Exhibit WAP-94, the tank study of West Coast refineries which added a coker, which clearly demonstrated that refineries adding a delayed coker do not add new tanks but rather utilized existing tankage. Mr. Jenkins admitted and agreed that this was true with respect to six of the refineries that *he* had included in his Exhibit EMT-63.

Eight Parties Reply Brief at p. 73 (emphasis in original; note and citation omitted).

represents an amount necessary for the site acquisition and the necessary connections to product pipelines as well as the cost of constructing the storage tanks. *Id.* at p. 78. They further note that the California Energy Commission report reflects that, were the storage tank constructed as part of the expansion of an already existing facility, the cost would be "in the $15 - $16 per barrel range." *Id.* at pp. 78-79.

1056. In closing, the Eight Parties declare that, "in the real world, refiners who operate integrated, economic and efficient refineries take advantage of existing facilities within the refinery which can be converted when changes in the process flow of the refinery occur." *Id.* at p. 79.

iv. Steam Generation and Cooling Water Facilities

1057. As for the steam generation and cooling water facilities cost estimates, Exxon asserts, Jenkins estimates are reasonable. Exxon Initial Brief at p. 105. His costs, Exxon notes, are consistent with the OSBL costing procedure in the Gary & Handwerk textbook and include itemized estimates based on recommendations within the Gary & Handwerk text. *Id.* Following that approach, Exxon states, Jenkins estimated that additional steam generation systems would cost approximately $20.1 million in Year 2000 dollars, and additional cooling water systems would cost approximately $2.6 million in Year 2000 dollars. *Id.* at p. 106. These estimates, Exxon points out, were not disputed by any witness or party. *Id.*

1058. O'Brien, on the other hand, Exxon states, did not itemize an estimate for the steam generation systems or cooling water systems, but, instead provided only a lump sum OSBL cost estimate of $37.6 million in Year 1996 dollars. *Id.* at p. 106. Exxon notes that, although O'Brien did not separately identify the portion of his overall OSBL cost that related to the cost of additional steam generation and cooling water systems, he did admit that "a substantial part" of the difference between his 35% OSBL factor and the 20 to 25% OSBL factor recommended by the Gary & Handwerk textbook was due to the fact that he did not separately cost out an allowance for any steam or cooling water facilities.[386] *Id.* In its Reply Brief, Exxon notes that its estimate of the cost of steam

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[386] Exxon is critical of O'Brien's method:

> Assuming that the full amount of that difference ($13.48 million) was attributable to steam and water cooling facilities, Mr. O'Brien's estimate was grossly inadequate, particularly when applied to the West Coast. At a minimum, the amount should be increased by a location factor of 1.3 to reflect the higher costs found on the West Coast. Even then, however, the resulting amount ($17.5 million) is still well below Mr. Jenkins's itemized estimate of $22.7 million based on the Gary & Handwerk treatise.

generation and cooling water facilities was not disputed by any witness or by the Eight Parties in their Initial Brief. Exxon Reply Brief at p. 107.

1059. The Eight Parties, in their Reply Brief, assert that they have not accepted Jenkins's estimate for the cost of steam generation and cooling water facilities. Eight Parties Reply Brief at p. 80. According to them, "O'Brien included these costs in his OSBL costs, which in part was why [he] used a thirty-five percent OSBL factor instead of the twenty-five percent recommended by Gary & Handwerk." *Id.* Moreover, they assert that O'Brien did not agree with Exxon counsel that even $13.5 million was a reasonable cost for steam and cooling water. *Id.*

1060. The Eight Parties also claim that Exxon's approach is based on a "'grass roots' refinery in that it assumes no steam generation or cooling water was required for any other refinery processes and therefore was non-existent prior to the addition of the delayed coker." *Id.* at p. 81. Thus, according to them, Jenkins's testimony has no credibility. *Id.*

v. Remaining OSBL Costs

1061. Finally, Exxon contends that O'Brien's cost estimate for the remaining OSBL costs is not sufficient.[387] Exxon Initial Brief at p. 107. To the standard list of facilities, Exxon states, O'Brien wished to add the Coker gas plant costs as well as unspecified coke handling costs. *Id.* However, Exxon insists, O'Brien's OSBL cost estimate of $37.6 million is clearly insufficient to cover all the costs:

> [I]f one simply subtracts the ISBL costs of the coker gas plant (at least $14 million) and the cost of the steam generation and cooling water facilities (at least $13.5 million) from Mr. O'Brien's total OSBL estimate of $37.6 million, the resulting amount (at most $10 million) is plainly not sufficient to cover the remaining OSBL costs. Further, Mr. O'Brien's OSBL cost estimate wholly fails to take into account higher West Coast costs.

Exxon Initial Brief at pp. 106-07.

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[387] The standard, agreed upon OSBL costs, Exxon relates, include the cost of electric power distribution systems, fuel oil and fuel gas facilities, waste water treatment and disposal systems, plant air systems, fire protection systems, flare, drain and waste containment systems, plant communications systems, roads and walks, railroad facilities, fences, buildings, vehicles, product and additives blending facilities, and product loading facilities. Exxon Initial Brief at p. 107.

Id.

1062. In its Reply Brief, after itemizing what it claims are other OSBL costs, Exxon argues that the Eight Parties's $37.6 million OSBL estimate is not sufficient to cover them. Exxon Reply Brief at p. 108.

1063. The Eight Parties, in their Reply Brief, attack Exxon's reliance on a "laundry list" of needed "off-site" items to establish OSBL costs. Eight Parties Reply Brief at p. 81. They assert that the items contained in Exxon's list reflect the needs of "a start-up grass roots refinery, not an existing refinery to which a delayed coker is being added." *Id.* at p. 82. Noting that even Exxon concedes that the needs would differ between different refineries, the Eight Parties indicate that because of those differences "the typical industry practice is to use the percentage of the ISBL approach to develop and estimate, and not a detailed cost estimate which in effect is refinery specific." *Id.*

c. Other Capital Costs

i. Sulfur Recovery Costs

1064. Exxon explains that the parties agreed that a sulfur plant would be necessary to convert hydrogen sulfide and other sulfur compounds coming out of the Coker and downstream hydrotreaters into elemental sulfur and also agreed that back up capacity was necessary for the sulfur plant. Exxon Initial Brief at p. 108. However, Exxon notes, the parties disagreed over the necessary amount of back-up sulfur plant capacity. *Id.* Exxon's witnesses argued for a 100% back up capacity while O'Brien argued for a 30% back up capacity. *Id.* at pp. 108-09.

1065. In order to meet West Coast environmental requirements, Exxon insists, and as a matter of good engineering and business practice, 100% sulfur processing back up capacity is required. *Id.* at p. 109. Sulfur plant average utilization rates for the West Coast, Exxon relates, are approximately 50%, indicating that refiners employ 100% backup capacity. *Id.* at p. 110. Exxon points out that this added capacity can be installed at a low cost compared to the potential costs and liabilities of operating without the added capacity. *Id.* According to Exxon, 100% backup capacity means only that a plant would have sufficient capacity to operate 100% of the time, which could be achieved "by building three units each capable of providing 50% of the total capacity required, such that if one unit goes down, another unit would be available to maintain a 100% level of operation even though the amount of spare capacity was only 50%." *Id.*

1066. Exxon maintains that O'Brien's 30% sulfur plant backup capacity is clearly inadequate to deal with the potential costs to the refiner should a unit go down. *Id.* at pp. 110-11. O'Brien admits, Exxon points out, that sulfur capacity must always be available when a Coker is operating. *Id.* at p. 111. Additionally, Exxon states, O'Brien's evidence justifying the 30% back up capacity assumption - a comparison of the difference between the amount of sulfur contained in the crude oil coming into West Coast refineries and the amount of sulfur in the products produced by those refineries - is "fundamentally flawed and produced illogical results." *Id.* Exxon asserts that O'Brien admitted that he understated the sulfur amount in coke produced from coking ANS Resid by almost 50 % and ignored sulfur removed during the refining process by means other than the sulfur plant. *Id.*

1067. O'Brien's analysis, Exxon argues, suggested that certain West Coast refineries had no spare capacity or insufficient capacity to remove the sulfur produced in their facilities. *Id.* Exxon believes that such an analysis is unsupportable because Dickman's analysis of West Coast sulfur refining capacity demonstrated that West Coast refineries had an average of about 54% excess or spare capacity in their sulfur plants. *Id.*

1068. Additionally, Exxon points out, O'Brien assumed a single sulfur plant with 130% of the required capacity, which would not provide backup if the unit failed. *Id.* at p. 112. Finally, Exxon insists, no justification exists for O'Brien's approach of estimating the cost of building a larger sulfur recovery plant with substantial scale economies, but then simply taking a pro rata share of those costs as the estimated cost of a much smaller plant. *Id.*

1069. According to Exxon, Jenkins's sulfur plant cost estimate is reasonable while O'Brien's is unsupportable. *Id.* at pp. 112, 114. Jenkins, Exxon explains, applies the sulfur recovery facility cost curve provided in the Gary & Handwerk text, determining that the ISBL capital costs of the sulfur recovery facilities for the Coker in Year 2000 dollars would be $24.7 million on the West Coast and $19.0 million on the Gulf Coast. *Id.* at pp. 112-13. Next, Exxon relates, Jenkins adds OSBL costs and deducts an allowance for economies of scale, resulting in a capital cost for the sulfur plant of $20 million on the West Coast and $15.4 million on the Gulf Coast in Year 2000 dollars. *Id.* at p. 113.

1070. O'Brien's cost estimate, Exxon notes, was merely $8.7 million on both coasts in Year 2000 dollars. *Id.* This estimate, Exxon explains, lacked both a West Coast location factor and 100% back up capacity. *Id.* Additionally, Exxon states, O'Brien admits that his estimate is based on an outdated version of the cost curve in the Gary & Handwerk text.[388] *Id.*

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[388] Exxon editorializes that:

> It is also revealing that, although Mr. O'Brien used a Gary & Handwerk cost curve to estimate the capital costs of the sulfur plant, he elected not to use the Gary & Handwerk cost curves in estimating the cost

1071. The Eight Parties characterize the sulfur recovery question differently than does Exxon:

> [D]o you assign the costs from the capacity plus a reserve from an existing efficiently sized sulfur recovery plant at the refinery as Mr. O'Brien proposes on behalf of the Eight Parties, or do you build a redundant (*i.e.* second full sized) sulfur recovery plant because you are adding a delayed coker as Mr. Jenkins proposes on behalf of [Exxon]?

Eight Parties Initial Brief at p. 91. According to the Eight Parties, O'Brien assumes an existing sulfur recovery plant capable of processing 200 long tons per day for all processing units at an existing refinery generating H_2S that has to be recovered in order not to violate environmental emission standards. *Id.* When he applies all costs, the Eight Parties continue, O'Brien's total capital cost allocated to the Coker for H_2S processing is $9.95 million, or $14.2¢/barrel. *Id.*

1072. Exxon's proposal, the Eight Parties accuse, is subjective and based upon erroneous assumptions. *Id.* at p. 92. According to the Eight Parties, Exxon proposed two identical, redundant, full-sized sulfur recovery plants. *Id.* Furthermore, the Eight Parties argue, Jenkins inconsistently derived his cost estimate for the redundant sulfur recovery plant using Gary & Handwerk text cost curve, even though Jacobs Consultancy has a cost curve for sulfur recovery plants. *Id.* at p. 93. Jenkins's assumptions, the Eight Parties contend, are flawed. *Id.* at p. 94. Despite his assertions, the Eight Parties relate, California does not require redundant sulfur recovery plants. *Id.* They point out that the South Coast Air Quality Management District under California's Best Available Control Technology Statute does not specify a redundant sulfur recovery plant. *Id.* at p. 95. Furthermore, the Eight Parties relate, the California Shell Martinez Refinery Coker project has only one installed sulfur plant. *Id.*

1073. On Reply, Exxon notes that, while the parties agree that a sulfur plant is necessary as well as back-up capacity for that plant, they disagree as to how the back-up capacity is to be supplied, the amount of the back-up capacity necessary, and the unit cost of the sulfur recovery unit. Exxon Reply Brief at p. 109. As to how the back-up capacity is to be supplied, Exxon declares, the Eight parties are simply wrong in suggesting that it can be supplied in the same unit as the original capacity: "If all of the sulfur recovery capacity is contained in a single unit, no matter how large, and that unit goes out of

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> for either the coker or the distillate hydrotreater. In those instances, he instead chose to use his own firm's cost curves, which resulted in outcomes more favorable to the position of his clients.

Exxon Initial Brief at pp. 113-14.

service, the refinery must either shut down or run the risk of substantial fines associated with violation of applicable environmental regulations." *Id.* Consequently, Exxon argues, O'Brien's proposal of a sulfur plant able to process 130% of the needed amount is simply unsound and that true back-up capacity can only come in multiple units. *Id.* at pp. 110-12.

1074. Turning to the amount of back-up capacity, Exxon argues that O'Brien, in suggesting that 30% is sufficient, errs. *Id.* at p. 112. It claims that the record indicates that, at the hearing, O'Brien "admitted . . . that he had understated the amount of sulfur in the Coke produced from coking the ANS Resid by almost 50%," and failed to take into consideration the sulfur which would be removed by other means than the sulfur plant. *Id.* at p. 113. According to Exxon, the average sulfur plant back-up capacity of West Coast refineries is 54%. *Id.*

1075. According to Exxon, its witness, Jenkins, estimated the cost, Year 2000 dollars, of sulfur recovery facilities to be $24.7 million on the West Coast and $19 million on the Gulf Coast. *Id.* at p. 114. It asserts that Jenkins's estimate is based on the cost curve from the Gary & Handwerk text. *Id.* Answering the Eight Parties's criticism of Jenkins's use of this cost curve, Exxon notes that O'Brien also used a Gary & Handwerk cost curve for his estimate of these costs and admitted that his estimate was based on "an outdated version of the cost curve." *Id.*

1076. On reply, the Eight Parties, first noting that O'Brien's estimate that only 30% of redundant capacity is needed was based on a study he had conducted of West Coast refineries not all of which had Delayed Cokers, attack Exxon's proposal that 100% excess capacity is required. Eight Parties Reply Brief at pp. 83-85. They argue that, despite the testimony of Exxon's witnesses, no evidence in the record established that there are any environmental requirement that there be such excess capacity, nor, they say, is there "any evidence proving that the Claus sulfur recovery plants used by the industry are hard to operate and prone to frequent breakdowns." *Id.* at p. 85. Acknowledging that Jenkins used the high range of the Gary & Handwerk OSBL factor (20-25%), the Eight Parties note that O'Brien testified that his standard practice is to use a 15% factor for an ISBL sulfur plant. *Id.* at p. 86.

ii. Downstream Hydrotreater

1077. Exxon explains that all parties agreed that the Coker requires downstream hydrotreaters to reduce the amount of sulfur and other impurities in the Coker Naphtha, Coker Distillate and Coker VGO products in order to bring those products up to the quality of the proxy products used by the Quality Bank to value "virgin" or Quality Bank Naphtha, Distillate and VGO. Exxon Initial Brief at pp. 114-15. Jenkins, Exxon notes, provided cost calculations for each of the hydrotreaters and, where the products were superior to the Quality Bank proxy products, he reduced the costs by a credit. *Id.* Also, Exxon relates, Jenkins credited the hydrotreaters with any economies of scale that a refinery might enjoy by building a larger hydrotreater integrated with other refinery operations. *Id.*

1078. In contrast, Exxon states, O'Brien assumed that a single distillate hydrotreater could be used to process the Coker Distillate and the "virgin" or "Quality Bank" Distillate, that another hydrotreater would be used to process the Coker VGO and "virgin" or "Quality Bank" VGO, and that a Naphtha hydrotreater would be used to process the combined Coker LSR, Coker Naphtha, and "virgin" or "Quality Bank" Naphtha streams. *Id.* at pp. 115-16. Furthermore, Exxon states, O'Brien assumed that his VGO and Naphtha hydrotreaters would be "hybrid" hydrotreaters operating at an intermediate pressure in view of the fact that Coker VGO and Coker Naphtha would require high pressure hydrotreating, while virgin VGO and virgin Naphtha could be hydrotreated using a less-costly medium-pressure hydrotreater. *Id.* at p. 116. O'Brien, Exxon explains, then calculates the incremental processing cost attributable to hydrotreating Coker products in order to bring them up to Quality Bank specifications.[389] *Id.* However, Exxon asserts, O'Brien's did not provide any factual support for his approach in estimating hydrotreating costs. *Id.*

1079. Exxon insists that O'Brien's approach to the costing of the Naphtha and VGO hydrotreaters was also inconsistent. *Id.* at p. 117. For pricing virgin Naphtha, Exxon explains, he assumed that the Naphtha hydrotreater would be a medium-pressure hydrotreater. *Id.* However, Exxon continues, his pricing assumed that the Coker Naphtha hydrotreater would be a hybrid intermediate-pressure hydrotreater with a pressure somewhere between high and medium. *Id.* He admitted, Exxon relates, that the medium-pressure hydrotreater used by a refinery to process virgin Naphtha would not be able to process the Coker Naphtha. *Id.*

1080. Additionally, Exxon notes, O'Brien admitted that the medium-pressure hydrotreater that a refinery without a Coker would build to process virgin VGO would be unable to process the VGO produced by the Coker, and that a higher pressure hydrotreater would be required to process Coker VGO. *Id.* Another flaw, according to Exxon, was that he was unable to explain how the medium-pressure hydrotreaters could be transformed into larger, higher pressure hydrotreaters when the Coker was added to the refinery, nor did he attempt to estimate the costs of doing so. *Id.* Exxon states that

[389] According to Exxon, O'Brien concedes that a refinery without a Coker would install economically sized hydrotreaters sufficient to process the Quality Bank products, and that, were a Coker subsequently added to the refinery, the refinery would add hydrotreating capacity to process the Coker products. Exxon Initial Brief at p. 116. Additionally, Exxon relates, he admits that the Quality Bank prices for Quality Bank VGO, Quality Bank Naphtha, and Quality Bank LSR do not capture any of the costs associated with hydrotreating the products of the Coker. *Id.*

Jenkins estimate on the Gulf Coast was $19.4 million in Year 2000 dollars, while O'Brien estimated that the Gulf Coast cost would be $14.6 million in Year 2000 dollars. *Id.* at p. 118.

1081. The Eight Parties argue that O'Brien followed standard industry practice by assuming that process units that are efficiently sized as they exist in an efficient West Coast coking refinery. Eight Parties Initial Brief at p. 96. Refinery processing units, the Eight Parties relate, are sized to process all of the material that comes from distillation, cracking and coking units, rather than from just one of them, which allows refiners to achieve economies of scale and reduce the cost per barrel of hydrotreating. *Id.*.

1082. According to the Eight Parties, Jenkins fails to follow standard industry practice in his Coker product treatment costs. *Id.* at p. 97. In creating his line item estimate, the Eight Parties assert, he does not follow actual refinery practice because he downsizes his hydrotreaters, treating only the respective product coming from the 40,000 barrels/day Delayed Coker. *Id.* Consequently, the Eight Parties explain, this results in factored costs for a 12,000 barrel/stream day Coker VGO hydrotreater, a 6,500 barrel/stream day Coker Naphtha hydrotreater, and an 8,300 barrel/stream day Coker Distillate hydrotreater. *Id.* No refiner, the Eight Parties insist, would build units this small, especially in a 200,000 barrels/day refinery. *Id.* As a result of choosing hydrotreating equipment and operating conditions producing products exceeding the applicable proxy product specifications, the Eight Parties maintain, Jenkins makes a series of subjective adjustments to the hydrotreating costs of the Coker VGO and Coker Distillate streams to compensate. *Id.*

1083. While admitting that the parties agree that downstream hydrotreaters will be necessary to reduce the amount of sulfur and other impurities in Coker Naphtha, Distillate and VGO products, in its Reply Brief Exxon notes that, although the parties followed different approaches to reach an estimate of their cost, the end results were close. Exxon Reply Brief at pp. 115-16. Nevertheless, Exxon explains that Jenkins used a "reasonable approach" to estimate the cost "with every aspect of his estimate transparent and subject to audit," while O'Brien "relied on impossible-to-audit cost curves." *Id.* at p. 116.

1084. According to Exxon, "Jenkins provided detailed cost calculations for each of the necessary hydrotreaters, and designed hydrotreaters of a size and type which would be found in actual refineries." *Id.* at p. 117. He also credited the hydrotreaters with the appropriate economies of scale. *Id.* Taking issue with the Eight Parties's claim that Jenkins's estimates were "subjective," Exxon declares this assertion to be without merit and states that the Eight Parties "had a full and fair opportunity to take issue" with them. *Id.* at pp. 117-18.

1085. Responding to the Eight Parties's claim that the approach O'Brien used to make his estimate followed an approach which was standard in the industry, Exxon asserts that they failed to identify any evidence to support it. *Id.* at p. 118. It adds that, at the hearing, "O'Brien conceded that a refinery without a coker would be expected to install economically sized hydrotreaters sufficient only to process the Quality Bank products, and that if a coker were subsequently added to the refinery, the refinery would have to add additional hydrotreating capacity to process the coker products." *Id.* at p. 119. Moreover, Exxon argues, on cross-examination, O'Brien admitted that the same hydrotreaters which were capable of treating virgin Naphtha or virgin VGO, which need only be medium-pressure hydrotreaters, would not be capable of treating Coker Naphtha, or Coker VGO. *Id.* at p. 120. It declares that his "approach required a complex and *highly subjective* cost allocation procedure." *Id.* (emphasis added). In closing, Exxon highlights its claim that the difference between the parties's estimates is less than $5 million.[390] *Id.* at p. 121.

1086. In their Reply Brief, the Eight Parties declare that "O'Brien followed standard industry practice with respect to the efficient sizing of process units which enables a refiner to achieve economics [sic] of scale that reduce the cost per barrel of hydrotreating." Eight Parties Reply Brief at p. 87. Thus, they say, using the Baker & O'Brien cost curves to determine the overall cost for an appropriate hydrotreater, O'Brien then assigned a portion of that cost to treating products from the Coker. *Id.* In comparison, wrongly they argue, Jenkins used hydrotreaters which he downsized solely to treat the Coker products.[391] *Id.* at p. 89. According to the Eight parties, no refiner would do what Jenkins did, instead they "build larger units that enjoy economies of scale." *Id.*

iii. Finance Costs

1087. Jenkins, Exxon begins, combined three different cost factors to produce a 19.5% total capital cost factor for computing the capital costs of the Coker and related downstream units.[392] Exxon Initial Brief at pp. 118-19. In contrast, Exxon relates,

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[390] Exxon states that its estimate, taking economies of scale into account, in Year 2000 dollars, is $19.4 million while the Eight Parties's is $14.6 million. Exxon Reply Brief at p. 121.

[391] According to the Eight Parties, Jenkins's approach results in "an almost doubling of the cost on a unit of throughput basis for his three hydrotreaters compared to Mr. O'Brien's efficiently sized hydrotreaters." Eight Parties Reply Brief at pp. 89-90.

[392] Exxon explains that, first, Jenkins used a 17% capital recovery factor, derived by Toof, based on an expected 25-year useful life and a resulting 4% depreciation rate, a capital structure of 35% debt/65% equity, a 7.85% cost of debt, and a 15.78% pre-tax cost of equity. Exxon Initial Brief at p. 118. Second, Exxon continues, Jenkins used an "owner's cost" of 10%. *Id.* Third, it states, Jenkins used an interest during construction

O'Brien assumes a five year payback for the Coker investment, equivalent to a 20% capital cost factor. *Id.* at p. 119. Exxon contends that O'Brien's approach oversimplifies, excluding relevant costs, but not by much. *Id.* Exxon contends that the error here from O'Brien's 20% capital recovery factor is relatively small and, as Jenkins's combined capital cost recovery factor is 19.5%, the outcome is essentially the same. *Id.* at pp. 119-20.

1088. The Eight Parties explain that O'Brien uses a capital recovery factor of 20%. Eight Parties Initial Brief at p. 100. According to the Eight Parties, a 20% annual capital recovery factor used in calculation costs for the adjustment to the Heavy Distillate price was found to be reasonable in the Certification of Contested Settlement and Ruling on Motion to Omit the Initial Decision, *Trans Alaska Pipeline System*, 80 FERC ¶ 63,105 at p. 65,235 (1997). *Id.* at p. 102.

1089. Exxon's approach, the Eight Parties contend, is subjective as it is nothing more than a snapshot for a one year period. *Id.* at pp. 103-04. Toof, the Eight parties state, testifies that the capital recovery factors cost can change from year-to-year and, therefore, he recommends an annual update. *Id.* at p. 104. The Eight Parties disagree with Exxon's approach to interest during construction, since they assume that the project is built with equity, thus avoiding the question of interest during construction. *Id.* However, like Exxon, the Eight Parties note that whichever approach is adopted the outcome is essentially the same. *Id.* at p. 105.

1090. In its Reply Brief, Exxon states that, to compute the finance costs of capitalizing the Coker and related downstream processing units, Jenkins used three multipliers: (1) a 17% capital recovery factor derived by Toof "from standard industry and financial indices, based on an expected 25-year useful life and a resulting 4% rate of depreciation, a capital structure of 35% debt and 65% equity, a 7.85% cost of debt, and a 15.78% pre-tax cost of equity;" (2) an owner's cost of 10% which it claims was "at the low end of the range of owner's cost as a percentage of total construction costs for a number of refinery construction projects;" and (3) "an 'interest during construction' ('IDC') factor of 4.3% based on a three-year construction schedule, a debt ratio of 35%, and an interest rate of 7.85%." Exxon Reply Brief at p. 122. It states that combining these factors resulted in a 19.5% total capital cost factor. *Id.* In contrast, Exxon states, O'Brien merely assumed a five-year payback on the Coker investment which resulted in a 20% capital cost factor. *Id.* at pp. 122-23.

1091. While admitting that O'Brien's approach often is used to make preliminary cost estimates, Exxon declares that it is inadequate to make final estimates because it can leave out relevant costs. Exxon Reply Brief at p. 123. Exxon notes that its witness,

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factor of 4.3% based on a three-year construction schedule, a debt ratio of 35%, and an interest rate of 7.85%. *Id.* at p. 119.

Baumol, testified that O'Brien's approach was simply wrong. *Id.*

1092. In their Reply Brief, the Eight Parties conclude as follows:[393] "O'Brien's twenty percent capital factor should be adopted because it doesn't have to be adjusted annually. Moreover, it is the same capital factor used for other Quality Bank components when a finished product has to be adjusted to reflect an intermediate feedstock value." Eight Parties Reply Brief at p. 93. In comparison, they argue that Toof agreed that his capital cost number would have be adjusted annually by the Nelson Farrar index. *Id.* at p. 92. According to them, once the project would be finished, "the costs would not be changed each future year." *Id.* at pp. 92-93.

3. Location Factor

1093. Exxon states that a major area of disagreement between the parties relates to using a location factor for the West Coast. Exxon Initial Brief at p. 121. All parties assumed the Coker would be built on the West Coast, Exxon begins, and Jenkins calculated construction and operating costs on the Gulf Coast, adding a location factor to reflect the West Coast's higher costs. *Id.* O'Brien, Exxon relates, makes no such adjustment. *Id.* It insists that this failure is a clear and indefensible error, departing from standard industry practice as well as the principal industry cost treatises and resulting in almost 50% of the \$2.40/barrel difference between the parties regarding the West Coast Resid value. *Id.* at pp. 121-22.

1094. Exxon explains that using a location factor with cost studies is "an appropriate and well-established industry practice." *Id.* at p. 123. As an example, Exxon points to the Gary & Handwerk treatise, which uses a factor of 1.0 for the Gulf Coast and gives a location adjustment of 1.4 for Los Angeles and 1.2 for Portland and Seattle. *Id.* at p. 124. Also, Exxon notes that a National Petroleum Council-commissioned study by Bechtel estimated that, taking into account differences in construction costs, building codes, environmental rules, and other design parameters, the cost to build a unit would be 40% higher in California and 20% higher on the rest of the West Coast than on the Gulf Coast. *Id.* Finally, Exxon states that O'Brien's own firm uses location factors in preparing cost estimates. *Id.*

1095. Pointing out that the parties agreed to value West Coast Resid on the basis of West Coast prices and not on Gulf Coast prices, Exxon suggests that West Coast costs rather than Gulf Coast costs must be used for valuation. *Id.* at p. 122. It accuses the Eight

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[393] It must be noted that the Eight Parties cite to no record evidence to support their claim that the 20% return "is the same capital factor used for other Quality Bank components when a finished product has to be adjusted to reflect an intermediate feedstock value."

Parties of undervaluing West Coast Resid by not accounting for the West Coast's higher costs. *Id.* According to Exxon, no one disputes that construction costs, labor costs, and permitting costs are significantly higher on the West Coast than on the Gulf Coast. *Id.* at p. 123. O'Brien concedes, Exxon relates, that no authority supports his position that a location factor should not be used in preparing cost estimates. *Id.* at p. 125. Exxon argues that O'Brien's explanation, that it is too early in the cost estimating process to use such a factor, is not credible. *Id.* Any credible analyst, Exxon insists, would use a location factor, even when starting from a cost curve. *Id.* Additionally, Exxon notes, the parties have assumed West Coast prices for other aspects of the case. *Id.*

1096. According to Exxon, O'Brien's attempt to confuse West Coast location factor with site preparation costs[394] has no valid basis. *Id.* Jenkins, Exxon explains, did not use any site preparation costs because he assumed that the Coker was to be added to an existing refinery without a Coker and the refinery site would already have been prepared. *Id.* at p. 126.

1097. Jenkins, Exxon points out, uses a West Coast location factor of 1.26 for the Coker and location factors ranging from 1.26 to 1.3 for other process units such as the hydrotreaters and the sulfur plant. *Id.* at p. 127. The varying West Coast location factors, Exxon explains, result from variations in the mix of equipment, structures, and other costs required for each type of processing unit. *Id.* These factors, Exxon believes, are reasonable for the West Coast, but are conservative for the Los Angeles area, noting that the Gary & Handwerk textbook uses 1.4 for the Los Angeles location adjustment. *Id.*

1098. The West Coast location factor, Exxon notes, is supported by more general construction and building authorities for different geographic regions:

> The September 11, 2000 edition of *Engineering News Record* ("*ENR*") provides relative cost indices applicable to all types of construction and buildings for U.S. cities, including New Orleans where numerous Gulf Coast refineries are located. These data show that West Coast construction costs are from 139% to 222% higher than Gulf Coast construction costs. A similar R.S. Means study of general construction cost location factors also showed a Los Angeles location factor of approximately 1.3, and an overall West Coast location factor of between 1.25 and 1.29, when the location factor for Gulf Coast cities that have refining capacity was set at 1.0.

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[394] Exxon explains that site preparation costs are costs associated with getting a site prepared to be built upon and that site preparation costs are specific to particular sites, involving costs distinct from location costs addressed by geographic location factors. Exxon Initial Brief at p. 126.

Id. at pp. 128-29 (internal citations omitted).

1099. According to the Eight Parties, no location factor is necessary in this case because the Delayed Coker is not for a specific project defined in sufficient detail and pinned down to a specific location. Eight Parties Initial Brief at pp. 105-06. They maintain that cost curves are the most appropriate basis for such a project.[395] *Id.* at pp. 106-09. Location factors, the Eight Parties assert, are highly subjective and differ by whoever does them. *Id.* at p. 109. Such subjectivity is demonstrated, the Eight Parties explain, in examining the *Engineering News Record,* which applies to all types of construction and which Jenkins relies on to demonstrate the higher West Coast costs. *Id.* at pp. 111-12.

1100. According to the Eight Parties, the *Engineering News Record* confirms their opinion of the subjectivity of location factors:

> A more detailed review of [the *Engineering News Record*] than the cursory reliance by Mr. Jenkins on the difference in the hourly rate for common labor also reveals the subjectivity of location factors or comparison of costs

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[395] The Eight Parties compare two refineries -- the Shell Deer Park Refinery on the Gulf Coast and Shell's Martinez Refinery on the West Coast – to demonstrate that California projects may, indeed, be cheaper than Gulf Coast projects:

> [T]he cost of the Deer Park Refinery coker project is $13,636 per barrels/day while the cost of the Martinez Refinery coker project is $10,331 per barrels/day. Thus, based on actual cost data for the two refineries owned by the same company, Shell, on an equivalent cost in dollars per barrels/day basis, the cost of the coker project on the West Coast is *lower* than the cost on the Gulf Coast.
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> [T]he only factual evidence of comparable cost data for a coker project on the West Coast and the Gulf Coast shows that the cost expressed in barrels/day in order to put the costs on the same basis, was *lower* not higher on the West Coast. This empirical data supports Mr. O'Brien's expressed concern that until you had a specific project it was appropriate to use only a generic cost curve and not apply a location factor because the cost might be lower. More significantly for this proceeding, the only record evidence does not support the use of any location factor in determining the delayed coker costs to be used in the Resid valuation formula.

Eight Parties Initial Brief at pp. 108-09 (emphasis in original; internal citations omitted).

> between the Gulf Coast and the West Coast. First, in the October 2, 2000 edition of [the *Engineering News Record*], the costs for common labor, skilled labor and materials are *lower* in St. Louis compared to Los Angeles, which is the exact opposite of what the Gary & Handwerk textbook shows for location factors for the two cities, 1.6 and 1.4, respectively. . . . The comparison of costs and location factors for a Chicago and Los Angeles refinery used in [the *Engineering News Record*] and Gary & Handwerk has the same dichotomy in results. In [the *Engineering News Record*], Chicago has higher common labor, skilled labor and materials costs than Los Angeles, while the Gary & Handwerk textbook location factor for Chicago is less than Los Angeles.

Id. at p. 112.

1101. Another approach to West Coast location factors, the Eight Parties assert, is to average several different locations. *Id.* at p. 114. Using PRISM, the Eight Parties state, the number would be 1.08 for Portland, 1.20 for Seattle and 1.35 for California (Los Angeles and the San Francisco Bay area). *Id.* Although Jenkins calculated the average of these three numbers to be 1.21, the Eight Parties note, if he had included the inland California refineries in the California number, changing the 1.35 to 1.28 rounded (1.35 + 1.20 divided by 2), the resulting average is 1.19. *Id.* All this demonstrates, the Eight Parties contend, the immense subjectivity involved in using location factors and "how they are affected by simply changing one number." *Id.* at p. 115.

1102. Acknowledging that the use of a location factor is a major difference between it and the Eight Parties, on reply, Exxon points out that, despite his failure to use a location factor to increase West Coast costs, O'Brien acknowledged that West Coast costs were higher than those on the Gulf Coast. Exxon Reply Brief at pp. 125-26. In contrast, Exxon claims that Jenkins, its witness, after determining construction and operating costs on the Gulf Coast applied "appropriate location factors to reflect" the higher West Coast costs. *Id.* at p. 126. As to O'Brien's failure to use a location factor, Exxon states:

> This failure by Mr. O'Brien to adjust his Gulf Coast cost estimate to reflect the higher West Coast costs is a clear error and an indefensible departure from both standard industry practice (including his own firm's practice) and all of the principal cost treatises that are used in the industry.

Id.

1103. Exxon challenges the Eight Parties's claim that there is no need to use a location factor because no specific project is being planned stating that, as all of the information for planning the project is available, it would be "plainly wrong" not to use a location factor to reflect the higher West Coast costs and that no "credible analyst" would fail to do so. *Id.* at p. 128. It adds that even using a cost curve requires the use of a location factor. *Id.* at p. 129.

1104. Responding to the Eight Parties's claim that its use of a 1.26 location factor is too subjective, Exxon claims that its use was not based solely on its data, but that its use is consistent with "the Gary & Handwerk treatise, the 1993 NPC commissioned study, and the 200 API study by Mr. O'Brien's firm, as well as the more general cost indices in *ENR* and R.S. Means." *Id.* at pp. 135-36.

1105. In its Reply Brief, the Eight Parties again defend O'Brien's refusal to adjust his cost curve to reflect the higher costs on the West Coast in comparison with those on the Gulf Coast indicating that he refused to do so because there was no "specific location" identified for the Coker. Eight Parties Reply Brief at pp. 93-95. They continue to attack Exxon for locating its hypothetical Coker in the Los Angeles area stating that there is no basis for doing so. *Id.* at pp. 95-96. In any event, the Eight Parties maintain that location factors are "highly subjective." *Id.* at pp. 98-99.

4. Operating Costs

a. Fixed Operating Costs

1106. The fixed operating costs, Exxon explains, include the labor required to operate the Coker and related downstream units, maintenance expense, plant supplies, administrative and technical management, taxes and insurance. Exxon Initial Brief at p. 129. Jenkins, Exxon states, provided a list of fixed operating costs necessary for the Coker, related downstream units, and offsite facilities. *Id.* at pp. 129-30. These costs, Exxon relates came to $1.19/barrel on the Gulf Coast and $1.43/barrel on the West Coast in Year 2000 dollars; while O'Brien's comparable estimate came to 96¢/barrel in Year 2000 dollars for both coasts. *Id.* at p. 130.

1107. According to Exxon, much of the difference between the two estimates results from the fact that a number of the fixed operating costs are computed as a percentage of either the ISBL costs or the total capital costs. *Id.* As the parties's capital cost estimates differ, Exxon states, the resulting fixed operating cost estimates differ. *Id.* Jenkins, Exxon notes, concludes that this factor accounts for nearly all the difference between the parties's estimates. *Id.* Another factor accounting for the difference, Exxon relates, is differing labor cost estimates. *Id.* Jenkins, Exxon explains, details the various parts of his labor cost estimate; while O'Brien puts forth labor cost estimates, adding a contingency allowance for miscellaneous fixed operating costs, which he calculated as a percentage of his ISBL capital cost estimate. *Id.* at pp. 130-31.

1108. Exxon contends that O'Brien's approach is a non-transparent black box and that Jenkins's approach is more reasonable. *Id.* at p. 131. Furthermore, Exxon claims, O'Brien's criticisms of Jenkins's labor cost assumptions are without merit. *Id.* In contrast, Exxon asserts, O'Brien's fixed operating cost estimate includes a number of unrealistic and uncorrected assumptions.[396] *Id.* at pp. 131-32.

1109. The Eight Parties explain that O'Brien and Jenkins presented fixed cost estimates that are 22¢/barrel apart for the Gulf Coast and 47¢/barrel different for the West Coast, on a Year 2000 basis. Eight Parties Initial Brief at pp. 115-16. Several elements of the fixed cost calculations, the Eight Parties note, are based on a percentage of capital costs and, therefore, some of the difference between the two fixed cost estimates is explained by the difference in the calculation of capital costs. *Id.* at p. 116. Three differences, the Eight Parties state, stem from differences that are not explained by different capital cost calculations, and these include: (1) the number of operators; (2) inclusion of a foreman; and (3) the labor multipliers used in estimating labor costs. *Id.*

1110. O'Brien assumes six operators per shift (25 in total), the Eight Parties state, while Jenkins assumes nine operators per shift (38 in total). *Id.* Part of the difference in number of operators, the Eight Parties relate, results from the difference between the 2-drum and 4-drum Coker assumptions. *Id.* Another difference, the Eight Parties contend, stems from Jenkins failure to account, in his staffing requirement, for the automatic deheading equipment, automatic chutes, and a sophisticated coke handling system used in reducing cycle time. *Id.* at p. 117.

1111. Jenkins also assumes a foreman to supervise the operations of the Coker, the Eight Parties note, while O'Brien does not. *Id.* Because there would not be a foreman assigned solely to the Coker in an integrated refinery, the Eight Parties insist, the refinery would not incur the incremental cost of a foreman to process Resid. *Id.*

1112. Regarding labor multipliers, the Eight Parties argue, Jenkins multiplies his direct labor values twice for benefits, overtime, and other labor related costs. *Id.* at p. 122. Such an approach is inappropriate, the Eight Parties believe, stating that it is appropriate to use a multiplier only once to reflect benefits and costs. *Id.* A proper multiplier in this situation, the Eight Parties assert, is 45%. *Id.*

1113. In its Reply Brief, Exxon notes, the parties agree that the "remaining differences in fixed operating costs are largely explained by differences relating to labor costs." Exxon Reply Brief at p. 140. According to Exxon, O'Brien based his operating costs on a six-operator per shift crew, while Jenkins based his on a nine-operator per shift crew. *Id.* at

[396] These assumptions, Exxon states, include O'Brien's contention that a 40,000 barrels/day Coker and required downstream processing units could be operated on a 14-hour cycle with only a 6-man crew. Exxon Initial Brief at p. 132. Also, Exxon points out, O'Brien's proposed work force could not operate the Coker 24 hours per day for seven days a week, and he did not include costs for the operators of hydrotreaters. *Id.*

p. 141. Exxon declares that the record reflects that a six-man crew would be inadequate to operate a Coker on a 24/7 basis and that a nine-man crew is required. *Id.* at pp. 141-42. Furthermore, explaining that O'Brien did not believe that the addition of a Coker to a refinery would not require any further supervision, Exxon asserts that Jenkins disagreed and testified that "it is simply not reasonable to assume" that this was possible. *Id.* at p. 142.

1114. Turning to labor multipliers, Exxon explains, O'Brien used a single multiplier of 45% to estimate the costs of overtime and benefits while Jenkins used three separate multipliers: (1) 45% for overhead; (2) 15% for offsite labor; and (3) 20% for administrative labor. *Id.* at p. 143. It declares that Jenkins multipliers are open and aboveboard with no hidden components and that the three multipliers he used are based "on the Pace Refinery model (Exhibit No. WAP-78), which is used in the normal course of business." *Id.* at pp. 143-44.

1115. In their Reply Brief, the Eight Parties agree with Exxon "that the major source of the difference in fixed operating cost estimates is that the estimates are based on a percentage of capital costs." Eight Parties Reply Brief at p. 100. They also indicate that another source of the difference relates to labor costs. *Id.* With regard to staffing, the Eight Parties maintain that a six-man crew is sufficient to operate the Delayed Coker. *Id.* at pp. 100-01. When asked, they note, whether he assumed only 18 workers (three shifts of six staffers), that O'Brien indicated that "he assumed 25.2 workers." *Id.* at pp. 101-02.

b. Variable Operating Costs

1116. As for the variable operating costs, Exxon relates, these include the costs of the fuel, electricity, steam, water, hydrogen, catalysts and chemicals used in processing coke and treating Resid to meet the quality standards of the Quality Bank proxy products. Exxon Initial Brief at p. 132. Jenkins, Exxon begins, details the variable operating costs a Coker and related downstream units require, but O'Brien offers an estimate of variable operating costs. *Id.* at p. 133. According to Exxon, Jenkins's estimate results in 92¢/barrel on the Gulf Coast and 90¢/barrel on the West Coast in Year 2000 dollars while O'Brien's results in operating costs of 79¢/barrel in Year 2000 dollars for both coasts. *Id.* Exxon believes that the difference between the estimates result from (1) O'Brien's failure to include variable operating costs for the Coker gas plant, (2) his failure to include energy for the amine unit, a part of the sulfur recovery system, and (3) his failure to include any allowance for antifoaming and other chemicals in his Coker estimate. *Id.*

1117. As for variable operating costs, the Eight Parties note, Jenkins calculated an 11¢/barrel difference between O'Brien's variable cost calculation (79¢/barrel) and his West Coast variable cost calculation (90¢/barrel), based on Year 2000 costs. Eight Parties Initial Brief at p. 123. However, the Eight Parties argue, Jenkins neglected to increase O'Brien's calculation, which had been performed on a Year 1996 basis, to account for increases in operating costs between Years 1996 and 2000. *Id.* When O'Brien's costs are increased to a 2000 basis, the Eight Parties explain, they come out to 85¢/barrel, which is only 5¢/barrel below Jenkins's West Coast cost calculation. *Id.*

5. Base Year

1118. The correct base year used to determine the cost of coking ANS Resid, Exxon states, is also in dispute. Exxon Initial Brief at p. 134. Exxon explains that Jenkins's cost analysis uses Year 2000 as the base year while O'Brien's cost curve approach uses Year 1996 as the base year. *Id.* at p. 134. A problem arises, Exxon notes, as there are two Nelson Farrar indices applicable to different types of costs, which produce different results depending on how they are applied and which base year is used: (1) the Nelson Farrar Refinery Construction Cost Index (sometimes referred to as the Nelson Farrar capital cost index), and (2) the Nelson Farrar Refinery Operating Cost Index. *Id.*

1119. According to Exxon, when adjusting Resid coking costs to the respective base years, both parties adjusted their estimates of the capital costs of the Coker and related downstream processing units by using the Nelson Farrar construction cost index, and both parties used the Nelson Farrar operating cost index to adjust their operating cost estimates. *Id.* at p. 135. The parties agree, Exxon relates, that it is appropriate to use the Nelson Farrar construction cost index to adjust the capital costs to the base year and that it would not be appropriate to use the Nelson Farrar operating cost index to adjust capital costs to the base year. *Id.*

1120. However, Exxon continues, once Coker costs have been adjusted to the base year, the Eight Parties insist that all Coker costs, including the capital costs, should be adjusted thereafter solely by the Nelson Farrar operating cost index. *Id.* This position, Exxon states, is based on the fact that the parties previously stipulated to the use of that index for adjustments to the value of the Quality Bank cuts. *Id.* at pp. 135-36. As applied to the capital costs of the Coker, Exxon relates, this proposal would distort Coker costs in all years other than the base year because the two Nelson Farrar indices do not track one another. *Id.* Exxon points out that, unlike the Nelson Farrar construction cost index, which has risen relatively steadily over time, the Nelson Farrar operating cost index has gone up and down from year to year. *Id.* Consequently, Exxon insists, future year costs will be different if the Nelson Farrar operating cost index is used to adjust the capital costs of the Coker relative to the base year instead of the Nelson Farrar construction cost index, and the selection of the base year will have an impact on the capital cost figure for all prior years as well. *Id.* To avoid this problem Exxon proposes two alternatives:

> One solution - the analytically correct solution - would be simply to direct that capital costs should be adjusted from the base year by the Nelson Farrar construction cost index rather than by the Nelson Farrar operating cost index. It makes no sense for capital costs to be adjusted *to* the base

> year by the use of the Nelson Farrar construction cost index - as all parties agree is the only appropriate approach - and then to adjust those same capital costs *from* the base year to other prior and subsequent years using the Nelson Farrar operating cost index. Using the Nelson Farrar construction cost index to adjust the base year capital costs for other years will eliminate this peculiar anomaly.
>
> Alternatively, the impact of the problem for future years can be limited by selecting the most current base year - namely, the base year 2000 proposed by [Exxon] rather than the base year 1996 proposed by the Eight Parties. While the selection of 2000 as the base year would not eliminate the anomaly of using an operating cost index to adjust capital costs, it would at least reduce the impact of that approach by bringing all of the capital costs forward to 2000 by using the correct Nelson Farrar construction cost index.

Id. at pp. 136-37 (emphasis in original).

1121. The Eight Parties believe that the differences in base years should not have any material impact on the outcome of this proceeding. Eight Parties Initial Brief at p. 124. The annual adjustments, the Eight Parties explain, apply to both proposals and adequately account for inflation. *Id.* Further, the Eight Parties contend, the Commission should resolve any disputes over equipment on the merits without regard to the base year assumed by the witness. *Id.* Once the merits of the dispute are resolved, the Eight Parties insist, the costs of that equipment can be determined for the appropriate base year and the resulting total costs adjusted to current levels according to the Nelson Farrar Operating Cost Index. *Id.*

1122. In its Reply Brief, Exxon acknowledges that the parties disagree as to whether the appropriate base year to use should be 2000, as it suggests, or 1996, as is suggested by the Eight Parties. Exxon Reply Brief at p. 146. Stating that, in theory, it shouldn't matter, Exxon states that the real problem is which Nelson Farrar index to use. *Id.* According to Exxon, both O'Brien and Jenkins support use of the Nelson Farrar Refinery Construction Index to adjust capital costs and that its use is therefore appropriate. *Id.* at p. 147. It also suggests use of the Nelson Farrar Operating Cost Index to adjust Coker operating costs. *Id.* Exxon implies that, were this done, the identity of the base year would not matter, but that, were the Nelson Farrar Operating Index used to adjust both the capital and the operating costs, 2000 should be used as the base year because "use of a 1996 value plus the Nelson Farrar Operating Cost Index will result in an underestimation of costs for all subsequent years." *Id.* at p. 148.

1123. In their Reply Brief, the Eight Parties agree with Exxon that the choice of the base year should not impact the results as, by use of the Nelson Farrar index, the cost could be inflated or deflated accordingly. Eight Parties Reply Brief at p. 104. They oppose, however, the suggestion in Exxon's Initial Brief, that "the capital costs should be adjusted by the Nelson Farrar Capital Cost Index, while other costs are adjusted by the Nelson Farrar Operating Cost Index." *Id.* The Eight Parties claim that this would "add a new level of complexity to the Quality Bank" which, currently, only uses the Nelson Farrar Operating Cost Index. *Id.* at p. 105. They add that, were this done, not only would the coker costs need to be broken down between capital and operating costs, but that the same thing would have to be done for the Heavy Distillate and Light Distillate cuts as well. *Id.* According to the Eight Parties, the "difference between changes in capital and operating cost methodologies are not significant" and, therefore, adding the additional level of complexity is unnecessary. *Id.* at pp. 105-06.

E. ADMINISTRATIVE FEASIBILITY

1124. According to Exxon, the Quality Bank Administrator, Mitchell, stated that both Exxon's and the Eight Parties's Resid valuation methodologies are administratively feasible. Exxon Initial Brief at p. 137. In both cases, Exxon states, the first step calculates the value of the products produced by processing the Resid through a Coker, while the second step deducts from that value the costs of coking the Resid and bringing the resulting Coker products up to the quality of the Quality Bank proxy products. *Id.* Mitchell, Exxon notes, has confirmed that its approach is feasible on both a prospective and a retroactive basis. *Id.* at pp. 137-38. Furthermore, Exxon relates, Mitchell has testified that both proposals would cost the same to administer and all the price data required to apply the Exxon Resid valuation methodology retroactively is available. *Id.* at p. 138.

1125. On a going forward basis, Exxon believes, the Commission should order the Quality Bank Administrator to retest the common stream properties whenever the Administrator believes significant change may have occurred. *Id.* at p. 139. Also, Exxon contends, the Administrator should be permitted to use samples taken at the Petro Star Valdez refinery of the passing stream and the return stream whenever he thinks a change in the common stream may have occurred. *Id.* Finally, Exxon advocates a periodic re-sampling every year at the Petro Star Valdez refinery connection to ensure the properties of the common stream are constant and the cost estimates based on those common stream properties remain valid. *Id.*

1126. Exxon advocates that the Quality Bank Administrator be instructed to use the Microcarbon test in the future instead of the ConCarbon test in order to measure the carbon residue content for Resid. *Id.* at p. 140. According to Exxon, the Microcarbon test is a newer method of measuring carbon residue equivalent to the ConCarbon test but more accurate, with a higher level of repeatability and reproducibility. *Id.* Also, Exxon notes, this test is now the industry standard, especially when testing heavy fractions such as the 1050ºF+ plus Resid. *Id.*

1127. All parties agree that, in order to avoid the expense of purchasing the PIMS model, the Quality Bank Administrator should be authorized to use the PIMS correlations found in various exhibits, which would be turned into an electronic spreadsheet used to calculate yields. *Id.* at p. 141.

1128. Also, Exxon believes that once the PIMS yields have been established, the Administrator should use 60°F as the C_5 cut point, which will be reflected in the electronic spreadsheet to be provided by the parties. *Id.* According to Exxon, neither the adjustment nor the determination of the coke price used in valuing Resid poses any administrative feasibility issue. *Id.*

1129. Finally, Exxon relates that the parties stipulated that coke will be valued based on the West Coast at the mid-point monthly quote from *PCQ* for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke, and on the Gulf Coast at the mid-point monthly quote from *PCQ* for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke. *Id.* Exxon advocates that in order to value coke to the refiner, these published FOB vessel prices should be adjusted downwards to reflect costs incurred when coke is moved from a refinery to the point of sale. *Id.* at pp. 141-42. This issue, Exxon states, will be resolved in this proceeding and, thus, does not present any administrative feasibility issue. *Id.* at p. 142.

1130. According to the Eight Parties, both their and the Exxon proposals are administratively feasible. Eight Parties Initial Brief at p. 125. As for the issues raised by the Quality Bank Administrator, the Eight Parties state that the Resid value should initially be based on an average of the 2001 Caleb Brett assay and the assay sample taken this year as part of the stipulation on the intra-cut issues. *Id.* at p. 127. The Quality Bank Administrator, the Eight Parties continue, should be granted discretion to take additional future samples if he determines they are necessary due to a change in circumstances. *Id.*

1131. The ConCarbon test, the Eight Parties state, should be used instead of the Microcarbon test because the PIMS model was based on a correlation with the ConCarbon test. *Id.* at p. 128. As for the PIMS model, the Eight Parties assert that the Quality Bank Administration, in implementing any changes associated with a new ANS Resid sample, should be required to use yields that are equivalent to the yields that would result from the most current version of PIMS. *Id.* at pp. 128-29. Further, the Eight Parties state that he should get the yields from the parties. *Id*. Also, the Eight Parties believe that shippers, Alaska, and any non-shipper parties should be notified before the Quality Bank Administrator implements any change in the Resid valuation formula and explains why the change was proposed. *Id.* at p. 129.

1132. In its Reply Brief, Exxon reiterates its assertion that the parties agree that, on a going forward basis, the Quality Bank Administrator should retest the common stream whenever the Administrator "has reason to believe that any significant change may have occurred." Exxon Reply Brief at p. 149. It further notes that the parties agree that the new samples should be taken "following the same procedures that have applied to the taking of the ANS samples in 2003 and 2004." *Id.* at 150. Exxon submits that it and the Eight Parties disagree on whether annual retesting should be done. *Id.*

1133. In their Reply Brief, the Eight Parties state the following: (1) they now agree with Exxon that "continuous monthly samples of the Petro Star Valdez passing and return streams taken for preparing the monthly Quality Bank assays are more likely to be representative;" (2) however, they do not agree, because of the costs involved, that it is necessary to resample the ANS stream each year unless the Quality Bank Administrator believes that there was "a material change in the qualities of the ANS Resid;" and (3) the Quality Bank Administrator should not have to spend the money to acquire the PIMS model, but ought to be able to get the PIMS Coker yields from the parties and ought "to use yields consistent with the most recent version of PIMS when performing yield calculations in the future." Eight Parties Reply Brief at pp. 107-08.

ISSUE 1 – DISCUSSION AND RULING

1134. In the distillation process,[397] when all else has boiled out, the remainder is Resid. *Exxon,* 182 F.3d at pp. 35-36. Under the Quality Bank,[398] Resid is any material which does not boil out until the temperature reaches or exceeds 1050°F. *Id.* at pp. 36-37; *OXY,* 64 F.3d at p. 688.

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[397] O'Brien describes the distillation process as follows: "[I]n distillation, the crude oil is heated until it starts to boil, and the different cuts boil out of the crude at different temperatures. The cuts produced in the distillation process are defined by the temperatures at which the cut is produced." Exhibit No. PAI-1 at p. 4.

[398] O'Brien states that the Quality Bank

> takes 9 basic cuts commonly produced by refiners in the distillation process, and determines how much of each of these cuts is contained in each of the crude streams transported by TAPS. The methodology then develops a price for each cut, multiplies that price by the percentage of the cut that is contained in the crude stream, and sums the resulting prices to develop a total crude stream value. These values are then used to determine Quality bank payments.

Exhibit No. PAI-1 at p. 5.

1135. The parties have stipulated that Resid should be valued as a Coker feedstock using the following formula: "Resid = Before-Cost Value of Coker Products – (Coking Costs * Nelson Farrar Index)." "Joint Stipulation of the Parties," filed October 3, 2002, at p. 1. The Stipulation provides that the Before-Cost Value is to be calculated using a 3-step process: (1) the product (Fuel Gas, Propane, Isobutane, Normal Butane, LSR, Naphtha, Heavy Distillate, VGO, and coke) yields are to be determined through the use of PIMS; (2) Values are to be determined for each;[399] and (3) the product yields are to be multiplied by the product prices and the resulting values are added together. *Id.* at pp. 1-2. Moreover, the parties agreed that coking costs are to be given a "single value," but failed to agree on what that value should be. *Id.* at p. 3. While not agreeing as to the "base year"[400] the parties agreed that the Nelson Farrar Index to be used is a ratio of the Nelson Farrar Index (Operating Indexes Refinery) for the year in which the value is sought and the Nelson Farrar Index (Operating Indexes Refinery) for the base year. *Id.*

1136. By the time at which the record closed in this matter, as indicated above, the parties had reduced their disputes to a number of very specific items. Each of the issues briefed by the parties requiring a ruling will be addressed below.[401]

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[399] Except for Fuel Gas and coke, the Quality Bank value for each product is to be used. As to Fuel Gas, on the West Coast, the monthly California Natural Gas spot quote from *Natural Gas Week* (South, delivered to pipeline) plus 15¢/MMBtu for transportation from the Arizona-California Border shall be used; and on the Gulf Coast, the monthly Gulf Coast (Henry Hub, Louisiana) Natural Gas spot price quote from *Natural Gas Week* should be used. As to coke, on the West Coast, the mid-point monthly quote from *PCQ* for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke should be used; and, on the Gulf Coast, the mid-point monthly quote from *PCQ* for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke should be used. However, then the parties disagreed that an additional adjustment should be made to the coke price. "Joint Stipulation of the Parties," filed October 3, 2002, at p. 2.

[400] As noted above, the Eight Parties have suggested that the base year should be 1996 and Exxon has suggested that it be 2000.

[401] At various places on brief, one party or the other has argued that the other has made a proposal which is in its economic interest. Of course, it is a given that a party is not going to assert a position in litigation which is not in its self-interest and it is also a given that a proclamation of this by an opposing party is not evidence that the position is not otherwise supported by evidence. In general, therefore, I reject all such arguments and will not further comment on them.

A. BEFORE-COST ISSUES

1. C_5 Cut Point

1137. The Quality Bank, as is pertinent to this discussion, uses the following cut points: C_5 - 175°F (Light Straight Run), 175°- 350°F (Naphtha), 350° - 390°+F (Distillate).[402] Exhibit Nos. PAI-58 at p. 5; EMT-84 at p. 46. In order to determine the volume of each cut as a percentage of the whole, the C_5 cut point must, therefore, be identified.

1138. O'Brien, the Eight Parties's witness, in his direct testimony, stated that he used the PIMS Coker yields. Exhibit No. PAI-1 at pp. 11-12. Nowhere in that testimony does he refer to a specific C_5 cut point. According to Tallett, Exxon's witness, in his answering testimony, O'Brien erroneously had used a 100°F C_5 cut point when the "standard figure accepted by the petroleum industry for this cut point is 60°F." Exhibit No. EMT-84 at p. 46. In his reply testimony, O'Brien agreed that he used a 100°F C_5 cut point and defended it as giving "the most accurate allocation" using "linear interpolation."[403] Exhibit No. PAI-58 at pp. 5-6. Moreover, acknowledging and not denying Tallett's assertion that 60°F is "commonly accepted . . . [as] the best boiling point for C_5s," O'Brien states:

> The question is *not* what is the most representative initial boiling point for C_5s. The question is what boiling point should be used in the linear interpolation in order to get the best estimate of how the C_5-390°F coker fraction should be divided into the LSR, Naphtha and Heavy Distillate Quality Bank cuts. The answer to this question must take into account the fact that the distillation curve for a typical C_5-390°F coker fraction is actually curved and not a straight line.

Id. at pp. 6-7 (emphasis in original).

1139. In the C_5 argument in their Initial Brief, which ironically contains no valid cite to O'Brien's testimony regarding his C_5 cut point proposal,[404] the Eight Parties suggest that

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[402] The temperature range for VGO is 650° - 1050°F and Resid is anything exceeding 1050°F. Exhibit Nos. PAI-1 at p. 6; EMT-84 at p. 46.

[403] According to O'Brien: "In linear interpolation, one assumes that the liquids are distributed linearly (evenly) over the entire boiling range." Exhibit No. PAI-58 at p. 6.

[404] In the only cite to O'Brien's testimony in the argument in their Initial Brief on C_5, Eight Parties Initial Brief at p. 15, the Transcript page to which the Eight Parties cite in support, 247, contains nothing whatsoever to do with the C_5 cut point. The Eight parties, in the same location in their brief, cite to Exhibit No. WAP-61 at p. 2 in support

the record has little evidence as to whether 60°F or 100°F is the most appropriate C_5 cut point because such data is proprietary and the companies possessing the data were unwilling to reveal it. Eight Parties Initial Brief at p. 14. Moreover, it appears that, on brief, the Eight Parties are abandoning O'Brien's 100°F cut point in favor of the 96°F on a True Boiling Point basis cut point which they claim is used in the PIMS model,[405] a 90°F cut point which they claim is used in the Gary & Handwerk textbook, and an 82°F cut point which they suggest Tallett admitted is the lowest C_5 boiling point and which testimony, they claim, was supported by Gary. *Id.* at pp. 15-16.

1140. Exxon explains that the PIMS model divides the total Coker yield into three boiling ranges on a True Boiling Point basis[406] while the Quality Bank divides the yield into the four boiling ranges indicated above. Exxon Initial Brief at pp. 18-19. It notes that the PIMS yields are apportioned, using "linear interpolation," among the Quality Bank cuts. *Id.* at p.19. Exxon strongly urges its continued support for Tallett's testimony that the appropriate C_5 cut point is 60°F. *Id.* at p. 20. It points out that his testimony was supported by Gary. *Id.*

1141. Tallett testified that the C_5 cut point "accepted by the petroleum industry" is 60°F.[407] Exhibit EMT-84 at p. 46. He also notes that, while the lowest boiling point of

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of a claim that the PIMS model uses a 96°F C_5 cut point. While the Eight Parties correctly indicate that the document indicates that the PIMS model uses a 96°F cut point for LSR, it was introduced during Tallett's cross-examination and not while O'Brien was on the stand. Moreover, it is only when the appropriate transcript pages, Transcript at pp. 2346-47, to which the Eight Parties did not cite, are read in conjunction with the exhibit, that the exhibit has any meaning.

[405] Incredibly, the Eight Parties, on at least one occasion argue in favor of the 100°F cut point, not because they offered evidence to support it, but because 96°F, the C_5 cut point used in the PIMS model, "is much closer to 100° than to 60°." Eight Parties Reply Brief at p. 10. Then they suggest abandoning O'Brien's proposal that 100°F cut point be used in favor of a 96°F cut point. *Id.*

[406] Naphtha (C_5 - 390°F), Distillate (390° - 650°F) and Gas Oil (650°+F). Exxon Initial Brief at pp. 18-19.

[407] Exxon notes that O'Brien, during a deposition, testified that the Quality Bank C_5 cut point is 60°F. Exhibit No. EMT-97 at p. 10. At the hearing, O'Brien also stated as follows: "What does C_5 mean in terms of temperature? I think we kind of agreed that is about 60." Transcript at p. 1248. In fairness, it must be noted that, after making that statement, O'Brien also said: "We're trying to get the best split there, the most accurate split. Our view is 100 degrees gives you a more accurate split for the C_5." *Id.*

isopentane, the lowest boiling virgin C_5 is 82.1°F; the Coker, which is a cracking unit, produces pentenes as well as pentanes. *Id.* at p. 47. Tallett adds that the lowest boiling point of pentenes is 68°F. *Id.* At the hearing, Tallett's testimony was consistent. *See, e.g.,* Transcript at pp. 2270-74, 2363-68.

1142. Gary, acknowledging that his textbook, as the Eight Parties pointed out, used a 90°F temperature for LSR, added that it might have been better to use 80°F because in "straight run naphtha, the lowest boiling point for the C_5 fraction is isopentane, and its boiling point is around 82 degrees Fahrenheit." Transcript at pp. 2652-53. He also said that Coker LSR would have a lower temperature because it not only has isopentane, it also has isopentene which has a 68°F boiling point. *Id.* at pp. 2653-54. Gary also made the following statement:

> If we're talking about the boiling range for the light coker naphtha, the initial temperature should be less than 68.
>
> Now, it can be anywhere between, 31 which is a boiling point of normal butane, which is the heaviest component in the C_4 and lighter gases, or the highest boiling component in the C_4 and lighter [gases] and between the 68 for the isopentane. It can be any temperature in there in that range, and wouldn't affect the amount of the light coker naphtha because there's nothing in between 31 and 68 to boil.
>
> It could be any number there. If I had to pick a number, I would pick a number that I could put a little bit of justification on, and that may be around 60. It's below 68, and whether it's 60 or 65 wouldn't make any difference as to the quantity of the light coker naphtha because there's nothing that boils between 60 and 68.

Id. at p. 2654. According to Gary, there is no justification for setting the C_5 cut point any higher than 68, and he does not understand how anyone could say that it should be in the 90° - 100°F range. *Id.*

1143. Based on Tallett's and Gary's testimony I am satisfied that the C_5 cut point should be set at 68°F on a True Boiling Point basis. They both testified that this would be the lowest boiling point for the isopentene created in the Coker, the lowest C_5 boiling point. O'Brien's testimony in support of a 100°F cut point is weak, as evidenced by the Eight Parties failure to cite to it on this point, and equivocal. I, therefore, hold that the C_5 cut point should be 68°F on a True Boiling Point basis.

2. Assays

1144. The parties's dispute regarding which assays should be used with the PIMS model to calculate the product yields from running ANS through a Coker is bifurcated: (1) which should be used on a going forward basis, i.e., from the effective date of the final decision in this matter forward; and (2) which should be used for the past period, i.e., from December 1, 1993, through the effective date of the final decision in this matter. Exxon Initial Brief at p. 25. "The assays are used to determine the API gravity, sulfur content and concarbon content of the Resid."[408] Eight Parties Initial Brief at p. 17 (note added).

(a) Going Forward Basis

(1) Assay

1145. In its Initial Brief, while Exxon supported using the 2001 Caleb Brett assay[409] as "a reasonable starting point," it states that, because of the possibility of changes in the ANS stream, "it would not be prudent to rely solely on that one assay." Exxon Initial Brief at pp. 27-28. Accordingly, it suggests comparing the 2001 assay against an assay run in 2003 and one which will be run in 2004. *Id.* at p. 28. Exxon adds that, if the new assays are consistent with the 2001 Caleb Brett assay, then the newest assay should be used; but if they are inconsistent, the Quality Bank Administrator should determine why they were inconsistent and should "determine which assay should be used." *Id.*

1146. The Eight Parties, in their Initial Brief, acknowledging that, at the hearing, they did not take a position on how to treat the new assays, now state that they should be averaged with the 2001 Caleb Brett assay. Eight Parties Initial Brief at p. 19. However, in their Reply Brief, the Eight Parties assert that there are problems with the 2003 assays, both with regard to the sampling and the testing and that, therefore, they should not be used. Eight Parties Reply Brief at p. 13. Exxon's position, in its Reply Brief, remained the same with regard to the assays. Exxon Reply Brief at pp. 22-23.

1147. There really is no dispute and little factual evidence in the record supporting any ruling on this question. However, both parties agree that the 2001 Caleb Brett assay is a starting point for use on a going forward basis; both parties also agree that the Quality Bank Administrator ought to have the discretion to re-test the common stream whenever

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[408] The API gravity, sulfur content and ConCarbon content are then input into the PIMS yield spreadsheet, which was made part of the record as Exhibit No. EMT-237, and the Coker yields are derived from it. Eight Parties Initial Brief at p. 17.

[409] Entered into the record as Exhibit No. EMT-96 pp. 1-11.

he has reason to believe that a significant change may have occurred in the Quality Bank stream.[410] Eight Parties Initial Brief at p. 127; Exxon Reply Brief at p. 22. The Quality Bank Administrator testified that, while he should not have to re-test frequently, the re-testing should be done, at least, annually. Exhibit No. TC-1 at p. 15.

1148. In view of the above, I hold that, until such time as the Quality Bank Administrator is satisfied that a new sample is properly taken and tested, the 2001 Caleb Brett assay shall be used to determine the API gravity, sulfur content and carbon residue content of the Resid. I further hold that the Quality Bank Administrator shall have the discretion to re-test whenever he believes that there may be a change in the common stream which will affect the Quality Bank and that, if he is satisfied that the new sample was properly taken and tested, the new assay should replace that previously used to determine the API gravity, sulfur content and carbon residue content of the Resid.

(2) Carbon Residue Test

1149. In its Initial Brief, Exxon "recommended" that, on a going forward basis, the carbon residue content of Resid be measured by the Microcarbon test rather than the ConCarbon test. Exxon Initial Brief at p. 29. It claims that the former test "is a newer, improved method of measuring carbon residue that is 'equivalent to ConCarbon but more accurate' with a higher level of 'repeatability' and 'reproducibility.'" *Id.* at pp. 29-30. As support for this claim, in part, it cites to the hearing testimony of Tallett who stated:

> The microcarbon test was developed through a large effort by an ASTM committee back in the 1980s. The reason for developing it was to arrive at a test of carbon residue that was equivalent to ConCarbon but more accurate. You can see this in the stated repeatabilities and reproducibilities that are in the ASTM standards. They show, on repeatability, microcarbon has a third of the variance of ConCarbon and it's also lower on reproducibility.
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> In addition to this, not only does microcarbon exist as a test, but it's really become the norm. It's become pretty much the industry standard test today for testing carbon residue, especially on heavy fractions like 1050 plus resid.

Transcript at p. 2282. Exxon also relies on the testimony of Mitchell, the Quality Bank Administrator, who agreed that the "repeatability and reproducibility" of the Microcarbon tests were "probably tighter than the ConCarbon test." *Id.* at pp. 13137-38. It notes, further, that Mitchell recommended using the Microcarbon test, stating that it "has largely

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[410] As does the Quality Bank Administrator. Exhibit No. TC-1 at p. 15.

supplanted the Conradson carbon residue test as standard industry practice." Exhibit No. TC-1 at p. 13.

1150. According to Exxon, Dayton, the Eight Parties's witness, agreed that the Microcarbon test is "less subjective" and had "better repeatability." Transcript at pp. 1623-24, 3672. This claim is somewhat misleading. In fact, while she did agree that the Microcarbon test "has been determined to be less subjective," *id.* at p. 1624, Dayton defended the use of the ConCarbon test stating that whether the Microcarbon test was more accurate depended "upon who's doing the analysis" and that, if a "single analyst" did both tests correctly, "then in the ideal world you would not necessarily get different results." *Id.* at pp. 1623-24. Later, under further cross-examination, Dayton stated that the PIMS model could be used "equally well" with the ConCarbon test and the Microcarbon test, but that it was developed using the former. *Id.* at pp. 3672-73. She also denied that the results from the Microcarbon test were "any better" than those from the ConCarbon test. *Id.* at p. 3673.

1151. In their Initial Brief, the Eight Parties, while not acknowledging that Mitchell recommended the use of the Microcarbon test, cited his testimony[411] in support of their claim that the ConCarbon test, and not the Microcarbon test should be used. Eight Parties Initial Brief at p. 128. In their Reply Brief, the Eight Parties, again citing Mitchell's testimony, noted that the Microcarbon tests "gave almost universally higher carbon residue results than the" ConCarbon test. Eight Parties Reply Brief at p. 15. They add that the choice between the two tests "is not just a question of which is the more accurate test, but whether a test should be used that reaches consistently higher carbon results." *Id.*

1152. I disagree with the Eight Parties's claim that the choice is not between which test is more accurate. That is exactly the choice I need to make, and it is perfectly clear that everyone agrees that the Microcarbon test is more accurate. Mitchell, the Quality Bank Administrator, recommends it and states that it has supplanted the ConCarbon test as the

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[411] After reviewing the assays in the record here, Mitchell stated:

> [A]lmost universally the microcarbon method gives you a higher residue number than the ConCarbon. I've not investigated why that would be the case, but that obviously means since some people have an interest in a higher one than the lower like everything else in this proceeding, that could be a point of controversy, and I just want to make sure any settlement agreement or order of the Commissions specifically sets out which test I should use.

Transcript at p. 13110.

industry standard, and Tallett testified that it is more accurate. The Eight Parties plaint that it results in a higher carbon content being reported is not evidence that supports the continued use of the ConCarbon test.

1153. Accordingly, I hold that, on a going forward basis, the Microcarbon test should be used to determine the carbon residue content of Resid.

(b) Past Period

(1) Assay

1154. In its Initial Brief, Exxon describes all of the various assay combinations discussed at the hearing and argues in favor of Tallett's 10-assay proposal.[412] Exxon Initial Brief at pp. 31-40. The Eight Parties, without citing to her testimony, reflect that they support Dayton's 3-assay proposal.[413] Eight Parties Initial Brief at pp. 20-27. As no one disagrees as to whether those three assays should be used, there is no need to discuss them. Consequently, the discussion will be focused on Dayton's objections to the use of the remaining seven assays.

1155. Referring to Exhibit No. PAI-122, but not her testimony, the Eight Parties explain that the problem with the four Haverly/Chevron assays is that the carbon residue testing was not performed on the 1050°F cut, but on one made at another temperature.[414] *Id.* at p. 21. According to Dayton, the correct data cannot be extracted from that single data point. Transcript at p. 3636; *see also id.* at p. 3638. The Eight Parties also note the following discussion between Exxon counsel and Tallett:

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[412] The 10 assays are: (1) the February 1994 Haverly/Chevron, (2) the August 1994 Exxon, (3) the 1995 Haverly/Chevron, (4) the January 1995 Williams/BP (Caleb Brett), (5) the 1996 Haverly/Chevron, (6) the April 1996 Exxon, (7) the October 1996 ARCO (Caleb Brett), (8) the 1998 Haverly/Chevron, (9) the January 2000 Exxon, and (10) the December 2001 Phillips (Caleb Brett) assay. Exhibit No. EMT-277. Exxon declares that, as "none of the assays was perfect," a need to use all of them is highlighted. Exxon Initial Brief at p. 33.

[413] The three assays she recommended being used were: (1) the August 1994 Exxon assay, (2) the October 1996 ARCO (Caleb Brett) assay, and (3) the December 2001 Phillips (Caleb Brett) assay. Eight Parties Initial Brief at p. 20; Exhibit No. PAI-122.

[414] It is reflected, on Exhibit No. PAI-122, that the temperature of the cuts was as follows: (1) February 1994 - 1005°F, (2) 1995 - 1065°F, (3) 1996 - 1000°F, and (4) 1998 - 650°F. In other testimony, Dayton described how she calculated the temperature of the cuts tested. *See* Transcript at pp. 3630-47.

> Q When she was here on Monday, I think Ms. Dayton indicated she would be particularly concerned if you were taking something like a 1023 cut-point for the resid and trying to extrapolate out. What's our reaction to that concern?
>
> A I would agree with that. If your last cut-point was 1023 and you were trying to get to 1050, you could make that extrapolation because the crude assay management systems all have curves built into them because properties tend to behave in similar ways, but that's a fairly long way to go in a vacuum resid.

Transcript at p. 2305.

1156. The Eight Parties also referred to Dayton's testimony regarding the 1994 and 2000 Exxon assays stating that she noted that testing was done at different temperature ranges and that, while the carbon residue reported at 650°F was the same on both, when the testing was done on the 1049°F cut, there was a difference of 1.75 wt%. *Id.* at pp. 3636-38. Of this variance, Dayton stated: "So they have distinctly different trends based on the measured data. So the trend is specific to the sample that you've taken, and if you haven't measured the data and established what the specific trends are, you have no basis to do an extrapolation of the data." *Id.* at p. 3638.

1157. In its Initial Brief, Exxon argues that there is no reason for excluding the Haverly/Chevron assays because they used "an assay manager computer program to recut the assay data and did not always use the 1050°F cut point used by the Quality Bank." Exxon Initial Brief at p. 35. They claim further that Dayton testified the quality rating of the assays was good and that there was no qualification as to their accuracy, but that claim is misleading as Dayton was asked what the assay reported as to its quality and she answered "good," and whether there was qualifications as to its Microcarbon numbers and she answered "no." Transcript at pp. 3661-68. That hardly reflects her opinion. All it does is represent her ability to read what is reported on the document which *may* contain self-serving information.

1158. Exxon also seeks support from Tallett's testimony. However, the testimony to which it cites,[415] in part, refers to the Caleb Brett assays, not the Haverly Chevron assays. While the remainder of the testimony to which it cites refers to the Haverly/Chevron assays,[416] it does not reflect that Tallett had substantial knowledge on which to base his testimony. For example, at Transcript p. 2301, he testified as to his *understanding* of

[415] Transcript at pp. 2401-03.

[416] Transcript at pp. 2300-04, 2404-08.

how Haverly Systems used the Chevron database, stating that he didn't "know specifically how many cuts Chevron will cut the resid or typically the 650 plus material up into." He also testified that, based on his claim that "Haverly Systems is the leading supplier of crude assay management and recutting software," the number of its clients, and that it "wouldn't exist if oil companies were not satisfied with [its] ability to recut assays using software," that "the assay results were within certain tolerances of accuracy." *Id.* at pp. 2303-04. Tallett also admitted that the carbon residue test performed by Haverly was the Ramsbottom test, rather than either the ConCarbon or the Microcarbon tests, that these were the results he used, and that he never saw the "Chevron assays that underlie the Haverly data." *Id.* at pp. 2403-04, 2406.

1159. According to the Eight Parties, Dayton also criticizes three other assays because the "reported Resid yields . . . are outside of the range of Resid volume yields in the assays taken each month of the year by the" Quality Bank Administrator. Eight Parties Initial Brief at p. 22. Included in this group is the April 1996 Exxon assay which displays a Resid content of 18.36% in comparison with the highest percentage reported by the Quality Bank Administrator of 18.1%, the 1998 Haverly/Chevron assay, previously discussed, and the 2000 Exxon assay, both of which, the Eight Parties claim, reported Resid percentages "well below the minimum [Quality Bank Administrator's] Resid yields for 1998 and 2000 respectively." *Id.* at pp. 22-23. The Eight Parties also suggest that Tallett agreed, on cross-examination, that these assays are questionable.[417] *Id.* at pp. 23-24.

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[417] The testimony to which the Eight Parties refer is as follows:

> Q And Ms. Dayton has indicated that the three assays, the Exxon '96 assay, the Haverly '98 assay and the Exxon 2000 assay, ought to be eliminated because their [Resid] volume percentages fall outside of the range of volume percentages reported by the Quality Bank - the Caleb Brett assays that are done for the Quality Bank administrator on a regular basis. Are you familiar with that criticism?
>
> A Yes, I am.
>
> Q What's your reaction to that criticism?
>
> A Well, if you go back to my prior testimony, I think that when an assay flags a value that is outside a range, there is some basis to question it. I think you could argue it either way, but the conservative approach, which is what Ms. Dayton followed, would be to reject those assays because they're outside the range of the averages.

Transcript at pp. 2311-12.

1160. Exxon, in its Initial Brief, accuses Dayton of making an "apples-to-oranges" comparison with regard to those three assays; i.e., it asserts that Dayton is comparing assays taken on a single day to the Quality Bank monthly sample average. Exxon Initial Brief at p. 36. It adds that it should be expected that a sample taken on any given day might be above or below a range of monthly samples, and further note that, in the past, Dayton stated that only yields *significantly* outside the monthly average should be questioned. *Id.* at p. 37; Exhibit No. EMT-135 at p. 2, n. 1.

1161. The last assay which the Eight Parties criticize is the 1995 Williams/BP (Caleb Brett) assay. Eight Parties Initial Brief at p. 24. They state that, according to Dayton, method D-2892 was the vacuum distillation procedure used and that such use was inappropriate.[418] *Id.* Moreover, while they claim that Tallett agreed with her, that assertion is not entirely correct. Tallett testified that, while it was correct of Dayton to "raise the flag," he thought the test actually was performed using the correct procedure (either D-2892 or D-5236) and was trying to confirm his analysis and verify which test was used. Transcript at pp. 2295-97. He added that while he "would still raise somewhat of a flag over that assay, . . . [he was] not convinced there's grounds for just rejecting it out of hand." *Id.* at p. 2297. The Eight Parties note that, they assume, Tallett was never able to confirm his analysis as Exxon never offered further evidence as to the procedure used. Eight Parties Initial Brief at p. 24. In its Reply Brief, Exxon uses Tallett's testimony to support inclusion of this assay, but fails to acknowledge that Tallett could not verify his analysis. Exxon Reply Brief at pp. 31-33.

1162. Based on Dayton's testimony and the documents associated with it, I am satisfied that the Haverly/Chevron assays should not be used. The evidence reflects that the carbon residue tests were not performed at the 1050°F temperature of the Quality Bank Resid cut. Moreover, Tallett's testimony regarding his discussions with Haverly personnel did not convince me that these assays were as reliable as the three upon which the parties agree. Consequently, I find the February 1994, 1995, 1996 and 1998 Haverly/Chevron assays should not be used.

1163. With regard to the April 1996 Exxon and January 2000 Exxon assays, I am not satisfied that Dayton has established that they should not be considered.[419] I agree with Exxon that the small deviation of a daily sample from a monthly average should not be cause for excluding them. Moreover, the Eight Parties have not proved, or even suggested, that there was anything incorrect in the manner in which these assays were performed. Consequently, I find that the April 1996 and January 2000 Exxon assays should be used.

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[418] Dayton's testimony appears at Transcript pp. 1448-49.

[419] I already have ruled that the 1998 Haverly/Chevron assay also included in this category should not be considered.

1164. It appears that the January1995 Williams/BP (Caleb Brett) assay may not have been performed using the appropriate procedure. Both Dayton and Tallett agree that, under those circumstances, it should not be used. While Tallett testified that, while he *believed* that the proper procedure was used, he "would still like to be able to confirm that positively." Transcript at p. 2297. Apparently, he was not able to do so as Exxon offered no further evidence on this point. Therefore, as I cannot be certain that the proper procedure was used to perform this assay, I must hold that it cannot be used.

1165. In view of the above, I hold that the following assays should be used for the past period: (1) August 1994 Exxon; (2) October 1996 Arco (Caleb Brett); (3) December 2001 Phillips (Caleb Brett); (4) April 1996 Exxon; and (5) January 2000 Exxon.

(2) Carbon Residue Test

1166. Exxon's argument in favor of the Microcarbon test, rather than the ConCarbon test, is the same for the past period as it was for the going forward period. Exxon Reply Brief at p. 26. However, while I held, above, that the evidence supported a conclusion that the Microcarbon test should be used in the going forward period, the record does not indicate at what point in time that test "supplanted" the ConCarbon test.[420] Additionally, I note that Mitchell testified that, if he were using any assay which only had a ConCarbon test result, he would only be able to use that test, Transcript at p. 13139, and I note that the 1994 Exxon assay[421] does not contain any Microcarbon test results.

1167. In view of the above, I cannot find that the Microcarbon test was acceptable for use during the whole period in question or that all of the assays which are to be used contained Microcarbon test results. Accordingly, I find that, for the past period, the ConCarbon test should be used to determine the carbon residue content of the Resid.

3. Coke Value

1168. As noted above, the parties have agreed that coke is to be valued at the FOB vessel prices for fuel grade coke published in the *PCQ*. Exxon Initial Brief at p. 40; Eight Parties Initial Brief at pp. 27-28. "More specifically, the parties have agreed that the published Coke prices to be used are: (1) on the West Coast, the mid-point monthly quote from *PC*Q for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke; and (2) on the Gulf Coast, the mid-point monthly quote from *PC*Q for Gulf Coast High Sulfur

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[420] As noted above. Mitchell recommended that the Microcarbon test be used in the going forward period because it "largely supplanted the Conradson carbon residue test as standard industry practice." Exhibit No. TC-1 at p. 13.

[421] Exhibit No. WAP-68.

(Above 50 HGI) Petroleum Coke." Exxon Initial Brief at pp. 40-41. However, the parties have not agreed as to whether those prices should be adjusted to account for the cost of shipping the coke from the refinery gate to the point of sale reflected in the FOB vessel price. *Id.* at p. 41.

1169. Exxon argues that the FOB vessel price does not accurately reflect the value of coke to the refiner because it must incur the cost of moving the coke from the refinery gate to the point of sale.[422] *Id.* at p. 42. Its evidence on this point, not unexpectedly, establishes that refiners incur these costs which, I think, is a given and, therefore, find no need to discuss. From this, Exxon argues that pricing coke at the refinery gate overvalues it. *Id*. at pp. 42-43.

1170. According to Exxon, the deduction which should be made to the West Coast price is \$10.75/short ton and \$6.00/short ton on the Gulf Coast. *Id.* at p. 49. Its proposal is based on Bartholemew's testimony who, after detailing how he made estimates of the costs of transportation, handling and reselling, came to the conclusion which Exxon supports.[423] Exhibit No. EMT-31 at pp. 14-19.

1171. Addressing what it claims is the Eight Parties only objection to its coke value proposal – "it is allegedly 'inconsistent' with the use of unadjusted waterborne prices for 'other liquid Quality Bank cuts'" – Exxon suggests that the opposition is without support

[422] Exxon submits that those costs include "transportation, handling, storage and reselling costs." Exxon Initial Brief at p. 41.

[423] Exxon claims that Ross, the Eight Parties's witness, did not dispute that these costs estimates are conservative, but this claim is not accurate. While Ross agreed that those types of cost are incurred, he specifically stated that he had not studied them and expressed "no opinion" as to the accuracy of Bartholemew's estimates. Transcript at pp. 1648-49. In point of fact, he asserted that they were "not relevant." *Id.* Exxon also refers to Ross's testimony at Transcript pp. 1650-51, 1799-1800, 1809-10, in support of its assertion that the "Eight Parties also agree that the value of Coke to the refiner is determined by the 'net-back' value that the refiner can earn from Coke produced in the coking process, and that this net-back value is the *PCQ* FOB vessel price less the costs of moving the Coke from the refinery to the vessel." Exxon Initial Brief at p. 43. Unfortunately for Exxon, however, in the first instance, Ross was answering questions, based on Exhibit No. EMT-35, as to what his understanding was of what Bartholemew did, and in the second and third instances, he was answering questions about Exhibit No. BPX-17, an Exhibit he prepared to demonstrate his claim that Bartholemew misinterpreted Exhibit Nos. EMT-34 and 35. Suggesting from this that the Eight Parties agreed with Exxon that the value of coke was its FOB price less the expenses of moving it from the refinery to the FOB point of sale is too much of a stretch for anyone to accept.

because coke is not a liquid product. Exxon Initial Brief at p. 44. It also suggests that, when compared with its “very low market value,” the costs of transporting, handling, storing and reselling coke are “of a wholly different order of magnitude than the transportation and handling costs associated with the other coker products.” *Id.* In support it points to Ross’s testimony, particularly Exhibit No. BPX-17 and Transcript at pp. 1795-97, which, Exxon correctly claims, reflects that, while it makes up only 4% of the common stream is responsible for 17.31% of the “total logistics costs for all Quality Bank products.” Exxon Initial Brief at p. 45. Exxon also correctly notes that the parties have agreed to value Fuel Gas at the refinery gate. *Id.* at pp. 45-46.

1172. The Eight Parties claim that coke already is valued on waterborne basis. Eight Parties Initial Brief at p. 28. As such, it argues, coke is treated like all other Coker products as the Circuit Court required in *OXY,* 64 F.3d at p. 693. Eight Parties Initial Brief at pp. 29-30.

1173. Coke is what remains after Resid is processed through the Coker. It is unique in that, whether it is shot coke or sponge coke, it is a solid, not a liquid or a gas as are all of the other products produced from crude oil, and “can be moved only by truck, rail, or solid bulk vessel.” Exhibit No. EMT-31 at pp. 10-11. While there is an FOB vessel price for coke, the price is sometimes so low that coke is sold at a deficit when the cost of moving it to the vessel is considered. *Id.* at pp. 11-12; Transcript at pp. 2181, 2203. Nevertheless, according to Bartholomew, and undisputed by the Eight Parties, it must be removed from the refinery, even at a loss, “because the refinery cannot store it and still continue its refining operation.” Exhibit No. EMT-31 at p. 12.

1174. I am unconvinced by the Eight Parties’s argument that the cost of moving coke from the refinery to the vessel should not be considered when determining what its value is. In this exercise, if I am truly to determine the *value* of coke, it is clear to me that I must consider certain refinery cost factors, but perhaps not all that Exxon espouses, and not just the market price at a delivered location. The Eight Parties next argue that, were this done, cost factors related to other products also would have to be considered. However, its argument errs in two regards: (1) the *OXY* court did not require that, were a proposal made regarding one of the nine Quality Bank cuts, the Commission must consider, at the same exact time, that same proposal as it relates to the remaining eight; and (2) it is clear that I may consider only those proposals which are actually made and referred to me by the Commission.[424]

1175. Based on the record, I am satisfied that Exxon has established that coke is a product which is unique enough to warrant being treated differently than the other Coker products. Moreover, I am convinced by Bartholemew’s testimony, as well as the

[424] *Sierra Pacific Power Co.*, 104 FERC ¶ 61,223 at P 36 (2003).

evidence attached thereto, that refiners must incur costs related to their sale of coke inordinate to their costs for sales of other products related to the Quality Bank process. Bartholomew testified that, based on his investigation and the experience of his Jacobs Consultancy, the company for which he works, on the West Coast, refiners incurred an average transportation cost of $2.00/short ton and an average storage and handling charge of $6.75/short ton, and that, on the Gulf Coast, refiners incurred an average transportation cost of $2.50/short ton and an average storage and handling charge of $2.50/short ton. Exhibit No. EMT-31 at pp. 9-19. The Eight Parties failed to present any evidence contradicting this testimony.

1176. Bartholomew also testified that sellers on both coasts also incurred "reselling fees or commissions." *Id.* at pp. 15-16, 18. However, in contrast with the evidence regarding transportation and handling fees, nowhere in the record did Exxon establish that incurring such costs was unique to coke either in magnitude or discrete association with any other Quality Bank product.

1177. In view of the above, I hold that, on the West Coast, the mid-point monthly quote from the *PC*Q for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke should be adjusted by $2.00/short ton for transportation and by $6.75/short ton for handling. I further hold that, on the Gulf Coast, the mid-point monthly quote from the *PC*Q for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke should be adjusted by $2.50/short ton for transportation and by $2.50/short ton for handling.

B. COKER COST ISSUES

1. Overall Approach

1178. A major area of dispute between Exxon and the Eight Parties involves how to determine how much it costs to coke Resid. The two presented diametrically opposite proposals for reaching the ultimate conclusion. In sum, Exxon presented what it describes as a "detailed cost study" revolving around Jenkins's

> detailed "line item" cost study that identifies the direct or "inside battery limits" . . . cost of all the major equipment required for both the coker itself and the related downstream refinery units that would be needed to process the coker products to bring them up to the quality specifications of the Quality Bank reference products.

Exxon Initial Brief at p. 50. Exxon added that Jenkins used "appropriate West Coast location factors" to adjust Gulf Coast costs. *Id.* According to Exxon, the costs Jenkins calculated "compared favorably with the coker cost estimates provided in several well known treatises, including the Gary & Handwerk treatise and the Meyers text." *Id.* at p. 52.

1179. Not disagreeing with Exxon as to the ultimate goal, the Eight Parties still have difficulty in agreeing with Exxon's approach. Eight Parties Initial Brief at pp. 33-34. They begin their criticism of Exxon's approach by stating: "Instead of trying to divine the processing costs of a delayed coker in a typical refinery, [Exxon's] approach is to determine the costs of adding a coker to an existing refinery utilizing efficient units and focusing on design rather than actual operations." *Id.* at pp. 36-37. The Eight Parties add that, despite the fact that Jenkins previously had used cost curves to estimate capital costs,[425] this time he used "a detailed capital cost estimate" to construct a hypothetical Delayed Coker in a hypothetical refinery located somewhere in the Los Angeles area. *Id.* at p. 37. According to them, this approach allowed Exxon to reach an "excessively high detailed cost estimate" which it then "subjected to an endless series of subjective multiplication factors." *Id.* at p. 38.

1180. Exxon claims that the "picture painted by the Eight Parties is demonstrably false." Exxon Reply Brief at p. 45. It claims that all of Jenkins's estimates are "transparent and . . . subject to audit." *Id.* According to it, Jenkins "identified the bare costs for each and every piece of equipment required for a 40,000 barrels/day coker (EMT-46) and the factors he used for each category of equipment to estimate the installed costs of the coker (EMT-47)." *Id.* To prove its point, Exxon claims that, were the costs of the equipment which O'Brien failed to include in his estimate deducted from Jenkins's estimate, Jenkins's estimate would be lower than O'Brien's. *Id.* at p. 46.

1181. Exxon attacks what it refers to as O'Brien's "'conceptual' cost estimate [which it asserts] O'Brien based entirely on his firm's proprietary 'conceptual cost curves' for a supposedly 'typical' coker for which there is no supporting documentation whatsoever." Exxon Initial Brief at p. 54. It also notes that O'Brien failed to adjust his estimate for its West Coast location though he admitted that West Coast capital costs were higher than those on the Gulf Coast,[426] and that his approach was not so well defined as to allow for a determination as to exactly what equipment were included.[427] *Id.* at pp. 54-55.

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[425] The Eight Parties note that, in 2000, Jenkins used his company's cost curve for a Delayed Coker whose cost he estimated to be $111 million, much closer to O'Brien's estimate of $107 million, than his detailed-cost estimate. Eight Parties Reply Brief at p. 27.

[426] On cross-examination, O'Brien admitted that, while West Coast construction costs may not always be higher than those on the Gulf Coast, "they will tend to be higher." Transcript at p. 231.

[427] On cross-examination, O'Brien stated that, as he was not actually building a Coker, "what's actually in the coker is not – cannot be that well-defined." Transcript at pp. 323-24.

1182. According to Exxon, the accuracy of cost curves to estimate Coker costs, in general, is questionable.[428] *Id.* at p. 56. In support, it cites the "Meyers Handbook," and its witness, Gary, who agreed that a "cost curve estimate is only going to be plus or minus 25 percent accurate" if you use a location differential.[429] Transcript at p. 2660. Asked, if that were so, how could the Commission rely on a cost curve to estimate the cost of a delayed coker, Gary stated:

> Well, Glenn Handwerk [his co-author] and I talked about this, and we're very surprised that cost curves are being used – even though we have a lot of confidence in our cost curves – in general, that cost curves are being used because they are so inaccurate.
>
> With the amount of money that we think is involved, which I don't know, but we're talking about millions of dollars, I understand – with the amount of money that's involved, it seems to be much better to do a detailed estimate where even though it's going to cost $2 or $3 million to get it, rather than something you can get out of a book like ours, to me, it doesn't make sense and neither did it to Glenn Handwerk.

Transcript at p. 2661. But Gary later explained the reason why a cost curve is ± 25% accurate and why a detailed estimate would be so expensive:

> Because it requires a lot of engineering manpower, and to get a detailed estimate, you have to really specify the equipment to a detail such that you can get adequate costs on it, whereas in a curve we're talking about an average cost. And that's why it's plus or minus 25 percent, because when you design a unit, you might not be using all average pumps – all average fractionating towers and so on.

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[428] Jenkins states:

> [the company for which he works] capital cost data base uses one parameter - - unit capacity. A Delayed Coker is one of the refinery units in which a number of technical factors other than capacity influence cost. These factors include coke make, feedstock sulfur, coke handling system and other technical factors.

Exhibit No. EMT-146 at p. 16.

[429] According to Gary, without using a location factor, a cost curve only is ± 50% accurate. Transcript at p. 2660.

Transcript at pp. 2665-66.

1183. Exxon also criticizes O'Brien's methodology for assuming that certain processing would be done by large units in the refinery and only assigning the incremental costs of those units to the Delayed Coker. Exxon Initial Brief at p. 58. Also, according to Exxon, O'Brien failed to include the cost of the Coker gas plant. *Id.* Moreover, Exxon declares that O'Brien's estimate to be "well below" the estimates in "petroleum engineering texts."[430] *Id.*

1184. In truth, neither Exxon's nor the Eight Parties's "overall approach" is satisfactory. I am troubled with the complexity and subjectivity of Jenkins's itemized list of components. Also, I question whether Jenkins expended the effort necessary, described by Gary, to actually do a detailed estimate which I could accept as accurate.[431] While I am troubled by O'Brien's lack of detail, in the final analysis, as will be seen below, I can adjust O'Brien's estimate in ways which satisfy me that the end result is as close a cost estimate as possible given the limitations of what can be accomplished in the hypothetical world in which we are trying to determine the cost of a Delayed Coker. I can find no way of modifying Jenkins's estimate to satisfy me that the end result is accurate and fair to all parties. In sum, there is nothing in Jenkins's testimony or Exxon's arguments that convinces me that Jenkins's itemized cost approach is objective or accurate enough to satisfy the needs of using it as part of the formula which will result in a determination of the value of Resid. Therefore I hold that, as modified below, O'Brien's cost curve should be used.

2. Capital Costs

1185. The parties agree that the Coker capital costs consist of the direct costs, referred to as "Inside Battery Limits" or "ISBL," which include the costs of the Coker itself and related downstream refinery units, the indirect costs, referred to as "Outside Battery Limits" or "OSBL," which include facilities necessary to support refinery processing units such as storage facilities, steam generation systems, etc., and finance costs. Exxon Initial Brief at pp. 59-60; Eight Parties Initial Brief at p. 28.

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[430] According to Exxon, while O'Brien's estimates was $107.4 million, Gary & Handwerk's estimate is $175 million and the Meyers Handbook estimates range from $109.5 million to $219.1 million. Exxon Initial Brief at p. 58.

[431] Jenkins admits that he and Dickman only spent three man weeks on "engineering" the project. Transcript at pp. 2762, 2770. However, he further stated that, to do a detailed estimate to the level of which Gary spoke, i.e., 30% engineering, would take "four to six months." *Id.* at p. 2770.

a. ISBL Coker Costs

(1) Approach

1186. For the most part, except as their discussions related to subissues ii – iv, which will be addressed at the appropriate time, the parties repeated their arguments regarding whether Jenkins's itemized approach or O'Brien's cost curve based approach should be followed. Inasmuch as I have decided that O'Brien's cost curve approach, as modified below, is preferable to Jenkins's itemized cost approach, there is no need to address the parties's arguments regarding this particular subissue again. It is only necessary for me to reject O'Brien's plaint, Transcript at pp. 321-22, for the reasons stated above, that "it would be adverse to [his] methodology" to adjust his cost curves.

(2) 2 Drums v. 4 Drums

1187. O'Brien's cost estimates are based, in part, on the assumption that a 2-drum Coker would be used, while Jenkins assumed a 4-drum Coker. Eight Parties Initial Brief at p. 49; Exxon Initial Brief at p. 66. According to O'Brien's testimony, Exhibit No. PAI-58 at pp. 13-15, the cost curve used by Baker & O'Brien indicates that a 4-drum Coker is not required until one is needed to process somewhat more than 40,000 barrels/day. He further indicated that 40,000 barrels/day was not even in the transition zone between the need for a 2-drum Coker and a 4-drum Coker. *Id.* The Eight Parties further note, Eight Parties Initial Brief at p. 52, that O'Brien testified that the Coker to which he referred was a 40,000 barrel/stream day Coker by which he meant "the amount that a refinery can run in one 24-hour period when it's operating under optimal conditions." Transcript at p. 852. O'Brien further testified that, assuming a typical utilization rate of 87%, it could be assumed that a Coker capable of processing 40,000 barrels/stream day of ANS would actually average 34,800 barrels/day. Transcript at pp. 852-53. From this testimony, the Eight Parties argue that "any two drum cokers with a barrels per calendar day capacity of 34,800 would be equivalent to the 40,000 barrels per stream day capacity" which O'Brien assumed. Eight Parties Initial Brief at p. 52. The Eight parties add, citing to Exhibit No. EMT-187, that there are three such refineries. Eight Parties Initial Brief at pp. 52-53.

1188. Exxon asserts that evidence which it submitted through Dickman established the actual capacities of all of the 2-drum and 4-drum Cokers in the United States,[432] and that this evidence "shows that a coker processing 40,000 bbl/d of ANS Resid would be expected to have four drums." Exxon Initial Brief at pp. 67-68. It further states that only one 2-drum Coker has the ability to process 40,000 barrels/day of Resid and that that coker produces shot coke which it claims "is much easier to remove from the coke drums

[432] Exxon cites Exhibit Nos. EMT-167 at pp. 21-22, EMT-187, and EMT-188. Exxon Initial Brief at p. 68.

than the sponge coke produced by ANS Resid, and employs automatic deheading equipment[433] to reduce cycle time." *Id.* at pp. 68-69 (note added). On Reply, Exxon states that O'Brien's 2-drum Coker is "not from an operational standpoint a 'typical' coker but rather [was] a coker 'pushing the maximum' possible capacity of a 2-drum coker at 'optimal operating conditions.'" Exxon Reply Brief at p. 62.

1189. The question which needs to be answered is whether the "typical" Coker needed to process 40,000 barrels/stream day of ANS Resid would need two drums or four. This dispute, peculiarly enough, is one created by the parties, who, themselves, decided early in this litigation that the "typical" Coker would process 40,000 barrels/stream day of Resid.[434] Had they chosen 35,000 barrels/day, they could agree that it would only require a 2-drum Coker; had they chosen 45,000 barrels/stream day, they could agree that the Coker would require four drums.[435] But, they chose 40,000 barrels/stream day.

1190. To begin, I find that the Eight Parties's attempt to argue, Eight Parties Initial Brief at p. 52, that the parties were really focusing on a Coker capable of processing, on the average, no more than 34,800 barrels/calendar day to be disingenuous. It is clear that the parties were contemplating a Coker designed to process 40,000 barrels of ANS Resid per stream day. That such a Coker, if actually built, would process less or, as more likely, more is irrelevant. The essence of what is being addressed here is the cost of building a Coker able to process 40,000 barrels of ANS Resid per stream day. O'Brien has not convinced me that 2-drum Cokers already existing in the United States which process 34,800 barrels of Resid/calendar day are sufficient proxies for the hypothetical Coker we deal with here.

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[433] O'Brien chose not to include automatic deheading equipment in his hypothetical coker. This is discussed below.

[434] Jenkins testified that O'Brien proposed a 40,000 barrels/day Coker, and that he thought it was a "reasonable size." Transcript at p. 3893. He later described the parties's dispute:

> Well, I think the two-drum, four-drum discussion really evolved. It occurred after the initial 40 was stated, and I put out my numbers and showed a four-drum. And then Mr. O'Brien said no, you can do that in two, so it wasn't the going-in premise to be in this range or recognized that we had this issue when we went into it.

Id. at p. 3894.

[435] Transcript at pp. 3893-94, 4554-55.

1191. Moreover, I am not convinced by O'Brien that the 2-drum Coker he conceptualized is one which can, in fact, be constructed. As Exxon notes, O'Brien could not indicate what size the drums of his Coker would be: (1) 27.5 feet in diameter and 110 feet tall as he indicated in his deposition;[436] (2) 29 feet in diameter and 120 feet tall as was indicated in an email sent after his deposition;[437] or (3) 28.5 feet in diameter and 120 feet tall as he indicated in his Rebuttal Testimony.[438] On the other hand, at the hearing, he testified that he had no drum size in mind.[439] In view of previous statements made by O'Brien, I find it difficult to accept that he had no particular drum size in mind when he made his ISBL estimate. And, if in fact he did not, he should have. While one does not expect a cost curve to have the precision of a truly itemized cost estimate, nevertheless, I believe, one needs to know what components are included and, at least, a range of, or an average of, the sizes of those components. Without these in mind, it is difficult to determine whether the conceptual Coker even could be built, much less whether it is *typical.*

1192. Furthermore, serious concerns regarding ongoing Coker operations are eliminated through adopting the 4-drum design scenario. When considering a Coker capable of processing 40,000 barrels/stream day of Resid, appropriate drum size and the associated vapor velocity[440] limits are not reasonably achieved using a 2-drum design assumption. Indeed, as noted above, the record indicates that in order to process the 40,000 barrels/stream day level a 2-drum Coker would need the largest drums that have been manufactured to date. Moreover, this 2-drum Coker would need to operate at a true zero recycle[441] to prevent excessive vapor velocity during the coking process. Excess vapor

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[436] "In order to process this amount of coke with two drums, the drums would need to be pretty much the largest size drums that are fabricated today, and they'd be about – the largest standard drums today are about 27.5 feet in diameter and about 110 feet tall." Exhibit No. EMT-176 at p. 2.

[437] "Mr. O'Brien. . . . should have stated that the largest standard coker drums currently being fabricated are 30 feet in diameter and 120 feet tall. In his coker calculations, Mr. O'Brien assumed drums with a 29 foot diameter and an overall length (i.e., from the bottom flange to the top flange) of 120 feet." Exhibit No. EMT-177.

[438] Exhibit Nos. PAI-58 at p. 10; PAI-62.

[439] "There was no drum size assumption. The conceptual cost curve makes no drum size assumption." Transcript at p. 502.

[440]Vapor Velocity refers to the speed at which vapor flows in the coke drum. Exhibit No. EMT-167 at p. 15, Transcript at p. 530.

[441] O'Brien defined "zero recycle" as meaning that all of the material coming into

velocity creates an undesirable condition which can force small coke particles, referred to as “coke fines”, to carry over into the fractionator causing plant complications such as pipeline plugging, reduced processing capacity, and potentially a complete shutdown. Exhibit Nos. EMT-167 at pp. 15-18, EMT-180.[442] This situation is complicated because O’Brien’s 2-drum Coker design has absolutely no spare design contingency capacity and thus no operating flexibility to deal with either these complications or the commensurate coke handling challenges during normal operations.[443] Moreover, O’Brien’s claim that his Coker was intended to operate at a true zero recycle consistent with the PIMS model does not withstand evidence to the contrary[444] and would require a greater capital investment than originally included in his proposal. Transcript at p. 3419.

1193. Furthermore, I am not satisfied that O’Brien’s assumption of a 14-hour cycle time is reasonable as there appears to be no evidence which supports it. The only evidence cited by the Eight Parties in support of this claim is O’Brien’s declaration that “many cokers [] operate on 14-16 hour cycles” and that he is “aware. . . of one coker that

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the coke drum goes through the coking process only once, and that no material is brought back through the coke drum a second time. Transcript at p. 1019.

[442] Indeed the evidence used by the Eight Parties to refute Dickman’s maximum vapor velocity recommendation does not serve the purpose the Eight Parties intended. In fact, although the Eight Parties have shown 40,000 barrels of ANS Resid *could* theoretically be processed by a 2-drum Coker, the article upon which they rely states that refiners which operate with a vapor velocity at the level they assume, however, do so at the risk of foam over during attempts to maximize throughput. These operational conditions have not been shown to be a typical scenario for coking of ANS Resid. What is further clear is that the article also states that the typical range for vapor velocity is 0.5 fps to 0.6 fps – well below the 0.71 fps calculated by the Eight Parties for the 2-drum design. Exhibit Nos. PAI-141, EMT-234 at p. 9. In my opinion, these facts demonstrate another stretch in the Eight Parties attempt to convince me that a 2-drum Coker can readily process 40,000 barrels/stream day of ANS Resid. Consequently, I am not persuaded either by these arguments or by any of their evidence that this is a reasonable scenario.

[443] The record shows that certain design contingencies permit Coker operators greater flexibility and are commonly used in refinery design. Transcript at pp. 3430, 4118-21, 4742-44, Exhibit Nos. EMT-321, EMT-167 at pp. 13-14, EMT-146 at pp. 28-29.

[444] Transcript at pp. 3405, 2756-57, 3408, 3700-01, 3878, 3890-91, 3417-18, 4611, 4615.

operates on an 11 hour cycle."[445] This bald assertion is insufficient to overcome O'Brien's admission that his cost curve does not assume a cycle time.[446] It also appears that the document on which he based his 14-hour cycle time was erroneous and actually should have reflected a 16-hour cycle time.[447] Moreover, I am satisfied that the cycle time for which Delayed Cokers are being designed is not less than 16 hours.[448] Further, O'Brien himself testified that, in estimating the construction costs of a Coker, one should use a longer design cycle time, rather than a shorter operating cycle time that a refiner *might* be able to achieve by making additional investments – those not included within the original design of the Coker and thus not reflected at all in O'Brien's proposal. Transcript at pp. 553, 3173-74, 3434-36, 4352, 654-55, 4364, 4371, 4546.

1194. Therefore, based on all of the evidence in the record, I am convinced that the typical Coker constructed to process 40,000 barrels/day of ANS Resid would have four drums. There is nothing in O'Brien's testimony which would lead me to be convinced that a *typical* 2-drum Coker would be sufficiently sized so as to be able to process 40,000 barrels/stream day of ANS Resid. I am not suggesting, however, that one could not design a 2–drum Coker to do just that. Rather I am only stating that such a Coker would not be *typical*[449] and that, here, we are trying to conceptualize a *typical* Coker capable of processing 40,000 barrels/stream day of ANS Resid. Consequently, I hold that the cost of the Coker should be based on a 4-drum, not a 2-drum, Coker.

(3) Automatic Deheading

1195. "Automatic deheading equipment is the equipment that is used to open up the coke drum to permit removal of the Coke. [It] is used both to improve worker safety and to reduce coker cycle time." Exxon Initial Brief at p. 80. O'Brien admits that his typical Coker would not include any automatic deheading equipment. Transcript at p. 373.

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[445] Eight Parties Initial Brief at pp. 54-55; Eight Parties Reply Brief at p. 44.

[446] Transcript at pp. 728-29.

[447] Transcript at pp. 570-75, 2846-50; Exhibit Nos. EMT-228, EMT-229, EMT-284.

[448] Transcript at pp. 3158-59, 3438-47, 4336, 4353-54, 4361-62, 4573; Exhibit Nos. EMT-171 at p. 10, EMT-234 at pp. 5-6.

[449] Considering all the aforementioned challenges associated with the 2-drum design when trying to process 40,000 barrels/stream day of ANS Resid, it is simply more logical and prudent to base a design on a reasonable 4-drum Coker configuration than to push a 2-drum plant to its assumed maximum operational abilities under optimal conditions. Transcript at pp. 474-75, 489-90, 3707, 3890, Exhibit No. PAI-58 at p. 9.

However, he could not identify any Cokers operating with large drums and very short cycle times without such equipment. *Id.* at p. 374. Nor could he identify any Coker that has been installed since 1996 which did not have automatic deheading equipment. *Id.* O'Brien admitted that automatic deheading equipment serves to make operating the Coker safer and speeds up the cycle time. *Id.* at pp. 374-75. When asked whether, under these circumstances, a "prudent refiner" would install a Coker without such equipment, O'Brien could only respond that it wasn't against the law to do so. *Id.* at pp. 375-76. He also admitted that his firm has never recommended that a refiner install a Coker without such equipment, though he cited cost as a reason why a refiner would not. *Id.* at p. 376.

1196. According to O'Brien, "the generic or normal typical coker would not necessarily include automatic deheading" equipment. Transcript at p. 373. He added: "As long as there are many cokers out there that do not have automatic deheaders, which there are, then the coker or the automatic deheader is not the one that's setting the marketplace." *Id.* at pp. 373-74.

1197. Jenkins testified that most, if not all, Cokers built in the last 10 years had automatic deheading equipment. *Id.* at p. 3894. His comment is supported by documentary evidence in the record such as a report presented at the 1992 National Petroleum Refiners Association meeting in which it was reported that, as of November 1991, refiners were beginning to install bottom head, but not top head, automatic deheading equipment. Exhibit No. EMT-211 at p. 11. In a report presented at the 1994 meeting of the same organization, it was indicated that "[m]odern cokers include remote, automatically operated unheading systems which enhance operator safety and save time." Exhibit No. EMT-217 at p. 11. While the report does not mention sponge coke, it indicates that automatic deheading equipment makes handling shot coke easier. *Id.* At the 1996 meeting of the same Association, it was indicated that all new Cokers would have automatic deheading equipment and that refiners were considering installing them on existing coke drums. Exhibit No. EMT-234 at p. 3.

1198. According to Exxon, Jenkins assumed the use of automatic deheading. Exxon Initial Brief at p. 81. Without citing to any evidence in the record, the Eight Parties declare that, as sponge coke, rather than shot coke, is produced from ANS Resid, "the safety issue is lessened . . . [and] a coker running ANS does not necessarily require automatic deheading." Eight Parties Initial Brief at p. 70. They further note that Jenkins admitted[450] that automatic deheading equipment is predominantly used on the bottom heads, rather than both the bottom and the top heads. *Id.* at p. 71. However, Jenkins also stated that, he believed, a refiner would install both bottom and top head automatic deheading equipment because, on a new project, the incremental cost was low. Transcript at p. 3991.

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[450] Jenkins stated: "There are more systems of this type, automatic deheading equipment of systems [sic] on bottom heads than top heads." Transcript at p. 3990.

1199. The evidence indicates that O'Brien errs in suggesting that the *typical* Coker built today would not have any automatic deheading equipment. Based on this record, it is clear to me that the better view is that, if a refinery were adding a Coker, in order to make its operation more safe and to speed up the cycle time, it would include such equipment. I also agree with Exxon that, were the refinery building a Coker from scratch, it probably would include automatic deheading equipment for both the top and the bottom heads.

(4) Coke Handling Equipment

1200. Jenkins included the cost of coke handling equipment, i.e., the "coke pit and crane, chutes and conveyor system, and covered storage," in his ISBL estimate.[451] Exxon Initial Brief at p. 84. On the other hand, the Eight Parties claim, Eight Parties Initial Brief at p. 73, O'Brien limited his ISBL coke handling cost and, for example, treated storage as an OSBL cost.[452] According to the Eight Parties, "O'Brien's cost curve encompasses various projects with different types of Coke handling systems and thus, represents the typical, economic and efficient refinery." *Id.* at pp. 73-74. In point of fact, when asked what kind of coke handling equipment was included in his company's cost curve, O'Brien stated:

> It is a mixture of different projects, some of which may have pits and cranes, some of which may have pads. What would be typical. In other words, this curve is supposed to show what's typical. We would not consider this enhanced dewatering and crushing and separation to be typical of your normal coker.

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[451] Describing what is pictured on Exhibit No. EMT-159, Jenkins described the "coke handling system that would typically be used on the West Coast" as follows:

> After the coke has been cut into the pit, a clamshell crane is used to pick it up and put it into a hopper where it is crushed and screened. The crushing and screening is a very "rough cut" system which is designed to get the larger "chunks" of coke to a size that they can be handled by the conveyor. This coke is then conveyed to a storage barn. From the barn, the coke is eventually loaded into trucks using a smaller conveyor system. . . . For environmental reasons, the trucks must be washed before they leave the refinery for the coke terminal, so a washing system is also needed.

Exhibit No. EMT-146 at pp. 33-34.

[452] In fact, the Eight Parties err in their claim regarding storage. At the hearing, O'Brien was asked whether he included the costs of storage in his ISBL or OSBL estimates and responded that he included it in neither. Transcript at p. 624.

Transcript at p. 280. This claim appears to conflict with the following assertion which he made in his rebuttal testimony: "I believe that the use of front-end loaders for coke handling is reasonable, common and supported by the facts." Exhibit No. PAI-58 at p. 15. Moreover, O'Brien claimed that he "didn't do any investigation of coke handling on the West Coast." Transcript at p. 335.

1201. On the other hand, when asked whether coke handling equipment was included in his OSBL estimate, O'Brien stated: "If you consider the pad or the crane and pit and things of that nature, if you consider those to be coke handling, those we include normally in ISBL. Anything else that takes it from the battery limits is OSBL." *Id.* at p. 441. However, this does not explain why O'Brien deducted the "extra cost for coke pit and crane" from the Meyer's estimate in an exhibit attached to his direct testimony. See Exhibit No. PAI-10. It is further noted that O'Brien also would exclude from his ISBL estimate "the coke crushing/screening equipment" and "enhanced dewatering and water purification," which Gary & Handwerk would include. Transcript at p. 441; Exhibit No. PAI-10.

1202. The Eight Parties, without citing to any evidence in the record, declare Jenkins's coke handling proposal to be a "world class," "state of the art," system for handling coke which included the "most expensive Coke handling system" available. Eight Parties Initial Brief at p. 74. They note that Jenkins admitted that not one of the refineries listed on Exhibit No. WAP-86, a summary of his answer to interrogatories, had all of the following: pit and crane, crusher, screening, and storage. *Id.* at p. 75. The Eight Parties argue, therefore, that Exxon has "failed to present evidence that a typical West Coast refinery includes all of the equipment Mr. Jenkins detailed." *Id.* at p. 76.

1203. Exxon argues that the "coke pad and front-end loader suggested by" O'Brien "would not be acceptable under current West Coast environmental requirements." Exxon Initial Brief at p. 85. Indeed, O'Brien admitted that, though a coke pad and front-end loader might have been acceptable in 1996, he did not "think it would be today." Transcript at pp. 331-32. He further admitted that he could not identify one Coker currently operating on the West Coast with just a coke pad and front-end loader. *Id.* at pp. 334-35. Moreover, in a report presented at the 1992 meeting of the National Petroleum Refiners Association, the following was stated regarding a coke pad:

> Most environmental problems are experienced at refineries with a so called "coke pad" handling scheme. Therefore this scheme, as a general rule, is not recommended.[453]

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[453] Asked whether he agreed with this statement, O'Brien said it would not be acceptable today, but it would have been acceptable in 1996. Transcript at pp. 331-32. When questioned about whether the coke pad handling system was acceptable in 1992, O'Brien did not answer either yes or no, but stated that, despite the statement in the

> In this scheme, coke from the drums is discharged onto a concrete pad. The pad is surrounded by a concrete wall on two sides leaving the third side open for a front loader
>
> A fines settling basin is adjacent to the coker pad. The basin is shallow and open on one side, so it can be accessed and cleaned by the front loader.
>
> A common problem with this scheme is that a large flow of coke slurry discharged from the coke drums into the fines settling basin will plug the screen separating the basin from the basin sump pump. This results in flooding of the area through the front end loader access.
>
> The front end loader operation prevents enclosing the coke discharge area completely, and leads to spreading coke over the adjacent area and, in general, making the are affected by the coke spillage larger than with other alternatives. The problems become more serious if a large coke storage surge capacity is required.
>
> Coke in the storage area is ground and compacted by the wheels of the front end loader and then dries. This becomes a source of dust and contamination of the storm water.

Exhibit No. EMT-211 at p. 15 (note added).

1204. I am not satisfied that O'Brien's ISBL estimate, based on his company's cost curve, adequately provides for coke handling equipment. The evidence clearly indicates that much more than a coke pad and front end loader is required,[454] particularly on the West Coast. It is clear to me that, in the 21st century, all of the equipment discussed by Jenkins would be required were a Coker added to an existing refinery. Therefore, I hold that O'Brien's ISBL estimate should be supplemented with the cost of this equipment.

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report, "there are still many cokers that operate with a simple pad." *Id.* at p. 332. Upon further questioning, he stated he had not done a study on this question and could not name a Coker on the Wet Coast that used a coke pad handling system. *Id.* at pp. 332-33.

[454] There is some confusion as to whether this was all of the equipment to which O'Brien referred. However, he did testify that he believed "that the use of front-end loaders for coke handling is reasonable, common and supported by the facts." Exhibit No. PAI-58 at p. 15. Based in part on this comment, as well as other statements which he made, I find that O'Brien, in fact, unreasonably was limiting the cost of the coke handling equipment by focusing on the least expensive equipment which might possibly be used.

(5) Coker Gas Plant

1205. According to Exxon, the "coker gas plant is used to process the gases produced in the coking of Resid." Exxon Initial Brief at p. 87. Jenkins included its cost in his ISBL estimate. *Id.* The Eight Parties claim that O'Brien included it in his OSBL cost estimate.[455] Eight Parties Initial Brief at p. 77. Exxon argues, however, that, even were it correctly placed in OSBL, "O'Brien's OSBL cost [estimate] was simply not large enough to include the coker gas plant plus all of the other costs allegedly included."[456] Exxon Initial Brief at p. 88. It also notes that O'Brien included the costs of hydrotreaters and sulfur plants, which Exxon claims serves a similar function, in ISBL, while not including the gas plant. *Id.* at p. 89. Exxon, finally, argues that O'Brien fails to take into account the location of the gas plant which, it claims, would "normally [be] located as close as possible to the fractionator of the coker because the heat from the fractionator is used in the gas plant." *Id.* at p. 91.[457]

1206. The Eight Parties argue that "the gas plant is shared among several units in the refinery, primarily the cat cracker and the coker." Eight Parties Initial Brief at p. 78 (note added). In making this argument they ignore that O'Brien testified that his conceptualized refinery does not have a cat cracker, and that the Coker would still need a gas plant. Transcript at pp. 288, 421. To add further confusion, O'Brien, after denying that his concept used the base refinery's gas plant to process the Coker gases, was asked whether he "assumed that the coker would borrow some of the gas plant from the catalytic converter," and he answered:

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[455] However, this claim may not be accurate. When given an opportunity to list the equipment covered by his OSBL estimate, O'Brien stated: "The specific equipment . . . includes, but is not necessarily limited to, electrical power distribution, boiler feed water, process and cooling water facilities, fuel gas facilities, steam systems, plant and instrument air systems, fire protection systems, and flare system and system tie-ins." Exhibit No. EMT-220 at pp. 2-3. I believe that O'Brien's failure to include a gas plant in this list was no mere oversight. It is too significant an item to not include in response to the question posed and, like Dickman, *see* Exhibit No. EMT-167 at p. 26, "I am skeptical of Mr. O'Brien's assertion that [the coker gas plant] is part of his OSBL estimate."

[456] In their Reply Brief, the Eight Parties suggest that this is beside the point because O'Brien assumes "that the gas plant would be shared by the several processes, including the coker, added to the base refinery in a typical West Coast refinery." Eight Parties Reply Brief at p. 65.

[457] Exxon cites the following portions of the record in support: Exhibit Nos. EMT-146 at pp. 36-37, EMT-167 at pp. 24-26, EMT-191 at pp. 5-6; Transcript at pp. 1327-28, 3493, 4084, 4093.

> I said in estimating the processing costs, that would be appropriate and reasonable to apply in this case. I would not build a small inefficient gas plant to process just the coker gases, which is what Mr. Jenkins did. What I said was you would integrate that processing with the existing processing in an integrated refinery on the West Coast, and so you would not spend this money to build a separate plant. You would integrate it with the refinery. That's, in fact, the way cokers are built and operated on the West Coast.

Id. at p. 289.

1207. In its Reply Brief, arguing that the Eight Parties are wrong to assert that the gas plant is not an ISBL item, Exxon cites,[458] to the following statement from Gary: "Because these facilities are part of the gas processing unit, they are 'inside' the battery limits of the refinery – and properly treated as ISBL costs – rather than OSBL costs." Exhibit No. EMT-191 at p. 4. Gary added that, though the gas plant's costs were not included in the Delayed Coker cost curve, a separate cost curve was supplied in his textbook. *Id.* at pp. 4-5. Despite Gary's comment, the Eight Parties cite Jenkins's testimony in Exhibit No. EMT-146 at p. 37 and declare that Gary & Handwerk did not include the gas plant as an ISBL cost. Eight Parties Reply Brief at p. 61. Their comment in this regard clearly is disingenuous as, while Jenkins did say that the gas plant was not included in the C*oker's ISBL cost*, he also said that the costs "are not treated as offsites," and that a separate cost curve was used on which its cost could "be estimated based on gas throughput and liquid recovery load." Exhibit No. EMT-146 at p. 37.

1208. The evidence submitted by the Eight Parties does not clearly establish how they proposed to treat the costs of the Coker gas plant,[459] or what the cost would be;[460] while the testimony of Jenkins and Gary, as well as the exhibits attached to them, satisfy me that the costs of the gas plant ought to be considered an ISBL cost. Moreover, by Exxon's admission on brief and O'Brien's testimony, I am further satisfied that the cost

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[458] Exxon Reply Brief at p. 89.

[459] As noted above, while the Eight Parties claim that it is included in the OSBL estimate, O'Brien failed to clearly identify it as such and, because of its significance, I do not think that he would have done so had he actually included it within his $37 million OSBL estimate. Moreover, I agree with Exxon that, were the gas plant included in O'Brien's OSBL cost estimate, his estimate would not be adequate to cover all costs.

[460] O'Brien indicates that there would be a "substantial" saving were the Coker gas plant integrated with the cat cracker gas plant, Transcript at p. 428, but not what the cost, integrated or not, would be.

of the Coker gas plant would be, about, $14 million.[461] Consequently, O'Brien's cost curve based ISBL estimate needs to be increased by this amount to account for the cost of the gas plant.

b. OSBL Coker Costs

1209. The Eight Parties, citing O'Brien's testimony, have suggested that the typical industry approach is to express OSBL as a percentage of ISBL costs. Eight Parties Initial Brief at p. 80. As to this matter, O'Brien stated:

> In addition to ISBL costs, when estimating the total costs of coking it is necessary to include "offsite" costs or what are also referred to as the Outside Battery Limits ("OSBL") costs. These costs represent refinery infrastructure that is necessary to support the operation of the project. OSBL costs typically are expressed as a percentage of the ISBL costs. I have used an average estimate for OSBL costs equal to 35% of the ISBL costs. This is higher than the Gary & Handwerk textbook estimate of 20 to 25%. However, a substantial part of the difference is because the Gary & Handwerk text does not include an allowance for any steam and cooling water facilities, which I included [in] my OSBL costs. Also, as noted previously, the Gary & Handwerk text includes in its ISBL estimates some facilities that I consider to be included in OSBL costs.

Exhibit No. PAI-1 at p. 24.

1210. According to Exxon, Jenkins followed the approach suggested in the Gary & Handwerk textbook. Exxon Initial Brief at p. 93. It states that, after he estimated the costs of the major process units needed to add a Coker to an existing refinery,[462] Jenkins "separately estimated the costs of the additional storage facilities, steam generation systems, and cooling water systems that would be required to support the coker," and then "applied a factor of 25% of the costs of the ISBL processing units to cover other OSBL costs." *Id.* at pp. 93-94. The Eight Parties note that even Jenkins admits, Transcript at p. 2719, that O'Brien's approach is more typical than the approach he followed.[463] Eight Parties Initial Brief at p. 81.

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[461] Exxon Initial Brief at p. 98; Transcript at pp. 422-23.

[462] "[T]he coker itself, the coker gas plant, the downstream hydroheaters, and the sulfur recovery plant." Exxon Initial Brief at p. 93.

[463] In his direct testimony, Jenkins states that "it is typical to estimate offsite costs as a percentage of the cost of the major refinery unit(s) being added." Exhibit No. EMT-37 at p. 47.

1211. Exxon argues that O'Brien's OSBL estimate is too low, but agrees that the percentage of ISBL costs he used (35%) was higher than that suggested in the Gary & Handwerk textbook (20-25%). Exxon Initial Brief at p. 95. In this regard, it should be noted that, as O'Brien's ISBL estimate has been increased as a result of the rulings I made on the ISBL issues, if no change is made in the manner in which he calculated the OSBL costs, his OSBL estimate will have a concomitant increase. This is especially true as I have held that the Coker gas plant costs should be treated as an ISBL cost and not included in the OSBL estimate.

1212. As both Jenkins and O'Brien agree that the typical approach to be followed in calculating OSBL costs is to use a percentage of ISBL costs, I find that O'Brien's approach of using 35% of the ISBL estimate should be followed.

1213. The parties, more or less, repeated the arguments that they made regarding the Coker gas plant issue in the ISBL portion of this issue discussed above. As I have held that the Coker gas plant ought to be considered an ISBL item, there is no need for me to rule again on this matter.

1214. Regarding the remaining OSBL matters specifically addressed by the parties, storage costs, steam generation and cooling water facilities, and miscellaneous items, I find that O'Brien's suggestion that they be calculated by taking 35% of ISBL costs to be adequate when the modifications which I have made in his ISBL estimate are taken into consideration.

c. Other Capital Costs

(i) Sulfur Recovery Costs

1215. The Eight Parties state the issue as follows:

> The issue related to sulfur recovery costs boils down to one single difference: do you assign the costs from the capacity plus a reserve from an existing efficiently sized sulfur recovery plant at the refinery as Mr. O'Brien proposes on behalf of the Eight Parties, or do you build a redundant (*i.e.*, second full sized) sulfur recovery plant because you are adding a delayed coker as Mr. Jenkins proposes on behalf of [Exxon]?

Eight Parties Initial Brief at p. 91. Basically agreeing, Exxon states that, as both parties agree that some backup capacity is required, the issue is how much is needed. Exxon Initial Brief at p. 108.

1216. On brief, the Eight Parties seem to indicate that one larger sulfur plant with excess capacity would provide the needed capacity as well as the necessary backup capacity.

Eight Parties Initial Brief at p. 93. However, a review of the record indicated that their witness, O'Brien, did not necessarily conceive that *only* one plant would exist. According to his testimony, he believed that only a 30% backup capacity was necessary, but he made no firm statement as to the appropriate configuration. Transcript at p. 1227. When he was asked about a three sulfur plant configuration with each capable of processing 50% of what was needed, O'Brien indicated that, while that would provide "more flexibility," he "looked at what people actually had, or tried to look at what people typically had." *Id.* at pp. 1227-28. Questioned about whether his concept involved two units each having 65% of the needed capacity, O'Brien answered that he "didn't try to estimate it that way." *Id.* at p. 1228. O'Brien also suggested that perhaps a configuration of "two 50-ton plants and one 30-ton" would work, but would only allow the Coker to operate at 80% of needed capacity if one of the 50-ton units went down. *Id.* He also stated that the three units would cost more than one 130-ton unit, but that he didn't know how many units were involved in his proposal. *Id.* at pp. 1228, 1348

1217. When asked about how he calculated his cost estimate for the sulfur plant, O'Brien testified as follows:

> [W]e used the same procedure we used on all the other units. We assumed a large plant. In fact, we assumed a 200-ton-per-day plant and we said what does that cost? We said how much total capacity do we need, and we just took it as a ratio of what a 200 ton per day plant would cost.
>
> To make it very simple, if we assumed the cost of a 200 ton a day plant, if we needed 50 tons, we said the cost would be 50 over 200. So we said it would be 25 percent, in effect, of the cost of a 200 ton a day plant and capital, a capital charge.

Id. at p. 1229. Given an opportunity to explain why, taking economies of scale into consideration, a 50-ton per day sulfur plant would not cost more to construct than 25% of the cost of constructing a 200-ton per day sulfur plant, O'Brien failed. *Id.* at pp. 1229-35.

1218. Exxon suggests that 100% backup capacity is required. Exxon Initial Brief at p. 109. However, it submitted evidence that the "average utilization [percentage] for [sulfur plants on the West Coast is] approximately 50%," Exhibit No. EMT-37 at p. 44, which indicates that, on the average, the needed backup capacity is about 50%.[464] Moreover, Dickman, Exxon's witness, testified that, if you were operating a two unit sulfur plant, you would want each capable of processing the full load, but that, most appropriately, a refinery would have a three unit sulfur plant with each unit capable of processing 50% of

[464] *See also* Exhibit No. EMT-325 which reflects that, in the refineries operating in Washington State and California, the excess capacity is 54%.

the load. Transcript at pp. 4741-42. However, when asked about this configuration, Jenkins testified as follows:

> That's the way in practice most people do handle the particular problem. The data says that there is this 100 percent capacity, but if you were charged with the task of determining how am I going to handle my sulfur plants, you would go more likely for three 50s, *but three 50s cost more than two 100s.*

Id. at p. 3913 (emphasis supplied).

1219. The record clearly reflects that the backup sulfur processing capacity needed must be sufficient to allow the refinery and the Coker to keep operating should the primary sulfur plant have a malfunction. Were the backup capacity contained in the same unit as the primary capacity, and were that unit to fail, the refinery and the Coker both would have to shut down or operate subject to penalties. Exhibit No. EMT-116 at p. 15; Transcript at p. 1347. O'Brien could not state how many units were contained in his proposal and, yet, he testified that his proposal was based on a ratio of the cost of a 200-ton per day plant, and the tons per day which were needed to process the sulfur plant influent resulting from his conceptualized Coker design. This, despite the fact that he admitted that multiple units would cost more than one large unit and that smaller units would cost more than the ratio he proposes be used to estimate the cost of such a plant. In view of this, I must conclude that O'Brien's proposal for the cost of the sulfur processing facility needed by the Coker is not only impractical, but lacks verisimilitude.

1220. Exxon has proposed using two units, each capable of processing 100% of the influent. At first blush, I was ready to reject it in favor of using three units, each having the ability to process 50% of the influent. However, it appears undisputed that those three units would cost more than two units, each capable of processing 100% of the influent, as Jenkins proposed. I, therefore, hold that the cost of Exxon's proposal for two sulfur processing units be used.

(2) Downstream Hydrotreater

1221. Exxon states that the parties agree that a downstream hydrotreater for the Coker was needed to "reduce the amount of sulfur and other impurities in the coker Naphtha, coker Distillate and coker VGO products in order to bring [them] up to the quality of the proxy products used by the Quality Bank." Exxon Initial Brief at pp. 114-15. To those three products, the Eight Parties add coker LSR. Eight Parties Initial Brief at pp. 95-96.

1222. According to Exxon, Jenkins "provided detailed cost calculations for each of the necessary hydrotreaters, . . . reduced those costs by appropriate 'quality credit[s],' . . . [and] credited the hydrotreaters with any economies of scale that a refinery might be expected to enjoy by building a larger hydrotreater integrated with other refinery operations." Exxon Initial Brief at p. 115. The Eight Parties state that O'Brien followed "standard industry practice," assuming efficiently sized process units which "would commonly be found in an existing and efficient West Coast coking refinery." Eight Parties Initial Brief at p. 96. They add that O'Brien then "assigned to the coking process" that portion of the costs of those units "attributable to treating" Coker products. *Id.*

1223. The Eight Parties find fault with Jenkins's methodology and with his estimate. They claim that no refiner would build the small units which are included in his estimate, citing O'Brien's Reply Testimony.[465] *Id.* at p. 97. Moreover, they claim that the operating conditions which Jenkins chose "produce products *that exceed* the applicable proxy product specifications." *Id.* (emphasis in original). The Eight Parties explain:

> In other words, Mr. Jenkins develops costs for producing *finished products* and not the Quality Bank intermediate products. Therefore, he has to "apply a 'credit' against the costs to reflect the fact that some of the Coker products are higher in quality than the virgin ANS cuts that are being valued in this estimate."

Id. at pp. 47-98 (emphasis in original).

1224. Exxon finds fault with O'Brien's approach which it claims has "no factual support." Exxon Initial Brief at p. 116. It argues that O'Brien conceded that, without a Coker, a refinery would have installed hydrotreaters which were sized only to treat Quality Bank products and that, if a Coker were later added, "the refinery would have to add additional hydrotreating capacity to process the coker products." *Id.* In support, Exxon cites to O'Brien's testimony during his cross-examination. There, O'Brien, though agreeing with Exxon's supposition, added:

> That would be true if we were building and constructing a refinery in our analysis. What we're looking at is what are the economic sized units

[465] O'Brien states:

> [Jenkins] assumes a distillate hydrotreater with a capacity of 8,300 barrels/day, compared to the 50,000 barrels/day that I assumes. This is an unrealistic assumption, and at his deposition, Mr. Jenkins was unable to identify any refiner that has ever constructed a hydrotreater limited to the size necessary to treat the coker products. Refiners instead typically build larger units that enjoy economies of scale.

Exhibit No. PAI-42 at p. 25.

> that refiners run their materials through because those are the units that establish the product prices in the marketplace, so your analysis is not what ends up flowing through and establishing the product prices. What established those product prices is what are the economically sized units that are available at refineries.

Transcript at p. 430. Further, O'Brien denies that he was "building a coker and adding it to a refinery and expanding all the downstream units." *Id.* at p. 432. Instead, he claimed that he was "using . . . the construction of an addition of a coker to a refinery to try to get a reasonable estimate of what the costs would be," but added that he was not "going through a complete material balance on the refinery." *Id.* According to O'Brien, the hydrotreater he conceived sets the marketplace value of the product irrespective of whether Coker or virgin product were run through it. *Id.*

1225. Despite the differences in the methodology followed by Jenkins and O'Brien, Exxon submits that the dollar difference between their results is "pretty close," less than $5 million. Exxon Initial Brief at pp. 117-18. The Eight Parties, on the other hand, suggest that the difference between the two estimates is closer to $27 million. Eight Parties Initial Brief at pp. 98-99. Exxon claims that the Eight Parties err in this regard because they omitted "Jenkins' economies of scale adjustments and the product credits." Exxon Reply Brief at p. 121. It adds that "much of the remaining difference is explained by Mr. O'Brien's failure to account for higher costs on the West Coast." *Id.*

1226. Once again, I am forced to choose between Jenkins's itemized estimate and O'Brien's cost curve based estimate. And once again, I am going to choose O'Brien's approach. I believe, based on a review of the record, that O'Brien's approach is reasonable, establishes a sufficient value for the hydrotreaters taking into consideration what is being attempted here, and is more simple to apply.

1227. I am not satisfied that Jenkins's approach is sufficiently objective to provide us with the appropriate result. Moreover, it is clear that Jenkins's proposal would, as the Eight Parties note, Eight Parties Initial Brief at p. 97 (emphasis in original), "produce products *that exceed* the applicable proxy product specifications," and I am not satisfied that the final result he reached accurately takes this anomaly into consideration. Furthermore, though I might agree with Exxon that Jenkins's estimate and O'Brien estimate are "pretty close," I cannot find that Jenkins's estimate is more reasonable than O'Brien's.

(3) Finance Cost

1228. O'Brien's approach was, as noted by the Eight Parties, "simple." Eight Parties Initial Brief at p. 100. He assumed a "simple five-year payback following commencement of operations, which is equivalent to a 20% capital recovery factor."

Exhibit No. PAI-1 at p. 24. O'Brien added that his "experience indicates that this is the type of financial return that refiners will typically require for projects of this kind, and that it is a reasonable approach for use in the Resid coker feedstock valuation calculation." *Id.*

1229. Under cross-examination, Exxon witness Baumol testified that a 20% payback was "simple and wrong." Transcript at p. 3620. While he refused to say he wouldn't use it, he did add that he wouldn't use it without knowing that he was "using a convention like straight line depreciation, which is a lie but may be a very acceptable lie." *Id.*

1230. Jenkins, based on advice from Toof,[466] used a 17% capital recovery factor. Exxon Initial Brief at p. 118; Exhibit No. EMT-37 at p. 22. He also used an "owner's cost" of 10%.[467] Exxon Initial Brief at p. 118; Exhibit No. EMT-37 at p. 52. Lastly, according to Exxon, Jenkins used "an 'interest during construction' ('IDC') factor of 4.3% based on a three-year construction schedule, a debt ratio of 35%, and an interest rate of 7.85%." Exxon Initial Brief at p. 119; Exhibit No. EMT-37 at p. 53. Exxon notes that, all of these calculations, however, results in a capital recovery factor of 19.5%, only slightly lower than O'Brien's 20%. Exxon Initial Brief at p. 120.

1231. Inasmuch as, based on the evidence and Exxon's admissions, the difference between the two proposals is de minimus and because O'Brien's 20% payback factor is simple and straight forward with no chance for subjective manipulation, I conclude that it should be applied.

3. Location Factor

1232. Exxon characterizes its use of a West Coast location factor and the Eight Parties non-use as a "major difference" between them. Exxon Initial Brief at p. 121. According to Exxon, its witness, Jenkins, calculated the cost of constructing and operating a Gulf Coast Coker and "then used appropriate location factors to reflect the higher costs that

[466] Toof's testimony, Exhibit No. EMT-1 at pp. 18-19, in this regard is summarized by Exxon as follows: "This 17% return was derived by Dr. Toof based on an expected 25-year useful life and a resulting 4% rate of depreciation, a capital structure of 35% debt and 65% equity, a 7.85% cost of debt, and a 15.78% pre-tax cost of equity." Exxon Initial Brief at p. 118.

[467] Jenkins testified that, based on documents, *see* Exhibit No. EMT-58, he determined that the range of owner's costs were from 9%-17%, but that based on discussions with refiners, he believed that "recent projects that were financed with general corporate funds incurred owner's costs in the range of 10%." Exhibit No. EMT-37 at p. 52.

would be incurred in constructing and operating such" a Coker on the West Coast. *Id.* It notes, too, that the parties have agreed that West Coast Resid should be valued on the basis of West Coast prices. *Id.* at p. 122. Exxon also claims that O'Brien agrees that the Coker's location can influence its construction and operating costs.[468] *Id.* It submits that, because of this, a West Coast location factor must be used to estimate West Coast costs. *Id.* Moreover, Exxon claims that there is no dispute that West Coast costs are higher than those on the Gulf Coast,[469] and that use of a location factor is "an appropriate and well-established industry practice." *Id.* at p. 123.

1233. The Eight Parties define a location factor as

> an adjustment . . . used to translate a construction cost estimate developed for a specific project in a specific location (usually the U.S. Gulf Coast) to obtain a cost estimate for the same project in different parts of the county under the assumption that the cost to build a similar facility will vary depending on where it is located.

Eight Parties Initial Brief at p. 105. They support O'Brien's assertion that it is inappropriate to use a location factor when the specific location is unknown.[470] *Id.* at pp. 105-6. The Eight Parties further argue that location factors are "highly subjective," and that they differ depending on who does them. *Id.* at p. 109. They further suggest that, should a location factor be used, it should be no higher than 1.16. *Id.* at pp. 113-15.

1234. The parties appear to agree that West Coast Resid should be valued on a West Coast basis. The evidence clearly establishes, and the parties also seem to agree, that prices on the West Coast, generally, tend to be higher than those on the Gulf Coast. Yet, despite the evidence and these agreements, the Eight Parties and their witness, O'Brien,

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[468] During cross-examination, O'Brien stated that he "would say that [plant location] can have a significant influence" on plant cost. Transcript at p. 243.

[469] O'Brien, under cross-examination, when asked whether West Coast prices are higher than those on the Gulf Coast, testified that, while it isn't universally true, "generally, they will tend to be higher." Transcript at pp. 231, 1241.

[470] O'Brien stated that "[u]ntil a specific refinery project is completely defined, there are too many factors that can impact the ultimate costs – up or down." Exhibit No. PAI-1 at p. 22. He also stated that, though he acknowledged that West Coast costs can be higher, he still believed that use of his generic cost curve is appropriate without using a West Coast adjustment. Exhibit No. PAI-58 at p. 29. However, O'Brien did agree that were the Coker built in Los Angeles, it was going to cost more, although he wasn't sure how much more. Transcript at pp. 1243-44.

assert that the cost of this facility should be determined on the basis of his generic cost curve without taking into consideration the higher West Coast costs because O'Brien's conceptualized refinery with the added Coker has not been located at a specific geographical location. I cannot accept their reasoning which I find to be illogical. Once you accept the fact that West Coast costs are generally higher than those on the Gulf Coast, it follows that, at least, a generic West Coast location factor should be used.

1235. I do agree with the Eight Parties that the location factor used should not be based on the cost of building and operating a Los Angeles refinery/Coker. Since the refinery/Coker is located on the West Coast without being focused on a specific geographical site, the location factor should be generic to that Coast.

1236. Jenkins testified that he applied a range of location factors (from 1.26 to 1.3) to various components in his itemized cost estimate. Exhibit No. EMT-37 at p. 27.[471] However, since his methodology has been rejected in favor of O'Brien's cost curve based approach there is no need to consider the entirety of his testimony in this regard. In its Reply Brief, Exxon indicates it would use 1.3 as the "generic" location factor. Exxon Reply Brief at pp. 137-39.

1237. The Eight Parties challenged Exxon's proposed 1.3 location factor as excessive. Eight Parties Initial Brief at p. 113. It suggests that the location factor should be no more than 1.16. *Id.* at p. 115. Exxon admits that the 1.3 location factor represents that at a California refinery. On brief it suggests that the parties "assumed that the refinery would be located in the Los Angeles area." Exxon Initial Brief at p. 125. However, its contention is not supported by the record cites it provides. There is nothing in the October 3, 2002, "Joint Stipulation of the Parties," or in the cited portion of O'Brien's testimony[472] which would lead to such a conclusion. Indeed, the record as a whole clearly indicates that the refinery was to be located "somewhere" on the West Coast without reference to Los Angeles or any other specific portion thereof.

1238. Exhibit No. EMT-208 contains a list of location factors for many refineries including the 27 on the West Coast.[473] The average location factor for these 27 refineries

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[471] *See also* Transcript at pp. 3924-25.

[472] Exxon references the Transcript at pp. 206 and 753. Exxon Initial Brief at p. 125.

[473] BP Amoco (Carson City, CA), Chevron (El Segundo, CA), Chevron (Richmond, CA), Edgington (Long Beach, CA), Equilon (Martinez, CA), Equilon (Wilmington, CA), ExxonMobil (Torrance, CA), Greka (Santa Maria, CA), Lundy (South Gate, CA), Paramount (Downy, CA), Phillips (St. Maria/San Francisco, CA), Phillips (Wilmington, CA), Ten By (Oxnard, CA), UDS (Martinez, CA), UDS (Wilmington, CA),

is about 1.27. Were one to just focus on the 3 different location factors,[474] the average would be 1.21. And were one to give equal weight to the average of the three states (California, Washington and Oregon), the average would be 1.24.

1239. Gary testified that Los Angeles had a location factor of 1.4 and that Portland and Seattle had location factors of 1.2. Exhibit Nos. EMT-116 at p. 7, EMT-169 at p. 6. The simple average of these three locations is about 1.27. For the same three locations, R.S. Means provides location factors of 1.24 (Los Angeles, 1.22 (Portland) and 1.19 (Seattle) for a simple average of about 1.22. Exhibit No. WAP-80 at p. 1. The PRISM simple average for these same three locations (Los Angeles-1.35, Portland-1.08, and Seattle-1.08) is 1.17. *Id.*

1240. Of all of the various mathematical suppositions put forth by the parties, the most logical one is an average of the location factors at all 27 refineries located on the West Coast. Therefore, I conclude that the appropriate location factor is 1.27.

4. Operating Costs

a. Fixed Operating Costs

1241. According to the Eight Parties, O'Brien's and Jenkins's estimates for fixed operating costs vary on the Gulf Coast by 22¢/barrel and on the West Coast by 47¢/barrel, all in Year 2000 dollars.[475] Eight Parties Initial Brief at p. 115. While the parties agree that much of the difference is caused by the difference in their capital costs since most of the fixed cost estimates are a percentage of the ISBL costs or total capital costs.[476] *Id.* at p. 116; Exxon Initial Brief at p. 130; Exxon Reply Brief at p. 140. Since

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Valero (Benecia, CA), Valero/Huntway (Wilmington, CA), Equilon (Bakersfield, CA), Kern (Bakersfield, CA), San Joaquin (Bakersfield, CA), Tricor Refining (Oildale, CA), BPAmoco (Cherry Point, WA), Chevron (Portland, OR), Equilon (Anacortes, WA), Phillips (Ferndale, WA), Tesoro (Anacortes, WA), and U.S. Oil (Tacoma, WA).

[474] 13 of the California refineries had a location factor of 1.35, the remaining four had a location factor of 1.20, and the refineries in Oregon and Washington had a location factor of 1.08.

[475] Exxon states that Jenkins estimated fixed costs of $1.18/barrel on the Gulf Coast (erroneously stated as $1.19 in Exxon's brief) and $1.43/barrel on the West Coast, while O'Brien estimated the fixed costs to be 96¢/barrel on each coast. Exxon Initial Brief at pp. 129-30.

[476] *See* Exhibit Nos. EMT-37, EMT-64, PAI-11, PAI-42

the parties have not placed these percentages into dispute, there is no need to discuss them.

1242. The parties have raised four matters for discussion: the number of operators, the inclusion of a foreman, the labor multipliers used in estimating labor costs, and the operators for downstream hydrotreating units. Eight Parties Initial Brief at p. 116; Eight Parties Reply Brief at pp. 100-01; Exxon Initial Brief at p. 132.

(1) Number of Operators

1243. O'Brien assumed that the Coker could be operated with six operators per shift (25.2 in total),[477] while Jenkins assumed that nine operators per shift would be required (38 in total).[478] Eight Parties Initial Brief at p. 116; Eight Parties Reply Brief at pp. 101-02. The Eight Parties concede that some of the difference is related to the number of drums assumed in the parties's proposals, and that a four-drum Coker would require more personnel than a two-drum Coker. Eight Parties Initial Brief at p. 116. As I have already decided that a four-drum Coker is required, it is clear that even the Eight Parties would agree that more than six operators per shift would be required. The Eight Parties, however, did not indicate how many more than six operators would be required under a four-drum scenario. I am compelled, therefore, to accept Jenkins's estimate of nine

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[477] At the hearing, under cross-examination, O'Brien had great difficulty in testifying as to the number of operators he proposed using. *See* Transcript at pp. 1336-42. When asked how many operators he included, O'Brien first said "18," and then "20." While the Eight Parties failed to refer to his later clarification in their Initial Brief, on reply, they noted that O'Brien stated:

> Where I was going wrong in my calculation of that is we covered the clock completely. Seven days a week, we included all the hours seven days a week, 52 weeks a year, the whole 365 days. In any one week, you have 24 hours in a day, 7 days in a week. You have to cover 168 hours. Any worker only works 40 hours of that, so if we divide 40 into that, that's the 4.2.
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> In effect, you can say that's the number of shifts, not the three shifts that I testified to. It's actually 4.2 shifts. . . . I was not calculating the number correctly when I was talking about it.

Id. at p. 1354. He then indicated that the number of operators required was 4.2 times six, or 25.2. *Id.*

[478] *See* Exhibit No. PAI-42 at p. 28.

operators per shift, which I find to be supported by substantial record evidence.[479]

(2) Inclusion of a Foreman

1244. Exxon submits that, to coke 40,000 barrels/day of ANS Resid, a refinery adding a Coker also would have to add, besides the Coker, three downstream hydrotreaters, a sulfur plant and an unsaturated gas plant.[480] Exxon Reply Brief at p. 142. Jenkins assumed that, were a refinery to add all of this equipment, an additional foreman would be required to supervise its operation.[481] *Id.* O'Brien assumed that the already existing supervisory staff is all that would be necessary.[482] Eight Parties Initial Brief at p. 117.

1245. The evidence here represents the differing opinions of experts. After listening to the witnesses and examining the documentary evidence, I am satisfied that Jenkins's view is the better one. Therefore, I hold that the fixed cost estimate should include the cost of an additional supervisor.

(3) Labor Multipliers

1246. According to the Eight Parties, O'Brien "used a 45% labor multiplier to increase the direct cost of the coker operators to account for benefits, overtime and other labor related costs."[483] Eight Parties Initial Brief at p. 118. Exxon states that Jenkins used "three labor multipliers: a 45% multiplier to cover 'Operating Overhead;' a 15% multiplier to cover 'Offsite Labor;' and a 20% multiplier to cover 'Administrative Labor.'"[484] Exxon Reply Brief at p. 143. It adds that his calculations are based on the

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[479] *See, e.g.*, Exhibit Nos. EMT-146 at pp. 47-48, EMT-167 at p. 19.

[480] *See* Exhibit No. EMT-62.

[481] Jenkins stated: "It is simply not reasonable to assume that the management team needed to operate Mr. O'Brien's Base Refinery would be the same as the management team that would be needed to run a more complex refinery that includes a Coker and the associated downstream processing units." Exhibit No. EMT-146 at pp. 47-48.

[482] O'Brien stated: "A refinery would not assign a foreman to oversee the operations of just the coking facilities, but instead would use a foreman with responsibilities over other parts of the refinery as well." Exhibit No. PAI-42 at p. 28.

[483] *See* Exhibit No. PAI-11.

[484] *See* Exhibit Nos. EMT-64, EMT-292.

"Pace Refinery Cost Model."[485] *Id.*

1247. I find that Jenkins's proposal is not supported by evidence in the record. Moreover, I find it to be overly complicated for the purposes for which it is being used and that it may include, as the Eight Parties suggest,[486] a "hidden multiplier." In view of this, I adopt O'Brien's 45% labor multiplier which I find to be supported by the record, and reasonable for the purposes for which it is used.

(4) Downstream Hydrotreating Units

1248. Exxon alleges that O'Brien failed to include, in his fixed cost estimate, the cost of operators for the downstream hydrotreaters. Exxon Initial Brief at p. 132. The Eight Parties, in reply, claim that O'Brien did include those costs.[487] Eight Parties Reply Brief at p. 101. They add, citing Exhibit No. EMT-231, that he "did not allocate any of the labor costs for these units to Resid because there would be the same number of operators for the hydrotreaters whether or not the hydrotreaters processed products from the coking process." Eight Parties Reply Brief at p. 101. A review of the exhibits to which the Eight Parties cite in support of their claim that O'Brien included the labor costs related to the hydrotreaters reflects that the hydrotreaters to which he referred were those in the refinery before the addition of the Coker. Therefore, I conclude that O'Brien did not include any *extra labor costs* for the operators required to operate the three additional hydrotreaters which will be necessary to support the added Coker.[488] Moreover, Jenkins clearly stated in his testimony that "hydrotreaters . . . are operator driven" and that he could not find any place where O'Brien included an "allocation or cost for operators in the hydrotreaters." Transcript at p. 3697.

1249. At a minimum, even if he included the full costs of all of the hydrotreaters which a refinery would need were a Coker added to it in his Coker cost estimate, O'Brien should have included the pro-rated costs of the operators of the hydrotreaters to account for the Resid being processed. But he did not. In any event, as noted above, I cannot conclude that he included any costs related to these hydrotreaters. Consequently, I hold, based on the evidence in the record, that Jenkins's proposal to add additional costs for these operators should be included in the project's fixed costs.

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485 *See* Exhibit No. WAP-78.

486 Eight Parties Initial Brief at pp. 119-20.

487 The Eight Parties cite Exhibit Nos. PAI-1 at p. 25, PAI-14, PAI-15, and PAI-16.

488 *See* Exhibit No. EMT-62.

b. Variable Operating Costs

1250. Exxon defines the Coker's variable operating costs as "the costs of fuel, electricity, steam, water, hydrogen catalysts and chemicals that are used in the process of coking and treating the Resid to meet the quality standards of the Quality Bank proxy products."[489] Exxon Initial Brief at p. 132. Jenkins once again presented an itemized list of estimated costs for the Coker and related downstream processing units.[490] *Id.* at p. 133. According to Jenkins, his estimate is that the variable costs are 92¢/barrel on the Gulf Coast and 90¢/barrel on the West Coast in Year 2000 dollars. Exhibit No. EMT-146 at p. 7. In comparison, O'Brien estimates the cost as being 85¢/barrel in Year 2000 dollars. Exhibit No. PAI-96 at p. 2.

1251. O'Brien testified that his estimates are based, in part, on the PIMS model and the Baker & O'Brien database. Transcript at pp. 658-60. When asked why, he replied:

> Because the PIMS model is used to establish the yields, and the PIMS model also provides operating costs for these units, for the coker unit, and we looked at them and they seemed to be reasonable, not much different from what we would use typically, so we decided to stick with the PIMS.

Id. at p. 658. O'Brien indicated further that the PIMS model did not have fixed operating costs, nor did it have capital costs. *Id.* at pp. 658-59. He also testified that the unit values he used for the Coker were based on the Jacobs Consultancy database while PIMS was used for the downstream units. *Id.* at pp. 660-61.

1252. Jenkins's estimates are based on the Jacobs Consulting database.[491] Exhibit No. EMT-37 at p. 61. Exxon argues that the difference between his estimates and that of O'Brien results from O'Brien's failure to include variable operating costs for the Coker gas plant, his failure to include energy costs for the amine unit "a key part of the sulfur recovery system," and his failure to include the costs of chemicals used in processing the Resid.[492] Exxon Initial Brief at p. 133. The Eight Parties submit, on the other hand, that

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[489] *See* Exhibit Nos. EMT-65, EMT-293.

[490] *See* Exhibit Nos. EMT-37 at p. 61, EMT-65, EMT-293.

[491] Exxon claims, Exxon Reply Brief at pp. 144-45, that Jenkins's variable cost estimate were not challenged by any party, but that claim is a non sequitur. It is clear that the Eight Parties do not agree with Jenkins or Exxon as to his variable cost estimate.

[492] Exxon cites Exhibit No. EMT-146 at p. 49 and Transcript at pp. 450-51, 3697-98, in support. Exxon Initial Brief at pp. 133-34.

the difference between the Jenkins estimate and that of O'Brien "result[s] from differences in how the capital cost calculation are performed." Eight Parties Reply Brief at p. 103.

1253. Irrespective of how the differences between Jenkins and O'Brien resulted, it is clear to me that the difference is not significant, only 5-7¢/barrel. Moreover, I am satisfied with neither approach. Jenkins's methodology is too complicated and too subjective, and I am not satisfied that there was any good reason for O'Brien to use the PIMS model for a portion of the variable costs and the Jacobs Consultancy database for others.[493] The PIMS model is a third party database which is not subject to any party's subjectivity or manipulation. Therefore, I hold that, based on the evidence in the record, the PIMS model should be used for all of the variable costs in order to provide a just and reasonable result for all parties.

5. Base Year

1254. O'Brien calculated his costs on the basis of Year 1996 dollars.[494] Eight Parties Initial Brief at p. 123. Jenkins calculated his costs on the basis of Year 2000 dollars.[495] Exxon Initial Brief at p. 134. At first blush, considering that, whichever year is used, adjustments can be made using the Nelson Farrar indices, it shouldn't matter which base year is used.[496] The Eight Parties note that a possible problem with that theory is that certain equipment may be used in Year 2000 which wasn't available in Year 1996. Eight Parties Initial Brief at p. 124. They suggest ignoring this question in order to simplify matters. *Id.*

1255. Exxon raises another matter:

> [A] problem arises because there are two Nelson Farrar indices applicable to different types of costs – (1) the Nelson Farrar Refinery Construction Cost Index (sometimes referred to as the Nelson Farrar capital cost index),

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[493] While O'Brien explained why he used the PIMS model for some of his variable cost estimates, he never explained why he used the Baker & O'Brien database for the others. Transcript at pp. 660-61. Indeed, he stated that he "felt it was appropriate to stay with PIMS because they have operating costs that say for that yield, use these operating costs." *Id.* at p. 661.

[494] *See* Exhibit No. PAI-1 at pp. 19-20.

[495] *See, e.g.,* Exhibit No. EMT-37 at pp. 24-25, 33, 40, 46, 52, 54.

[496] Exxon Initial Brief at p. 134.

> and (2) the Nelson Farrar Refinery Operating Cost Index – which produce different results depending on how they are applied and which base year is used.

Exxon Initial Brief at p. 134. Stated differently, Exxon, citing Bartholomew's testimony,[497] claims the problem is that the Nelson Farrar Construction Cost Index "has risen relatively steadily over time, [while] the Nelson Farrar operating cost index has gone up and down from year to year." *Id.* at p. 136.

1256. Despite Exxon's assertion, in the cited transcript page, Bartholemew was not asked, nor did he testify, about the Nelson Farrar Construction Cost Index. Rather, he was asked about the Nelson Farrar Operating Cost Index for the period January 1992 through December 2001, and stated: "It actually shows a perfectly flat number. It shows some costs going up – the index goes up during some periods and goes back down. If you were to take a look at 1992 versus 2000, I think the indices are almost identical." Transcript at p. 2252. As Exxon's assertion on brief is solely supported by testimony, which is limited in time and limited to the Nelson Farrar Operating Cost Index, I find that its assertion is not supported by any record evidence. Thus, I find that only the Nelson Farrar Operating Cost Index should be used.

1257. Alternatively, Exxon suggests that Year 2000 should be established as the base year as "it would at least reduce the impact . . . by bringing all of the capital costs forward to 2000 by using the correct Nelson Farrar construction cost index." Exxon Initial Brief at p. 137.

1258. Based on the record, and taking the parties's arguments on brief into consideration, I find that the base year should be Year 2000 and that the existence or non-existence of certain equipment should not be considered in making any calculations.

ISSUE NO. 2: WHAT IS THE LEVEL OF ADJUSTMENT NECESSARY TO BRING THE HEAVY DISTILLATE CUT INTO LINE WITH THE SPECIFICATIONS FOR PLATT'S WEST COAST LA PIPELINE LOW SULFUR NO. 2? WHAT SHOULD BE THE EFFECTIVE DATE OF THE CHANGE IN THE HEAVY CUT DISTILLATE CUT PRICE

A. LEGAL STANDARDS AND BURDENS OF PROOF

1259. According to the Eight Parties, the issue related to the Heavy Distillate cut arises as a result of a November 24, 1999, Quality Bank Administrator Notice that explained

[497] Transcript at p. 2252.

that there had been a change in the Platts reporting of the reference price that was used to value the Heavy Distillate cut.[498] Eight Parties Initial Brief at p. 131. Previously, according to the Eight Parties, the Quality Bank used Platts West Coast High Sulfur (0.5%) Waterborne Gasoil assessment.[499] *Id.* Platt's discontinued that assessment, the Eight Parties state, and began a new assessment for West Coast Los Angeles Waterborne Low Sulfur No. 2, which has a sulfur content of 0.05%.[500] *Id.* The Quality Bank Administrator requested guidance from the Commission on what should be the appropriate replacement reference price.[501] *Id.*

1260. All parties agreed, according to the Eight Parties, that the correct Heavy Distillate price should be based on the Platts West Coast Los Angeles Pipeline Low Sulfur No. 2 reference price, but the parties disagreed over the proper adjustments needed to make that price appropriate for use in the TAPS Quality Bank. *Id.* at pp. 131-32. Furthermore, the Eight Parties contend that, because the dispute results from a notice of the Quality Bank Administrator related to the discontinuation of a reference price and the appropriate replacement reference price, and not from a protest or complaint, the burden of proof lies equally with the Eight Parties and Exxon to demonstrate that their proposed adjustments to the West Coast Los Angeles Pipeline No. 2 price are needed to make the use of that reference price and adjustments a just and reasonable approach for valuing West Coast Heavy Distillate. *Id.* at p. 132.

1261. The Eight Parties also note that all parties stipulate that the effective date for the change in the West Coast Heavy Distillate cut price should be February 1, 2000.[502] *Id.* at pp. 132-33. They view the disagreement as primarily one over the cost of desulfurization and the appropriate methodology to employ for identifying those costs. *Id.* at p. 133. In addition, the Eight Parties assert, the parties disagree over whether a logistics adjustment is necessary to put the West Coast Los Angeles Pipeline No. 2 price onto a waterborne basis consistent with other similar Quality Bank reference prices. *Id.*

1262. In Exxon's view, the sole valuation question presented by Issue No. 2 is "the level

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[498] *Trans Alaska Pipeline System*, 90 FERC ¶ 61,123, at p. 61,370 (2000).

[499] *Id.*

[500] *Id.*

[501] *Id.* at p. 61,371.

[502] The Eight Parties explain that this date is the date the change would have taken place under the Quality Bank tariff had a new price been implemented in accordance with the terms of the tariff. Eight Parties Initial Brief at p. 133.

of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the [new West Coast reference] price," which all parties have agreed will be the Platts West Coast Los Angeles Pipeline Low Sulfur (0.05 wt%) No. 2 Fuel Oil price. Exxon Initial Brief at p. 143**.**

1263. The "logistics adjustment" proposed by the Eight Parties is opposed by Exxon because, Exxon claims, it (1) is not a "sulfur processing adjustment" within the scope of the Commission's order setting the West Coast Heavy Distillate valuation for hearing, and is thus outside the scope of this proceeding, and (2) has not been justified, is not supported by substantial evidence, and is premised on numerous false assumptions. *Id.* at pp. 143-44.

1264. This issue arises, according to Exxon, because Platts, effective November 1, 1999, discontinued reporting prices for West Coast High Sulfur (0.5 wt%) Waterborne Gasoil. *Id.* at p. 144. Exxon states that the Commission had previously designated that product as the West Coast reference price for the Quality Bank Heavy Distillate cut, subject to a reduction of 1¢/gallon to reflect the cost of reducing the sulfur level of the Quality Bank Heavy Distillate cut (which has a sulfur content of 0.57 wt%) to the lower sulfur level (0.50 wt%) on which the reference price was based. *Id.* The only disagreement, according to it, related to "the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the [new proxy] price." *Id.* In particular, it states, the Eight Parties initially proposed that the sulfur processing adjustment to the new proxy price should be 6¢/gallon, while Exxon proposed that the sulfur processing adjustment should be 3.5¢/gallon. *Id* at pp. 144-45.

1265. In response to these conflicting proposals regarding the magnitude of the costs required to desulfurize the Quality Bank Heavy Distillate cut from 0.57 wt% sulfur down to the much lower 0.05 wt% sulfur content of the new West Coast reference products, Exxon points out that the Commission issued an order on February 9, 2000, in which it "accept[ed]" the Platts Los Angeles Pipeline Low Sulfur No. 2 Oil price as the new West Coast reference price for the Heavy Distillate cut and referred the issue of the "appropriate [sulfur] processing cost adjustment" to a settlement judge.[503] *Id.* at p. 145. Similarly, in its subsequent order establishing this consolidated hearing, Exxon's position is that the Commission set for hearing and resolution only the issue of "the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the [new proxy] price."[504] *Id.*

1266. Until such time as the new sulfur processing cost adjustment is finally resolved,

[503] *Trans Alaska Pipeline System*, 90 FERC at pp. 61,370, 61,372.

[504] *Trans Alaska Pipeline System*, 97 FERC ¶ 61,150, at pp. 61,650, 61,652 (2001).

Exxon contends, the Commission, in accordance with Section III.G.5 of the TAPS tariff, ordered the Quality Bank Administrator to continue to determine the West Coast value of the Heavy Distillate cut on the basis of the frozen October 1999 Platts West Coast High Sulfur (0.5 wt%) Waterborne Gasoil price reduced by 1¢/gallon. *Id.* at p. 146. However, Exxon also points out that the Commission observed, in the same order, that the TAPS tariff provision requiring continuation of the prior price "obviously contemplated only a short period when that price would remain in effect," because the Commission was required to act within 60 days of the notice by the Quality Bank Administrator.[505] *Id.* Further, Exxon notes that, because the final decision on the new West Coast sulfur processing cost adjustment was not likely to be issued until a longer period of time had elapsed, the Commission further directed that the issue of whether the new price "should be applied on a retroactive basis" should also be addressed in the consolidated proceedings.[506] *Id.*

1267. In resolving the dispute between the parties over the valuation of the Heavy Distillate cut on the West Coast, Exxon maintains, the Commission has an obligation to reach a just and reasonable resolution of the issues on the basis of all the evidence in the record. *Id.* While it agrees that the Commission may take into consideration its resolution of similar issues pertaining to other Quality Bank cuts, Exxon interprets the Commission's decision as meaning that the Commission cannot base its decision simply on some global view of what might be a reasonable overall result. *Id.* at p. 147. Exxon also argues that there is case law that should be interpreted to mean the Commission should not be influenced either by the fact that a position presented by a group of parties may be supported by a larger number of parties or by the fact that a position presented by a group of parties may itself be the product of a compromise among those parties. *Id.*

1268. As to the sulfur processing cost adjustment, Exxon's position is that each party has the burden of supporting its own position. *Id.* Exxon cites 5 U.S.C. § 556(d) as support for this position. *Id.* The additional "logistics adjustment" proposed by the Eight Parties is not, in Exxon's view, a "sulfur processing adjustment" within the scope of the Commission's order setting the West Coast Heavy Distillate valuation for hearing, and is thus outside the scope of this proceeding. *Id.* at pp. 147-48. However, to the extent that the Commission nevertheless considers that the adjustment proposed by the Eight Parties is appropriate, Exxon maintains, the Eight Parties clearly have the burden of proving not only that this proposed additional adjustment is within the scope of the issues set for hearing in this proceeding, but also that the "logistical adjustment" they propose is necessary to achieve a just and reasonable valuation of West Coast Heavy Distillate for Quality Bank purposes and that the specific magnitude of the proposed adjustment is just

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[505] *Trans Alaska Pipeline System*, 90 FERC at p. 61,372.

[506] *Trans Alaska Pipeline System,* 90 FERC at p. 61,372.

and reasonable. *Id.* at p. 148.

B. STIPULATED MATTERS AND AREAS OF DISPUTE

1269. The parties have reached two stipulations related to the valuation of West Coast Heavy Distillate. Eight Parties Initial Brief at p. 132; Exxon Initial Brief at p. 151. First, they have agreed that the West Coast Heavy Distillate cut should be valued using the reported price for Platts West Coast Los Angeles Pipeline No. 2, minus certain deductions that are disputed. Eight Parties Initial Brief at p. 132. Second, they have agreed that the effective date for the implementation of the change in the West Coast Heavy Distillate cut price should be February 1, 2000, which is the date that the change would have taken place under the Quality Bank tariff had a new price been implemented in accordance with the tariff's terms. *Id.* at pp. 132-33.

1270. Both parties also agree that the deductions should include the cost of desulfurizing the ANS Heavy Distillate (which has a sulfur content of 0.57%) to meet the much lower 0.05% sulfur specification of the agreed-upon reference price. *Id.* at p. 133; Exxon Initial Brief at pp. 148-49. However, although the parties agree that there should be some deduction, they disagree about the cost of desulfurization and the appropriate methodology to employ for identifying those costs.[507] Eight Parties Initial Brief at p. 133; Exxon Initial Brief at p. 149.

1271. Additionally, Exxon states that the parties disagree on whether there should be an additional logistics adjustment to put the West Coast Los Angeles Pipeline No. 2 price onto a waterborne basis consistent with other similar Quality Bank reference prices. Exxon Initial Brief at p. 150; Eight Parties Initial Brief at p. 133. The Eight Parties believe that a logistics adjustment is needed; Exxon does not. Eight Parties Initial Brief at p. 133. In addition, the parties disagree about the base year that should be used for computing the various adjustments. *Id.* The Eight Parties use a 1996 base year; while Exxon uses a 2000 base year. Eight Parties Initial Brief at p. 133; Exxon Initial Brief at p. 151. They do not believe that the base year issue should have any impact on the outcome of the Heavy Distillate issue. Eight Parties Initial Brief at p. 133.

1272. The proposed "logistics adjustment" (to be imposed in addition to the sulfur processing cost adjustment) is, in Exxon's view, ostensibly designed to place the agreed-upon Los Angeles pipeline reference price for Heavy Distillate on a West Coast waterborne basis. Exxon Initial Brief at p. 150. Exxon opposes this logistics adjustment on the grounds that it is outside the scope of this proceeding, not justified as being necessary to achieve consistency, not supported by substantial evidence, and not based on valid assumptions. *Id.* at pp. 150-51.

[507] *See* Joint Stipulation, filed October 3, 2002, at p. 3.

1273. Exxon contends that the amount of the sulfur processing cost adjustment should be \$1.821/barrel, or 4.3¢/gallon, stated in Year 2000 dollars. Exxon Initial Brief at p. 149. Exxon contrasts this with the Eight Parties's proposed sulfur processing cost adjustment of \$1.717/barrel, or 4.1¢/gallon, stated in 1996 dollars. *Id.* When the Eight Parties's sulfur processing costs are stated on a Year 2000 dollar basis using the appropriate Nelson Farrar indices, Exxon points out, it is very similar to its estimated cost. *Id.*

1274. Although similar in overall result, Exxon goes on to explain the two sulfur processing cost estimates differ because the Eight Parties used four "flawed" assumptions. *Id.* at p. 150. First, Exxon claims that the Eight Parties assumed that a more expensive, high-pressure hydrotreater would be required; whereas Exxon's cost figure assumed a medium-pressure hydrotreater. *Id.* Second, Exxon asserts, the Eight Parties did not include any allowance for the costs of storage associated with the processing of the ANS Heavy Distillate, which it argues is required. *Id.* Third, Exxon declares, the Eight Parties failed to use a West Coast location factor to account for the substantially higher West Coast capital and fixed operating costs, again, which it argues is required. *Id.* Fourth, Exxon argues, the Eight Parties overestimated the amount of hydrogen that would be consumed by the distillate hydrotreater in the desulfurization process. *Id.*

C. SULFUR PROCESSING COST ADJUSTMENTS

1. Capital Costs

1275. The Eight Parties claim that Exxon tries to mask its inconsistent approach between its Resid cost determination approach and its Heavy Distillate desulfurization approach by stating that "[O'Brien's] estimate is very similar to Jenkins's calculation," \$1.821/barrel for Jenkins, and \$1.80/barrel for O'Brien.[508] Eight Parties Reply Brief at p. 110 (quoting Exxon Initial Brief at p. 149). While the results may be similar, the Eight Parties note that O'Brien developed his ISBL costs in accordance with "typical" industry practice and consistent with his Resid cost calculations. *Id.* at pp. 110-11. The Eight Parties assert that the same cannot be said for Jenkins. *Id.* at p. 111.

[508] The Eight Parties suggest that O'Brien's proposed sulfur processing cost adjustment is actually \$1.717/barrel, or 4.1¢/gallon in 1996 dollars. Eight Parties Reply Brief at p. 110, n.50. Further, state the Eight Parties, Jenkins's proposed cost is 4.3¢/gallon. *Id.* (citing Exxon Initial Brief at p. 149). The Eight Parties assert that their adjustment is greater than 4.1¢ and 4.3¢ because it includes a logistics adjustment. *Id.*

a. Inside Battery Limits Costs

1276. For the Heavy Distillate component of the Quality Bank, according to the Eight Parties, "significant treatment cost must be incurred for hydrotreating of the Heavy Distillate cut to reduce the sulfur content from approximately 0.52% sulfur to the specified 0.05% sulfur" level of the product being used.[509] Eight Parties Initial Brief at p. 134. The Eight Parties argue that the difference of 0.2¢/gallon between the Exxon and Eight Parties's processing cost numbers is largely attributable to the difference in cost data that Exxon used to calculate its cost numbers. *Id.* They argue that if Exxon had used the same approach as it did when doing the Resid calculations its cost estimate for Heavy Distillate would have been considerably higher.[510] *Id.* In contrast with Exxon's approach, the Eight Parties maintain that their expert, O'Brien, used an approach to calculate costs that is consistent with the approach used in his Resid delayed coker and coker product hydrotreating processing. *Id.* The Eight Parties claim that he used what they characterize as the appropriate Baker & O'Brien cost curve to estimate the processing costs. *Id.*

1277. The Eight Parties assumed a 50,000 barrels/day high-pressure hydrotreater at an existing refinery as the basis for "estimating a reasonable allowance for recovery of capital investment." *Id.* at p. 135. O'Brien chose this size hydrotreater, according to the Eight Parties, because he believed it to be an economically sized unit that would be commonly installed at a large existing refinery. *Id.* The Eight Parties estimated the reasonable ISBL cost to be $49.5 million. *Id.* Exxon, through Jenkins, takes exception with O'Brien's use of a high-pressure distillate hydrotreater, asserting that a lower cost medium-pressure hydrotreater, which Jenkins uses, would be more appropriate. *Id.* That position does not represent what a typical refinery likely would do in this age of ever tightening sulfur limitations in diesel fuels, according to the Eight Parties.[511] *Id.* Jenkins

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509 *See* Exhibit No. PAI-1 at p. 41.

510 To bolster this argument, the Eight Parties submit that, had Exxon used the applicable cost curve from the Gary & Handwerk textbook as it did to calculate the sulfur recovery plant in the Resid cost estimate, the cost would have been $66 million, or 50% more than the $44.4 million cost that was used. Eight Parties Initial Brief at p. 134, n.78. This would have translated, according to the Eight Parties, into 5.55¢/gallon in Year 2000 dollars rather than the 4.34¢/gallon Exxon used. *Id.* The Eight Parties claim that Exxon's expert, Jenkins, acknowledged that Exxon would benefit from a lower processing cost for the Heavy Distillate component. *Id.*

511 The Eight Parties support this assertion by citing Exhibit No. WAP-102 at p. 2, "An Assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel," prepared by employees of the Charles River Associates, Inc., and Baker and O'Brien, Inc.:

acknowledged that "high pressure" in terms of a distillate hydrotreater includes 800 psi. *Id.*

1278. The Eight Parties view Jenkins's, Exxon's expert, use of the Jacobs Consultancy cost curve when determining the capital costs for the distillate hydrotreater for this valuation as an unwarranted inconsistency. *Id.* When asked why he used a cost curve, the Eight Parties state Jenkins answered that "it basically met the test" and that after reviewing the data "and rules of thumb in terms of dollars per barrel . . . [I] felt like it was quite reasonable." *Id.* at pp. 135-36.

1279. For this valuation, the Eight Parties point out that Exxon used the same size distillate hydrotreater as the Eight Parties. *Id.* at p. 136. This 50,000 barrels/day distillate hydrotreater designed to desulfurize the Heavy Distillate cut is larger, according to the Eight Parties, than the amount of Heavy Distillate that would be processed in a 200,000 barrels/day refinery running ANS crude oil. *Id.* ANS crude oil, according to the Eight Parties, contains only 18.45% of Heavy Distillate, or 36,900 barrels/day. *Id.* Thus, in this instance, the Eight Parties note, Exxon follows typical industry practice to construct efficient sized hydrotreaters and take advantage of the lower cost per unit of throughput. *Id.* By contrast, the Eight Parties note that, in valuing Resid, Exxon's Coker distillate hydrotreater was scaled down to handle only the Coker distillate output, resulting in approximately double the cost of a 50,000 barrels/day hydrotreater similar to that which O'Brien used. *Id.* Thus, in this instance, the Eight Parties point out, Jenkins managed to have his base hydrotreater cost less than O'Brien's, $44.4 million on the Gulf Coast in Year 2000 dollars,[512] compared to O'Brien's $49.5 million in Year 1996 dollars.[513] *Id.*

1280. The Eight Parties assert that Jenkins also used an entirely different approach to

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> We have assumed that all new grass roots units constructed since 1992, in response to the EPA's 500 ppm diesel regulation, employ pressures in the higher range. Many refiners determined that the incremental cost to build at least an 800 psi unit versus a lower pressure unit was small, and an 800 psi unit protected their investment in the event diesel regulations lowered sulfur in the future.

Eight Parties Initial Brief at p. 135. They go on to note that, since this study was published, the EPA has promulgated ultra low sulfur specifications for diesel that take effect in 2006. *See* 40 C.F.R. § 80.500, *et seq*. (2004).

[512] *See* Exhibit No. EMT-37 at p. 14.

[513] The Eight Parties note that Jenkins increases this base figure to a West Coast figure of $57.7 million by using a 1.3 location factor. Exhibit No. EMT-37 at p. 14.

develop his ISBL costs for calculating the adjustment to Platts Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil Price. Eight Parties Reply Brief at p. 111. They maintain that Jenkins's inconsistency conveniently squares with Exxon's economic interests and results in a low cost adjustment for the West Coast Heavy Distillate component and a high cost adjustment for the Resid component. *Id.*

1281. Exxon summarizes Jenkins's rationale for using a cost curve for the distillate hydrotreater, the Eight Parties note, by stating: "general cost curve data are reliable for relatively simple types of equipment, such as a distillate hydrotreater, for which the other available data are consistent and produce little variance or 'scatter.'" *Id.* (quoting Exxon Initial Brief at p. 153). According to the Eight Parties, it is not surprising that Exxon's only support for this proposition is what the Eight Parties characterize as Jenkins's self-serving testimony. *Id.* The Eight Parties assert that the record does not support Jenkins's characterization of a hydrotreater as simple. *Id.* They point out that the only evidence introduced into the record on that subject was a complexity table developed by Maples, and argue that a hydrotreater is more complex (2.19, according to the Maples scale) than a delayed coker (1.52) which Jenkins characterizes as "complex." *Id.* at pp. 111-12.

1282. According to the Eight Parties, even Jenkins's choice of cost curve is inconsistent when compared to the sulfur recovery plant in his Resid calculations. *Id.* at p. 112. They note that Jenkins elected to use the cost curve in the Gary & Handwerk textbook rather than his own company's cost curve for the Resid calculations, and that, by contrast, he elected to use his company's cost curve rather than the Gary & Handwerk cost curve for the Heavy Distillate calculations. *Id.* The result, according to the Eight Parties, is a distillate hydrotreater cost that is 50% higher (using Gary & Handwerk) than it would be if the Jacobs cost curves were used. *Id.* They note that this would have resulted in a cost adjustment larger than what the Eight Parties are recommending, including the necessary logistics adjustment.[514] *Id.*

1283. More significantly, in the Eight Parties's view, if Jenkins had derived his cost for the delayed coker using a method consistent with his approach for the distillate hydrotreater, using the Jacobs Consultancy's cost curve, his Delayed Coker ISBL cost would have been virtually the same as O'Brien's. *Id.* Instead of varying his approaches to calculating ISBL costs for different process units, as Jenkins did, the Eight Parties state that O'Brien used the same approach, the Baker & O'Brien cost curves, for calculating both the delayed coker and distillate hydrotreater ISBL costs. *Id.* at p. 113 (citing Exhibit No. PAI-1 at p. 42).

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[514] The Eight Parties assert that the Exxon cost adjustment would have been even larger had Jenkins used the proper high-pressure hydrotreater. Eight Parties Reply Brief at p. 112, n.51.

1284. The Eight Parties assert that the only similarity between Jenkins's and O'Brien's approaches is their use of the same efficiently sized (50,000 barrels/day) distillate hydrotreater. *Id.* They point out that Jenkins downsized the Coker distillate hydrotreater to 8,300 barrels/stream day, and explain that this almost doubled the processing cost per barrel of throughput for Jenkins's distillate hydrotreater costs related to the Resid component compared to the distillate hydrotreating costs related to the Heavy Distillate component. *Id.* at pp. 113-14. In contrast, state the Eight Parties, O'Brien used a 50,000 barrels/day distillate hydrotreater in both instances. *Id.* at p. 114.

1285. Neither Jenkins nor Dickman, the Eight Parties argue, provide any support for their use of a less costly medium-pressure hydrotreater to desulfurize Heavy Distillate. *Id.* They point out, however, that in Jenkins's pre-filed testimony he stated that "because the Coker products contain significantly more contaminants than the virgin ANS cuts, it might be necessary to install higher-pressure units to process both the virgin material and the coker products, which in turn would result in higher capital costs for those units." *Id.* (citing Exhibit No. EMT-37 at p. 55.)

1286. Exxon frames the dispute between the parties over the ISBL capital costs as relating to whether a high-pressure distillate hydrotreater would be required or whether a lower cost, medium-pressure hydrotreater would be sufficient to reduce the sulfur level of the ANS Heavy Distillate from 0.57 wt% to the much lower 0.05 wt% sulfur level on which the agreed-upon Platts Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil reference price is based. Exxon Initial Brief at p. 151.

1287. In its cost study for the distillate hydrotreater, Exxon concluded that a medium-pressure hydrotreater would be sufficient to reduce the sulfur content of the ANS Heavy Distillate. *Id.* at p. 152. Based on this conclusion, Jenkins used the cost curve data maintained by his firm, Jacobs Consultancy, to determine the capital costs for a medium-pressure distillate hydrotreater and related fixed and variable costs. *Id.*

1288. Although the Eight Parties maintain that a more expensive high-pressure hydrotreater would be employed, according to Exxon, they offered no evidence that a medium-pressure unit would not be sufficient. *Id.* Moreover, Exxon points out, the Eight Parties initial explanation that a high-pressure unit would be required due to the high nitrogen content of the ANS Heavy Distillate was shown to be irrelevant and was abandoned, because there is no nitrogen specification for the reference product. *Id.* Exxon also notes that O'Brien has never, unlike Jenkins, designed a hydrotreater, and was unable to state whether the hydrotreater at the Phillips refinery in Ferndale, Washington, on which he relied, was operated at high pressure for the purpose of sulfur processing, or for some other purpose such as aromatics reduction. *Id.*

1289. Further, Exxon argues that the Eight Parties's criticism of the use of the cost curve by Jenkins for this issue is devoid of merit. *Id.* at pp. 152-53. Exxon asserts that the evidence is clear that general cost curve data are reliable for relatively simple types of equipment, such as a distillate hydrotreater, for which the other available cost data are consistent and produce little variance or scatter. *Id.* at p. 153. Consistent with this approach, Exxon believes Jenkins's review of the "fair amount of [cost] data available about distillate hydrotreaters" and determination that they were consistent, made it reasonable to use cost curve data to estimate the ISBL costs of a virgin distillate hydrotreater.[515] *Id.* Exxon also takes issue with the Eight Parties's argument that Jenkins should not have used cost curves for the hydrotreater calculations, because he did not use them for the Delayed Coker calculations. Exxon Reply Brief at pp. 158-59. Its decision, Exxon notes, not to use cost curves for the Resid issue is justified by O'Brien's widely variable coker cost estimates. *Id.* Because this variability in cost estimates does not exist for distillate hydrotreaters, Exxon maintains, it is appropriate to use the cost curves for the heavy distillate calculations. *Id.*

1290. Exxon states that the lone argument offered by the Eight Parties that refineries today would install high-pressure hydrotreaters is based on an assumption, contained in a study by Baker & O'Brien, that hydrodesulfurization units installed after 1992 would use pressures in the higher range. Exxon Reply Brief at p. 158, n.83 (citing Exhibit No. EMT-294). According to Exxon, the study did not define what that higher range would be, nor did it define the terms high and medium pressure as they relate to hydrotreaters. *Id.* It maintains that the Eight Parties assertion that high-pressure hydrotreaters would be installed is, therefore, not supported. *Id.*

1291. There was no basis, Exxon also asserts, for the Eight Parties's criticism of Jenkins's sulfur processing cost adjustment on the ground that it was designed to produce a higher value for the Heavy Distillate cut, which the Eight Parties alleged is in Exxon's economic interest. Exxon Initial Brief at p. 153. In fact, Exxon states, Jenkins's sulfur processing cost estimate is marginally higher than the Eight Parties's, and thus results in a slightly lower value for the West Coast Heavy Distillate cut, contrary to the Eight Parties's view of Exxon's economic interest. *Id.* at pp. 153-54. Further, Exxon asserts, the Eight Parties's argument concerning Exxon's economic interest is undercut because its witness, O'Brien, used cost curve data appropriate for a medium-pressure hydrotreater even though he was purportedly estimating the cost for a high-pressure unit. Exxon Reply Brief at p. 160, n.85.

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[515] Exxon also noted that Jenkins decided not to use cost curve data to determine the cost of a Delayed Coker (*see* discussion of the value of Resid) because of the complexity of the equipment and because the high level of variance or scatter among the available cost curves demonstrated that the data were not reliable. Exxon Initial Brief at p. 153, n.66.

b. Outside Battery Limits Costs

1292. The Eight Parties assert that their approach to offsite costs is consistent. Eight Parties Initial Brief at p. 136. They added $14.36 million for necessary ancillary equipment to their ISBL cost of $49.5 million, giving them a total capital cost of $63.86 million in 1996 dollars. *Id.* According to them, O'Brien then points out that the OSBL cost estimate (29% of ISBL) is equivalent to approximately 22.5% of the total capital cost and is, according to the Gary & Handwerk textbook, within the expected range for capital additions to existing refineries. *Id.* at p. 137.

1293. The approach of Jenkins, according to the Eight Parties, is inconsistent when compared to his Resid valuation resulting in lower OSBL costs for the distillate hydrotreater and, therefore, a lower cost deduction from the product price used to value the Heavy Distillate component of the Quality Bank. *Id.* For instance, in this valuation, Jenkins uses the low end of 20% of the ISBL costs from the Gary & Handwerk textbook factor range of 20-25%, compared with the 25% he used in the Resid valuation. *Id.* According to the Eight Parties, Jenkins justifies this lower percentage by stating that the distillate hydrotreater is less complex. *Id.* However, the Eight Parties point out, the Maples textbook has a higher complexity factor (Nelson Farrar Index) for a hydrotreater than for a delayed coker. *Id.*

1294. While Exxon adds two intermediate product tanks in this cost study, the Eight Parties note, it properly added no additional feed tanks, unlike its method in the Resid study. *Id.* However, the Eight Parties characterize this as an inconsistency, because it does not comport with either the Gary & Handwerk textbook or Exxon's methodology in its Resid cost study. *Id.* The result of all of these inconsistencies, according to the Eight Parties, is that Exxon's effective OSBL costs for the distillate hydrotreater are 38% of the ISBL estimate for the distillate hydrotreater compared to 48% of the ISBL estimate for the delayed coker. *Id.* at pp. 137-38. In addition, the Eight Parties claim, while "Jenkins still follows the Gary & Handwerk non-typical industry approach of adding separately the dollar costs for steam generation, cooling water system and tanks, for the Distillate hydrotreater, the add on is *only* $10.5 million for two intermediate storage tanks versus the $57 million in add-ons before adjustments for the delayed coker."[516] *Id.* at p. 138 (emphasis in original).

1295. In their Reply Brief, the Eight Parties assert that there is no reason to include storage tank costs, because no new tanks have to be constructed and there is no evidence that any existing storage tanks for the distillate hydrotreater would have to be revamped at a Quality Bank refinery. Eight Parties Reply Brief at pp. 115-16. The Eight Parties

[516] The Eight Parties cite to Exhibit No. EMT-37 at p. 18. Eight Parties Initial Brief at p. 138.

point out that the Heavy Distillate cut already has its sulfur level reduced to meet the specification of the finished product used by the Quality Bank. *Id.* at p. 116. They note that Jenkins agreed that the existing refinery must have a distillate hydrotreater to meet the Quality Bank cut specification for Heavy Distillate, but that he stated that he did not use the Quality Bank refinery when making his assumption of what tanks existed. *Id.* Rather, explain the Eight Parties, he used a refinery with no distillate hydrotreater and then calculated the cost of adding one. *Id.* Thus, according to them, reducing the sulfur further does not change the use or size of existing intermediate product storage tanks, thereby negating any additional cost whatsoever for tanks. *Id.* Moreover, the Eight Parties argue, adding storage tank costs would be inconsistent with the cost adjustment that it is replacing. *Id.* They note that there were no storage tank costs included in the 1¢ adjustment to the old Gasoil product price. *Id.*

1296. Exxon argues that the Eight Parties err in failing to include the cost of storage in their estimate of the OSBL cost of the distillate hydrotreater. Exxon Initial Brief at p. 154. In its view, the evidence strongly supports Jenkins's position on storage costs. *Id.* Jenkins, according to Exxon, included a separate cost estimate of the storage tanks that would be required to support the distillate hydrotreater, because that is the approach recommended in the Gary & Handwerk textbook for calculating OSBL costs. *Id.* Exxon believes this is a reasonable approach because, it claims, the distillate hydrotreater would require the use of intermediate storage tanks to store the Heavy Distillate product prior to processing, and the costs of those storage tanks should be allocated to the distillate hydrotreater whether the tanks are newly built to serve the distillate hydrotreater or borrowed from storage tankage that already exists in the refinery. *Id.* at pp. 154-55. Further, it views both the storage capacity used (50,000 barrels/day capacity hydrotreater, total cost of $10.5 million, and 2 tanks with a combined capacity of 15 days's output) and the cost per barrel as reasonable in light of the Second Stillwater Report, prepared for the California Energy Commission.[517] *Id.* at p. 155.

1297. The Eight Parties, Exxon claims, did not challenge the storage cost figures; instead they omitted storage costs entirely from their calculations.[518] *Id.* Exxon contends that

[517] Exxon states that the Stillwater report used a storage cost of $31/barrel. Exxon Initial Brief at p. 155.

[518] Exxon claims that, although Boltz later disputed Jenkins's cost estimate for the storage tanks that would be required for the Delayed Coker, he did not address the reasonableness of Exxon's cost estimate for the storage tanks that would be required for the desulfurization of the Heavy Distillate. *Id.* at p. 155, n.68. In any event, Exxon notes that Boltz's testimony was based on cost estimates that did not include most of the instrumentation, piping, pumps, containment dikes, site preparation, permits, utilities, fire protection and other safety equipment that would be required for the storage tanks. *Id.*

O'Brien's failure to include any allowance for storage costs in his calculation of the OSBL costs for the Heavy Distillate hydrotreater was clearly erroneous in view of the fact that O'Brien did not dispute that the distillate hydrotreater would require the use of intermediate storage tanks to store the Heavy Distillate that comes off the distillation tower before it goes into the hydrotreater. *Id.* at pp. 155-56.

1298. Exxon also asserts that the fact that there may already be storage tanks at the refinery which could be used with the distillate hydrotreater does not justify omitting the storage costs. *Id.* at p. 156. It explains that the distillate hydrotreater would plainly require the use of storage tanks, and the costs of those storage tanks should be included in the costs allocated to that hydrotreater even if the tanks are already in existence because those tanks would have alternative uses if they were not used by the distillate hydrotreater. *Id.* Exxon points out that the costs of common facilities that are used to support a group of refinery products should be attributed to all of those products for valuation purposes. *Id.*

1299. In its Reply Brief, Exxon claims that the Eight Parties's allegations of inconsistencies in its OSBL calculations are unfounded. Exxon Reply Brief at p. 161. First, Exxon notes, the Eight Parties criticize Jenkins's decision to use an OSBL factor of 20%, rather than 25%, of ISBL costs even though that decision was justified by the fact that a hydrotreater is not as complex a unit as a Coker—a conclusion that draws support, according to Exxon, from the fact that O'Brien's firm's OSBL factor for a Coker (35%) exceeds his firm's OSBL factor for a distillate hydrotreater (29%). *Id.*

1300. Second, Exxon finds no merit to the claim that Jenkins's decision not to make any specific allowance for steam generation and/or cooling water facilities in connection with his distillate hydrotreater OSBL estimate was somehow inconsistent. *Id.* Exxon points out that this is completely justified by the fact that a distillate hydrotreater does not consume large amounts of power, cooling water, or other utilities and, therefore, a separate adjustment is not necessary. *Id.* It asserts that this observation clearly is not applicable to a Coker. *Id.* at p. 162.

1301. Third, Exxon claims that the Eight Parties's assertion that Jenkins's $10.5 million estimate of Heavy Distillate storage costs is inconsistent with Jenkins's $57 million estimate of "add-ons before adjustments for the delayed coker" is wholly disingenuous. *Id.* at n.86 (quoting Eight Parties Initial Brief at p. 138). The Eight Parties should realize, notes Exxon, that the Coker estimate included storage costs for five of the Coker distillate products (Naphtha, Distillate, Gas Oil, Propane, and Butane) as well as steam and cooling water. *Id.* By contrast, Exxon points out, the Heavy Distillate hydrotreater estimate is limited only to the two storage tanks that would be required. *Id.*

1302. Fourth, Exxon states that the Eight Parties's suggestion that Jenkins underestimated distillate hydrotreater OSBL costs to further Exxon's economic interests is particularly difficult to understand. *Id.* It notes that Jenkins's estimated distillate hydrotreater OSBL costs total $22 million; while O'Brien's estimated distillate hydrotreater OSBL costs total only $14.36 million. *Id.*

1303. Finally, Exxon asserts that the Eight Parties's claim that O'Brien's approach is somehow consistent with the approach taken in the Gary & Handwerk textbook is incorrect. *Id.* at p. 162. Contrary to O'Brien's testimony, Exxon states that the Gary & Handwerk textbook does not provide an estimate of the OSBL costs required to add process units to an existing refinery on the basis of a percentage of total capital costs. *Id.* Consequently, explains Exxon, the fact that O'Brien's OSBL estimate equals 29% of his total ISBL cost estimate merely indicates that his offsite costs percentage is somewhat higher than the percentage range in the Gary & Handwerk textbook for offsite costs not including storage costs, steam generating facility costs, or water cooling facility costs. *Id.* It does not, in Exxon's view, justify O'Brien's failure to include any costs for storage in his OSBL cost estimate. *Id.*

2. Location Factor

1304. The Eight Parties explain that a location factor is an adjustment factor used to translate a construction cost estimate developed for a specific project in a specific location (usually the U. S. Gulf Coast) to a cost estimate for the same project in a different part of the country. Eight Parties Initial Brief at p. 138. They claim that their underlying assumption is that the cost to build a similar facility will vary depending on where it is located. *Id.* The issue with respect to location factor, according to the Eight Parties, is twofold: (1) is it appropriate to apply a location factor to a cost estimate developed for a generic project location in determining the cost of the distillate hydrotreater to reduce the sulfur content of the ANS Heavy Distillate that will be subtracted from the product price used to value the Heavy Distillate of the Quality Bank; and (2) if it is appropriate to use a location factor, what location factor should be used. *Id.* at pp. 138-39.

1305. The use of a location factor, the Eight Parties argue, is not appropriate when estimating the cost of the Heavy Distillate high-pressure distillate hydrotreater for purposes of the Quality Bank, because "the Distillate hydrotreater proposed is not for a specific project defined in sufficient detail and pinned down to a specific location." *Id.* at p. 139. Instead, they recommend the use of generic cost curves. *Id.* The Eight Parties state that this is the most appropriate method when, as in this case, one is dealing with a general project with limited information. *Id.* They acknowledge that costs can be higher on the West Coast, but point out that they can sometimes be lower than on the Gulf coast as well. *Id.* at p. 140.

1306. As part of its justification for its position that a 1.3 West Coast location factor should be used when adjusting sulfur processing costs, the Eight Parties state, Exxon uses the September 11, 2000, edition of the *Engineering News Record* and its information on New Orleans, Louisiana. *Id.* The Eight Parties note that Exxon only looks at the hourly rate for common labor, which is 222% higher in New Orleans than it is on the West Coast. *Id.* They claim that it is surprising that Jenkins picked labor to compare and that he makes a big point of the large difference. *Id.*

1307. To bolster this point, the Eight Parties refer to a redacted portion of a Jacobs Consultancy report titled "Cost Structure and Employment Scheme for Operations in United States Refineries."[519] *Id.* They point out that average refinery operators's wages, which should include operators of a refinery distillate hydrotreater, for the West Coast are either 1.04 (average), or 1.02 (median), times the wages of operators on the Gulf coast. *Id.* at pp. 140-41. However, the Eight Parties note that the "California factor" that Jenkins uses in his detailed cost estimate for the Coker to convert the Gulf Coast labor dollar amount to a West Coast labor dollar amount is 1.35. *Id.* at p. 141. In addition, while he agreed that materials cost was virtually identical between New Orleans and Los Angeles, he nonetheless used a factor of 1.02 to convert Gulf Coast materials costs to West Coast materials costs in computing "coker" costs. *Id.*

1308. According to the Eight Parties, this empirical data supports their argument that, until you have a specific project, it is appropriate to use only a generic cost curve and not apply a location factor because the costs might be lower. *Id.* As all of the data is for 2000 and as Jenkins expresses his cost calculations in 2000 dollars, and as the costs for two key cost centers, operators of refinery process units (i.e., labor) and materials between a refining center on the Gulf Coast (New Orleans) and a refining center in California (Los Angeles) are almost the same, the Eight Parties argue, there appears to be no factual justification for applying a location factor of 1.3 to the capital costs for the Heavy Distillate hydrotreater. *Id.* at pp. 141-42.

1309. Another concern of the Eight Parties with respect to the use of location factors is that they are highly subjective and vary too widely among analysts for their use to be appropriate in this proceeding. *Id.* at p. 142. The Eight Parties contend that the evidence in this proceeding supports this view. *Id.* They contend that there is little consensus on what such factors should be for various areas of the country and that they differ according to the judgment of the analysts computing them even for the same area. *Id.* The Eight Parties point out that Exxon's own witness, Toof, reached the conclusion that different analysts will derive different location factors for the same locations. *Id.*

1310. The Eight Parties also note that the PRISM model (owned by O'Brien's company) shows no difference between costs for locations in California and Alaska, contrary to the

[519] *See* Exhibit No. PAI-100.

expectations of Exxon's witness, Toof.[520] *Id.* at pp. 142-43. Similarly, while Exxon's witness expected a refinery in Los Angeles, California, to cost more than a refinery in St. Louis, Missouri, the Eight Parties claim that, according to the Gary & Handwerk textbook, St. Louis has a higher location factor than Los Angeles. *Id.* at pp. 143-44. The Eight Parties argue that this demonstrates that at least some of the location factors in both the PRISM model and the Gary & Handwerk textbook were counterintuitive to what Exxon's lead witness, Toof, expected with respect to comparisons of costs involving refineries in California and other geographic locations. *Id.* at p. 144. They assert that these examples unquestionably demonstrate just how subjective location factors are and further bolster their argument that they should not be used. *Id.*

1311. Another indicator of subjectivity, according to the Eight Parties, is that Exxon's own witnesses acknowledge the fact that "you can get different location factors by different analysts." *Id.* As the Eight Parties discussed in the Resid section, Exxon's support for the use of location factors for both its Heavy Distillate cost estimate and its Resid cost estimate, is the September 11, 2000, edition of *Engineering News Record*, which provides relative cost indices for U.S. cities. *Id.* According to Exxon, data in that report shows that West Coast construction is far more costly than Gulf Coast construction. *Id.*

1312. The Eight Parties contend that a more detailed review of the *Engineering News Record* than Exxon's cursory glance at labor costs further reveals the subjectivity of location factors. *Id.* First, they point out that in the October 2, 2000, edition of *Engineering News Record*, the costs for common labor, skilled labor and materials are lower in St. Louis compared to Los Angeles, which is the exact opposite of what the Gary & Handwerk textbook shows for location factors for the two cities. *Id.* at pp. 144-45. Second, they note that Jenkins expects costs in Chicago to be lower than costs in Los Angeles, but in fact the available literature does not consistently show that to be true. *Id.* at p. 145. The Eight Parties state that comparison of costs and location factors for a Chicago and Los Angeles refinery used in *Engineering News Record* and the Gary & Handwerk textbook shows the same dichotomy of results. *Id.* In the *Engineering News Record*, Chicago has higher common labor, skilled labor and materials costs than Los Angeles, while the Gary & Handwerk textbook location factor for Chicago is less than that for Los Angeles. *Id.* The Eight Parties argue that this shows that location factors are extremely dependent on the analysts developing them. *Id.*

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[520] The Eight Parties note that Baker & O'Brien did not develop the PRISM model; rather it purchased the company that developed the model. Eight Parties Initial Brief at p. 143, n.86. Even though Exxon introduced Baker & O'Brien's PRISM model to bolster its case for use of a location factor, the Eight Parties point out, Exxon's expert witness questioned its reasonableness and therefore its usefulness in this proceeding, particularly with respect to California. *Id.* (citing Transcript at pp. 3732-33).

1313. In conclusion, the Eight Parties argue that what has been introduced into the record concerning location factors shows that they are highly subjective with no consistent pattern whatsoever. *Id.* This fact, coupled with the data in the record showing that: (1) Year 2000 operator costs and materials were almost the same in New Orleans and Los Angeles, and (2) the cost of a delayed coker on the West Coast, when compared on an equivalent basis with the cost of a delayed coker on the Gulf Coast, is lower, underscores and justifies, in the opinion of the Eight Parties, the use of a generic cost curve without applying any location factor. *Id.* The Eight Parties believe this will establish a cost estimate applicable on a general basis over a large geographical area which is not to the level of detail justifying the attempt to quantify the cost on a specific location basis which is the function of a location factor. *Id.* at pp. 145-46.

1314. In the alternative, the Eight Parties argue, if a location factor is applied, it should be less than 1.30. *Id.* at p. 146. They restate their claim that the record provides no basis for use of a location factor, but assert that if one is used it cannot be the 1.3 factor Exxon favors for the processing cost estimate for the Heavy Distillate valuation. *Id.*

1315. According to the Eight Parties, there is clear evidence in the record of the subjectivity of Exxon's detailed cost estimate and any location factors stemming from it. *Id.* For example, they cite data concerning indirect factors used to calculate the cost estimates. *Id.* Also, they point out that a very slight change to the ratios of indirect dollar costs to labor costs produces a significantly larger change to the overall resulting West Coast location factor: it reduces it from 1.26 to 1.20. *Id.* at pp. 146-47.[521] The Eight Parties acknowledge that the record shows Exxon does not agree with the premise behind this change, however, they point out that Exxon concedes that the change in independent variable does produce the cited change in the location factor. *Id.* at p. 147. They further argue that the West Coast location factor reasonably could be as low as 1.19 depending on exactly how one defines "West Coast." *Id.* The Eight Parties arrive at this figure by averaging the numbers from the PRISM model for Portland, Seattle, Los Angeles, San Francisco, and the inland California refineries.[522] *Id.*

1316. However, the Eight Parties argue that even the 1.20 figure for a location factor is likely high. *Id.* They point out that, because Jenkins's calculations effectively assume a Los Angeles location for the Delayed Coker, the corrected 1.20 is not reflective of the West Coast, but rather only California (hence Jenkins refers to the numbers as "California factors.") *Id.* Because the PRISM model shows that Los Angeles costs are higher than Seattle and Portland costs, they argue that a further (equally weighted) averaging could

[521] See *also* Exhibit Nos. WAP-80, WAP-81, WAP-83.

[522] See *also* Exhibit No. EMT-208.

be done using the 1.20 calculated number, and the PRISM 1.20 for Seattle and 1.08 for Portland, the result of which is 1.16. *Id.* at pp. 147-48. Moreover, the Eight Parties argue that the *Engineering News Record* 2000 materials comparison and the Jacobs Consultancy 2000 operators's compensation comparison also support there being no location factor applied. *Id.* at p. 148.

1317. What all of the above demonstrates, according to the Eight Parties, is the subjectivity of using location factors and how they are affected by simply changing one number. *Id.* Using the 1.3 location factor changes the capital cost number by 30%, they claim, if Exxon's approach is adopted. *Id.* The Eight Parties maintain there has been no showing that such a result is reasonable. *Id.* Indeed, they assert, the exact opposite has been shown by the empirical data related to the Shell Martinez West Coast Refinery and the Shell Deer Park Gulf Refinery that show, on a barrels/day basis, the cost of a Gulf Coast delayed coker project was higher than the cost of a delayed coker on the West Coast. *Id.*

1318. In conclusion, the Eight Parties do not advocate that any location factor be applied to O'Brien's processing costs. Eight Parties Reply Brief at p. 116. They maintain that it would be inconsistent to apply a location factor to O'Brien's Resid costs, but not to his Heavy Distillate processing costs. *Id.* The Eight Parties assert that they have demonstrated that application of any location factor to any calculations related to the Quality Bank would be subjective, unsupported by the empirical evidence, unreliable, and, hence, would result in skewed cost figures. *Id.* at pp. 116-17.

1319. By contrast, Exxon insists, it is the Eight Parties's cost estimate for the distillate hydrotreater that is deficient in that, although purporting to estimate the cost of constructing and operating such a unit on the West Coast, they failed to make any adjustment to the Gulf Coast costs used in the cost estimate to reflect higher West Coast costs. Exxon Initial Brief at p. 156. For this reason, Exxon asserts Jenkins's sulfur processing cost adjustment is clearly more reasonable than the Eight Parties's sulfur processing adjustment, because Jenkins used an appropriate West Coast location factor to reflect the higher West Coast costs. *Id.* at pp. 156-57.

1320. Exxon argues that failing to account for the higher West Coast costs is unreasonable, because the reference price for Heavy Distillate, at issue here, is a West Coast price. *Id.* at p. 157. It asserts that it is beyond reasonable dispute that construction costs, including labor costs, environmental costs, and regulatory costs, are significantly higher on the West Coast than they are on the Gulf Coast. *Id.* In support of this assertion, Exxon states that it introduced evidence that a West Coast location factor of 1.3 is both conservative and well supported by industry standards, by the Gary & Handwerk textbook, and even by a study prepared by O'Brien's own firm. *Id.* For this reason, Exxon recommends that the proper method is to first determine the cost of constructing a medium-pressure distillate hydrotreater on the Gulf Coast and then apply a location factor of 1.3 to adjust the cost estimate for the higher costs that would be incurred on the West Coast. *Id.*

1321. In sharp contrast to its recommended approach, Exxon points out, the Eight Parties failed to adjust their Gulf Coast sulfur processing cost estimate to reflect the higher level of costs found on the West Coast, even though O'Brien admitted that he was using Gulf Coast costs to estimate the sulfur processing cost adjustment that would be applied to the West Coast reference price. *Id.* at pp. 157-58. In the opinion of Exxon, this failure results in a significant understatement of the costs to be applied to the West Coast reference price. *Id.* at p. 158.

1322. Further, Exxon notes that, even though the Eight Parties claim that O'Brien's cost curves are generic, they are not. Exxon Reply Brief at p. 164. Exxon explains that the cost curves are clearly based on Gulf Coast construction costs. *Id.* It argues that, in view of O'Brien's admission that costs are significantly higher on the West Coast and the fact that both the Gary & Handwerk textbook and O'Brien's own company[523] employ location factors in doing similar cost estimates, the record evidence clearly shows that the Eight Parties's failure to adjust their Gulf Coast costs for the higher level of West Coast costs was an indefensible departure from standard industry practice. Exxon Initial Brief at p. 158.

1323. Exxon emphasizes that Issue No. 2 addresses the level of the sulfur processing cost adjustment to be applied to the West Coast reference price to determine the net value of the Heavy Distillate cut on the West Coast.[524] *Id.* It necessarily follows, in Exxon's view, that West Coast costs must be used to determine the level of the sulfur processing cost adjustment rather than Gulf Coast costs.[525] *Id.* at pp. 158-59. This is especially true,

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[523] Exxon notes that, in a study for the American Petroleum Institute, Baker & O'Brien applied location factors to their cost curve estimates to derive the ISBL costs of distillate hydrotreaters at various locations throughout the country. Exxon Initial Brief at p. 161 (citing Exhibit Nos. EMT-82, EMT-208; Transcript at pp. 238-39, 2106-08). Similarly, it asserts that the evidence shows that the PRISM database (formerly known as the Vector database) that is marketed by Baker & O'Brien assigns location factors ranging from 1.08 for Washington and Oregon to 1.35 for most California locations. *Id.* Exxon suggests that the Eight Parties's attempts to distance themselves from the use of the PRISM is unsuccessful in view of their expert's continued use and advertisement of this software package. Exxon Reply Brief at p. 166, n.88.

[524] *Trans Alaska Pipeline System*, 97 FERC at pp. 61,650, 61,652.

[525] In fact, Exxon points out, the Eight Parties's expert has indicated that he recognized this need when he used California natural gas prices in estimating fuel costs for both the Coker and the distillate hydrotreater. Exxon Initial Brief at p. 159, at n.69

according to Exxon because, it asserts, there is no dispute that plant location can have "a significant influence" on costs. *Id.* at p. 159. For this reason, Exxon's position is that it is essential that a location factor be used to reflect regional cost differences when estimating costs applicable to a particular location like the West Coast. *Id.*

1324. There is also no dispute, according to Exxon, that construction costs, labor costs, and permitting costs are widely known in the industry to be significantly higher on the West Coast than on the Gulf Coast. *Id.* In particular, it contends that the evidence supports the conclusion that construction costs are from 20% to 40% higher on the West Coast than they are on the Gulf Coast. *Id.* at p. 160.

1325. Further, Exxon presents what it considers undisputed evidence that use of location factors when doing cost studies (including studies based on cost curves) is an appropriate and well-established industry practice. *Id.* For example, it points out that the Gary & Handwerk textbook gives a location adjustment of 1.4 for Los Angeles and 1.2 for Portland and Seattle,[526] for an average West Coast location factor of 1.3. *Id.* at pp. 163-64. Similarly, it cites a National Petroleum Council-commissioned study by Bechtel[527] which estimated that, in 1992, the cost to build a unit on the West Coast would be 20% higher than on the Gulf Coast and that differences in building codes, environmental rules, and other design parameters would add another 20%, for a total California factor of 1.4. *Id.* at p. 164. Lastly, Exxon cites the August 2000 study for the American Petroleum Institute, prepared jointly by Charles River Associates and O'Brien's firm, Baker and O'Brien, which used a West Coast location factor in the range of 1.4 to 1.5.[528] *Id.* The undisputed evidence relating to location factors for use in the petroleum industry clearly shows, in Exxon's opinion, that its use of 1.3 as a West Coast location factor is both appropriate and conservative. *Id.*

1326. Exxon also states that O'Brien conceded that there is no authority at all supporting his position that a location factor should not be used in preparing cost estimates. Exxon Initial Brief at p. 161. O'Brien's contention, according to Exxon, that it is too early in the cost estimating process to use a location factor is not credible and is plainly wrong.[529] *Id.* All of the information required for the application of a location factor is clearly available,

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(citing Exhibit Nos. PAI-12, n.2, PAI-19, n.1).

[526] Exhibit No. EMT-169 at p. 6.

[527] Exhibit Nos. EMT-87, EMT-295.

[528] Exhibit No. EMT-82.

[529] S*ee* Exhibit No. PAI-42 at p. 20.

Exxon suggests. *Id.* It argues that, in the circumstances presented here, "any credible analyst," including one using a cost curve, would use a location factor to reflect the higher expected cost of the project on the West Coast. *Id.* at pp. 161-62.

1327. In Exxon's opinion, there also is no valid basis for the Eight Parties's attempt to confuse a West Coast location factor with site preparation costs. *Id.* at p. 162. "Site preparation costs [are the] costs associated with getting a site prepared to build on," Exxon states, such as terracing a hilly site to have flat land on which to build. *Id.* It contends that site preparation costs are specific to a particular site, and involve costs that are separate and apart from the location costs that are addressed by the geographic location factors used by its expert. *Id.* Neither party's expert included site preparation costs in their respective cost estimates. *Id.* Instead, because Jenkins assumed that the distillate hydrotreater would be added to an existing refinery, he assumed that the refinery site would already have been prepared and that no further site preparation costs would be required. *Id.* Exxon agrees with this approach. *Id.*

1328. Nor does the mere hypothetical possibility that some costs might be lower on the West Coast – a possibility that Exxon finds is wholly lacking in evidentiary support – provide any justification, in Exxon's view, for the failure to apply an appropriate West Coast location factor to reflect the undisputed fact that West Coast costs are generally higher than Gulf Coast costs. *Id.* Although the Eight Parties suggested that a refinery built on swampy ground in the Mississippi River Delta of Louisiana might be particularly costly to construct, Exxon notes they provided no evidence to support this claim. *Id.* at pp. 162-63. Further, Exxon suggests, neither the PRISM database of O'Brien's own firm, nor any other source of location factors, makes any distinction between different Gulf Coast locations based on the nature of the terrain involved. *Id.* at p. 163. Moreover, as discussed above, Exxon argues that any such additional costs would be included in site preparation costs and would not be part of the location factor. *Id.*

1329. Furthermore, Exxon maintains, the evidence is overwhelming that a location factor should be used in connection with a study using a cost curve. Exxon Reply Brief at p. 165. For example, Exxon notes, the Gary & Handwerk textbook specifically states that "[t]he cost curve method of estimating, if carefully used and properly adjusted for local construction conditions, can predict costs within 25%." *Id.* (quoting Exhibit No. EMT-169 at p. 3). Exxon asserts that the accepted method, when making a cost curve estimate, is to estimate costs as accurately as possible, including ISBL and OSBL, and then multiple the total by a location factor. *Id.*

1330. Exxon argues that this conclusion is also confirmed by other, more general, materials relating to construction and building costs for different locations. Exxon Initial Brief at p. 164. For example it cites the September 11, 2000, edition of *Engineering News Record* which provides relative cost indices applicable to all types of construction and buildings for U.S. cities, including New Orleans where numerous Gulf Coast refineries are located. *Id.* These data show, according to Exxon, that West Coast construction costs are from 139% to 222% higher than Gulf Coast construction costs.[530] *Id.* at pp. 164-65. Exxon cites a similar study by the R.S. Means Company, which it claims shows that general construction cost location factors are approximately 1.3 for Los Angeles, and between 1.25 and 1.29 overall for the whole West Coast.[531] *Id.* at 165. The location factor for Gulf Coast cities that have refining capacity was set at 1.0 in this study, according to Exxon. *Id.*

1331. The Eight Parties, Exxon asserts, make a number of unsuccessful arguments that attempt to cast doubt on the use of a West Coast location factor. Exxon Reply Brief at p. 167 (citing Eight Parties Initial Brief at pp. 140-46). For example, notes Exxon, the Eight Parties claim that Exxon's witness, Jenkins, detailed Coker capital cost estimate used a labor cost that was much higher than the West Coast data contained in a report by Jacobs Consultancy. *Id.* at pp. 167-68 (citing Eight Parties Initial Brief at pp. 140-41). Exxon asserts that this criticism is wholly misplaced, in that the Jacobs Consultancy report plainly addresses labor costs involving refinery operations, not labor costs related to refinery construction. *Id.* at p. 168. (citing Exhibit No. PAI-100 at p. 2).[532] It notes that O'Brien recognized this significant difference when he agreed[533] that Exhibit No. PAI-100's costs related to operators, and not construction laborers. *Id.*

1332. Exxon also states that the Eight Parties's reliance on data contained in an October 4, 2000, issue of *Engineering News Record*, which indicated that the cost of materials in New Orleans and Los Angeles were almost the same, also misses the mark. *Id.* Contrary to the Eight Parties's claim, Exxon maintains, this information does not call into question or cast doubt on Jenkins's use of a 1.02 location adjustment with respect to such costs in his detailed Coker cost estimate. *Id.* Exxon expresses surprise that the Eight Parties would focus on an adjustment of 2/100ths and asserts that that adjustment was inconsistent with an observation that material costs were almost the same on the two Coasts. *Id.* at pp. 168-69. Further, Exxon states, it was not material that had the most

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[530] In point of fact, the September 11, 2000, ENR shows a 180% differential for Construction Costs, a 139% differential for Building Costs, a 222% differential for Common Labor, a 178% differential for Skilled Labor, and a 99% differential for Materials. Exhibit No. EMT-41.

[531] Exhibit Nos. EMT-296, WAP-80.

[532] Exxon notes that such costs were covered in Jenkins's fixed operating cost estimates, not his construction cost estimate which is the subject of the Eight Parties's criticism. Exxon Reply Brief at p. 168, n.90.

[533] Transcript at p. 1269.

impact on Jenkins's location factors; rather, it was differences in construction labor costs, building costs, and permitting costs. *Id.* at p. 169. Ironically, according to Exxon, the *Engineering News Record* data on which the Eight Parties's rely in mounting this particular criticism help to establish this point. *Id.*

1333. The Eight Parties's use, according to Exxon, of St. Louis, Alaska, and Chicago to support their point that location factors are subjective and have no consistent pattern is misleading. *Id.* It notes that, as with Resid, comparisons involving St. Louis, Chicago, or Alaska say nothing about Gulf Coast versus West Coast costs and are intended only to distract the Commission from the key issue of whether O'Brien's cost curves—which use primarily Gulf Coast data—should be adjusted to reflect higher West Coast costs. *Id.*

1334. Exxon argues that the Eight Parties present no foundation for their assertion that the 1.3 location factor is too high. *Id.* at p. 171. For example, explains Exxon, the Eight Parties give no justification for their proposal to calculate an equal weighted average of the location factors in the PRISM model for Portland (1.08), Seattle (1.20) and California (1.35), to arrive at a West Coast location factor of 1.21. *Id.* (citing Eight Parties Initial Brief at p. 147).[534] Exxon asserts that no justification exists and recommends a weighted average, producing a location factor of approximately 1.3, which accounts for relative refining capacity.[535] *Id.*

1335. The Eight Parties's suggestion that inland California refineries should be included in the California location factor also is wrong, Exxon declares. *Id.* at p. 172. In addition to the fact that the three inland refineries have a combined capacity of approximately 10% and would thus have a minimum effect on the calculations, Exxon claims, including them would be inconsistent with the fact that the agreed upon Heavy Distillate reference price is a Los Angeles assessment. *Id.* (citing Exhibit No. WAP-96 at pp. 7-9). Additionally, Exxon points out, Fuel Gas costs, which are an important component of the

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[534] Exxon points out that the 2000 EIA data contained in Exhibit No. WAP-96 shows that there is only one refinery in the entire state of Oregon, the Chevron Willbridge plant in Portland, which has no Coker and has a total vacuum distillation capacity of only 12,000 barrels/stream day. Exxon Reply Brief at p. 171, n.92 (citing Exhibit No. WAP-96 at p. 15). By contrast, explains Exxon, California contains over 20 refineries with a total crude capacity of over 2,000,000 barrels/stream day and vacuum distillation capacity of 1,162,900 barrels/stream day. *Id.* (citing Exhibit No. WAP-96 at pp. 7-9).

[535] Exxon points out that the Eight Parties weighted average of 1.16 included only the California location factors and the straight averages for Seattle and Portland. Exxon Reply Brief at p. 171, n.93. According to Exxon, a valid weighted average would have to include, as Jenkins did, all refineries on a total capacity basis, not merely the refineries in California. *Id.*

cost of operating a distillate hydrotreater, are also Los Angeles based. *Id.*

1336. Exxon asserts that all of the industry studies in the record, in addition to the testimony of Jenkins, Gary, Dickman, and Toof, demonstrate that a 1.3 West Coast location factor constitutes an appropriate and conservative adjustment.[536] *Id.* Consequently, Exxon states that the Eight Parties present no grounds for correcting Jenkins's indirect costs factor, or for utilizing a location factor of less than 1.3. *Id.*

3. Operating Costs

1337. The Eight Parties view the major difference in operating costs between the parties's experts as being the amount of hydrogen[537] that each expert assumes is required to hydrotreat Heavy Distillate. Eight Parties Initial Brief at p. 148. They state that O'Brien assumed that 250 cubic feet of hydrogen is required to process one barrel of Heavy Distillate, while Jenkins assumed that 180 cubic feet/barrel was necessary. *Id.* According to them, this difference works out to 0.3¢/gallon in the total processing cost calculation. *Id.*

1338. Exxon's hydrogen consumption value used in calculating sulfur treating costs, the Eight Parties contend, was inconsistent with estimates contained in the Maples and the Gary & Handwerk texts. *Id.* Even though Exxon stated that its calculation was based on the specific qualities of ANS Heavy Distillate and is, therefore, more reliable than the textbooks's estimate, it became evident during the hearing, in the Eight Parties's view, that this was not entirely true. *Id.* at 148-49.[538]

1339. The Eight Parties argue that the discrepancy is related to the value of "solution loss" used in the hydrogen consumption calculation. *Id.* at p. 149. According to them, the record shows that Exxon based this solution loss value not on ANS Heavy Distillate, but on its expert's experience with a completely different technology from 1980. *Id.* This solution loss value is much lower than that suggested by either the Gary & Handwerk textbook or that used by the Eight Parties, according to them. *Id.* at p. 149.

1340. If either the Gary & Handwerk or Eight Parties's value for solution loss is used in Exxon's calculations for hydrogen consumption, according to the Eight Parties, then the

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[536] Exxon cites: Transcript at pp. 2097-98, 2745; Exhibit Nos. EMT-37 at p. 14-15, EMT-116 at p. 8, EMT-118 at p. 20, EMT-76 at p. 22 – 23.

[537] In their brief, the Eight Parties actually stated "the amount of sulfur," Eight Parties Initial Brief at p. 148. However, I am sure they meant "hydrogen."

[538] *See also* Exhibit No. EMT-166.

resulting value for hydrogen consumption is even higher than the value initially calculated by the Eight Parties themselves. *Id.* The Eight Parties point out that this result was acknowledged by Exxon's expert during the hearing. *Id.*

1341. Thus, even were Jenkins's calculations based on the qualities of ANS Heavy Distillate correct, the Eight Parties assert, this does not completely answer the question of which hydrogen consumption estimate is correct. *Id.* at p. 150. The answer to that question depends on the validity of Jenkins's solution loss estimate, they state. *Id.* The Eight Parties frame the Commission's choice as follows: accept either (1) Jenkins's estimate based on his experience in 1980 with a project that is not a Heavy Distillate hydrotreater, or (2) the higher estimates from the Gary & Handwerk and Maples texts that do relate specifically to Heavy Distillate hydrotreaters. *Id.* The Eight Parties argue that choice two is clearly the correct one, because the texts are written by disinterested third parties based on their industry experience with the exact equipment that is at issue here. *Id.* They conclude that the textbooks support O'Brien's assumption, which should be adopted. *Id.*

1342. Further, the Eight Parties believe that Exxon's reference to a graph contained in a study jointly performed by Charles River Associates and Baker & O'Brien leaves the Commission with conflicting authorities regarding hydrogen consumption. Eight Parties Reply Brief at p. 117. It is the Eight Parties's position that the Commission should accept the consumption estimates from the texts cited by the Eight Parties in their Initial Brief. *Id.* According to the Eight Parties, this is appropriate because those texts have been used by both parties for a number of issues in this proceeding, and because the study that Exxon uses[539] was presented with no opportunity for discovery or cross-examination of Jenkins's testimony regarding the study. *Id.* at pp. 117-18. The Eight Parties do not assert that it was improper for Exxon to have presented Exhibit No. EMT-294 on redirect examination, only that this study was not subjected to the same scrutiny as other evidence and, therefore, should carry less weight. *Id.* at p. 118.

1343. Exxon agrees that the amount of hydrogen required for hydrotreating is the area of contention with respect to the level of the sulfur processing cost adjustment and advocates for the hydrogen consumption figure presented by its expert, Jenkins. Exxon Initial Brief at p. 165. According to it, the evidence shows that "a key objective of hydrotreating for sulfur removal is to minimize hydrogen consumption while achieving the desired sulfur reduction." *Id.* Exxon explains that O'Brien assumed that 250 standard cubic feet of hydrogen would be consumed per barrel of ANS Heavy Distillate processed; while Jenkins estimated the hydrogen consumption at 180 standard cubic feet/barrel. *Id.* at pp. 165-66. It notes that both Jenkins and O'Brien testified that their respective estimates of hydrogen consumption were correct. *Id.* at p. 166.

[539] Exhibit No. EMT-294.

1344. In the view of Exxon, however, the evidence shows that its expert's estimate of hydrogen consumption was reasonably based on the specific properties of the ANS Heavy Distillate cut being valued. *Id.* Exxon claims that Jenkins made his calculation on the basis of chemical reactions that take place in a distillate hydrotreater, and that he provided exhibits which showed the basis for his estimate of hydrogen consumption. *Id.* Exxon also believes in the reasonableness of Jenkins's estimate of hydrogen consumption, because it is supported by a study by Charles River Associates and O'Brien's firm. *Id.* That study estimated hydrogen consumption for a distillate with a sulfur content similar to ANS Heavy Distillate in the range of 160 to 170 standard cubic feet/barrel – much closer to Jenkins's estimate of 180 standard cubic feet/barrel than to O'Brien's estimate of 250 standard cubic feet/barrel. *Id.*

1345. According to Exxon, the reason the parties's estimates of hydrogen consumption differ is because of the difference in the parties's assumptions regarding the pressure of the distillate hydrotreater rather than the value of solution loss used. *Id.* at p. 166. Exxon asserts that, as hydrotreater pressure goes up, the amount of hydrogen used also goes up. *Id.* at pp. 166-67. It points out that, if it had used the same high-pressure hydrotreater that the Eight Parties used, its hydrogen consumption estimate would have been even higher than the Eight Parties's estimate. *Id.* at p. 167.

1346. Exxon also points out that Jenkins's testimony on solution loss was in fact based on both the qualities of the ANS cut and his personal experience and not just his personal experience as the Eight Parties allege. Exxon Reply Brief at pp. 174-75 (citing Eight Parties Initial Brief at p. 149). It asserts that solution loss, and hence the amount of hydrogen consumed, is determined by the hydrotreater pressure one assumes. *Id.* Further, Exxon explains, Jenkins's choice of a medium-pressure hydrotreater is reasonable in this case, because it was based on the qualities of the ANS Heavy Distillate cut. *Id.* Therefore, according to Exxon, there is no basis in the record for postulating different values of solution loss from either the Gary & Handwerk or Maples texts as the Eight Parties advocate (Eight Parties Initial Brief at p. 149) in order to arrive at a higher value for hydrogen consumption. Exxon Reply Brief at pp. 174-75. Because it is the pressure of the hydrotreater that drives solution loss and hydrogen consumption, and not the other way around, Exxon asserts, one cannot use either the Gary & Handwerk or Maples solution loss figures accurately without knowing how they were derived. *Id.* at pp. 175-76. Exxon also argues that the fact that no witness supported such high rates of solution loss also casts doubt on the reasonableness of relying on these figures in the context of this case. *Id.* at p. 176.

1347. Finally, Exxon notes, O'Brien provided no evidentiary support for his calculation of either solution loss or hydrogen consumption. *Id.* In addition, Exxon points out, O'Brien acknowledged that he has never designed a distillate hydrotreater. *Id.* Jenkins, according to Exxon, had such experience and in the context of this case made specific hydrogen consumption calculations based on the facts of this case. *Id.*

D. LOGISTICS ADJUSTMENT

1348. In addition to the desulfurization costs, the Eight Parties advocate a "logistics adjustment" to bring the Heavy Distillate reference price onto a consistent basis with all of the other liquid Quality Bank cuts. Eight Parties Initial Brief at p. 150. The Eight Parties recommended adjustment, derived using a cost-based measure, is 1.1¢/gallon. *Id.* This adjustment is based on the cost of transporting product from harbor to pipeline, and the Eight Parties advocate its deduction from the Los Angeles Pipeline No. 2 price after the sulfur processing costs described by O'Brien are deducted. *Id.* The Eight Parties argue that consistent valuation of the Quality Bank cuts is essential in order to achieve a just and reasonable valuation methodology. *Id.* In order to achieve this consistency, the Eight Parties believe it is important to value all of the liquid Quality Bank cuts at a common location where each of them is currently or proposed to be valued - on a waterborne basis. *Id.* They argue that their proposed 1.1¢/gallon logistics adjustment to the Heavy Distillate reference price will do that. *Id.*

1349. It cannot be disputed, the Eight Parties contend, that consistency within the Quality Bank is a goal which all parties to this proceeding and the Commission have sought to achieve. *Id.* at p. 151. Baumol, Exxon's witness, they assert, stated that "[a]ll parties agree, as logic dictates, that to achieve the purpose of the Quality Bank the valuation of each of the component cuts, including the Resid cut and the Coker products into which the Resid cut is processed, should therefore be carried out on a comparable basis." *Id.* (citing Exhibit No. EMT-66 at p. 10). Further, the Eight Parties note that the Circuit Court has stated that "the [Commission] must accurately value all cuts - not merely some or most of them - or it must overvalue or undervalue all cuts to approximately the same degree." *Id.* (quoting *Oxy*, 64 F.3d at p. 693).

1350. The Eight Parties believe that, should the Commission adopt their proposal, every liquid product on both coasts will be valued on a consistent waterborne basis. *Id.* They argue that waterborne prices are the most appropriate and consistent basis for valuing liquid products, because they represent cargoes or barges at their source or destination harbor. *Id.* As such, they are generally the largest parcels available and include the least marketing margins. *Id.* Thus, the Eight Parties contend, the most desirable consistency can be achieved by deducting logistics costs (in addition to desulfurization costs) from the Heavy Distillate reference price to bring it to a consistent valuation basis with the other liquid cuts - waterborne. *Id.*

1351. Their proposed logistics adjustment, the Eight Parties argue, represents the average of costs incurred in transporting product inland to the pipeline from its arrival point at the harbor. *Id.* at p. 152. With such inland movement to the pipeline, the Eight Parties suggest, value is added as a result of the logistics costs of moving the product from waterborne status to the pipeline terminal. *Id.* This allows it, they contend, to command a higher price than waterborne deliveries. *Id.* The Eight Parties argue that this logistics related transportation cost must be deducted to bring the value of the product back to a consistent waterborne location, because the Los Angeles product primarily flows from the harbor to the pipeline. *Id.*

1352. The average, over time, for all of these transportation costs ranges from 1.04¢ to 2.09¢/gallon.[540] *Id.* at p. 153. To determine what costs are actually incurred in the marketplace, the Eight Parties suggest the use of a value calculated on behalf of BP.[541] *Id.* Thus, calculating the cost for transporting Waterborne Low Sulfur Gasoil to the pipeline is a proper calculation, according to them, to ascertain the differential between these waterborne and pipeline prices. *Id.* As further support for the market-realized transportation costs, the Eight Parties also cite waterborne/pipeline differentials in reported prices for the similarly situated products of regular gasoline and jet fuel. *Id.*

1353. The Eight Parties argue that each of the three waterborne/pipeline differentials supports their 1.1¢/gallon proposed logistics adjustment. *Id.* Specifically, they point out that the annual average difference between Waterborne Low Sulfur Gasoil and Los Angeles Pipeline No. 2 shows that the waterborne price is almost precisely 1.1¢/gallon less than the pipeline price. *Id.* at pp. 153-54. Further, they argue that, from 1997 through 2001, the waterborne/pipeline differential for regular gasoline totaled 1.23¢/gallon and for jet fuel totaled 0.95¢/gallon. *Id.* at p. 154. The close match of the differentials for regular gasoline and jet fuel as compared to the differential between West Coast Waterborne Low Sulfur Gasoil and LA Pipeline No. 2 is cited by the Eight Parties as strong support for their proposed 1.1¢/gallon logistics adjustment. *Id.*

1354. In addition to the price differentials cited above, the Eight Parties argue that statistical tests support their contention that there is a statistically significant differential between West Coast Waterborne Low Sulfur Gasoil and Los Angeles Pipeline No. 2 and that the differential is consistent with the proposed logistics adjustment of 1.1¢/gallon.[542]

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[540] The Eight Parties list the costs incurred in transporting product to the pipeline from the harbor as: cargo inspection, dock and wharf fees, terminal charges and pipeline tariff charges. Eight Parties Initial Brief at p. 153.

[541] According to the Eight Parties, this value is the actual observed waterborne/pipeline differentials between West Coast Waterborne Low Sulfur Gasoil and LA Pipeline No. 2. *Id.* While these two products are not identical, the Eight Parties cite Platts and state that it specifically stated that they are considered interchangeable. *Id.* The value was calculated by Ross, whose testimony is sponsored by BP, and supported by the Eight Parties. *Id.*

[542] These statistical tests were conducted by Cavanagh whose testimony was

Id. The Eight Parties argue that the statistical tests Cavanagh performed properly led him to conclude that, in each of these cases, the hypothesis that there is no systematic difference must be rejected in favor of the hypothesis that pipeline prices are systematically and statistically significantly higher than waterborne prices.[543] *Id.* at p. 156. They claim that these tests show that the observed differences cannot be explained as occurring through random chance and that there is no close relationship in time that would account for the differences. *Id.* at pp. 154-56.

1355. The Eight Parties go on to take exception with Exxon's challenges to the proposed logistics adjustment. *Id.* at p. 156. They present five reasons why Exxon's challenges should be found unavailing: (1) the logistics adjustment is clearly within the scope of the proceedings, (2) consistency is a factor utilized in valuing the various Quality Bank cuts, (3) the predominate flow of West Coast Waterborne Low Sulfur Gasoil is from harbor to pipeline, (4) the proposed logistics adjustment is sound and grounded in fact, and (5) there are consistent price differentials between West Coast and Gulf Coast products. *Id.* at pp. 156-58; Eight Parties Reply Brief at pp. 118-19.

1356. First, the Eight Parties state that the proposed logistics adjustment is clearly within the scope of these proceedings. Eight Parties Reply Brief at p. 119. They assert that the logistics adjustment was fully briefed by Exxon and the Eight Parties beginning in February of 2002; it was the subject of several rounds of discovery; it was included in opening statements; and it was the subject of several witnesses's testimony during the

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sponsored by BP and supported by the Eight Parties. Eight Parties Initial Brief at p. 154. The Eight Parties state that Cavanagh first showed that there is a high correlation between waterborne and pipeline prices, indicating the samples are highly interdependent. *Id.* at p. 155. Then, the Eight Parties state, because the samples are interdependent, he used a matched pairs t-test to show that there is a systematic difference between pipeline and waterborne prices. *Id.* Finally, the Eight Parties note, Cavanagh also performed the same waterborne/pipeline comparison for regular gasoline and jet fuel. *Id.* at pp. 154-55.

[543] The Eight Parties explain that using the matched pairs t-test, Cavanagh computed t-statistics as follows: (1) 14.27 for jet fuel; (2) 11.86 for gasoline; and (3) 9.95 for West Coast Waterborne Low Sulfur Gasoil versus Los Angeles Pipeline No. 2. Eight Parties Initial Brief at p. 155. They also explain that, to interpret these statistics, Cavanagh computed the corresponding p-values. *Id.* (A p-value is the "probability that we would observe, by chance, a statistic at least as large as that which we actually observe if there were no systematic difference between the waterborne and pipeline prices." Exhibit No. BPX-60 at p. 12.) According to the Eight Parties, small p-values indicate that the observed differences are much larger than one would observe by pure chance. Eight Parties Initial Brief at p. 155. Here, the Eight Parties note, the p-values for each of the three relationships discussed above are less than one in one billion. *Id.*

hearing. *Id.* Yet, note the Eight Parties, Exxon never moved to strike the testimony, never objected to the opening statement, and never sought to exclude testimony or evidence on the grounds that it was outside the scope of these proceedings. *Id.* The Eight Parties point out that Exxon has, in fact, submitted testimony on this issue at every stage of these proceedings. *Id.* They argue that Exxon's failure to object until now on these grounds, and its decision to present testimony on the proposed logistics adjustment, should be fatal to Exxon's argument.[544] *Id.* at pp. 119-20. In arguing that the logistics adjustment issue is not within the scope of these proceedings, the Eight Parties maintain, Exxon ignores the fact that neither the Commission nor the Circuit Court has ever ruled as to what is properly considered part of the adjustment to be made to West Coast LA Pipeline No. 2 in order to arrive at a just and reasonable reference price for the Heavy Distillate cut. *Id.* at p. 120.

1357. The Eight Parties explain that, because they proposed that the new Heavy Distillate reference price be adjusted for desulfurization and logistics (i.e., transportation) costs and this issue was included in the issues set for hearing in this proceeding, that all of the issues raised in the Eight Parties's contested settlement, including both the proposed desulfurization and logistics adjustments to the Heavy Distillate reference price, are properly before the Commission and properly within the scope of these proceedings. *Id.* at pp. 120-21. Further, the Eight Parties argue that is true even though the Commission used the term "processing costs" in its order consolidating these proceedings, the Commission did not completely define the scope of that term and, therefore, it would be inappropriate to exclude the proposed logistics adjustment from consideration. *Id.* at p. 121.

1358. Second, the Eight Parties disagree with Exxon's assessment that there is no consistency utilized in valuing the various Quality Bank cuts. Eight Parties Initial Brief at p. 156. As set forth in the discussion regarding coke value, the Eight Parties aver that a consistency does exist. *Id.* According to them, all four gas plant products are valued on a pipeline basis on the Gulf Coast and on a truck/rail basis on the West Coast. *Id.* Accordingly, all of the gas plant products are consistently valued on each coast using the largest parcel sizes available. *Id.* As for the liquid products, the Eight Parties argue, all five Gulf Coast liquid products are consistently valued on a waterborne basis. *Id.* at pp. 156-57. Additionally, on the West Coast, they point out that Naphtha, Light Distillate and VGO are currently valued on a waterborne basis. *Id.* at p. 157. Further, the Eight Parties propose that the remaining two West Coast liquid cuts, Heavy Distillate and Resid, be valued on a waterborne basis. *Id.*

[544] In support, the Eight Parties cite *City of Alma, Michigan*, 97 FERC ¶ 61,147, at p. 61,639 (2001); *Jupiter Energy Corp.*, 41 FERC ¶ 63,008, at p. 65,013 (1987). Eight Parties Reply Brief at p. 119.

1359. Third, the Eight Parties argue, Exxon's witness, Pavlovic, attempted to obscure the fact that the predominate flow of West Coast Waterborne Low Sulfur Gasoil is from harbor to pipeline by focusing on the movement of all petroleum products across the West Coast in addition to discussing refinery production data and product movement. *Id.* In fact, in the Eight Parties's view, most of this product movement is irrelevant and their witness, Ross, properly focused his analysis on whether the proposed logistics adjustment captures the cost associated with moving West Coast Waterborne Low Sulfur Gasoil from the harbor to the pipeline hub. *Id.*

1360. Exxon's argument related to product flow is, in the Eight Parties's view, pointed in the wrong direction, and they maintain that Exxon continues its attempts to obscure the facts by focusing on the predominance of all products moving from refineries to pipeline terminals on the West Coast. Eight Parties Reply Brief at p. 123 (citing Exhibit No. EMT-102 at pp. 7-11). The Eight Parties argue that such movement has nothing to do with the relationships between waterborne and pipeline prices in Los Angeles for low sulfur gasoil. *Id.*

1361. To establish the proper logistics adjustment necessary to bring pipeline prices onto a consistent waterborne basis, the Eight Parties maintain that all that needs to be determined is whether the products at issue are imported or exported from Los Angeles. *Id.* Since 1999, explain the Eight Parties, imports of low sulfur gasoil[545] into the ports of Los Angeles and Long Beach have far exceeded exports. *Id.* at pp. 123-24 (citing Exhibit Nos. BPX-55 at p. 6, BPX-56). Once imported, continue the Eight Parties, cargoes with the product specifications matching that of low sulfur gasoil or West Coast LA Pipeline No. 2, which cannot be used in California due to CARB standards, must be shipped by pipeline to markets east of California. *Id.* at p. 124. Accordingly, the Eight Parties state, they must be transported to the pipeline for disposition, thereby adding value to the product, reflected in the transportation cost, and allowing for a higher price than waterborne deliveries. *Id.* In order to bring the West Coast LA Pipeline No. 2 price back to a consistent waterborne basis with all of the other liquid products, they argue, the Quality Bank must subtract this added value from the pipeline price. *Id.*

1362. Fourth, the Eight Parties characterize Pavlovic's attack on the cost basis used by Ross in determining the appropriate logistics adjustment as unsound and ungrounded in fact. Eight Parties Initial Brief at p. 157. They assert that even Pavlovic's own data set forth on page 13 of Exhibit No. EMT-102 shows that there is a consistent differential between pipeline and waterborne prices for like products such as gasoline and jet fuel.

[545] The Eight Parties explain that while not precisely the same product, "Platt's specifically stated that Low Sulfur No. 2 [West Coast LA Pipeline No. 2] and Low Sulfur 0.05% Gasoil are interchangeable." Eight Parties Reply Brief at p. 123, n.55 (citing Exhibit No. BPX-55 at p. 10).

Id. The observed differentials for these products range from 0.2¢ to 3.3¢/gallon according to them. *Id.* Although broader, the Eight Parties point out that this range is similar to Ross's cost estimate range of 1.04¢ to 2.09¢/gallon. *Id.* According to the Eight Parties, this similarity between the range of observed price differentials and the range of logistics costs provides powerful support for a causal relationship. *Id.* at pp. 157-58.

1363. Fifth, the Eight Parties argue, Pavlovic is wrong when he claims that there are no systematic price differentials between West Coast Waterborne Low Sulfur Gasoil versus LA Pipeline No.2, waterborne versus pipeline gasoline, or waterborne versus pipeline jet fuel. *Id.* at p. 158. They assert this is because Pavlovic used a statistical test suited for independent price samples rather than one suited for interdependent samples, which the Eight Parties believe is the correct test.[546] *Id.* After repeating their argument that a high correlation between analyzed products proves a high degree of interdependence, not independence, the Eight Parties assert that, because Cavanagh's critique went unanswered and unchallenged, this lack of independence invalidates Pavlovic's analysis using the two sample t-test. *Id.*

1364. Further, the Eight Parties point out, a simple review of the number of times that average waterborne prices were lower than average pipeline prices provides evidence that Pavlovic performed a faulty analysis. *Id.* at pp. 158-59. They quote Cavanagh's statement that: "If there truly were no systematic difference between [waterborne and pipeline] prices, we would expect to see waterborne prices greater than pipeline prices in about one-half of the months that we observe" as support of this proposition. *Id.* at p. 159 (quoting Exhibit No. BPX-60 at p. 10). However, the Eight Parties point out that Pavlovic's own work papers reveal that average pipeline prices were higher than average waterborne prices significantly more often, and in one case, always. *Id.* Specifically, the Eight Parties point to Cavanagh's testimony that pipeline prices were higher than waterborne prices in 26 out of 26 observed months for West Coast Waterborne Low Sulfur Gasoil versus LA Pipeline No. 2, in 134 out of 144 observed months for gasoline, and in 129 out of 144 observed months for jet fuel. *Id.*

1365. If there were no statistically significant difference between waterborne and pipeline prices, then, in the Eight Parties view, the chances that pipeline prices would be higher than waterborne prices to such a great degree would be either close to or less than one in one million. *Id.* Hence, based on the undisputed evidence presented by Cavanagh, the Eight Parties argue that Pavlovic's conclusion that there is no statistically significant

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[546] Rather than applying what the Eight Parties view as the proper matched pairs t-test to the data, the Eight Parties complain that Pavlovic used a two-sample t-test, which is only proper, according to them, if the samples are independent of each other. Eight Parties Initial Brief at p. 158. The Eight Parties also question Pavlovic's qualifications as a statistician. *Id.*

difference between pipeline and waterborne prices is plainly wrong and must be entirely discarded. *Id.*

1366. According to the Eight Parties, Exxon's argument that the Eight Parties 1.1¢/gallon logistics adjustment is not supported by any evidence reveals that Exxon has chosen to ignore the facts presented in this case. Eight Parties Reply Brief at p. 124. The Eight Parties assert that the 1.1¢/gallon figure is based on undisputed evidence and, therefore, it cannot be overlooked. *Id.* In addition to the pipeline charges established through a tariff, the Eight Parties point out that there is evidence of the cost of Los Angeles cargo inspection, dock and wharf fees and of terminal charges. *Id.* (citing Exhibit No. BPX-1 at pp. 12-13). The Eight Parties argue that the fact that these costs were developed through phone calls, discussions, and other forms of information does not make them suspect. *Id.* They maintain that these are the best and only sources of evidence for these market-driven rates, which are confidentially negotiated between suppliers and users of these services. *Id.* at pp.124-25. According to them, there are no published tariffs for such costs and other information is not widely available, particularly as a time series. *Id.* at p. 125. However, they note, just because it may be difficult to establish a consistent basis upon which to place values, this does not mean that one is excused from putting forth ones best efforts to do so. *Id.* The Eight Parties contend that Ross has attempted to provide his best estimate, based on the best information available, to determine the proper logistics adjustment for the Heavy Distillate reference price. *Id.*

1367. Furthermore, state the Eight Parties, both Ross and Cavanagh conducted significant analysis to verify that 1.1¢/gallon reflects the costs of moving product from the harbor to the pipeline. *Id.* They believe that the fact that Exxon stipulated that Cavanagh need not appear at the hearing and did not mention Cavanagh in their brief indicates that Exxon found nothing to challenge about Cavanagh's testimony. *Id.* Further, the Eight Parties assert, the fact that the waterborne prices were not below the pipeline prices every single month, as Exxon points out, in no way alters the fact that, on average, these differentials are consistent with a 1.1¢/gallon proposed adjustment. *Id.* at p. 126. Indeed, the Eight Parties claim, Pavlovic's own testimony shows that, for regular gasoline, only in nine out of 144 months, and not once since July 1992, were waterborne prices higher than pipeline prices and that in only fourteen of 144 months, and only once since May 1992, were West Coast jet fuel waterborne prices higher than pipeline prices. *Id.*

1368. Exxon argues that, as the proponents of this logistics adjustment, the Eight Parties have the burden of proving both the need for the proposed adjustment and the reasonableness of the amount proposed. Exxon Initial Brief at p. 167. Further, Exxon asserts, the Eight Parties have not met either of these burdens, and it presents five reasons why they have not. *Id.* As a threshold matter, Exxon argues that the proposed logistics adjustment is clearly not a "sulfur processing cost adjustment," and is thus outside the scope of the issues to be addressed in this case. *Id.* Second, contrary to Ross's claim, Exxon asserts the proposed logistics adjustment is neither required nor justified on the alleged ground that it will achieve consistency with the other liquid cuts. *Id.* at pp. 167-68. Third, in Exxon's opinion, the size of the proposed 1.1¢/gallon logistics adjustment is plainly not supported by substantial evidence. *Id.* at p. 168. Fourth, the proposed logistics adjustment is premised on what Exxon states is a false assumption – that the predominant flow of low sulfur fuel oil on the West Coast is from harbor to pipeline. *Id.* Fifth, Exxon views Ross's attempt to validate his proposed logistics adjustment on the basis of waterborne/pipeline price differentials for low sulfur fuel oil and other products as based on invalid assumptions and not supported by substantial evidence. *Id.*

1369. According to Exxon, the proposed "logistics adjustment" must be rejected as a threshold matter because it is outside the scope of the Heavy Distillate issue that was referred for hearing in this case. *Id.* Exxon points out that the Commission stated repeatedly in its order establishing this consolidated hearing that the only issue relating to Heavy Distillate to be addressed in this case was the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the new reference price. *Id.* Further, notes Exxon, the Eight Parties did not address this jurisdictional issue in their initial brief, stating, without support, that a logistics adjustment is required for consistency. Exxon Reply Brief at p. 178.

1370. Exxon explains that, when Platts ceased publication of the price for West Coast High Sulfur Gas Oil, all parties agreed that the Platts LA Pipeline Low Sulfur No. 2 Fuel Oil price should be used as the new West Coast proxy price for valuing the Quality Bank Heavy Distillate cut. Exxon Initial Brief at pp. 168-69. However, the parties were unable to agree on the cost that would be incurred to bring the sulfur content of the Heavy Distillate cut into line with the much lower sulfur level on which the new reference price was to be based. *Id.* at p. 169.

1371. Exxon points out that, in its order accepting the new West Coast reference product for the Heavy Distillate cut,[547] the Commission rejected the Eight Parties's proposal for a sulfur processing cost adjustment of 6.0¢/gallon because that adjustment did not "reflect the actual processing cost differential." *Id.* Exxon also points out that, in the same order,[548] the Commission declined to accept Tesoro's proposal for a 3.5¢/gallon sulfur processing cost adjustment because all parties had not reviewed it. *Id.* Further, Exxon notes that the Commission made clear that the issue to be resolved was "the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line

[547] *Trans Alaska Pipeline System*, 90 FERC at p. 61,371.

[548] *Trans Alaska Pipeline System*, 90 FERC at pp. 61,371-72.

with the [new] quoted price."[549] *Id.*

1372. Further, according to Exxon, any possible uncertainty on the proper scope of the term "sulfur processing adjustment" is eliminated by the Commission's subsequent order establishing this consolidated hearing, in which the Commission described the sole issue in the "replacement product proceeding" relating to the new West Coast Heavy Distillate reference price as follows:[550] "At issue in the replacement product proceeding is the level of the *sulfur processing adjustment* necessary to bring the TAPS Heavy Distillate cut into line with the quoted price." *Id.* at p. 170. And again, in framing the "Replacement Product Issue" being set for hearing, Exxon claims, the Commission stated[551] that the only matter "[a]t issue in the replacement product proceeding is the level of the *sulfur processing adjustment* necessary to bring the Trans-Alaska Pipeline System Heavy Distillate cut into line with the quoted price." *Id.* at pp. 170-71. Consequently, Exxon asserts, there can be no doubt that the sole issue relating to the new West Coast reference price for the Heavy Distillate cut set for hearing is the level of the sulfur processing cost adjustment required to bring the sulfur content of the ANS Heavy Distillate cut to the sulfur level on which the reference price is based. *Id.* at p. 171.

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[549] *Trans Alaska Pipeline System*, 90 FERC at p. 61,371. Exxon points out that Williams recognized this fact when it sought judicial review of the Commission's February 9, 2000, order (*Trans Alaska Pipeline System*, 90 FERC ¶ 61,123 (2000)), setting the sulfur "processing cost adjustment issue" for hearing, claiming that the Commission order was a "final determination" that certain other costs, which Williams referred to as "terminal fees," would not be included in the adjustment to the replacement proxy price for Heavy Distillate. Exxon Initial Brief at p. 170, n.70. It points out that the Commission's February 9, 2000, referral order was plainly "not a reviewable final order," and Williams's appeal was dismissed as premature by the Circuit Court. *Williams Alaska Petroleum Inc. v. FERC*, Case No. 00-1153 (D.C. Cir. June 29, 2000). Exxon argues that, therefore, contrary to Williams's argument, the court's statement that Williams "may raise on appeal, after a final Commission order establishing the appropriate processing cost adjustment, any issue it may have with respect to the processing cost adjustment, including whether terminal fees are properly included" (*id.*), does not support Williams' position regarding the proposed "logistics adjustment." Exxon Initial Brief at p. 170, n.70. By that language, Exxon believes the court plainly intended only that Williams could again raise on appeal from the Commission's final order its claim that the Commission erred in limiting the scope of the issue to only sulfur processing costs and not broadening the scope to include non-processing costs, such as terminal fees. *Id.*

[550] *Trans Alaska Pipeline System*, 97 FERC at p. 61,650 (emphasis added by Exxon).

[551] *Trans Alaska Pipeline System*, 97 FERC at p. 61,652 (emphasis added by Exxon).

1373. Therefore, Exxon argues, under no conceivable theory is the "logistics adjustment" proposed by the Eight Parties a "sulfur processing adjustment." *Id.* Exxon views as undisputed that the Eight Parties's proposed logistics adjustment has nothing to do with the cost of desulfurizing the Quality Bank Heavy Distillate cut to the lower sulfur level of the agreed-upon reference price. *Id.* Rather, Exxon's view is that the proposed logistics adjustment is a completely separate adjustment that attempts to take the agreed-upon Platts LA Pipeline Low Sulfur reference price and convert it to a waterborne cargo price. *Id.* Exxon also explains that BP acknowledged that the proposed Heavy Distillate logistics adjustment differed from the N+A adjustment for Naphtha in that the logistics adjustment is not based on the chemical characteristics of Heavy Distillate. Exxon Reply Brief at p. 178. Accordingly, Exxon contends that the logistics adjustment proposed by the Eight Parties is outside the scope of this proceeding and should be rejected on that ground alone. Exxon Initial Brief at p. 171.

1374. According to Exxon, the sole reason offered by Ross for his proposed logistics adjustment was that "a logistics adjustment is needed to ensure that the Heavy Distillate cut is valued on a consistent basis with all other liquid cuts." *Id.* at p. 172 (citing Exhibit No. BPX-1 at p. 9). Exxon asserts, however, that the evidence shows that there is no factual basis for Ross's claim that valuation of the various cuts must be done on a consistent basis. *Id.*

1375. First, Exxon states that Ross's assumption that all of the Quality Bank "liquid cuts" are valued on a waterborne basis is wrong. *Id.* Exxon maintains that the evidence clearly shows that LSR – one of the "liquid products" initially identified by Ross – is valued on a Bakersfield truck/rail basis.[552] *Id.* Furthermore, Exxon points out that Ross's attempt at the hearing to repudiate his prior written testimony (identifying LSR as a "liquid cut" that is valued on a "waterborne basis") as an editing error was itself repudiated by his subsequent testimony that LSR is in fact a "liquid" that is not valued by the Quality Bank on the basis of a "waterborne price." *Id.* (citing Transcript at pp. 1722-23).

1376. Exxon goes on to argue that the evidence shows that, of the nine West Coast Quality Bank proxy products, only one – Light Distillate (jet fuel) – is currently valued on a West Coast waterborne basis. *Id.* at p. 173. Further, Exxon points out, Ross himself conceded that all of the natural gas liquids – including Propane, Isobutane, Normal

[552] Exxon points out that when this error was brought to Ross's attention by Exxon in a data request, BP filed a "Revised Version" of Exhibit No. BPX-1 on March 8, 2002, which eliminated LSR from Ross's list of "liquid products." *See* Exhibit No. BPX-1 at p. 5. Exxon points out that O'Brien, the Eight Parties's expert, views LSR as a liquid product. Exxon Initial Brief at p. 172, n.71.

Butane, and LSR – are valued on the West Coast on a "land-based" truck or railcar basis, rather than on a waterborne basis. *Id.*

1377. Nor, in the opinion of Exxon and contrary to Ross's contention, is a logistics adjustment necessary to ensure that the Quality Bank pricing bases are consistent with respect to transaction size. *Id.* According to Exxon, the Quality Bank has never articulated or followed a course of choosing the largest available transaction quantities, and, as Ross himself admitted, the Quality Bank does not always value cuts based on the largest parcel of product available. *Id.* For example, Exxon notes that the VGO cut has been valued on both the West Coast and Gulf Coast on the basis of the OPIS Gulf Coast High Sulfur VGO barge price assessment, which represents transactions that are much smaller than the transactions represented by the OPIS Gulf Coast High Sulfur VGO cargo price assessment. *Id.* As Ross acknowledged, the smaller cargo price was selected for VGO valuation because it was more "robust," that is, "[t]here's a greater frequency of transactions and therefore, it is a more reliable indication of the actual spot market on the day it was picked." *Id.* (citing Transcript at p. 1719). According to Exxon, this same reasoning is equally applicable to the Platts LA Pipeline Low Sulfur price that has been accepted by the Commission as the reference price for West Coast Heavy Distillate. *Id.* at p. 174.

1378. The evidence also shows, in Exxon's view, that many other Quality Bank proxy prices are not presently consistent with regard to location. *Id.* Exxon contends that the Eight Parties's proposed logistics adjustment would do nothing to cure this inconsistency. *Id.* For example, Exxon notes that the West Coast Propane, Isobutane, and Butane proxy products are priced at Los Angeles, while the LSR proxy product is priced at Bakersfield in the San Joaquin Valley. *Id.* Similarly, Exxon notes that, on the Gulf Coast, the Propane, Isobutane, Butane, and LSR proxy products are priced at Mt. Belvieu, Texas, which is significantly removed from the marine terminals on which the waterborne price assessments for the Naphtha through Resid cuts on the Gulf Coast are based.[553] *Id.* Contrary to Ross's contention, therefore, Exxon argues that the evidence clearly shows that a consistent location has never been a requirement in the selection of the Quality Bank proxy prices. *Id.*

1379. Finally, according to Exxon, the Eight Parties's claim regarding "largest available parcels" is not supported by the Energy Information Administration data that Ross presented in support of his testimony regarding the valuation of West Coast Naphtha. Exxon Reply Brief at p. 182. It is common for products to be shipped in part cargoes, i.e., ships with more than one product contained in segregated compartments, Exxon

[553] Similarly, Exxon notes that the new proposals for valuing the Resid cut are not based exclusively on waterborne prices, but rather are a mixture of prices at different locations. Exxon Initial Brief at p. 174, n.72.

contends. *Id.* (citing Transcript at pp. 10021-22). Indeed, continues Exxon, Platts recognizes this in its specifications for products including diesel fuel. *Id.* (citing Exhibit No. EMT-105 at p. 4). Exxon asserts that Ross's testimony regarding the purported need for a logistics adjustment does not take this fact into account. *Id.* at pp. 182-83.

1380. Rather than focusing on such issues as whether the reference price is set forth on a waterborne basis or whether it represents the largest parcels available, Exxon points out, the Circuit Court[554] and the Commission[555] have made it abundantly clear that the Quality Bank methodology requires that the reference price for each cut should reflect the market value of that cut. *Id.* at pp. 180-81. In Exxon's opinion, the evidence makes clear that the Quality Bank Administrator, a neutral, independent party, has, in managing the Quality Bank, abided by the principle that each cut should be valued in a way that best captures its market value. *Id.* at p. 181. For example, in 1998, Exxon explains, the Quality Bank Administrator recommended adopting the OPIS VGO barge assessment because that price assessment was "the most representative indicator of High Sulfur VGO market value and therefore seems to be the best single price to reflect the market for High Sulfur VGO on the Gulf Coast." *Id.* (quoting Exhibit No. TC-23 at p. 4). Similarly, notes Exxon, in recommending the adoption of the Platts Gulf Coast "Heavy Naphtha" assessment in February 2003, the Quality Bank Administrator specifically relied on this same guiding principle: "It is . . . my understanding that the intent of the [Commission] . . . is that all components be valued on the basis that best reflects their value in the market."[556] *Id.* (quoting Exhibit No. PAI-222 at p. 4).

1381. Exxon argues that the Platts LA Pipeline Low Sulfur No. 2 Fuel Oil price is a better representation of "the real market for low-sulfur heavy distillate than the waterborne price." Exxon Initial Brief at p. 174. It notes that Ross conceded the "vast majority of Los Angeles refinery production" of Heavy Distillate that is sold by refineries is sold "at the pipeline terminal," and not on the basis of any waterborne price. *Id.* at pp. 174-75 (citing Transcript at pp. 1792-93). By attempting to place the pipeline price on a waterborne basis, therefore, according to Exxon, Ross's proposed logistics adjustment

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[554] Exxon cites *Tesoro*, 234 F.3d at p. 1289; *Exxon*, 182 F.3d at p. 35.

[555] Exxon cites *Trans Alaska Pipeline System*, 97 FERC at p. 61,649; *Trans Alaska Pipeline System*, 81 FERC at p. 62,457.

[556] Exxon notes that the Quality Bank Tariff's provision governing "Unanticipated Implementation Issues" expressly authorizes the Quality Bank Administrator to resolve such issues "in accordance with the best understanding of the intent of the [Commission] that the Quality Bank Administrator can derive from [its] orders regarding the Quality Bank methodology." Exxon Reply Brief at p. 181, n.98 (quoting Exhibit No. TC-3 at p. 8).

violates Ross's own purported objective of establishing a price that is "more representative of the values of these streams to the refinery." *Id.* at p. 175 (citing Exhibit No. BPX-1 at p. 16). The true value to the refiner, according to Exxon, of the various Quality Bank cuts, is the value of the cut at the refinery gate. *Id.* In Exxon's view, Ross's proposed logistics adjustment does not represent this true value, but seeks, instead, to adjust the agreed-upon pipeline reference price not to the refinery gate, but to the harbor – a location that has no relevance either to the refiner or to the reference price. *Id.*

1382. There is also no substantial evidentiary support, according to Exxon, for the 1.1¢/gallon figure that Ross proposed for his logistics adjustment. *Id.* It states that the Eight Parties represent this amount to be the sum of three categories of costs that would be incurred in moving a product from the Los Angeles harbor to the Kinder Morgan pipeline terminal at Watson, California: (1) Los Angeles cargo inspection, dock and wharf fees, (2) terminal charges in the Port of Los Angeles, and (3) pipeline tariff charges from the port to Watson. *Id.* However, Exxon claims that Ross stated at the hearing that he had no reliable evidence to back up any of this data, and that his estimates were based on information from a small number of telephone calls that he made no effort to verify. *Id.* at pp. 175-76.

1383. In addition, Exxon argues that the evidence presented regarding terminal and pipeline tariff charges is based on only one or two telephone calls and has not been verified with any substantial data records. *Id.* at p. 176. For example, Exxon states, the evidence presented by Ross of typical terminal charges was based entirely on two telephone conversations from 2000 and 2002. *Id.*

1384. Ross also stated that he did not know what the range of terminal charges was over the longer five to ten year period, according to Exxon. *Id.;* Exxon Reply Brief at p. 183. Similarly, with respect to the pipeline tariff charges, Exxon asserts that Ross admitted that he did not know what these charges were for any year earlier than 2002 and that he had no work papers showing any of those changes, even though he claimed to have tracked the changes in the tariffs and other charges. Exxon Initial Brief at p. 176. Exxon also declares that, despite his professed concern for consistency, Ross admitted that he never tried to get 1996 data for the pipeline tariffs, even though O'Brien used 1996 costs for his estimate of sulfur processing costs for valuing the Heavy Distillate cut. *Id.*

1385. Exxon also argues that Ross premised his logistics adjustment upon an incorrect factual assumption: that the predominant flow of low sulfur fuel oil in West Coast markets is from harbor to pipeline. Exxon Initial Brief at p. 177. While Exhibit No. BPX-5 purports to show that there is a significant net inflow of certain petroleum products to the West Coast, Exxon contends that there is an error in the Exhibit. *Id.* The error, according to Exxon, is in combining waterborne and pipeline shipments and calling them net receipts, thereby giving what Exxon believes is a false impression that waterborne shipments into the West Coast outweighed waterborne shipments out of the West Coast. *Id.* Exxon asserts that, in fact, the overwhelming majority of the shipments that Ross reported as net receipts were actually pipeline shipments to the West Coast, which do not pass through West Coast harbor terminals. *Id.* If this error is corrected, Exxon states that it becomes clear both that product outflows in general dwarf waterborne inflows to the West Coast, and that waterborne low sulfur fuel oil outflows have exceeded or roughly equaled waterborne inflows in all but one of the last seven years. *Id.*

1386. Further, Exxon asserts, Pavlovic also demonstrated that the predominant flow of products in the Los Angeles market is not from harbor to pipeline, but from the refineries (1) to the pipeline terminal for further shipment to inland markets in California, Nevada, and Arizona, or (2) to the harbor for export or shipment to other West Coast domestic markets, supplemented by imports and domestic shipments from other refinery centers. *Id.* at pp. 177-78. It states that, during the hearing, Ross conceded that the majority of the product sold at the pipeline is produced in California. *Id.* at p. 178.

1387. Exxon also maintains that the Eight Parties's claim that Pavlovic was attempting "to obscure the fact that the predominate flow of West Coast Waterborne Low Sulfur Gasoil is from harbor to pipeline by focusing on the movement of all petroleum products across the West Coast" is false. Exxon Reply Brief at p. 185 (quoting Eight Parties Initial Brief at p. 157). While Pavlovic looked at other products, Exxon points out that he also focused specifically on low sulfur No. 2 distillate fuel oil with a sulfur content less than 0.05% — the very product chosen by all parties as the reference product for the Heavy Distillate cut — and determined that "with regard to LS No. 2 waterborne outflows have balanced or exceeded waterborne inflows in all but one of the last seven years." *Id.* (quoting Exhibit No. EMT-102 at pp. 10-12; citing Exhibit No. EMT-106 (showing separately the net waterborne flows for "Distillate Fuel Oil <0.05% S" and that only in the year 2000 did imports exceed exports)).

1388. Further, by making the assertion that the movement of other West Coast products is irrelevant (Eight Parties Initial Brief at p. 157), Exxon states that the Eight Parties apparently concede that, as the record amply shows, "refinery production and its attendant product outflows dwarf import and domestic waterborne inflows to the West Coast market" for other Quality Bank reference products, such as jet fuel. *Id.* at pp. 185-86 (quoting Exhibit No. EMT-102 at p. 10). Moreover, asserts Exxon, Ross's claim in this regard is difficult to square with his reliance on the waterborne-pipeline price differentials of other products to support his proposed logistics adjustment of 1.1¢/gallon. *Id.* at p. 186.

1389. Exxon concludes, therefore, that the evidence shows that Ross's assumption about the predominance of the harbor-to-pipeline flow was erroneous. Exxon Initial Brief at p. 178. Indeed, according to Exxon, Ross's own testimony showed that he had no substantial evidence to support his assumptions about product flow. *Id.* To bolster this assertion, Exxon cites testimony in which Ross admitted that he did not know what actually happened to waterborne cargoes, and that he could not say whether any waterborne cargo was actually moved from the Port of Los Angeles to a pipeline to be sold at the pipeline hub.[557] *Id.* Exxon notes that Ross further admitted that the net flow of products on the West Coast has been changing over time and the predominant flow prior to 1999 was not from harbor to pipeline.[558] *Id.* As a result, Exxon states that Ross was unable to say whether his proposed logistics adjustment would have been appropriate prior to 1999.[559] *Id.*

1390. Moreover, even if one were to assume that the harbor price reflected an import price, as Ross contended, Exxon asserts this would buttress the conclusion that the pipeline price, not the waterborne price, is the best indicator of the value of the reference product to a refiner. *Id.* Exxon argues for this conclusion because, it claims, Ross's proposed logistics adjustment assumes that the harbor price is equal to the pipeline price minus the costs of moving the Heavy Distillate from the harbor to the pipeline. *Id.* It asserts that, were this the case, a West Coast refiner would never sell at the harbor price, because it would always be able to sell for a higher price at the pipeline. *Id.* at pp. 178-79. Because the purpose, according to Exxon, of the Quality Bank is to establish the value of the Heavy Distillate cut to a West Coast refiner, the only logical conclusion is that Ross's assumed harbor price has no relevance to the valuation of the West Coast Heavy Distillate cut. *Id.* at p. 179.

1391. Having argued that a proposed 1.1¢/gallon logistics adjustment has no substantial evidentiary basis, Exxon then takes exception to Ross's attempts to validate his figure by comparing the "waterborne/pipeline differentials in the reported prices for similarly situated products," namely, regular gasoline and jet fuel. *Id.* Exxon contends that Ross's analysis in this effort is wholly lacking in credible evidentiary support. *Id.*

1392. Exxon points out that Pavlovic presented substantial evidence that during the period from 1990-2001 there were four West Coast refined petroleum products[560] for which Platts published both waterborne and pipeline daily spot price assessments, and that his analysis demonstrates that the waterborne price was not consistently lower than

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[557] Transcript at pp. 1707-08.

[558] Transcript at pp. 1739-40.

[559] Transcript at p. 1740.

[560] Exxon states that the four products are: regular gasoline (1990-2001), jet fuel (1990-2001), FO 380 residual fuel oil (1990-1995), and FO 180 residual fuel oil (1994-95). Exxon Initial Brief at p. 179.

the pipeline price for any of the four price pairs. *Id.* Indeed, notes Exxon, there have been a number of times when the waterborne price was higher than the pipeline price. *Id.* at pp. 179-80. The same is also true, continues Exxon, of the comparison of LA Pipeline LS No. 2 with West Coast Waterborne LS gas oil. Exxon Reply Brief at p. 187.

1393. If Ross is correct, Exxon suggests, that both the pipeline/waterborne price differentials reflect a simple logistics cost relationship for moving from the harbor to the pipeline terminal and that such costs have been generally stable over time, then those price differentials should be stable over time as well. Exxon Initial Brief at p. 180. Exxon points out that, in fact, the differentials between the waterborne and pipeline prices have fluctuated widely over time. *Id.*

1394. As support for this, Exxon cites evidence that, for example, the differential for regular gasoline ranged from –9.6¢/gallon to +16.3¢/gallon over a 10-year period.[561] *Id.* Further, notes Exxon, Pavlovic found no stable differential over time looking even at the annual averages for regular gasoline, jet fuel, F.O. 380, and F.O. 180.[562] Exxon Reply Brief at p. 188. For this reason, explains Exxon, Pavlovic concluded that "there is no consistent pipeline/waterborne differential – only many average differentials, the values of which depend on the period over which the average is taken." *Id.* (quoting Exhibit EMT-102 at pp.13-14). In light of this variability, Exxon argues there is no evidence that Ross's proposed logistics adjustment of 1.1¢ is any more than coincidentally related to waterborne/pipeline price differentials.[563] Exxon Initial Brief at p. 180.

1395. Further, Exxon contends that, if Ross were correct that pipeline/waterborne price differentials in the West Coast market bore a direct relationship to the costs of transport from the harbor to the pipeline terminal, then the logistics costs for similar products should be the same, because the products use the same basic facilities – the same docks and pipelines – and should incur the same costs in moving from the harbor to the pipeline

[561] Exhibit No. EMT-102 at p. 12.

[562] Exhibit No. EMT-102 at p. 13.

[563] Exxon asserts that none of the Eight Parties's statistical arguments support adoption of the proposed logistics adjustment. Exxon Reply Brief at p. 188, n.101. For example, Exxon argues, the fact that, when averaged over a five-year basis, the waterborne/pipeline differentials for regular gasoline and jet fuel come out "close" (1.23¢ and 0.95¢/gallon, respectively) to Ross's proposed 1.1¢/gallon proposed logistics adjustment does not establish the reasonableness of using that adjustment. *Id.* This averaging over several years, it declares, masks significant variation in the differentials and fails to explain why the regular gasoline and jet fuel differentials do not behave like cost-based differentials when viewed on a daily, monthly, or even annual basis. *Id.*

terminal. Exxon Initial Brief at p. 180. Yet, Exxon notes, Platts prices show that there is an average variance of 40% between the average waterborne/pipeline differential for regular gasoline (1.5¢/gallon) and that for jet fuel (1.1¢/gallon.) *Id.* at pp. 180-81.

1396. Exxon also points out that the differential between the Platts published LA pipeline reference price for low sulfur fuel oil and the Platts West Coast waterborne price was only within the range of 1.0¢ to 1.5¢/gallon about 60% of the time, and that, on a number of occasions, the waterborne price was actually lower than the pipeline price. *Id.* at p. 181. These data squarely, Exxon suggests, refute Ross's claim that a logistics adjustment of 1.1¢/gallon is based on any valid, real world evidence of a waterborne/pipeline price differential.[564] *Id.*

1397. Ross's analysis concerning an alleged price differential, Exxon also argues, is based on the erroneous assumption that the Platts West Coast waterborne low sulfur fuel oil price is reliable when Exxon asserts that the record evidence shows that it is not. *Id.* First, it notes, Platts must often estimate, as conceded by Ross, the waterborne price due to the infrequency of waterborne transactions and, as a result, "there is that tendency of an upward bias between cargoes." *Id.* (citing Transcript at pp. 1779-80). Second, Exxon states, Ross's waterborne/pipeline price differential is not based on a true apples to apples comparison because, although the agreed-upon pipeline reference price is a Los Angeles-based price, Ross compares this Los Angeles pipeline price to a West Coast waterborne price, which consists of prices from San Francisco and Seattle, as well as Los Angeles. *Id.* at pp. 181-82. Moreover, Exxon points out, Ross conceded at the hearing that any price differential is due at least in part to the undisputed fact that Platts West Coast low sulfur waterborne price is based on a product specification that is superior to the product on which the Platts Los Angeles pipeline low sulfur reference price is based. *Id.* at p. 182.

1398. Relying on Ross's testimony, states Exxon, the Eight Parties also argue that the 0.2 to 3.3¢/gallon range observed in the annual average waterborne/pipeline differential for unleaded regular gasoline from 1990 to 2001 is similar to Ross's 1.04¢ to 2.09¢/gallon low-high range estimate for the logistics costs, and that this "powerfully supports a causal relationship." Exxon Reply Brief at p. 189 (quoting Eight Parties Initial Brief at p. 158). In fact, according to Exxon, the ranges are not comparable. *Id.* It asserts that the regular gasoline differential is almost three times wider than Ross's

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[564] Exxon notes that Ross conceded both the points in the paragraph and also admitted that the chart (*see* Exhibit No. BPX-22) he was using in this proceeding to justify a combined adjustment of 5.2¢/gallon (his logistics adjustment of 1.1¢/gallon combined with O'Brien's proposed 4.1¢/gallon sulfur processing cost adjustment) was the same chart that he had used in 2000 in an attempt to justify a proposed 6¢/gallon adjustment to the Heavy Distillate price. Exxon Initial Brief at p. 181, n.73.

logistics costs. *Id.* Additionally, continues Exxon, the comparisons are based on different time periods: 1990-2001 for the annual average gasoline differential versus 2000-2001 for the logistics cost figures that Ross gathered in his one or two telephone conversations. *Id.* Consequently, Exxon maintains that this comparison clearly does not prove a causal relationship based on logistics costs. *Id.*

1399. Finally, Exxon states, the Eight Parties's reliance on the testimony of Cavanagh is misplaced. *Id.*[565] While Cavanagh concluded that there is a statistically significant "difference between pipeline and waterborne prices in favor of the hypothesis that pipeline prices are higher than waterborne prices,"[566] Exxon notes, he testified that he had no information that explained why pipeline prices tended to be higher and offered no testimony as to whether logistics costs were the cause. *Id.* at pp. 189-90. Exxon also notes that Cavanagh conceded that his "statistical analysis has not sought to identify the source or the reason" for the statistically significant difference he found. *Id.* at p. 190 (quoting Exhibit No. BPX-114 at pp. 7-8).

1400. By contrast, according to Exxon, Pavlovic concluded that West Coast waterborne/pipeline differentials were the result of market conditions, not logistics costs. *Id.* Exxon declares that Cavanagh agreed that waterborne and pipeline prices could differ because of supply, demand or other market conditions and testified that he had not analyzed these factors to see if they explained the price differentials he found. *Id.* In addition, notes Exxon, Cavanagh conceded that he had not done the additional analysis that would be needed to explain the difference between his and Pavlovic's testimony, determine who was correct, or discover whether the differences are market driven or cost driven. *Id.*

1401. Further, Exxon points out that despite the fact that Cavanagh agreed that it is necessary in most cases to understand how the data used in a statistical test is gathered, he testified that he did not understand how the price data he analyzed had been gathered. *Id.* at p. 191. Exxon notes that Cavanagh mistakenly believed that the reported West Coast waterborne prices reflected solely transactions at LA, rather than transactions

[565] The Eight Parties's claim that "Cavanagh's critique went unanswered and unchallenged" (Eight Parties Brief at p. 158) is misleading, according to Exxon, since he submitted only rebuttal testimony; thus Exxon's witnesses had no opportunity to respond to his critique. Exxon Reply Brief at p. 189, n.102. Moreover, Exxon claims it "waived cross-examination" of "Cavanagh and instead [relied] on his deposition transcript . . . because that testimony clearly demonstrates that his written testimony did not answer the myriad problems with the Eight Parties' proposed 'logistics adjustment.'" *Id.* (citing Exhibit No. BPX-114; Transcript at pp. 158, 1884–85).

[566] Exhibit No. BPX-60 at p. 12.

occurring at other terminals on the West Coast. *Id.* Finally, Exxon states that Cavanagh also agreed it was accurate to state that he had not done any analysis on whether the way the data was collected had any impact on the price differentials he identified. *Id.*

E. BASE YEAR

1402. As explained in the section concerning Resid, the Eight Parties state they chose 1996 as the base year for calculating Heavy Distillate processing costs in order to put all of the processing cost calculations on a consistent basis. Eight Parties Initial Brief at p. 160. The Eight Parties assert that no issue regarding appropriate assumptions about facilities configuration in the base year was raised for Heavy Distillate. *Id.* They do not believe that choice of a base year should have a material impact on the outcome of the Heavy Distillate issue. *Id.*

1403. According to the Eight Parties, the need to use different indices is even less material for the Heavy Distillate cut than it is for the Resid cut. Eight Parties Reply Brief at p. 127 (referring to the Resid cut section of the Eight Parties Reply Brief). They point out that the use of different indices changes O'Brien's capital cost calculation by 1¢/barrel of Heavy Distillate over the four years from 1996-2000. *Id.* at pp. 127-28.

1404. The parties have agreed that the effective date for the new West Coast Heavy Distillate price should be February 1, 2000, Exxon begins. Exxon Initial Brief at p. 182. Nevertheless, there is a dispute about what base year should be used in calculating the sulfur processing cost adjustment. *Id.* The sulfur processing cost estimate presented by the Eight Parties stated all costs using 1996 as the base year, while the cost analysis presented by Exxon states all costs using 2000 as the base year. *Id.*

1405. Exxon asserts that, in theory, it should not matter which year – 1996 or 2000 – is used as the base year. *Id.* It notes that whichever base year is used, the costs for that year can be converted to the costs in another year by inflating or deflating the base year costs using the Nelson Farrar cost index. *Id.* However, Exxon identifies a potential problem because there are two Nelson Farrar indices applicable to different types of costs – (1) the Nelson Farrar Refinery Construction Cost Index (sometimes referred to as the Nelson Farrar Capital Cost Index), and (2) the Nelson Farrar Refinery Operating Cost Index – which produce different results depending on how they are applied and which base year is used. *Id.* at pp. 182-83. The TAPS Carriers's Tariff, notes Exxon, currently provides that all costs (both capital and operating) be adjusted by the same cost index, the Nelson Farrar Operating Cost Index. Exxon Reply Brief at p. 192.

1406. In adjusting their costs to the base year, both parties adjusted their estimates of the capital costs by using the Nelson Farrar Construction Cost Index, and both parties used the Nelson Farrar Operating Cost Index to adjust their operating cost estimates. Exxon Initial Brief at p. 183. There was no dispute that it is appropriate to use the Nelson Farrar

Construction Cost Index to adjust capital costs to the base year. *Id.* Likewise, there was no dispute that it would not be appropriate to use the Nelson Farrar Operating Cost Index to adjust capital costs to the base year. *Id.*

1407. However, once the costs have been adjusted to the base year, Exxon states that the Eight Parties take the position that, with the exception of their proposed logistics adjustment, all costs, including the capital costs, should be adjusted thereafter using only the Nelson Farrar Operating Cost Index. *Id.* at pp. 183-84. This position, according to Exxon, is based on the fact that the parties previously stipulated to the use of that index for adjustments to the "value" of the Quality Bank cuts. *Id.* at p. 184. As applied to the capital cost portion of the sulfur processing cost adjustment, Exxon's concern is that this proposal would have an impact in all years other than the base year because, although all capital costs are adjusted to the base year by using the Nelson Farrar Construction Cost Index, those same capital costs would then be adjusted from the base year to subsequent years using the Nelson Farrar Operating Cost Index. *Id.* Moreover, according to Exxon this difference is exacerbated by the fact that, unlike the Nelson Farrar Construction Cost Index which has risen relatively steadily over time, the Nelson Farrar Operating Cost Index has gone up and down from year to year. *Id.*

1408. As a result, Exxon states the costs for future years will be quite different if the Nelson Farrar Operating Cost Index is used to adjust the capital costs of the Heavy Distillate hydrotreater relative to the base year instead of the Nelson Farrar Construction Cost Index; and the selection of the base year will have an impact on the capital cost figure for all subsequent years. *Id.* In particular, Exxon maintains that by selecting a base year of 1996 rather than 2000, the Eight Parties's approach of using the Operating Cost Index has the effect of reducing the capital costs of the Heavy Distillate hydrotreater in subsequent years. *Id.*

1409. Exxon believes this problem can and should be avoided. *Id.* The analytically correct solution, Exxon argues, would be simply to direct that capital costs should be adjusted from the base year by the Nelson Farrar Construction Cost Index rather than by the Nelson Farrar Operating Cost Index. *Id.* at pp. 184-85. Exxon maintains that it makes no sense for capital costs to be adjusted to the base year by the use of the Nelson Farrar Construction Cost Index – as all parties agree is the only appropriate approach – and then to adjust those same capital costs from the base year to subsequent years using the Nelson Farrar Operating Cost Index. *Id.* at p. 185. Exxon's preferred solution is to use the Nelson Farrar Construction Cost Index to adjust the base year capital costs for other years in order to eliminate this peculiar anomaly. *Id.*

1410. Alternatively, Exxon contends, the impact of the problem for future years can be limited by selecting the most current base year – namely, the base year 2000 proposed by Exxon rather than the base year 1996 proposed by the Eight Parties. Exxon Initial Brief at p. 185. Given the stipulation of the parties that the effective date for the new Heavy

Distillate price will be February 1, 2000, Exxon believes it makes no sense to use 1996 as the base year rather than 2000. *Id.* While the selection of 2000 as the base year will not eliminate the anomaly of using an Operating Cost Index to adjust capital costs, it would at least reduce the impact of that approach by bringing all of the capital costs forward to 2000. *Id.*

1411. Finally, Exxon argues that there is no merit to the claim that use of 1996 as the base year is necessary to ensure uniform implementation of the Quality Bank's procedures. Exxon Reply Brief at p. 194. Exxon notes that the use of a 1996 base year with the Nelson Farrar Operating Cost Index applied to all costs produces an inaccurate result. *Id.* According to Exxon, it is clear that principles of uniformity cannot be used to justify such a result. *Id.* (citing *Exxon*, 182 F.3d at p. 42).

F. ADMINISTRATIVE FEASIBILITY

1412. The Eight Parties state that their proposal for valuing Heavy Distillate is based on the Platts LA Pipeline No. 2 assessment, with adjustments made for sulfur processing costs and for logistics. Eight Parties Initial Brief at p. 160. In their opinion, the new valuation basis for Heavy Distillate should be made retroactive to February 1, 2000. *Id.* The Eight Parties claim that the Quality Bank Administrator has stated that the Eight Parties's proposal submitted for valuing Heavy Distillate is administratively feasible. *Id.* Moreover, they assert that, because none of the parties has challenged the administrative feasibility of the Eight Parties's proposal for valuing Heavy Distillate, the Quality Bank could use the Eight Parties's proposal to value Heavy Distillate on the West Coast. *Id.*

1413. According to Exxon, the Quality Bank Administrator testified that both the Exxon proposal and the Eight Parties proposal would be administratively feasible. Exxon Initial Brief at p. 185. Further, Exxon asserts, the proposal to use both the Nelson Farrar Construction Cost Index and the Nelson Farrar Operating Cost Index, rather than just the Nelson Farrar Operating Cost Index, also should not pose any problems. *Id.* at pp. 185-86. Both parties's cost estimates separately set forth the capital and operating costs for their respective base years, according to Exxon. *Id.* at p. 186. Consequently, Exxon states, all that would needed would be to adjust the capital costs of the distillate hydrotreater from the base year to the chosen year by the Nelson Farrar Construction Cost Index, while adjusting the operating costs of the hydrotreater by the Nelson Farrar Operating Cost Index. *Id.* Exxon believes this change would eliminate the base year issue and produce a more accurate result. *Id.*

1414. The TAPS Carriers state that there has been one change since Exxon and the Eight Parties submitted their proposals that needs to be reflected in any Commission order. TAPS Carriers Initial Brief at p. 11. Effective May 1, 2003, Platts renamed as "low sulfur diesel" the product formerly referred to in its price assessments as "low sulfur No. 2." *Id.* The TAPS Carriers point out that there was no change in Platts methodology in establishing its assessments. *Id.* at pp. 11-12. They recommend that the Commission's order specifically state that, in valuing Heavy Distillate, the base price should be Platts West Coast pipeline low sulfur No. 2 assessment through April 2003 and Platts West Coast pipeline low sulfur diesel assessment beginning May 1, 2003. *Id.*

ISSUE 2- DISCUSSION AND RULING

1415. Exxon and the Eight Parties agree that the starting point for establishing the value of Heavy Distillate is Platts West Coast LA Pipeline Low Sulfur No. 2 Fuel Oil price. Exxon Initial Brief at p. 143; Eight Parties Initial Brief at pp. 131-32. They disagree, however, as to in what manner that price ought to be adjusted.[567] Exxon Initial Brief at p. 144; Eight Parties Initial Brief at p. 132. The parties have agreed that the effective date for the new price ought to be February 1, 2000. Joint Stipulation, filed October 3, 2002, at p. 3. Not only do the parties disagree as to the extent of the desulfurization cost adjustment and whether there ought to be a logistics adjustment, they also disagree as to the base year which should be used.

A. SULFUR PROCESSING COSTS ADJUSTMENT

1. Capital Costs

a. ISBL Costs

1416. Stating that the cost of hydrotreating Heavy Distillate represents a significant cost, the Eight Parties reflect that O'Brien's estimate was 4.1¢/gallon in Year 1996 dollars and that Jenkins's estimate was 4.3¢/gallon in Year 2000 dollars. Eight Parties Initial Brief at p. 134 (citing Exhibit No. EMT-37 at p. 12). They add that O'Brien followed an approach which was consistent with that which he followed regarding Resid; he applied the "appropriate" Baker & O'Brien cost curve. *Id.*

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[567] In pertinent part the Joint Stipulation provides:

> West Coast Heavy Distillate will be valued at the published Platt's West Coast price for Los Angeles Pipeline low sulfur (0.05%) No. 2 Fuel Oil, less appropriate deductions. The Parties agree that deductions should include the cost of desulfurizing ANS Heavy Distillate to meet the 0.05% sulfur specifications, but they do not agree as to the cost of desulfurization. They also disagree as to whether there should also be a logistics adjustment to the reference price.

Joint Stipulation, filed October 3, 2002, at p. 3.

1417. Unlike the itemization approach he followed with regard to Resid, Jenkins used the Jacobs Consultancy data base to estimate the cost of desulfurizing virgin Heavy Distillate. Exhibit No. EMT-37 at p. 14. Under redirect examination, he explained that he did so because, while the Resid data showed "large variation," there was a "fair amount of data available about distillate hydrotreaters" which he felt "basically met the test." Transcript at p. 3721. He also stated that "[t]he use of a cost curve to estimate the ISBL costs for a hydrotreater, for example, is more reliable than for a Coker." Exhibit No. EMT-146 at p. 18.

1418. The Eight Parties, without effectively citing to any evidence in the record,[568] assert that, had Jenkins used the same approach in calculating the Heavy Distillate ISBL costs as he did with regard to those for Resid, "his cost number would have been considerably higher." Eight Parties Initial Brief at p. 134. They do, however, correctly note that Exxon admitted that it would benefit from a high Heavy Distillate value.[569] *Id.* at n.78. As to the latter, I do not consider this proof of anything as the reverse would be true for the Eight Parties; i.e., the Eight Parties would benefit from a low Heavy Distillate value.

1419. Unlike in the Resid value determination, I am not presented with two distinct methodologies from which to choose an approach to be followed to establish a capital ISBL cost. Here, I am presented with competing cost curves. A review of the evidence cited in the parties's briefs reflects that each side presented substantial evidence to support its position, but that neither side provided evidence compelling a decision in its favor. However, I am troubled by the change in approach which Jenkins made when estimating the Heavy Distillate capital ISBL value as compared with that which he followed in doing the same calculation for Resid. I find his explanation for doing so too facile. Moreover, I find that accepting O'Brien's Baker & O'Brien cost curve approach, as I did with Resid, to add a certain consistency to the Quality Bank calculations. As a result, I will require that it be used to establish the Heavy Distillate capital ISBL value.

1420. O'Brien, according to the Eight Parties, assumed a 50,000 barrels/day high-pressure hydrotreater installed at an existing refinery.[570] *Id.* at p. 135. While it is not

[568] In a footnote, the Eight Parties make an arcane argument in support of their claim to which I give no credence. *See* Eight Parties Initial Brief at p. 134, n.78. *See also* Exhibit No. WAP-101 at p. 4.

[569] Exxon counsel stated on the record: "I don't think there's any dispute on the record, your Honor, that we're actually benefited by high heavy distillate price [sic]." Transcript at p. 3094.

[570] O'Brien testified that he chose the 50,000 barrels/day hydrotreater because he believed it "to be an economically sized unit that would be commonly installed at a large existing refinery." Exhibit No. PAI-1 at p. 42.

clear on the face of his direct testimony, it appears that it is a high-pressure hydrotreater as O'Brien's proposal is criticized on this point by Dickman. *See* Exhibit No. EMT-118 at pp. 20-21. According to Dickman, based on his "experience, all that would be needed would be a medium-pressure hydrotreater." *Id.* at p. 20.

1421. O'Brien, in response, notes that Dickman's sole support for his criticism is his claimed experience. Exhibit No. PAI-58 at p. 20. He adds that his "experience, however, is that a high pressure hydrotreater (around 800 pounds per square inch (psi) or above) will typically be employed to process virgin Heavy Distillate to a 0.05% sulfur specification" and further states:

> There are only a few refineries on the West Coast that process substantial ANS crude oil and do not have coking units. One of these is the Phillips refinery at Ferndale, Washington. This refinery is a good example because its hydrotreater presumably processes mostly virgin distillates. I understand that the distillate hydrotreater at Phillips' Ferndale refinery operates at a pressure over 1,000 pounds per square inch (psi), which confirms my operating assumption.

Id. at pp. 20-21.

1422. The Eight Parties also refer, in support of O'Brien's proposal, to a Charles River Associates, Inc./Baker & O'Brien study, published in 2000, in which the following comment is made:

> We have assumed that all new grass roots units constructed since 1992, in response to the EPA's 500 ppm diesel regulation, employ pressures in the higher range. Many refiners determined that the incremental cost to build at least an 800 psi unit versus a lower pressure unit was small, and an 800 psi unit protected their investment in the event diesel regulations lowered sulfur in the future.

Exhibit No. WAP-102 at p. 2.

1423. Jenkins conceded, under cross-examination, that an 800 psi hydrotreater is considered to be a high pressure unit. Transcript at p. 3083. While he indicated that he might agree that a high-pressure hydrotreater appropriately would be installed in 2003, in response to whether it would be prudent for a refinery to install such a unit, he replied that "the assertion that somebody in 1992 could anticipate a 15 ppm [EPA] diesel regulation that I don't believe even becomes active until 2005, I struggle with that." *Id.* at p. 3084.[571]

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[571] In response to another question on the same subject, Jenkins stated: "One can

1424. In his direct testimony, Jenkins testified that all that was required to reduce the sulfur content of virgin ANS Heavy Distillate from 0.57% to 0.05% is a medium-pressure hydrotreater. Exhibit No. EMT-37 at p. 13. Therefore, the hydrotreater he used in his concept was a 50,000 barrels/day medium-pressure unit. *Id.*

1425. While neither side presented strong evidence to support its position, I find that the evidence supporting O'Brien's use of a high-pressure hydrotreater is far stronger than that supporting Jenkins's medium-pressure hydrotreater proposal. The Eight Parties note the increasing stringency of the Environmental Protection Agency regulations governing sulfur content of diesel fuel require the use of a high-pressure hydrotreater. While Jenkins argued, during his cross-examination, that one could not forecast that fact in 1992, I do not think that we are compelled to view the case from a 1992 perspective. The parties have not even presented their evidence from this perspective.

1426. I recognize that Dickman testified that, in his "experience," all that was required is a medium-pressure unit. This testimony was countered by O'Brien who testified that his experience was to the contrary. O'Brien also pointed out that the Phillips Ferndale refinery used a high-pressure hydrotreater to process virgin ANS Heavy Distillate.

1427. Exxon argues that the Eight Parties failed to prove that a medium-pressure hydrotreater was not sufficient. Exxon Reply Brief at p. 158. I do not find this argument persuasive as Exxon had the affirmative burden of proving that its proposal was best, and it failed to do so. Indeed, other than Dickman's claim that a medium-pressure hydrotreater was all that was necessary, discussed above, I can find no evidence in the record, and Exxon has pointed to none on brief, which supports Jenkins's proposal.

1428. In view of the above, I find that the Heavy Distillate capital ISBL cost should be calculated on the basis of a high-pressure hydrotreater.

b. OSBL Costs

1429. O'Brien calculated the Heavy Distillate capital OSBL cost as being 29% of its ISBL cost.[572] Eight Parties Initial Brief at pp. 136-37. Referring to the Gary & Handwerk textbook, without providing a page citation, he claims that "this percentage is within the expected range for capital additions to existing refineries." Exhibit No. PAI-1 at p. 42.

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know in 1992 or whenever this date is that there was an EPA regulation requiring 500 ppm diesel. For one to say you know that the EPA 10 years later or nine is going to specify lower sulfur diesel, I don't see how we can say that." Transcript at p. 3084.

[572] Exhibit Nos. PAI-1 at p. 42, PAI-19.

1430. Exxon argues that, while Jenkins included them in his estimate, O'Brien "made no allowance at all for storage." Exxon Initial Brief at p. 154. In his testimony, Jenkins states:

> I have adopted the approach recommended in Gary & Handwerk's treatise (pp. 333 to 338). Most estimators refer to all facilities other than the process units themselves as "offsite facilities," and use a single offsite cost factor. However, in estimating the costs of offsite facilities required for the addition of individual process units in an existing refinery, Gary & Handwerk separately estimate costs for three specific types of major support facilities -- storage tanks, steam generation equipment, and cooling water systems -- and then apply a percentage factor to the process unit costs to account for the costs of all of the other offsite facilities. For these other facilities, Gary & Handwerk suggest a factor equal to 20% to 25% of the process unit costs.

Exhibit No. EMT-37 at p. 17. Despite this, in a footnote, Exxon admits that Jenkins did not fully apply the Gary & Handwerk methodology because he only provided a separate estimate for the storage costs and failed to do so for the costs of the steam generation equipment and cooling water systems because the hydrotreater does not use a large amount of either and because "'only minor modification' to existing steam or cooling water systems would be needed." Exxon Initial Brief at p. 154, n.67.

1431. According to Exxon, two intermediate storage tanks "with a combined capacity of 15 days' output" would be necessary to store the Heavy Distillate prior to processing. *Id.* at pp. 154-55. It notes that the reasonableness of Jenkins's $14/barrel cost for Heavy Distillate storage tanks was proven by the $31/barrel estimate contained in the Stillwater Report.[573] *Id.* at p. 155. However, the authors of the Stillwater Report, at least where it was cited by Exxon, were discussing the construction of a Strategic Fuel Reserve capable of holding 5 million barrels. Exhibit No. EMT-489 at pp. 83-84. Exxon has not pointed to any evidence in the record which supports a conclusion that the costs of such a product are comparable to the costs of building Heavy Distillate storage tanks capable of holding a 15 day supply.

1432. The Eight Parties argue that "[t]here is no reason to include storage tank costs because no new tanks had to be constructed, and there is not even any evidence that any existing storage tanks for the Heavy Distillate hydrotreater would have to be revamped at a Quality Bank refinery." Eight Parties Reply Brief at pp. 115-16.

1433. I find Jenkins's approach, once again, to present an anomaly. He claims to be

[573] Exhibit No. EMT-489 at pp. 83-84.

following the methodology set forth in Gary & Handwerk, but admits that he didn't totally accept it. In other words, though Gary & Handwerk recommend making separate estimates for the costs of storage, steam, and cooling water, Jenkins only separately estimated the costs of storage. His explanation, that the costs for steam and cooling water were insignificant, is too easy an explanation for omitting those steps and is not supported by any evidence.

1434. O'Brien followed an approach which is accepted by the industry. He estimated the OSBL cost to be 29% of the ISBL cost or 22.5% of the total capital cost. This is clearly within the range specified in the Gary & Handwerk textbook. Taking all of the evidence into consideration, I find this method to be appropriate, and the result to be just and reasonable.

2. Location Factor

1435. As noted above,

> [a] location factor is an adjustment factor used to translate a construction cost estimate developed for a specific project in a specific location (usually the U.S. Gulf Coast) to obtain a cost estimate for the same project in different parts of the country under the assumption that the cost to build a similar facility will vary depending on where it is located.

Eight Parties Initial Brief at p. 138. The Eight Parties and their witness, O'Brien, claim it is not appropriate to use a location factor here because the "Distillate hydrotreater proposed is not for a specific project defined in sufficient detail and pinned down to a specific location." *Id.* at p. 139. They also suggest that location factors are overly subjective. *Id.* at pp. 142-46. Moreover, they argue, were a location factor to be used, it should be no higher than 1.16, not the 1.3 proposed by Exxon. *Id.* at pp. 146-48.

1436. Exxon argues that the use of a location factor is appropriate because "it is beyond reasonable doubt that construction costs, including labor costs, environmental costs, and regulatory costs, are significantly higher on the West Coast than they are on the Gulf Coast." Exxon Initial Brief at p. 157. It suggests that the use of a 1.3 location factor "is both conservative and well supported by industry standards, by the Gary & Handwerk treatise, and even by a study prepared by Mr. O'Brien's own firm." *Id.*

1437. With respect to this issue, the parties make exactly the same argument as to the use of a location factor as they did with respect to the use of a location factor on the Resid estimates. Moreover, the evidence on which those arguments are based is exactly the same. As to Resid, I determined that a location factor should be used inasmuch as the record clearly supported a conclusion that construction costs were higher on the West Coast, that the fact that a "specific" site for construction of the plant on the West Coast was irrelevant, and that a just and reasonable location factor to be used was 1.27. For the reasons stated in that discussion I find that a location factor is appropriate to be used as to the Heavy Distillate cut and the appropriate location factor to be used is 1.27.

3. Operating Costs

1438. Another area of dispute between the parties revolves around the amount of hydrogen which would be used to reduce the sulfur content of the Heavy Distillate. Exxon Initial Brief at p. 165. It states that Jenkins assumed a consumption rate of 180 standard cubic feet/barrel. *Id.* at pp. 165-66. In his testimony, Jenkins claimed that he "calculated hydrogen consumption based on the specific properties of the ANS Heavy Distillate cut." Exhibit Nos. EMT-146 at p. 57, EMT-166. He adds that O'Brien did not do so, but based his estimate on Gary & Handwerk data. Exhibit No. EMT-146 at p. 57.

1439. Exxon, further, asserts that an August 2000 Charles River Associates, Inc./Baker & O'Brien study prepared for the American Petroleum Institute[574] supports Jenkins's testimony:

> That study estimated hydrogen consumption for a distillate with a sulfur content similar to ANS Heavy Distillate in the range of 160 to 170 standard cubic feet per barrel – much closer to Mr. Jenkins' estimate of 180 standard cubic feet per barrel than to Mr. O'Brien's estimate of 250 standard cubic feet per barrel.

Exxon Initial Brief at p. 166.

1440. According to Exxon, a difference between the Jenkins and O'Brien estimate of hydrogen consumption lies in O'Brien's use of a high-pressure hydrotreater and Jenkins's use of a medium-pressure hydrotreater. *Id.* at pp. 166-67. The former, it says, uses more hydrogen.[575] *Id.* at p. 167.

1441. The Eight Parties assert that, contrary to his claim, Jenkins did not base his calculations on ANS Heavy Distillate. Eight Parties Initial Brief at p. 149. Rather, they claim, he admitted that the last element in his calculation, solution loss, "is based not on ANS Heavy Distillate, but rather on his experience that solution loss is less than industry

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[574] Exhibit No. EMT-294, Figure 4.1 at p. 3.

[575] Jenkins testified that "[a]s pressure goes up, then hydrogen consumption goes up even if there's no change in desulfurization." Transcript at p. 3347. He also stated that, if he had assumed a pressure higher than the one he did (650 pounds), the hydrogen consumption he forecasted would rise. *Id.* at p. 3350.

rules of thumb."[576] *Id.* Moreover, the Eight Parties declare, Jenkins agreed that, had he used the Gary & Handwerk solution loss figure (190 cubic feet/barrel), his total hydrogen consumption estimate would increase to 324 cubic feet/barrel.[577] *Id.* (citing Transcript at pp. 3080-81).

1442. Exxon asserts that the real difference between O'Brien's and Jenkins's hydrogen consumption estimates lies in the pressure of the hydrotreater each used. Exxon Reply Brief at p. 174. O'Brien used a high-pressure hydrotreater and Jenkins used a medium-pressure hydrotreater. Above, I decided that the high-pressure hydrotreater should be used. Concomitantly, therefore, I am compelled to accept O'Brien's estimate of hydrogen consumption.

B. LOGISTICS ADJUSTMENT

1443. The Eight Parties argue that "the Heavy Distillate reference price requires a logistics adjustment to bring it onto a consistent basis with all of the other liquid Quality Bank cuts." Eight Parties Initial Brief at p. 150. They suggests that the adjustment should be 1.1¢/gallon. *Id.* According to them, the adjustment is required to place Heavy Distillate on the same waterborne basis as the other liquid cuts.[578] *Id.* at p. 151-52. In other words, the Eight Parties claim that the 1.1¢/gallon is "the average of costs incurred in transporting product inland [sic] to the pipeline from its arrival point at the harbor." *Id.* at p. 152. They suggest that, as the pipeline reference price is inflated by this cost factor, in order for the value of Heavy Distillate to be set at the same waterborne level as the other liquid cuts, the costs of transportation must be deducted. *Id.*

1444. Exxon asserts that this question is not before me at this time. Exxon Initial Brief

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[576] Under cross-examination, Jenkins testified that the 30% solution loss figure he used was based on his "experience" that solution loss "tends to be less than some of the rules of thumb." Transcript at p. 3077. He also said that the figure was not based on a design, but on a 1980 project "where we were trying to determine where hydrogen was lost in refineries." *Id.*

[577] This claim is not entirely accurate. Jenkins agreed with the math, but stated that he disagreed "with the premise, because hydrogen solution loss is a function of pressure. And so without knowing that and without having really better understanding, I really can't see how plugging that in works." Transcript at p. 3081.

[578] Ross testified that "product arriving by sea must first be transported from the harbor area to a pipeline hub before it can be sold. Value is added in moving product to the pipeline hub, which allows product at the pipeline hub to command a higher price than waterborne cargoes." Exhibit No. BPX-1 at p. 10.

at p. 167. According to it, with regard to Heavy Distillate, the only issue which the Commission referred to me regarded the appropriate sulfur processing adjustment. *Id.* at p. 168 (citing *Trans Alaska Pipeline System*, 97 FERC at pp. 61,650, 61,652).

1445. It also asserts that Ross, the Eight Parties's witness, erroneously stated that all of the liquid cuts, other than Heavy Distillate, were valued on a waterborne basis since LSR, also a liquid cut, was valued on a Bakersfield truck/rail basis. Exxon Initial Brief at p. 172 (citing Exhibit No. EMT-11 at p. 12). Exxon notes that, on cross-examination, Ross admitted that LSR was a liquid at room temperature which was not valued on a waterborne basis.[579] *Id.*

1446. Further, Exxon states, Ross's evidence in support of this proposal is questionable. It notes that much of his support for the proposal is based only on two telephone conversations, one in 2000 and the other in 2002, regarding the costs of transporting the product from the harbor to the pipeline.[580] *Id.* at p. 176 (citing Transcript at pp. 1690-92, 1698). Exxon also points out that Ross admitted that he did not know what the costs were in 1991 or 1992 or what the range was over a five or 10 year period. *Id.* (again citing Transcript at pp. 1690-92, 1698).

1447. The scope of the hearing is set by the Commission, and I cannot consider any matter not referred to me by it. *See Sierra Pacific Power Co.*, 104 FERC ¶ 61,223 at P 33-36 (2003). In its November 7, 2001, Order referring these matters to the Office of Administrative Law Judges for hearing, the Commission stated: "At issue in the replacement product proceeding is the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the quoted price." *Trans Alaska Pipeline System*, 97 FERC at p. 61,652.[581] In view of this, I find that the question of whether the Heavy Distillate reference price should be adjusted by the cost of transporting the product from the harbor to the pipeline is not before me.

1448. Even were the issue before me, I would find that the Eight Parties failed to satisfy their burden of showing that it was warranted, in general, and that its specific proposal, that the adjustment be 1.1¢/gallon, was just and reasonable. Though their argument is primarily justified on the Eight Parties's claim that the adjustment is necessary to place Heavy Distillate on the same waterborne basis as *all* of the other liquid cuts, even Ross admits, it is not the only liquid cut which is not valued on a waterborne basis. As a result,

[579] See Transcript at pp. 1722-23.

[580] Ross admitted that he did not even verify the information he received in those phone conversations. Transcript at pp. 1699-1700.

[581] *See also Trans Alaska Pipeline System*, 90 FERC ¶ 61,123 at p. 61,371 (2000).

the Eight Parties's theory collapses. Moreover, there is no consistency in where cuts are valued; some are valued at truck/rail location, others at a pipeline, still others are valued on a waterborne basis.[582] Consequently, contrary to another of the Eight Parties's arguments, there is no necessity that the Heavy Distillate reference price be adjusted by the cost of placing it on a waterborne basis for the sake of consistency. Thus, had I been required to rule, I would have concluded that the Eight Parties failed to prove that their proposed adjustment was warranted. Furthermore, their proposed 1.1¢/gallon adjustment is based, at least in part, on specious evidence.[583]

C. BASE YEAR

1449. The Eight Parties note that O'Brien chose 1996 as the base year, but state that they "do not believe that choice of a base year should have a material impact on the outcome of the Heavy Distillate issue." Eight Parties Initial Brief at p. 160. Exxon notes that Jenkins used 2000 as his base year. Exxon Initial Brief at p. 182. Moreover, it makes the same argument regarding use of both the Nelson Farrar Construction Cost Index and the Nelson Farrar Operating Cost Index as it made with regard to Resid. *Id.* at pp. 183-85. Aside from that, Exxon concedes "it should not matter which year – 1996 or 2000 – is used as the base year." Exxon Reply Brief at p. 192.

1450. With regard to the base year to be used in connection with Heavy Distillate, the parties made the same arguments, based on the same evidence, as they made with regard to the base year to be used in connection with Resid. My rulings remain the same and for the same reasons: (1) only the Nelson Farrar Operating Cost Index should be used; and (2) the base year should be Year 2000 and the existence or non-existence of certain equipment should not be considered in making any calculations.

ISSUE NO. 3: WHETHER THE CURRENT METHOD FOR VALUING THE WEST COAST NAPHTHA CUT IS JUST AND REASONABLE, AND IF NOT, WHAT IS THE APPROPRIATE METHOD FOR VALUING THE NAPHTHA CUT? WHAT SHOULD BE THE EFFECTIVE DATE OF ANY CHANGE TO THE WEST COAST NAPHTHA CUT?

A. LEGAL STANDARD AND BURDEN OF PROOF

1. Exxon

[582] Exhibit No. EMT-253. *See also* Exxon Initial Brief at p. 174.

[583] *See* Transcript at pp. 1690-92.

1451. In response to a Circuit Court decision that the Commission's practice of valuing West Coast Naphtha on the basis of Platts Gulf Coast Naphtha price was not just and reasonable,[584] explains Exxon, the Commission set the issues of whether the current method of valuing the Quality Bank Naphtha cut on the West Coast is just and reasonable, and if not, what new methodology should be adopted for valuing West Coast Naphtha for hearing in this proceeding. Exxon Initial Brief at p. 187.

1452. Exxon argues, and other parties agree, that the Commission has an affirmative statutory obligation to ensure that the method selected for valuing the West Coast Naphtha cut produces a just and reasonable result. *Id.* at pp. 187-88; *see also* Exxon Reply Brief at p. 195. In particular, according to Exxon, the Commission has directed that the value produced must "bear a rational relationship to the actual value" of the particular product in the real world marketplace. Exxon Initial Brief at p. 188 (quoting *Trans Alaska Pipeline Co.,* 97 FERC at p. 61,651). In addition, Exxon notes, the Commission has directed that all proposals be administratively feasible. *Id*. And in prior decisions in this case, it points out, the Commission has also stressed that the methodology should "not [be] susceptible to manipulation." *Id.* (quoting *Trans Alaska Pipeline Co*., 65 FERC at p. 62,289).

1453. It is also well established, according to Exxon, that a prior determination that a particular rate or practice was just and reasonable does not preclude the Commission from later reviewing the evidence and making a new determination that the previously approved rate or practice is no longer just and reasonable. *Id.* Exxon points out that, according to the Circuit Court, the Commission has an ongoing obligation to ensure that rates are just and reasonable and a rate once found acceptable could later be found unreasonable. *Id.*

1454. For these reasons, Exxon asserts that Commission rate orders are never constrained by principles of res judicata. *Id.* at pp. 188-89. On the contrary, Exxon states that any party believing that an existing rate is not just and reasonable may file a complaint at any time, and the Commission has both the power and the duty to re-examine the reasonableness of such existing rates whenever there is evidence warranting a change. *Id.* at p. 189.

1455. Further, Exxon states that, contrary to the position of Williams, the law is clear that there is no need for the proponents of a new West Coast Naphtha valuation to show any changed circumstances above and beyond the new evidence that the Supreme Court held to be sufficient to require further Commission investigation. *Id.* In view of Supreme Court and Circuit Court decisions holding that new evidence imposes a duty upon an agency to investigate further the reasonableness of challenged rates, Exxon asserts, the Commission plainly has no authority to impose a higher burden on

[584] *Tesoro*, 234 F.3d at pp. 1292-93.

complainants before they will consider new evidence that a challenged rate is unreasonable. *Id.*; *see also* Exxon Reply Brief at p. 196. Accordingly, Exxon states, as a matter of law, any changed circumstances requirement must be construed to be equivalent to new evidence. Exxon Initial Brief at p. 189.

1456. In any event, Exxon asserts, the record in this case demonstrates beyond any possible question that there is both new evidence and changed circumstances regarding the value of Naphtha on the West Coast. *Id.* at p. 190. First, Exxon notes, the fact that the Commission has now abandoned its former policy of using only market prices instead of formulæ to value all ANS cuts by adopting adjusted prices for several ANS cuts is clearly a changed circumstance that bears directly on the reasonableness of the Commission's prior reliance on the Gulf Coast Naphtha price as a proxy for the value of West Coast Naphtha. *Id.*

1457. Second, Exxon states, the reduction in deliveries of ANS crude to the Gulf Coast from nearly 17% in 1994 to zero by mid-1999 is another changed circumstance that renders the use of the Gulf Coast Naphtha price to value West Coast Naphtha invalid. *Id.*

1458. Third, Exxon cites the large disparity between the Gulf Coast Naphtha price adopted by the Commission in 1993 as a proxy for the value of West Coast Naphtha and the actual market value of West Coast Naphtha as more than sufficient to establish changed circumstances. *Id.*

1459. Fourth, according to Exxon, the use of Naphtha to make gasoline on the West Coast (but not on the Gulf Coast) was impacted by the California Air Resources Board (sometimes "CARB") requirements that came into play in 1996. *Id.*

1460. Fifth, Exxon asserts, the evidence shows that, beginning in 1999, any similarities that may have previously existed between Gulf Coast and West Coast gasoline prices came to an end as gasoline prices on the West Coast and the Gulf Coast diverged even further. *Id.* at pp. 190-91.

1461. Lastly, Exxon claims, the mere passage of time between rate proceedings and the resulting different rate periods has been held to be sufficient to establish materially different circumstances. *Id.* at p. 191.

1462. Exxon concludes that, in these circumstances, the Commission has a clear statutory obligation to weigh the evidence that using the Gulf Coast Naphtha price to value Naphtha on the West Coast does not produce a just and reasonable result and, if it so finds, to determine what valuation methodology would produce a just and reasonable value for West Coast Naphtha. *Id.* Further, because the evidence presented in this case is more than sufficient to establish that the current method of valuing Naphtha is not just and reasonable; there is no need to resolve the distinction between "new evidence" and "changed circumstances" in this proceeding. Exxon Reply Brief at p. 197.

1463. In a complaint case, Exxon explains, challenging an existing rate as unjust and unreasonable, the complainant has the burden of proof. Exxon Initial Brief at p. 191. While the complainant always bears the ultimate burden of persuasion, once the complainant has established a prima facie case of unreasonableness, Exxon claims, a presumption of unreasonableness arises and the burden of going forward and producing evidence showing that the rate is just and reasonable shifts to the proponent of the rate.[585] *Id.* at pp. 191-92.

1464. Exxon states that there already has been a specific determination by the Circuit Court in *Tesoro* that the evidence previously presented by Tesoro to the court (showing that the Gulf Coast Naphtha price is not an appropriate proxy for valuing West Coast Naphtha) was more than sufficient to establish a prima facie case and that, therefore, the Commission was required to re-examine its policy of using the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at p. 192. It explains that the Circuit Court held the evidence of unreasonableness presented – including the rejection and abandonment of the Commission's no adjustment policy, the decline in Gulf Coast ANS sales since 1993, and the large disparity between the Gulf Coast Naphtha proxy price and the true market value of Naphtha on the West Coast – established at least a prima facie case of unreasonableness that warrants re-examination of how West Coast Naphtha should be valued. *Id.*

1465. Each of these three pieces of evidence also has been clearly established in this phase of the case, Exxon asserts. Exxon Reply Brief at p. 198. First, states Exxon, it is undisputed that deliveries of ANS crude to the Gulf Coast have not only nearly disappeared; they have completely disappeared for more than four years. *Id.* In accordance with the Circuit Court's *Tesoro* decision, continues Exxon, this evidence alone renders the current practice of using a Gulf Coast Naphtha price to value West Coast Naphtha more suspect than it was in 1993. *Id.*

1466. Second, explains Exxon, the fact that the Commission's 1993 decision to use the Platts Gulf Coast price to value West Coast Naphtha was rejected in the *OXY* decision and abandoned on remand clearly constitutes a changed circumstance. *Id.* at pp. 198-99.

1467. Third, Exxon notes, it has introduced substantial evidence that a large disparity exists between the Platts Gulf Coast Naphtha price and the actual market value of West Coast Naphtha and that disparity is growing larger. *Id.* at pp. 199-200. Contrary to

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[585] Exxon cites two cases in support of the statement: *St. Mary's Honor Center v. Hicks*, 509 U.S. 502, at p. 506 (1993) and *Texas Dep't of Community Affairs v. Burdine*, 450 U.S. 248, at p. 254 (1981). Exxon Initial Brief at pp. 191-92.

Williams's contention, therefore, Exxon asserts, all three of the factors found by the *Tesoro* Court to establish at least a prima facie case that the use of a Gulf Coast price to value West Coast Naphtha is unreasonable are also clearly established in this case. *Id.* at pp. 200-01.

1468. In addition, Exxon argues, substantial new evidence has been presented in this proceeding that the use of the Gulf Coast price to value West Coast Naphtha is unreasonable. *Id.* at p. 201. For example, states Exxon, it is undisputed that, beginning in 1999, any similarities that may have previously existed between Gulf Coast and West Coast gasoline prices came to an end as gasoline prices on the West Coast spiked upward and diverged sharply from Gulf Coast gasoline prices. *Id.* Therefore, according to Exxon, it is no longer valid to link West Coast Naphtha values to Gulf Coast Naphtha prices. *Id.*

1469. Further, explains Exxon, there was a major change in the market for Naphtha on the West Coast, but not the Gulf Coast, in 1996, because of the introduction of CARB Phase II gasoline in California and the subsequent effect on the gasoline and jet fuel markets on the West Coast. *Id.* at pp. 201-02. While the parties dispute the impact of this change, Exxon asserts that there is no dispute that the 1996 CARB gasoline requirements are a changed circumstance that has affected the relationship between the value of West Coast Naphtha and the Gulf Coast Naphtha price. *Id.* at p. 202.

1470. In light of this substantial new evidence that the Gulf Coast Naphtha price does not represent the value of West Coast Naphtha, Exxon, Phillips, BP, and Alaska have clearly met their burden of establishing a prima facie case that the current practice of using the Platts Gulf Coast Naphtha price to value West Coast Naphtha is not just and reasonable. *Id.* Indeed, under the Circuit Court's *Tesoro* decision, according to Exxon, that evidence has established a prima facie case as a matter of law. *Id.* (citing *Tesoro*, 234 F.3d at p. 1293). As a result, Exxon argues, a presumption that the use of the Gulf Coast Naphtha price to value West Coast Naphtha does not produce a just and reasonable result exists, and the burden of going forward to produce evidence that the use of the Gulf Coast Naphtha price to value West Coast Naphtha is just and reasonable should be shifted to those parties who advocate the continued use of the Gulf Coast Naphtha price to value West Coast Naphtha. Exxon Initial Brief at pp. 192-93.

1471. Regardless of how the burden of proof and the burden of producing evidence are allocated, however, Exxon's view is that the evidence introduced at the hearing in this case clearly establishes beyond any possible doubt that the use of the Gulf Coast Naphtha price to value West Coast Naphtha is not just and reasonable, and that some other method is required to value West Coast Naphtha consistent with the Commission's statutory mandate to establish just and reasonable rates and practices. *Id.* at p. 193.

1472. In an attempt to avoid its burden of defending the use of a Gulf Coast price to value West Coast Naphtha, states Exxon, Williams also seeks to impose additional burdens on those parties that wish to change the existing practice by expanding their burden into a "three part inquiry:" (1) that there are changed circumstances, (2) that those changed circumstances render the existing methodology unjust and unreasonable, and (3) that the proposed alternative methodology is just and reasonable. Exxon Reply Brief at p. 204. Exxon suggests that, as noted above, the first two of these hurdles are obviously one and the same because changed circumstances are one form of new evidence that can render the existing methodology unjust and unreasonable. *Id.* Nor, in Exxon's view, is there any basis for Williams's third hurdle since, as the law is clear that once it has been established that the existing methodology is unreasonable and unlawful, the Commission has a statutory obligation to put in place a new valuation methodology that is just and reasonable. *Id.* It explains that at least six new valuation methodologies have been proposed in this proceeding, and with respect to those proposed methodologies, each party has the burden of supporting its own proposal. *Id.*

2. Phillips

1473. According to Phillips,[586] three decisions by the Circuit Court regarding the Quality Bank methodology provide guidance for the valuation of the West Coast Naphtha cut.[587] Phillips Initial Brief at p. 5. In particular, Phillips asserts, court precedent and the tenet of reasoned decision making requires uniform approach and consistency in the Commission's approach to valuation of West Coast Naphtha. *Id.* at p. 6.

1474. As all parties have agreed that West Coast VGO should be valued based on the published West Coast price for VGO, Phillips states, Naphtha is the only cut where any party contends that West Coast deliveries should be valued based on Gulf Coast prices. *Id.* To meet the uniformity requirement, Phillips argues, Naphtha also should be valued on the same basis as the other West Coast cuts; that is, on a West Coast basis. *Id.* at pp. 6-7.

1475. To be able to satisfy the *OXY* uniformity requirement, Phillips asserts, the evidence in the record supporting the use of a Gulf Coast price to value West Coast Naphtha would have to demonstrate that the published Gulf Coast Naphtha price would consistently match the West Coast value of Naphtha almost exactly over a long period of time. *Id.* at p. 7. Here, points out Phillips, the evidence not only fails to show the

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[586] Except as regards a proposed minor modification to O'Brien's proposal regarding valuing West Coast Naphtha, and additional commentary on the Naphtha contract analyses, both discussed below, Alaska states that it joins and supports Phillips's position on Issue No. 3. Alaska Initial Brief at p. 1.

[587] Philips cites *Tesoro*, 234 F.3d 1286; *Exxon*, 182 F.3d 30; *OXY*, 64 F.3d 679.

requisite close correlation between the Gulf Coast proxy and the West Coast value, but it also demonstrates that the West Coast value continually exceeds the Gulf Coast proxy by amounts that clearly are significant under *OXY*. *Id.*

1476. Phillips explains that the *OXY* decision also provides guidance for evaluating the various proposed alternative West Coast Naphtha valuation methodologies. *Id.* at p. 8. Because all other Quality Bank cuts are valued at the published price on the coast where the cut is delivered less the processing costs, Phillips asserts, in order to satisfy the *OXY* consistency requirement, the West Coast Naphtha price adopted by the Commission should follow the same approach. *Id.* It points out that the proponents of using the Gulf Coast Naphtha price to value West Coast Naphtha have completely ignored the *OXY* holding, and notes that they did not attempt to explain how valuing West Coast Naphtha with Gulf Coast prices could satisfy this standard when no other cut will have its West Coast value determined through Gulf Coast prices. Phillips Reply Brief at p. 8. Phillips states that Williams, in particular, fails to acknowledge the central holding of *OXY* that cut valuations must be uniform to the extent possible. *Id*. at p. 8, n.8.

1477. According to Phillips, the *Exxon* decision requires that the Gulf Coast Naphtha price be more than similar to the value of West Coast Naphtha or just fall within some observed range of West Coast Naphtha values. Phillips Initial Brief at p. 9. Instead, explains Phillips, there must be some rational relationship between the Gulf Coast price and the actual market value of West Coast Naphtha. *Id.* Further, notes Phillips, they must correlate consistently and closely over the long term. *Id.* Phillips also notes that the *Exxon* court specifically stated that "the goal of administrative efficiency and objectivity [did] not free [an] agency from [this] requirement." *Id.* (quoting *Exxon*, 182 F.3d at p. 42).

1478. Phillips concedes that it is difficult to apply the *Exxon* holding here where the actual market value of West Coast Naphtha is not known. *Id.* There is, according to Phillips, abundant evidence on the record regarding the differences between the Gulf Coast and West Coast markets, in general, as well as of West Coast Naphtha contract prices. *Id.* at pp. 9-10. As this evidence strongly supports the conclusion that the Gulf Coast Naphtha price does not correlate consistently and closely with the West Coast Naphtha value over the long term, Phillips argues, the use of the Gulf Coast Naphtha price to value West Coast Naphtha violates the *Exxon* holding. *Id.* at p. 10. Nevertheless, explains Phillips, the Gulf Coast pricing advocates simply ignore the "rational relationship" requirement and base their case on a hypothesis of long term price "similarity" that is indistinguishable from the one rejected in *Exxon*. Phillips Reply Brief at p. 9.

1479. Phillips notes that Williams cites *Exxon* for the following proposition: "the fact that a more precise method exists for determining the relative value of the streams [would] not render [a] decision to adopt a less accurate, but more administrable, method arbitrary and capricious." *Id.* (quoting *Exxon*, 182 F.3d at p. 40). It notes that the language Williams quotes, however, dealt with Exxon's claim that there should be intra-cut differentials established for the Resid and Heavy Distillate cuts. *Id.* However, it states, the Circuit Court was referring to the valuation of "streams," rather than cuts, and nothing in that proposition suggests any basis on which Gulf Coast pricing of the Naphtha cut could be reconciled with West Coast valuation of all other cuts. *Id.* It also states that the *Exxon* court reiterated the requirement that there be "reasoned relative uniformity" in the valuation of all Quality Bank cuts, and it imposed the additional requirement that there be a demonstrable "rational relationship" between the values of the proxy and the cut. *Id.* at pp. 9-10 (quoting *Exxon*, 182 F.3d at p. 38). Phillips states these are all requirements that the Gulf Coast Naphtha proxy cannot meet. *Id.* at p. 10.

1480. According to Phillips, the Circuit Court's decision in *Tesoro* provides the most directly applicable guidance for the West Coast Naphtha issue. Phillips Initial Brief at p. 10. It explains that Tesoro relied on three propositions in its complaint to support its claim that use of Gulf Coast Naphtha prices to value West Coast Naphtha is not just and reasonable. *Id.* The first, states Phillips, was that Gulf Coast ANS deliveries "have declined considerably from the somewhat less than 20% level that existed in 1993." *Id.* (quoting *Tesoro*, 234 F.3d at p. 1292). It further notes that the Court found that "[t]he nearly complete disappearance of Gulf Coast ANS sales suggests that the Commission's current reliance [on Gulf Coast prices] is more dubious now than in 1993." *Id.*

1481. Second, continues Phillips, Tesoro asserted that the decision to use the Gulf Coast Naphtha price was based on a "No Adjustment Policy" that the Circuit Court rejected and which, since then, has been abandoned by the Commission. *Id.* It notes that the Circuit Court further made clear that the principle of uniformity announced in *OXY* "would be breached if the availability of an adequate non-adjusted benchmark for the Gulf Coast prevented the use of an adjusted benchmark for the West Coast." *Id.* at p. 11 (quoting *Tesoro*, 234 F.3d at p. 1293). In Phillips's view, this ruling clearly precludes the use of the Gulf Coast price for Naphtha in lieu of an adjusted West Coast value – the very point at issue here. *Id.*

1482. Phillips states that the proponents of Gulf Coast pricing not only ignore this holding, they affirmatively rely on the No Adjustment Policy to support their position. Phillips Reply Brief at p. 14. It notes that both Williams and Unocal/OXY cite the policy as if it were still in effect without even mentioning the controlling contrary ruling by the *Tesoro* court or attempting to explain why that ruling does not apply. *Id.* at p. 15.

1483. The Circuit Court noted, Phillips explains, that Tesoro had presented calculations showing that the Gulf Coast Naphtha price in December 1996 undervalued West Coast Naphtha by \$2.71/barrel: "This alleged disparity dwarfs the ones that required remand in *OXY*. *See* 81 FERC at 62,462 (revising valuation of light distillate by \$0.005 per gallon, or \$0.21 per barrel, after *OXY* remand)." Phillips Initial Brief at p. 11 (quoting *Tesoro*, 234 F.3d at p. 1293). For that reason, it states, the issue of West Coast Naphtha valuation was remanded for hearing. Phillips Reply Brief at p. 15.

1484. Phillips claims that there were two categories of evidence in the hearing record as to the actual value of Naphtha in the West Coast market. *Id.* The first consists of the Naphtha contracts, and the second is the valuation methodologies advanced by the experts. *Id.* It asserts that the Naphtha contracts constitute the only direct evidence of value. *Id.* Phillips claims that the contracts provided the most accurate benchmark because they represent actual prices that sophisticated market participants paid in arms-length transactions over a number of years. *Id.* Further, it explains, four different experts from differing points of view offered analyses of the prices paid in these transactions (O'Brien, Pulliam, Tallett and Culberson). *Id.* According to Phillips, despite the range in their views regarding Naphtha contracts, their analyses all showed that the West Coast Naphtha values exceeded the Gulf Coast by at least 6¢/gallon in the period 1994-2001 and by considerably more in the period 1999-2001. *Id.* Phillips notes that the differences are similar to or larger than the differences in value that were alleged in Tesoro's complaint and found by the Circuit Court to "dwarf" the differences that required remand in *OXY*. *Id.* at p. 16 (citing *Tesoro,* 234 F.3d at p. 1293).

1485. According to Phillips, the only experts who calculated West Coast values for Naphtha were O'Brien, Tallett and Dudley. *Id.* It contends that the values calculated by O'Brien and Tallett were soundly based technically, and they correlated well with the values proved in the Naphtha contracts. *Id.* Phillips asserts that Dudley's calculation had no rational basis and that he used an approach he created for this litigation that was wholly different from what he had done for clients in the past. *Id.* It argues that it was not reconcilable with the contract evidence and is not worthy of consideration in evaluating West Coast Naphtha values. *Id.*

1486. Under the Interstate Commerce Act, states Phillips, the burden of proof in a complaint proceeding rests with the party asserting that an existing rate or practice should be changed. Phillips Initial Brief at pp. 11-12. It asserts that the relevant statutory provision requires the Commission to make an affirmative finding that an existing rate or practice is unjust and unreasonable. *Id.* at p. 12.

1487. At the time the complaints were filed, notes Phillips, the TAPS Carriers had not proposed any change in the valuation of the West Coast Naphtha cut. *Id.* That cut was valued at the published Gulf Coast Naphtha price, and, explains Phillips, this valuation had been established by the Commission in 1993 and was not among the issues challenged on appeal to the Circuit Court. *Id.* As a result, under the complaint proceedings initiated to review the West Coast Naphtha value used in the Quality Bank, Phillips asserts, the parties proposing to change the West Coast Naphtha valuation have the burden of proving that the use of the published Gulf Coast price is unjust and unreasonable. *Id.*

1488. Phillips states that a party bearing the burden of proof has an "obligation to produce substantial evidence for the record" demonstrating the current methodology is unjust and unreasonable. *Id.* (quoting *Amerada Hess Pipeline Corp*., 71 FERC ¶ 61,040 at p. 61,166 (1995)). Once that substantial evidence is presented and a prima facie case is made, however, Phillips explains that the burden of going forward shifts to the other side. *Id.* (*citing SFPP, L.P*., 84 FERC ¶ 61,338 at p. 62,498 (1998)).

1489. In this proceeding, Phillips claims that it and the other parties opposing the continued use of the Gulf Coast published price to value West Coast Naphtha have submitted substantial evidence demonstrating that use of such prices is unjust and unreasonable. *Id.* The hearing record includes not only substantial evidence supporting the three points that the *Tesoro* Court found establish a prima facie case for reevaluation of the Naphtha methodology, but, in Phillips's view, also substantial additional evidence demonstrating the very significant differences between the two markets and the higher value Naphtha commands on the West Coast. *Id.* at pp. 12-13. As a result, Phillips believes that the parties advocating a West Coast value have met the burden of proof assigned to them in the complaint proceedings. *Id.* at p. 13.

1490. On the other hand, asserts Phillips, the parties advocating continued use of the Gulf Coast Naphtha price to value West Coast Naphtha have not met the burden of going forward placed on them as a consequence of the showing made by Phillips and others. *Id.* Phillips argues that the evidence that supporters of the current methodology have submitted does not justify continued use of the Gulf Coast price for West Coast Naphtha. *Id.* It points out that the proponents of the Gulf Coast price admit that the Gulf Coast and West Coast markets are different and that the value of Naphtha will be different in the two markets. *Id.*

1491. Further, Phillips states, the proponents of Gulf Coast pricing ignore the key holdings in the *Tesoro* opinion -- both its ruling as to what must be shown to satisfy the burden of proof and its ruling on the sufficiency of the three allegations in Tesoro's complaint. Phillips Reply Brief at p. 11. Indeed, it states that the proponents present arguments directly affected by the *Tesoro* decision as if that decision did not exist. *Id.* For example, Phillips notes, both Williams and Unocal/OXY discuss the changed circumstances issue at length and argue that no changed circumstances have been demonstrated. *Id.* However, it notes that neither Williams nor Unocal/OXY ever mentions the strong expression of doubt in the controlling *Tesoro* opinion as to whether a showing of changed circumstances is required at all. *Id.* at pp. 11-12.

1492. Furthermore, Phillips states that Williams and Unocal/OXY give scant attention to what it claims is the *Tesoro* court's holding that Tesoro's three factual allegations constituted a prima facie showing that the use of Gulf Coast pricing is no longer just and reasonable. *Id.* at p. 12. It notes that Williams argues that the Circuit Court did not hold that changed circumstances had already been demonstrated, but only that allegations had been raised that had to be answered. *Id.* In Phillips's view, that is not enough. *Id.* Now that substantial evidence has been submitted proving the three allegations that had been made by Tesoro in its complaint, it asserts that Williams and the other advocates of Gulf Coast pricing must introduce evidence that actually provides an answer. *Id.* Phillips further argues that this failure on the part of the proponents of Gulf Coast pricing to even address, much less answer, the Tesoro propositions is fatal.[588] *Id.*

1493. Phillips asserts that Williams is wrong to argue that the Commission must continue using the Gulf Coast Naphtha price, even if it is not just and reasonable, should the Commission also find that none of the proposed replacement methodologies is just and reasonable. *Id.* at p. 17. It points out that the Interstate Commerce Act prohibits the charging of rates that are unjust and unreasonable and provides that, whenever the Commission determines in a complaint proceeding that a rate is not just and reasonable, the Commission "is authorized and empowered to determine and prescribe what will be the just and reasonable individual or joint rate, fare, or charge." *Id.* (quoting Interstate Commerce Act, 49 U.S.C. App. § 15(1)(1988)). Phillips asserts that the Act does not limit the Commission's power to implement the proposals submitted by the parties to the proceeding. *Id.* Further, it contends that, if the Commission was to find flaws in all of the existing proposals, they would still be obligated by the controlling statutes to adjust these proposals as may be necessary to establish a West Coast Naphtha price that is just and reasonable. *Id.* at pp. 17-18.

3. BP

1494. BP states that the initial Naphtha related issue is whether, for the purpose of valuing Naphtha on the West Coast, the use of the Gulf Coast Platts Naphtha price should be replaced by a West Coast derived Naphtha valuation. BP Initial Brief at p. 3. Since the hearing began, continues BP, two other Naphtha issues have arisen. *Id.* It explains that the first new issue relates to Platts decision to publish a second Gulf Coast Naphtha price, which Platts calls "Heavy Naphtha." *Id.* This new quotation provides an additional Naphtha pricing point on the Gulf Coast, notes BP, and does not replace the pre-existing Platts Naphtha quotation. *Id.* According to BP, all parties agreed that Platts Heavy Naphtha's quality is closer than Platts Naphtha's quality to Quality Bank Naphtha's quality; therefore, all parties agreed that Platts Heavy Naphtha quotation should be used to value Gulf Coast Quality Bank Naphtha on a going-forward basis. *Id.* (citing Transcript at p. 13339).

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[588] Phillips also disagrees with Exxon's assertion that the *Tesoro* decision held that the burden of proof had already been met. Phillips Reply Brief at p. 13, n.11. Instead, it relies on the overwhelming evidence in the record in this proceeding demonstrating the factual validity of the three propositions alleged by Tesoro. *Id.*

1495. The second issue, continues BP, involves Exxon's and Phillips's claim that a naphthenes-plus-aromatics content (N+A) adjustment is needed to account for purported differences between the N+A of ANS Naphtha and Platts Heavy Naphtha. *Id.* at p. 4. Because the approved Quality Bank methodology does not include an N+A adjustment, BP asserts, Exxon and Phillips have the burden of proving that the existing Naphtha valuation approach, which does not account for N+A differences, no longer is just and reasonable. *Id.* (citing *Texas Eastern Transmission Corp. v. F.E.R.C.*, 893 F.2d 767 at p. 771 n.5 (5th Cir. 1990)). If Exxon and Phillips meet that burden, then, notes BP, any party proposing a Naphtha valuation approach that includes an N+A adjustment must show that its proposed replacement methodology is just and reasonable. *Id.*

4. Williams

1496. Williams explains that the court in *OXY*, 64 F.3d 679, affirmed the Commission's determination changing the Quality Bank methodology, and, in doing so, accepted the methodology set forth by the Commission except for the valuation of the Distillates and Resid cuts. Williams Initial Brief at p. 4. More importantly, states Williams, because the *OXY* Court did not remand the Commission's determination regarding the Naphtha cut, it follows that Court upheld its determination that the Naphtha valuation, under the distillation methodology, was just and reasonable. *Id.*

1497. Following *OXY*, states Williams, Exxon filed a complaint challenging the distillation methodology and the Commission consolidated Exxon's complaint with the *OXY* remand. *Id.* Contrary to Exxon's argument, Williams states, Exxon did not raise the propriety of the current Naphtha valuation methodology in its complaint. Williams Reply Brief at p. 5. Williams further suggests that simply joining with Tesoro to present its case does not make Exxon a party to Tesoro's original complaint and further notes that the Naphtha valuation issue is beyond the scope of the *Exxon* remand. *Id.* at p. 6.

1498. The Commission, according to Williams, approved the Nine-Party Settlement, as certified, in *Trans Alaska Pipeline System*, 81 FERC ¶ 61,319 (1997). Williams Initial Brief at p. 5. Williams adds that the changes ordered by the Commission were to take place on a prospective only basis. *Id.* Subsequent to the Commission's approval of the Nine-Party Settlement, continues Williams, the Eight Parties filed a Motion for Summary Disposition, which was granted over the opposition of Exxon, Tesoro and Phillips. *Id.* (citing *Exxon Company, U.S.A. v. Amerada Hess Pipeline Corporation*, 83 FERC ¶ 63,011 (1998)). In *Exxon*, Williams notes, the Nine-Party Settlement was affirmed in part. *Id.* at p. 6. However, Williams states, the Circuit Court held that the settlement proxy price for Resid did not meet "the requirement that the chosen proxy bear a rational relationship to the actual value of resid" and vacated and remanded that portion of the order pertaining to Resid valuation as well as the portion directing that the change take effect only prospectively. *Id.* (citing *Exxon* at p. 42). Tesoro intervened and attempted to bootstrap arguments that the Commission should have re-evaluated other cuts, specifically Naphtha and Gas oil; however, notes Williams, the Circuit Court noted that "[w]hatever the merits of these arguments might be, the issues they raise are beyond the scope of the limited remand, and therefore are not properly before us." *Id.* (citing *Exxon* at p. 46). In *Tesoro*, which dealt with Tesoro's complaint challenging the West Coast Naphtha and VGO valuations, Williams points out, the Circuit Court reversed the Commission because it failed to respond specifically to "objections that on their face appear legitimate," and thus remanded the case to the Commission for further proceedings. *Id.* at p. 6 (quoting *Tesoro*, 234 F.3d at pp. 1294-95).

1499. According to Williams's, as a result, the current Naphtha methodology has been in place since the initial adoption of the distillation methodology. *Id.* at p. 7. Moreover, explains Williams, the Commission and the Circuit Court have previously determined the Naphtha valuation to be just and reasonable. *Id.* Therefore, says Williams's, the proponents of any change must prove changed circumstances which have rendered the existing methodology unjust and unreasonable. *Id.*

1500. Any party seeking to change the current methodology, Williams states, bears the burden of proving that changed circumstances require the existing valuation be found to be unjust and unreasonable (or unduly preferential and discriminatory), and further, that the proposed replacement methodology is just and reasonable. *Id.* at p. 7. (citing *Texas Eastern Transmission Corp. v. F.E.R.C.*, 893 F.2d at p. 771 n.5). In essence, it states, the proponents of any change must satisfy a three part inquiry: (1) are there changed circumstances; (2) do the changed circumstances render the existing methodology no longer just and reasonable; and (3) if the existing methodology is no longer just and reasonable, is the methodology proposed just and reasonable. *Id.* at p. 7.

1501. Williams explains that the proponents must demonstrate that the record evidence not only raised, but also provided sufficient evidence of changed circumstances which materially impact and render the current methodology unjust and unreasonable. *Id.* at pp. 7-8. It notes that parties involved in the various TAPS Quality Bank proceedings have argued in the past that the doctrines of collateral estoppel and res judicata do not apply to Commission rate proceedings and, thus, a showing of changed circumstances is not required. *Id.* at p. 8. However, Williams asserts, the more correct view is that "the preclusion doctrines are applicable to rate proceedings unless the petitioner (or complainant) adduces new evidence or demonstrates changed circumstances." *Id.* (quoting *Exxon Company, U.S.A. v. Amerada Hess Pipeline Corp.*, 83 FERC at p. 65,094). Further, states Williams, the Supreme Court has stated that "if new evidence warrants the change" a regulatory agency "has the power and duty to modify its order." *Id.* (quoting *Tagg Bros. & Moorehead v. United States*, 280 U.S. 420, at pp. 444-45 (1930)).

1502. The threshold inquiry, then, according to Williams, is whether there are any changed circumstances which allow the Commission to proceed with a determination of whether the changed circumstances make the existing methodology no longer just and reasonable. *Id.* It asserts that there is a long line of precedent holding that, where a challenged methodology previously has been approved by the Commission, there must be a showing of changed circumstances otherwise re-litigating settled issues is a waste of resources. *Id.* at pp. 8-9. Williams points out that Exxon itself has admitted that a failure to establish changed circumstances is fatal to an attempt to change the methodology.[589] *Id.* at p. 9.

1503. While the Commission has a continuing obligation to ensure that rates are just and reasonable, Williams reiterates, the inquiry nevertheless requires a showing of changed circumstances. *Id.* Indeed, Williams claims that, if the Commission were to initiate an investigation, it would bear the burden of proving that the existing provision is unjust and unreasonable. *Id.* (citing *Sea Robin Pipeline Co. v. F.E.R.C.*, 795 F.2d 182, at p. 188 (D.C. Cir. 1986)). Finally, Williams notes, the record evidence must show that the proponents adduced evidence demonstrating a "significant change in circumstances." *Id.* at pp. 9-10.

1504. Further, Williams argues, not only must the proponents present evidence of changed circumstances, the evidence they present must also be sufficiently substantial to warrant a conclusion that the existing provision is unjust. *Id.* at p. 10 (citing *Sea Robin Pipeline Co.,* 795 F.2d at pp. 187-89). Williams cites *Trans Alaska Pipeline System*, 80 FERC ¶ 63,015 at pp. 65,232-33 (1997), in support of its view that

> the disposition of the remanded issues is transformed into the question whether the record contains "substantial evidence" from which the Commission could reach a reasoned decision. Substantial evidence requires more than a scintilla, but less than a preponderance of the evidence. . . . It means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.

Id.

1505. In addition, Williams asserts that a party cannot simply show a changed circumstance without also demonstrating why the changed circumstance necessarily warrants a change in methodology. *Id.* Notes Williams, "[i]t is not every 'new factual

[589] According to Williams, Exxon acknowledged that, in one of its prior attempts to force a return to the gravity-based Quality Bank, parties seeking to change the Quality Bank methodology "had the burden of demonstrating that changed circumstances had rendered that methodology no longer just and reasonable." Williams Initial Brief at p. 9, n.8.

assertion' or every 'new argument' which would permit relitigating a substantive ratemaking principle. There must be sufficient substance to the 'new' material so that there is a reasonable possibility the Presiding Judge or the Commission would decide the substantive ratemaking principle should be changed." *Id.* (quoting *Minnesota Power and Light Co.*, 13 FERC ¶ 63,014 at p. 65,030 (1980. Further, Williams explains, the fact that another method exists for valuation does not render the current methodology unjust and unreasonable. *Id.* (citing *Trans Alaska Pipeline System*, 29 FERC at p. 61,239).

1506. Williams notes that Exxon argued that the *Tesoro* decision definitively determined that there were changed circumstances warranting a change in the methodology valuing West Coast Naphtha and VGO and, therefore, Exxon has already satisfied its burden to show changed circumstances. *Id.* at p. 11; Williams Reply Brief at p. 7. However, Williams argues, Exxon's interpretation of the *Tesoro* decision is patently incorrect. Williams Initial Brief at p. 11. Instead, claims Williams, the *Tesoro* opinion simply found that the "evidence" submitted was "sufficiently compelling to require reconsideration of the earlier resolution" and therefore, remanded the case to allow the Commission to reconsider or to "provide a suitable explanation for why it should not." *Id.* (quoting *Tesoro* 234 F.3d at p. 1288). Williams claims that the court did not hold, or make any finding, with regard to whether or not Tesoro satisfied its burden to show that there are changed circumstances which warrant a finding that the current Naphtha and VGO valuations are unjust and unreasonable. *Id.*

1507. On reply, Williams notes that Exxon argues that the passage of time can be sufficient to establish material change in circumstances. Williams Reply Brief at p. 8. It argues that the case cited by Exxon[590] does not relate to a determination of the materiality of evidence relating to changed circumstances as Exxon would have the Commission believe. *Id.* at pp. 8-9. Williams also asserts that Exxon's reasoning that any changed circumstances must be construed to be the equivalent of new evidence is fundamentally flawed, and that new evidence does not directly translate into changed circumstances. *Id.* at p. 9. Instead, Williams suggests that the new evidence must be shown by a proponent of change to demonstrate changed circumstances which render the current methodology unjust and unreasonable. *Id.* In 1993, notes Williams, the Commission found that there were changed circumstances (an increase in the amount of natural gas liquids injected into the TAPS stream) and that those circumstances meant the then current methodology was no longer just and reasonable, namely the resulting increase in refining operations midstream and the return of an altered stream to the pipeline. Williams Initial Brief at p. 13 (citing *Trans Alaska Pipeline System*, 65 FERC at p. 62,287).

1508. William points out that all rates charged must be just and reasonable and it is

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[590] *Hawaiian Telephone v. P.U.C. of State of Hawaii*, 827 F.2d 1264, at p. 1274 (9th Cir. 1987).

within the province of the Commission to prescribe just and reasonable rates "when it determines that any rate or practice . . . is 'unjust or unreasonable.'" *Id.* at p. 14 (quoting *OXY*, 64 F.3d at p. 690). It notes that, if the Commission changes course and adopts a new methodology, the Commission "must supply a reasoned analysis indicating that prior policies and standards are being deliberately changed." *Id.* (quoting *OXY*, 64 F.3d at p. 690). Further, continues Williams, a significant change rendering a methodology unjust and unreasonable may be found when the evidence "strongly establishes the distortion of value caused" by the change and as applied no longer yields a just and reasonable result. *Id.* (quoting *Trans Alaska Pipeline System*, 57 FERC at pp. 65,049-50, 65,052-53.

1509. According to Williams, one should bear in mind that the Quality Bank's purpose is to "establish the relative value of the different quality oils that are tendered to TAPS. As such, it must incorporate a valuation methodology that is a reasonable proxy for the difference in the market value of the TAPS streams." *Id.* (quoting *Trans Alaska Pipeline System*, 65 FERC at p. 62,286). Therefore, Williams asserts, Phillips's argument regarding the uniformity requirement of *OXY* is incorrect. Williams Reply Brief at p. 11. It states that, while the basic precept is to use published intermediate feedstock product prices where available, the so-called uniformity requirement does not mandate only the use of published prices on a particular coast to value a product on that same coast. *Id.*

1510. Acknowledging that Exxon has set forth five examples of alleged changed circumstances, two of which are discussed here, Williams contends that it is substantively important that both Exxon's and Phillips's witnesses testified and admitted there have been no changed circumstances and that Tallett's baseline year for measuring changed circumstances is 2000. *Id.* at p. 12. It asserts that none of the five examples represents true changed circumstances, and that it does not follow that any and every change to TAPS valuation methodology automatically means the prior methodologies are now unjust and unreasonable. *Id.* at pp. 12-15.

1511. Williams notes that Exxon describes a great disparity between the Gulf Coast Naphtha price and the market value of West Coast Naphtha as reflected in the contract data as a changed circumstance. *Id.* at p. 13. It disagrees with Exxon's characterization of the contract analyses as actual sales which translate to a market value of West Coast Naphtha, and states that such an argument is patently disingenuous because the record demonstrates that the West Coast Naphtha market is opaque, i.e., the contract volumes represent almost non-existent volumes of the total Naphtha throughput on the West Coast, and most of the contracts do not represent spot volumes consistent with Platts method of pricing. *Id.* at pp. 13-14. Williams contends that the Naphtha contract analyses in no way can be construed to be representative of its "actual market value." *Id.* at p. 14. Moreover, Williams notes, these contracts existed during the period 1994-2001, a portion of which is before Tallett's baseline year. *Id.*

1512. According to Williams, if the introduction of California Air Resources Board requirements is a changed circumstance as Exxon suggests, then it renders Tallett's proposed regression formula totally meaningless and unusable. *Id.* It notes that Tallett testified that any major change would require a change in the formula, but that he made none to reflect the California Air Resources Board requirements and argues that the evidence demonstrates that CARB gasoline lessened the value of Naphtha on the West Coast, contrary to Exxon's assertion. *Id.*

1513. Williams argues that, contrary to BP's claim regarding the parties's agreement on the valuation of VGO and Ross's testimony, VGO and Naphtha are valued on a consistent price basis. *Id.* at p. 15. It notes that the pricing data shows that, for the period 1992 through 2002, the differential between the Gulf Coast and VGO published prices is approximately 1¢/gallon, and it maintains that a one-cent differential is not significant under the circumstances. *Id.* More importantly, Williams claims, the use of Platts Gulf Coast Heavy Naphtha (cargo) price assessment has increased the Gulf Coast Naphtha value by approximately 1¢/gallon. *Id.* at p. 16. It asserts that Ross's testimony, in effect, is that continued use of the Platts Gulf Coast Heavy Naphtha (cargo) price assessment is just and reasonable. *Id.*

1514. According to Williams, the changed circumstance alleged by BP is that differences between the Gulf and West Coasts, especially the lack of petrochemical demand for Naphtha on the West Coast, is a changed circumstance that supports the use of a West Coast based price assessment. *Id.* Williams asserts that the fallacy with this alleged changed circumstance is that the petrochemical market on the Gulf Coast existed long before 1994. *Id.* at pp. 16-17. It claims that Ross presented no evidence whatsoever that the Gulf Coast petrochemical market suddenly appeared once the TAPS Quality Bank adopted the distillation methodology in 1993. *Id.* at p. 17.

1515. Williams argues that Phillips incorrectly relies on *SFPP, L.P.*, 84 FERC at p. 62,498 for the proposition that a prima facie case has been established and that the burden of going forward has shifted to the proponents of the status quo. *Id.* at pp. 17-18. It states that because the *Tesoro* court did not find that a prima facie case had been established, no burden shifting has taken place, and the proponents of change continue to bear the burden of proof that the existing methodology is no longer just and reasonable. *Id.* at p. 18 (citing *Tesoro*, 234 F.3d at p. 1294).

1516. However, asserts Williams, the rate may only be changed prospectively. *Id.* (citing *Arizona Grocery*, 284 U.S. at p. 389). Because the Commission adopted the Gulf Coast Naphtha value to value West Coast Naphtha, it explains, the value is now the reasonable and lawful value for West Coast Naphtha. *Id.* at p. 20. Therefore, Williams maintains, it may only be changed prospectively from the date that the Commission decides that the valuation needs to be changed. *Id.*

5. Unocal/OXY

1517. Unocal/OXY submit that the current method for valuing the West Coast Naphtha cut is just and reasonable and that no change in the existing method is warranted. Unocal/OXY Initial Brief at p. 1. However, they state that, should a change be ordered, the Commission may make such change effective only on a prospective basis. *Id.* at p. 2.

1518. Unocal/OXY note that, in 1993, the Commission adopted a general provision in the Quality Bank that requires the use of prices from one market to value both the Gulf and West Coast products if pricing from only one market is available. *Id.* (citing *Trans Alaska Pipeline System*, 65 FERC at p. 62,289). Further, explains Unocal/OXY, the Commission specifically invoked its authority under the Interstate Commerce Act to determine a just and reasonable rate after investigation, and adopted the Naphtha provision as part of its own determination of what the just and reasonable Quality Bank methodology should be. *Id.*

1519. Phillips reads too much into the three appellate cases[591] it uses to argue that the Gulf Coast Naphtha price can no longer be used to value West Coast Naphtha, according to Unocal/OXY. Unocal/OXY Reply Brief at pp. 1-2. In *OXY*, they note, the Circuit Court approved the distillation methodology, notwithstanding the fact that it used Gulf Coast prices to value both the West Coast Naphtha and VGO cuts. *Id.* at p. 2. Further, Unocal/OXY explain, the Circuit Court remained entirely silent as to the Naphtha and VGO cuts and whether or not it was appropriate to use Gulf Coast prices to value West Coast cuts. *Id.* They assert that the same is true of the *Exxon* decision, where the court did not remand the Naphtha and VGO cuts, implying that these cuts had become final following the *OXY* decision. *Id.* Unocal/OXY state that while *Tesoro* did deal with the Naphtha and VGO cuts, the court did not foreclose the continued used of Gulf Coast prices. *Id.* Instead, they claim, the court found that Tesoro presented sufficient evidence that there was new evidence to warrant a review of how West Coast Naphtha should be valued. *Id.* at pp. 2-3. According to Unocal/OXY, this makes it clear that the use of Gulf Coast prices is not foreclosed. *Id.* at p. 3.

1520. Unocal/OXY also argue that Phillips is wrong when it argues that continued use of Gulf Coast prices for Naphtha would violate the consistency requirements of *OXY*. *Id.* Unocal/OXY state that use of Gulf Coast prices is acceptable because Gulf Coast prices value the Naphtha cut no less precisely than do the proxies for other cuts. *Id.* They explain that it is not inconsistent to retain Gulf Coast pricing for only one cut if there is a rational basis for doing so and that, in this case, the rational basis is the lack of a published West Coast price for Naphtha. *Id.* Further, Unocal/OXY assert that there is no convincing evidence that Naphtha has a higher value on the West Coast. *Id.*

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[591] Unocal/OXY refer to *OXY*, 64 F.3d 679; *Exxon*, 182 F.3d 30; *Tesoro,* 234 F.3d 1286. Unocal/OXY Reply Brief at p. 1.

1521. Unocal/OXY also contend that Gulf Coast prices meet the rational relationship criterion of the *Exxon* case because the evidence establishes that there is a rational relationship between the published Gulf Coast price and the West Coast value of Naphtha. *Id.* They maintain that a close correlation cannot be established for any method selected to value West Coast Naphtha because the actual value of West Coast Naphtha is not known, as conceded by Phillips. *Id.* Unocal/OXY also maintain that continued use of Gulf Coast prices is justified under the *Tesoro* ruling because evidence that answers the propositions submitted by Tesoro has been submitted by Williams, Unocal/OXY, and Petro Star. *Id.*

1522. Contrary to Phillips argument, Unocal/OXY assert, neither *OXY* nor *Exxon* should be interpreted as requiring proof of price equivalency between the Gulf and West Coasts in order to continue using Gulf Coast published prices in both markets. *Id.* at p. 4. They note that, because there are no published prices for West Coast Naphtha, price equivalency cannot be demonstrated as a matter of fact. *Id.* Unocal/OXY also state that, because of the sporadic, non-public nature of the West Coast Naphtha contracts, no average price obtained from the contracts is comparable to the published Gulf Coast price. *Id.*

1523. They argue that this point is further underscored by the fact that Naphtha deliveries under contracts such as the ones analyzed in this case are not, as Culbertson stated, even considered by Platts in establishing its Gulf Coast Naphtha price assessments. *Id.* Furthermore, Unocal/OXY note, Gulf Coast Naphtha contracts, like their West Coast counterparts, sometimes base their prices on the price of gasoline minus a deduction and reflect prices that vary by a penny or more from Platts published Gulf Coast Naphtha assessments. *Id.* at pp. 4-5. Thus, they conclude, the only available data on West Coast Naphtha prices is of a different character than the data used to establish Platts Gulf Coast assessments, and absolute equivalency, even if it could be demonstrated, would not prove that West Coast and Gulf Coast Naphtha values are equivalent. *Id.* at p. 5.

1524. Unocal/OXY point out that Sanderson did not admit, as Phillips appears to believe, that retaining single market pricing for Naphtha was inconsistent with the valuation of the other cuts of the Quality bank. *Id.* Instead, they note that he admitted that the proposal to retain Gulf Coast pricing for Naphtha was not consistent with the proposal to abandon single market pricing for VGO. *Id.*

1525. More importantly, in Unocal/OXY's view, all of the proposals for changing the current method of valuing the Naphtha cut are inconsistent with the valuation of the other cuts. *Id.* at p. 6. They note that no party claims that Tallett's proposal is consistent with the way other cuts are priced and also point out that the evidence shows that O'Brien's proposal is not consistent with the Eight Party proposal for Resid and is clearly inconsistent with the use of published prices for all other cuts. *Id.* In contrast, Unocal/OXY explain, Sanderson noted that continuation of the current method, based on single market pricing, is consistent with way other cuts are valued because it uses objective, published prices for Naphtha. *Id.*

1526. Unocal/OXY assert that Naphtha is unique, that it is the only cut in the Quality Bank with an acceptable price on one coast and no price published on the other, and that this differentiates it from Resid. *Id.* at pp. 6-7. In their view, any valuation method chosen to value the West Coast Naphtha cut must confront Naphtha's uniqueness, and the solution to this problem may require an approach that is different than the way in which other cuts are valued. *Id.* at p. 7.

1527. Arguably, state Unocal/OXY, single market pricing, because of its potential to apply to any cut, is a consistent policy that applies to all cuts. *Id.* They point out that the Circuit Court has expressed skepticism regarding the continued use of single market pricing, saying that the principle of uniformity announced in *OXY* "would be breached if the availability of an adequate non-adjusted benchmark for the Gulf Coast prevented the use of an adjusted benchmark for the West Coast." *Id.* (quoting *OXY*, 234 F.3d at p. 1293). Unocal/OXY contend that it is the lack of a benchmark for West Coast Naphtha, and not the lack of availability of a Gulf Coast price, that prevents the use of a proper adjusted West Coast Naphtha benchmark. *Id.* They also contend that the record demonstrates that there is no benchmark that could be adjusted and that only the experts who support the continued use of Gulf Coast prices as the unadjusted benchmark for West Coast Naphtha came to an agreement on this issue. *Id.*

1528. Unocal/OXY explain that single market pricing was not designed and used only for Naphtha. *Id.* at p. 8. They note that it has been applied to Naphtha, VGO and Resid. *Id.* Given that it is reflected in the Tariff and has been applied and upheld for three different cuts, Unocal/OXY believe that it retains its vitality despite the court's skepticism. *Id.* More than that, they contend that, under the facts of this case, single market pricing is appropriate for Naphtha because Gulf Coast Naphtha is the best benchmark for the value of West Coast Naphtha. *Id.* at pp. 8-9.

1529. Phillips concedes, Unocal/OXY claim, that were one to demonstrate a close correlation between the Naphtha value on the Gulf Coast and the West Coast that would satisfy the requirements of *OXY*. *Id.* at p. 9. They contend that, contrary to Phillips's view, the evidence shows just such a correlation. *Id.* Unocal/OXY note that the contracts show a rough equivalence, or close correlation, between the Gulf Coast Naphtha price and the Naphtha contract prices between 1994-1998, and also point out that the differential between the average West Coast contract price and Gulf Coast Platts price is less than 2¢/gallon, within the range of the spread between Gulf Coast contracts and the Platts Gulf Coast Naphtha price. *Id.* at pp. 9-10. Further, they state, the lack of West Coast imports of Naphtha and the existence of separate price series for intermediate products both show that West Coast Naphtha does not have a higher value than Gulf Coast Naphtha and may have a lower value. *Id.* at p. 10. Accordingly, they maintain that continued use of Gulf Coast pricing for Naphtha meets the correlation test of *Exxon*. *Id.*

1530. The just and reasonable standard emphasized by Exxon and contained in the statute and the *OXY* decision, Unocal/OXY agree, is the appropriate standard to use in this case. *Id.* (citing 49 U.S.C. App. §§ 1(5), 15(1)(1988)). They state that a just and reasonable determination must be made in light of the purpose of the Quality Bank, which is to establish relative values for the different cuts in the TAPS stream. *Id.* In their view, the valuation must also meet the consistency test of *OXY* and the rational relationship test of *Exxon*. *Id.* at pp. 10-11. They note, however, that these two criteria may be considered part of the just and reasonable standard, as construed and applied in *OXY* and *Exxon*. *Id.* at p. 11. According to Unocal/OXY, the Circuit Court in *OXY* stressed consistency over accuracy when it stated that relative accurate values are what is required. *Id.* They note that the Circuit Court recognized that there was no perfect way to value the different cuts and that the Commission should not be held to an impossibly high standard. *Id.* Therefore, they conclude, the evidence in this case demonstrates convincingly that continued use of Gulf Coast pricing to value the enter Naphtha is just and reasonable. *Id.*

1531. Unocal/OXY note that use of Gulf Coast pricing for this cut was not disturbed on appeal and thereby became an approved final part of the TAPS Quality Bank methodology. Unocal/OXY Initial Brief at p. 2 (citing *OXY*, 64 F.3d 679). As such, they assert that it is protected by the filed rate doctrine. *Id.* (citing *Arizona Grocery*). Thus, according to Unocal/OXY, any party seeking to change the current method of valuing the Naphtha cut bears the burden of proving that changed circumstances have caused the existing valuation to be unjust and unreasonable (or unduly preferential and discriminatory), and that the recommended replacement methodology is just and reasonable. *Id.* at pp. 2-3. (citing *Texas Eastern Transmission Corp.*, 893 F.2d at p. 771 n.5). The Naphtha issue is before the Commission now, they explain, because Tesoro made a sufficient showing of changed circumstances to require the Commission to determine whether the new evidence "warrants re-examination of how West Coast naphtha should be valued." *Id.* at p. 3 (quoting *Tesoro*, 234 F.3d at p. 1293). It is Unocal/OXY's position that the evidence submitted does not warrant a change in the current methodology. *Id.*

1532. In reply to the argument by Exxon that a showing of new evidence is sufficient to require a reexamination of the reasonableness of an existing rate, Unocal/OXY assert that Commission precedent uses the term changed circumstances. Unocal/OXY Reply Brief at p. 12. They assert that the Commission prefers, for reasons of administrative economy, not to reopen matters once they have been resolved merely because a party may have found a new approach to a previously litigated issue. *Id.* Unocal/OXY agree with Williams that the new evidence or changed circumstances must be substantial enough to call into question the reasonableness of the prior rulings. *Id.* They maintain that under the more stringent standard applicable to Commission proceeding, the parties arguing for change have not satisfied their burden of proof. *Id.*

1533. While claiming that they do not have a burden of going forward with evidence to support the current methodology, Unocal/OXY acknowledge that they must answer evidence submitted by the proponents of change. Unocal/OXY Initial Brief at p. 3. They claim that they have submitted the testimony of Culberson (Exhibit Nos. UNO-1 and UNO-7), Sanderson (Exhibit Nos. WAP-1, WAP-8, and WAP-33), and Boltz (Exhibit No. PSI-I), which taken together and supplemented by other record evidence, provide substantial, credible evidence to sustain the continued use of Gulf Coast Naphtha prices to value the West Coast Naphtha cut. *Id.* at pp. 3-4.

6. Petro Star

1534. Petro Star asserts that: (1) the current use of Gulf Coast Naphtha prices to value Naphtha on the West Coast continues to be just and reasonable; and (2) if the Commission decides to depart from the use of Gulf Coast Naphtha prices, then Dudley's methodology is the best of the alternatives that have been presented and should be selected. Petro Star Initial Brief at p. 2. It states that Boltz testified that Naphtha valuation is important to Petro Star despite the fact that Petro Star does not manufacture gasoline, and that Dudley presented an alternative Naphtha valuation to be implemented if the Commission finds that use of Gulf Coast prices to value West Coast Naphtha is no longer just and reasonable. *Id.*

B. STIPULATED MATTERS AND AREAS OF DISPUTE

1. Exxon

1535. Exxon states that there are no stipulated facts pertaining to the value of West Coast Naphtha, but that all parties agree that the central matter at issue is whether the current practice of using the Platts Gulf Coast Naphtha price assessment to value West Coast Naphtha produces a just and reasonable value. Exxon Reply Brief at p. 209. According to Exxon, at least six different proposals have been presented for valuing the West Coast Naphtha cut. Exxon Initial Brief at p. 194. It notes that the Alaska refiners (Petro Star and Williams) and Unocal/OXY argue in favor of maintaining the status quo by continuing to value the West Coast Naphtha cut on the basis of the prices published by Platts Oilgram ("Platts") for Naphtha on the Gulf Coast. *Id.* All of the other parties (Phillips, Exxon, BP, and Alaska) to this proceeding, states Exxon, reject that position as unjust and unreasonable, and take the position that the West Coast Naphtha cut should be valued on the basis of West Coast market conditions using the West Coast prices of the petroleum products that are produced from Naphtha. *Id.* However, according to Exxon, the latter disagree regarding the particular methodology that should be used to achieve that result. *Id.*

1536. Because, Exxon claims, Naphtha is used on both coasts as a feedstock to make gasoline and jet fuel, the West Coast Naphtha cut should be valued based on the prices of unleaded regular gasoline and jet fuel on the West Coast using a regression formula derived from the published prices of Naphtha, unleaded regular gasoline, and jet fuel on the Gulf Coast. *Id.* It notes that Phillips and Alaska agree that the West Coast price of gasoline is the appropriate starting point for developing a value for the West Coast Naphtha cut, but that they propose an alternative approach that values West Coast Naphtha on the basis of the price of unleaded regular gasoline on the West Coast less the cost of reforming and blending the Naphtha into gasoline. *Id.*

1537. Exxon points out that BP also initially proposed a formula that valued Naphtha on the West Coast based on the price of gasoline on the West Coast reduced by the cost of transforming Naphtha into gasoline. *Id.* at p. 195. However, notes Exxon, BP further proposed that a so-called "governor" should be imposed that would effectively cap the value of the West Coast Naphtha cut at $1.49/barrel above the Gulf Coast Naphtha price.[592] *Id.* At the hearing, explains Exxon, BP withdrew its proposal and, instead, stated that it was willing to accept either the Naphtha valuation proposed by Exxon or the valuation proposed by Phillips provided that the valuation selected was limited by its proposed "governor." *Id.* In addition, Exxon notes, during the hearings, BP suggested an alternative governor based on a variable transportation differential rather than the fixed price ceiling of $1.49/barrel. *Id.*

1538. Further, notes Exxon, as an alternative to its status quo proposal, Petro Star proposed a contingent alternative methodology under which the West Coast Naphtha cut would be valued based on the relationship between the Gulf Coast price of Naphtha and a weighted incremental differential between Gulf Coast and West Coast VGO prices and Gulf Coast and West Coast LSR prices. *Id.* During the hearing, Exxon states, the witness for Williams suggested yet another alternative approach for valuing Naphtha on the West Coast based on the market price of ANS crude plus the cost of producing Naphtha from the crude (ANS + $4.00/barrel). *Id.* at pp. 195-96.

1539. Although all parties agree that the new Platts Gulf Coast Heavy Naphtha price assessment more closely matches the quality of Quality Bank Naphtha than the Platts Full Range Naphtha price assessment for the Gulf Coast, Exxon notes that Petro Star and Unocal/OXY raise procedural objections to the steps taken by the TAPS Quality Bank Administrator to implement the use of the new heavy Naphtha quote. Exxon Reply Brief

[592] Exxon notes that BP's proposed governor also contains a floor which would prevent West Coast Naphtha from being valued at less than the price of ANS crude plus $4.00/barrel. Exxon Initial Brief at p. 195, n.78.

at p. 210. In addition, Exxon and Phillips propose that the new Platts Heavy Naphtha price assessment for the Gulf Coast should be adjusted to reflect the higher naphthene plus aromatic ("N+A") content of Quality Bank Naphtha based on new evidence that the Platts Gulf Coast price assessments are based on an N+A that is much lower than the N+A of Quality Bank Naphtha. *Id.*

1540. Exxon states that the parties disagree over whether the Quality Bank Administrator's proposal to average the Platts monthly Heavy Naphtha barge and Heavy Naphtha cargo price assessments for the Gulf Coast should be approved. *Id.* at pp. 210-11. Exxon and Phillips take the position that the Quality Bank Administrator's averaging proposal should be adopted for the Gulf Coast, while Williams, Unocal/OXY, BP, and Petro Star oppose that proposal. *Id.* at p. 211.

1541. According to Exxon, both the Exxon proposal and the Phillips proposal (and BP's original proposal without the artificial "governor") value the West Coast Naphtha cut at levels that are significantly higher than the Platts Gulf Coast Naphtha price and that are close to the actual market value of Naphtha on the West Coast as indicated by the West Coast Naphtha contracts which were produced during discovery in this proceeding. Exxon Initial Brief at p. 196. By contrast, Exxon asserts, the application of the so-called "governor" proposed by BP, would reduce the value of the West Coast Naphtha cut to a level only slightly above the Platts Gulf Coast Naphtha price. *Id.* Similarly, Exxon states, the Petro Star alternative proposal values the West Coast Naphtha cut at or very close to the Platts Gulf Coast Naphtha price, while William's alternative West Coast Naphtha valuation using the price of ANS crude plus the cost of producing Naphtha from the crude, also produces a valuation at or very close to the Platts Gulf Coast Naphtha price depending on which proxy is used for the cost of producing Naphtha from crude. *Id.* at pp. 196-97.

2. Phillips

1542. Phillips states that the parties were unable to reach any stipulations with respect to the West Coast Naphtha value issue beyond agreeing on a description of following three broad areas of dispute: (1) whether a West Coast-based methodology should be used to value West Coast Naphtha instead of using the Gulf Coast price; (2) how West Coast Naphtha should be valued if the Commission decides to adopt a new valuation methodology; and (3) what the effective date should be for any new West Coast Naphtha valuation Phillips Initial Brief at p. 14.

3. BP

1543. BP states that the parties have entered into no stipulations on the primary Naphtha issue, the valuation of West Coast Naphtha. BP Initial Brief at p. 4. According to it, Williams, Petro Star, and Unocal/OXY posit that the Commission should continue to use a Gulf Coast assessment to value West Coast Naphtha. *Id.* Further, notes BP, Petro Star has proposed an alternate West Coast methodology to derive a West Coast Naphtha value if it is determined that a West Coast Naphtha methodology should replace the Gulf Coast price for valuing West Coast naphtha. *Id.* BP states that it, Exxon, Phillips, and Alaska agree that the Quality Bank should use a West Coast price to value Quality Bank naphtha on the West Coast, but have proposed three different valuation methodologies, with BP proposing one, Exxon proposing a second, and Phillips and Alaska proposing a third. *Id.* at pp. 4-5. Further, it states that all parties have agreed that the Platts Heavy Naphtha quotation should replace the Platts Naphtha quotation for valuing Naphtha on the Gulf Coast. *Id.* at p. 5. Finally, notes BP, Exxon, Phillips, and Alaska argue the Quality Bank additionally should adjust this reference price to account for alleged N+A differences. *Id.*

1544. Since creating the Platts Heavy Naphtha price, BP notes, Platts has added an additional Gulf Coast Naphtha assessment, so that there is now a Heavy Naphtha barge quote in addition to the Platts Heavy Naphtha quote. BP Reply Brief at p. 5. It states that the parties disagree as to whether Platts Heavy Naphtha quote should continue to be used to value Naphtha on the Gulf Coast or whether an average of the Platts Heavy Naphtha and Heavy Naphtha Barge price quotes should be used. *Id.* BP also states that it, Williams, Petro Star, and Unocal/OXY support continued use of the Platts Heavy Naphtha quote, while Exxon, Phillips, and the TAPS Carriers support use of the Quality Bank Administrator's averaging proposal. *Id.* Also, BP points out, Exxon, Phillips, and Alaska support adjusting any chosen Gulf Coast reference price to account for N+A differences. *Id.* at p. 6. Finally, BP notes, it, Williams, Unocal/OXY, and Petro Star oppose an N+A adjustment. *Id.*

4. Williams

1545. Williams agrees that the parties have not stipulated to any issues related to the valuation of the West Coast Naphtha. Williams Initial Brief at p. 15. It notes that the closest area of agreement among the parties appears to be that all support substitution of Platts Gulf Coast Heavy Naphtha price quote for the Platts Gulf Coast waterborne price quote that has been used to value both the Gulf Coast and West Coast Quality Bank Naphtha components since the effective date of use of a distillation methodology. *Id.* at pp. 15-16.

1546. According to Williams, it, along with Unocal/OXY and Petro Star, supports continued use of Platts Gulf Coast Heavy Naphtha price quote. *Id.* Conversely, states Williams, the remaining parties advocate discarding the use of a Gulf Coast published price and adopting some formula-based approach using West Coast gasoline prices as part of the formula. *Id.* But, notes Williams, even the parties who agree on the need for a changed methodology are not unified. *Id.* Williams explains that Exxon supports a regression-based formula approach, while Phillips and Alaska support a different processing-based formula approach, and that BP proposes that a governor with a floor and cap be applied to either the Exxon proposal or the Phillips proposal. *Id.*

1547. Although all the parties appear to support the use of Platts Gulf Coast Heavy Naphtha price quote, Williams points out, Exxon, Philips and Alaska seek to have 1.5¢/gallon added to that price by making an "N+A" adjustment to the published price. *Id.* Williams states that it, Unocal/OXY, Petro Star and BP oppose such an adjustment, particularly because no other Quality Bank component has the published price used to value that component adjusted based on a constituent characteristic of the product itself. *Id.* at pp. 16-17.

5. Unocal/OXY

1548. Unocal/OXY state that the areas of dispute are whether the current method of using Gulf Coast prices to value West Coast Naphtha is just and reasonable, and if not, what methodology should be used in its place. Unocal/OXY Initial Brief at p. 4. They explain that there is also a dispute as to which of the Platts Naphtha prices should be used, both for Gulf Coast Naphtha and for West Coast Naphtha. *Id.* Although the parties have not stipulated with respect to West Coast Naphtha prices, Unocal/OXY note that no party contends that prices for West Coast Naphtha are published by any price quoting services or are otherwise publicly available. *Id.*

1549. They also disagree with Exxon's statement that the Tallett and O'Brien proposals produce results close to the actual market value of Naphtha as measured by the contracts, and point out that, in their view, this is merely Exxon's opinion and that the actual market value of Naphtha on the West Coast is unknown. Unocal Reply Brief at p. 15.

6. TAPS Carriers

1550. The TAPS Carriers assert that by far the most important of the issues before the Commission with respect to valuing the Naphtha component is what methodology to use for valuing it on the West Coast. TAPS Carriers Initial Brief at p. 13. If the Commission adopts a methodology for valuing West Coast Naphtha other than using a Gulf Coast price assessment, the TAPS Carriers state, the Gulf Coast price assessments proposed by the Quality Bank Administrator will have significance only as interim prices (if the Exxon proposal to adopt the West Coast methodology retroactively is accepted) or for a relatively brief period from the date that the Quality Bank Administrator's proposal was accepted until a new methodology is adopted for valuing Naphtha on the West Coast (if one of the proposals for prospective adoption of a West Coast methodology is accepted). *Id.* This is so, explain the TAPS Carriers, because, under the Quality Bank methodology, prices are weighted by the percentage of ANS going to the Gulf Coast and West Coast, and since mid-1999 100% of ANS has been delivered to the West Coast. *Id.*

C. IS THE CURRENT NAPHTHA VALUE JUST AND REASONABLE?

1. Exxon

1551. Exxon points out that until March 1, 2003, the Quality Bank used a single Gulf Coast waterborne spot price published by Platts to value the Naphtha cut on both the Gulf Coast and the West Coast. Exxon Initial Brief at p. 197. Beginning on March 1, 2003, notes Exxon, the Quality Bank began using a new Platts Gulf Coast price for Heavy Naphtha (subject to refund) instead of the Platts Gulf Coast price for full range Naphtha.[593] *Id*. According to Exxon, the Alaska refiners (Petro Star and Williams) and Unocal/OXY argue in favor of continuing to value the West Coast Naphtha cut on the basis of one of these Platts Gulf Coast Naphtha prices. *Id.* Exxon states that this position is opposed by all other parties to the proceeding and the evidence overwhelmingly shows that this approach does not produce just and reasonable results. *Id.* at pp. 197-98.

1552. According to Exxon, the current policy of using a Platts Gulf Coast Naphtha price to value West Coast Naphtha was never advocated by any party. *Id*. at p. 198. Rather, Exxon states, it was adopted by the Commission, in 1993, based on the Commission's policy of making no adjustments to market prices. *Id*. Exxon asserts that this policy was subsequently rejected by the Circuit Court as arbitrary and capricious and abandoned by the Commission. *Id*. Eight years of experience have clearly shown, in Exxon's opinion, that the current methodology does not produce values for West Coast Naphtha that fairly reflect West Coast market conditions. *Id*. It states that the evidence reflects that the West Coast and the Gulf Coast are separate and distinct markets for petroleum products, and that prices on the West Coast are significantly different from those on the Gulf Coast, both a short term and a longer term basis. *Id.* In addition, according to Exxon, the contracts for the sale of Naphtha on the West Coast that were produced in this case show that West Coast Naphtha is almost always priced on the basis of higher West Coast gasoline prices and that the resulting West Coast Naphtha contract prices are on average substantially higher than the Gulf Coast Naphtha prices. *Id.* Similarly, continues Exxon, none of the Naphtha traders contacted by Unocal/OXY's witness supported the use of a

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[593] Exxon notes that shortly after the conclusion of the hearing, the Quality Bank Administrator learned that, as of May 1, 2003, Platts began publishing *two* waterborne Heavy Naphtha prices for the Gulf Coast, one labeled "Heavy Naphtha" for large ship cargoes up to 250,000 barrels and the other labeled "Heavy Naphtha Barge" for smaller barge cargoes typically in the range of 50,000 barrels. Exxon Initial Brief at p. 197, n.79. To deal with this situation, the Quality Bank Administrator has proposed that all Quality Bank Naphtha should be valued on the basis of the arithmetic average of the Heavy Naphtha and Heavy Naphtha Barge average monthly prices reported by Platts. *Id.* By order dated August 18, 2003, the Commission accepted that rate on an interim basis subject to refund and directed that this issue be addressed in the context of this proceeding. *Id.*

Gulf Coast Naphtha price to value Naphtha on the West Coast, and at least one trader specifically rejected that approach in favor of a Naphtha price based on the price of gasoline. *Id.* at pp. 198-99. In short, Exxon argues, the evidence is overwhelming that it would be unjust and unreasonable to continue using a Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at p. 199. Each of these points is discussed below.

1553. Exxon notes that the settlement agreement presented to the Commission in 1993 proposed that Naphtha should be valued on the West Coast by "applying a Gulf Coast-derived ratio of naphtha to gasoline prices to the Platt's Los Angeles pipeline spot quote for gasoline." *Id*. (quoting *Trans Alaska Pipeline System*, 65 FERC at p. 62,288). This approach was proposed, according to Exxon, because there was no Platts or other published price quoted for Naphtha on the West Coast. *Id*. Exxon asserts that this formula appropriately recognized that the primary determinant of the value of Naphtha is the price of gasoline in the market because gasoline is the principal finished product that is produced from Naphtha.[594] *Id.*

1554. The Commission, Exxon notes, did not adopt the West Coast Naphtha valuation proposed by the parties in the 1993 settlement adopting, instead, a policy that all Quality Bank cuts had to be valued on the basis of "unadjusted quoted market prices." *Id.* at pp. 199-200. Under this policy, explains Exxon, the Commission directed the use of prices quoted in a single market for the entire stream when no price was posted for a given product. *Id*. at p. 200. Applying this policy to the West Coast Naphtha cut, states Exxon, the Commission required that the "Gulf Coast price be used to value the entire naphtha cut in both markets, instead of applying the settlement's formula" for West Coast Naphtha. *Id*. (quoting *Trans Alaska Pipeline System*, 65 FERC at p. 62,289). Further, notes Exxon, in its order on rehearing, the Commission specifically denied Exxon's request that the pricing methodologies contained in the settlement proposed by the parties be adopted without modification. *Id*.

1555. On review of the Commission's 1993 decision, explains Exxon, the Circuit Court held that the Commission's determination that the Quality Bank Administrator had to value all cuts at published market prices without adjustment was "arbitrary and capricious" and did not meet "the requirement of reasoned decisionmaking." *Id*. (quoting *OXY*, 64 F.3d at pp. 693-94). In particular, states Exxon, the Circuit Court found that the Commission's selection of unadjusted market proxies to value the Distillate and Resid cuts was arbitrary and capricious because the Commission had offered no data to indicate

[594] Exxon notes that this 1993 settlement was supported by the Alaska, Amoco, BP, Exxon, Mapco, Petro Star, and Phillips; it was opposed by ARCO, Tesoro, Unocal, Conoco and OXY. Exxon Initial Brief at p. 199, n.80. According to Exxon, no party opposing the settlement advocated the use of the Gulf Coast Naphtha price to value Naphtha on the West Coast. *Id*

that the selected proxy market prices were a reasonable approximation of the market values of the cuts. *Id*. at pp. 200-01.

1556. On remand, continues Exxon, the Commission abandoned its policy of requiring the use of unadjusted market prices to value all ANS cuts, adopting new adjusted valuation methodologies for both the Light and Heavy Distillate and Resid cuts, with separate valuations for each on the Gulf Coast and the West Coast. *Id.* at p. 201. Although requests from Exxon and Tesoro that the Commission also consider whether other cuts – including West Coast Naphtha – were properly valued were declined at that time on the ground that those cuts were not within the limited scope of the *OXY* remand, Exxon asserts that claim is now squarely before the Commission as a result of the complaints which were filed by Tesoro and Exxon. *Id*.

1557. According to Exxon, at no time has any party ever presented any evidence demonstrating that the existing methodology accurately represents West Coast Naphtha values, and no prior decision of the Commission provides any logical or factual support for it. *Id.* at p. 202. Exxon maintains that the Circuit Court specifically has found that evidence previously presented by Tesoro – including the rejection and abandonment of the Commission's policy of no adjustment, the significant reduction in Gulf Coast ANS sales, and the disparity between the Gulf Coast Naphtha proxy and the true market value of Naphtha on the West Coast – was sufficient to establish a prima facie case that the current practice of using the Gulf Coast Naphtha price as a proxy for valuing West Coast Naphtha is not just and reasonable.[595] *Id.* It argues therefore, that no presumption of legality should be attached to the existing practice of valuing West Coast Naphtha on the basis of the Gulf Coast Naphtha price. *Id*.

1558. Ever since the distillation methodology was adopted in 1993, notes Exxon, the Commission and all parties to this proceeding have agreed that the valuation of each Quality Bank ANS cut should be market based. *Id*. at p. 203. Moreover, states Exxon, recognizing that the Gulf Coast and the West Coast are separate markets for petroleum products with different supply and demand conditions and different prices, the parties have proposed separate prices for the Gulf Coast and the West Coast for all Quality Bank cuts. *Id.* And with only two exceptions – Naphtha and VGO – Exxon explains that the Commission has adopted separate prices for the Gulf Coast and the West Coast for all Quality Bank cuts. *Id.*

1559. In the case of VGO, Exxon asserts that all parties now agree that the current

[595] The Circuit Court actually held that Tesoro "at the least establish[ed] a prima facie case that new evidence warrants re-examination of how West Coast naphtha should be valued." *Tesoro*, 234 F.3d at p. 1293. This holding is significantly different than Exxon asserts.

method of valuing the West Coast VGO cut on the basis of the OPIS Gulf Coast spot price for high sulfur VGO does not produce a just and reasonable result, and that the proxy price for valuing the VGO cut on the West Coast should be changed to the OPIS West Coast spot price for high sulfur VGO. *Id*. at p. 203 (citing Joint Stipulation of the Parties, filed October 3, 2002, at p. 4). Therefore, states Exxon, for all Quality Bank cuts other than West Coast Naphtha, the parties agree that different market conditions on the West Coast require the use of West Coast prices to fairly value the West Coast cuts. *Id*. at pp. 203-04. In addition, notes Exxon, the use of a Gulf Coast price to value West Coast Naphtha does not meet the legal requirements established by the Circuit Court in *OXY*, where the court held that the Commission must adopt a sufficiently consistent approach in valuing the various Quality Bank cuts so as to assign accurate relative cut values. Exxon Reply Brief at p. 213. Accordingly, Exxon states, using a Gulf Coast price to value Naphtha on the West Coast is inconsistent with the methodologies that have been adopted for all other Quality Bank cuts, or in the case of VGO, with the methodology that is supported by all parties. Exxon Initial Brief at p. 204.

1560. Exxon cites evidence in the record and argues that this evidence clearly shows that the West Coast and the Gulf Coast are separate and distinct markets with different market prices for both intermediate and finished petroleum products. *Id*. For example, according to Exxon, the evidence shows that, throughout the 1994-2001 period, both the price of gasoline and the price of every intermediate petroleum product valued by the Quality Bank was significantly different on the Gulf Coast and the West Coast, and the price differentials between the West Coast and the Gulf Coast prices varied widely on both a monthly and an annual basis.[596] *Id.* Exxon notes that these price differentials between the West Coast and the Gulf Coast were acknowledged to be significant even by those parties advocating the use of the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.*

1561. Further, Exxon asserts, Williams's claim that the Gulf Coast price should be similar to the value of Naphtha on the West Coast over the long run, a claim that is not substantiated by the evidence, does not meet the requirements of the *OXY* and *Exxon* decisions that more than "a limited and unquantified relationship" between the proposed proxy price and the actual market value of the cut must be established, and that the proxy price must be shown to "correlate consistently within some specified range" with the market value of the cut. Exxon Reply Brief at pp. 213-14 (quoting *Exxon*, 182 F.3d at pp. 36, 42). Indeed, Exxon asserts, the evidence is undisputed that the current practice of using a Platts Gulf Coast Naphtha price to value the West Coast Naphtha cut was never justified by the Commission under those standards, but was based solely on a now abandoned 1993 policy of using only "unadjusted quoted market prices" to value all

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[596] In support, Exxon cites Exhibit Nos. BPX-35, EMT-14, EMT-453, EMT 477 through EMT-482, PAI-176. Exxon Initial Brief at p. 204.

Quality Bank cuts. *Id.* at p. 214.

1562. According to Exxon, no party contends that the value of Naphtha is actually the same on the Gulf Coast and the West Coast. Exxon Initial Brief at p. 205. On the contrary, Exxon states, it is undisputed and conceded by opposing party witnesses that there have been, and will continue to be, different supply and demand forces at work in the markets for Naphtha on the two coasts. *Id*. pp. 205-06. To ascertain the value of Naphtha on the West Coast, Exxon argues, one has to look at the supply and demand for Naphtha on the West Coast. *Id*. at p. 206. In recognition of this market reality, Williams's witness, Sanderson, stated that when he worked at a West Coast refinery he did not rely on Gulf Coast prices for Naphtha and would not recommend that anyone now assume that Gulf Coast and West Coast Naphtha prices were the same. *Id*. Further, Exxon notes that Sanderson viewed the question of whether the Platts Gulf Coast price for Naphtha was an accurate value for West Coast Naphtha to be an exercise of subjective judgment. *Id.*

1563. Exxon also notes that, while Naphtha is used on the Gulf Coast to make both gasoline and jet fuel and as a petrochemical feedstock, virtually its only use on the West Coast is to make gasoline and jet fuel. *Id*. at pp. 206-07. Nonetheless, Exxon states, the use of Naphtha as a petrochemical feedstock on the Gulf Coast does not impact the price of Quality Bank Naphtha because a substantial portion of the Naphtha used there as a petrochemical feedstock is a different, lighter Naphtha that is used to produce ethylene rather than the reformer grade Naphtha used to produce gasoline on the West Coast. *Id.* at p. 207.

1564. There are a number of other differences that distinguish the West Coast market for Naphtha from the Gulf Coast market, Exxon states. *Id*. For example, explains Exxon, much of the gasoline on the West Coast is required to meet more stringent environmental requirements established by the California Air Resources Board or by the Federal reformulated gasoline specifications that apply in Las Vegas and Phoenix, whereas most of the gasoline produced on the Gulf Coast must meet only conventional gasoline standards. *Id*. at pp. 207-08. As a result, Exxon explains, gasoline prices on the West Coast have consistently been higher than on the Gulf Coast by several cents per gallon. *Id*. at p.208. Further, according to Exxon, the much larger size of the Gulf Coast gasoline market also makes it less volatile and better able to absorb the impact on supply caused by refinery outages. *Id*. In addition, Exxon explains, Gulf Coast refiners routinely import Naphtha from nearby Caribbean sources. *Id.* On the West Coast, according to Exxon, refiners are generally able to satisfy their demand for Naphtha from internal sources and do not, therefore, require imports. *Id*. As a result, Exxon notes, West Coast refineries have not constructed the tankage and terminal facilities needed to import substantial quantities of Naphtha. *Id*. at pp. 208-09.

1565. Exxon points out that the quality specifications for the Platts Gulf Coast Naphtha prices are also different from the quality of the ANS Naphtha. *Id.* at p. 209. In particular, Exxon notes, the reported Platts prices for both Heavy Naphtha and Full Range Naphtha are based on an N+A specification of 40, whereas ANS crude produces Naphtha with an N+A in the 55 to 60 range. *Id*. According to Exxon, this means that Naphtha produced from ANS crude will be higher in quality because it will produce reformate with a higher octane, and thus be more valuable than the Naphtha specified in the Gulf Coast price published by Platts. *Id*. Exxon also notes that West Coast refineries also have a greater percentage of hydrocracking capacity as a percentage of crude than Gulf Coast refineries, with the result that West Coast refineries have a greater ability to alter the amount of Naphtha or jet fuel that is produced from the crude oil. *Id*. pp.209-10.

1566. Given these many differences, Exxon argues, none of the evidence introduced supports the conclusion that the price of Naphtha on the Gulf Coast is a good representation of the value of West Coast Naphtha. *Id.* at p. 210. On the contrary, Exxon asserts that the evidence shows that the current method of valuing the West Coast Naphtha cut on the basis of a Gulf Coast Naphtha price has significantly undervalued West Coast Naphtha over the past 10 years by, on average, over $2/barrel. *Id.*

1567. Exxon cites extensive contract data produced in the proceeding to support its contention that West Coast Naphtha has a higher value than Gulf Coast Naphtha. *Id.* at p. 211. It asserts that these contracts provide the best available direct evidence of the value of West Coast Naphtha, because they reflect the result of negotiations between independent and knowledgeable parties seeking to maximize their own profit. *Id.* Exxon notes that it is significant that none of the nearly 300 contracts produced in this proceeding priced Naphtha on the West Coast on the basis of an unadjusted Gulf Coast price of Naphtha. *Id.* at p. 212. Further, Exxon notes that only three of those West Coast Naphtha contracts even used an adjusted Gulf Coast price. *Id.* Two of those three contracts priced West Coast Naphtha on the basis of a Gulf Coast Naphtha price plus a premium, and the third contract only included a Gulf Coast price as part of a complex series of pricing terms that included a price cap and floor. *Id*.

1568. The West Coast Naphtha contracts, Exxon contends, also consistently valued West Coast Naphtha at levels that were significantly higher than the Platts Gulf Coast Naphtha price, thereby further demonstrating that the current Quality Bank practice of valuing West Coast Naphtha at the Platts Gulf Coast Naphtha price is, in Exxon's view, unjust and unreasonable. *Id*. at p. 213. It cites numerous studies and exhibits introduced into the record that show that the contract price of Naphtha on the West Coast exceed Platts Gulf Coast Naphtha by from 2 to 12¢/gallon during the period 1994-2001.[597] *Id*. According to Exxon, this conclusion was also confirmed by all of the witnesses who

[597] *See, e.g.,* Exhibit Nos. SOA-1, SOA-8, SOA-28, EMT-133, EMT-140, EMT-380, EMT-381, WAP-230.

addressed the issue. *Id*. at pp. 213-14. Exxon argues that the contract evidence shows that sellers of Naphtha on the West Coast have been able, in fact, to charge prices that were higher than Platts Gulf Coast Naphtha price. *Id*. at p. 214. Further, Exxon notes, Sanderson stated that he did not know of any sales of Naphtha on the West Coast that were made at the Platts Gulf Coast Naphtha price. *Id.* Also, Exxon cites an analysis of West Coast Naphtha contracts by Culbertson that showed that, on a volume weighted basis, the price of Naphtha reflected in the West Coast contracts exceeded the Platts Gulf Coast Naphtha price by more than 8¢/gallon.[598] *Id*.

1569. Exxon argues that evidence presented during trial regarding discussions held with Naphtha traders did not show a consistent approach to the use of a Platts Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at pp. 214-15. It states that the notes of these discussions show that none of the traders endorsed the use of a Gulf Coast Naphtha price to value West Coast Naphtha. *Id*. at p. 215. Instead, according to Exxon, the traders either expressly rejected that approach or they were never asked for their opinion on that issue. *Id.*

1570. Moreover, while the interview notes introduced by Culberson included a representative of Platts, Exxon points out that Culberson admitted that the Platts representative was never asked whether it would be appropriate to use a Platts Gulf Coast price to value Naphtha on the West Coast. *Id.* at pp. 216-217. Although Culberson sought to defend this omission on the ground that he did not believe that the Platts representative was qualified to have an opinion on that issue, Exxon states that Culberson admitted that he had never tried to contact anyone at Platts to find out whether they thought it would be reasonable to use Platts Gulf Coast Naphtha prices to value West Coast Naphtha. *Id.* at p. 217. Exxon concludes, therefore, that the only traders who were asked to express an opinion on Culberson's proposal to use Platts Gulf Coast Naphtha prices to value West Coast Naphtha rejected that proposal. *Id.*

1571. The evidence, Exxon argues, also makes clear that those parties who advocate the continued use of the Platts Gulf Coast Naphtha price to value the West Coast Naphtha cut have not carried their burden. *Id*. According to Exxon, the *Exxon* ruling requires that there be a rational, demonstrated relationship between the proposed proxy price and the value of the cut sufficient to show a consistent correlation between the proxy and the cut being valued. *Id*. at pp. 217-18. It maintains that this relationship test has not been met. *Id*. at p. 218. Further, Exxon asserts, there is no evidence to support the claim of Williams and Unocal that the prices of Naphtha on the West Coast and Gulf Coast are linked by the ability to move crude oil imports or Naphtha between the two markets in such a manner that the differential between the price of Gulf Coast Naphtha and the value of Naphtha on the West Coast would, on average, be expected to be zero. *Id.* Nor,

[598] *See* Exhibit Nos. UNO-52, UNO-56.

according to Exxon, is there any evidence to support Williams's argument that sellers of Naphtha on the West Coast would be unable to capture any portion of the higher gasoline refining margins found on the West Coast, or that the 1996 California Air Resources Board requirements somehow justify the use of a Gulf Coast Naphtha price. *Id.* Finally, Exxon states, the evidence is clear that the mere fact that the use of the Platts Gulf Coast Naphtha price to value West Coast Naphtha has provided a financial benefit to Petro Star and Williams plainly does not support the continued use of the Platts Gulf Coast price to value West Coast Naphtha. *Id.*

1572. According to Exxon, Williams defends using a Gulf Coast Naphtha price to value West Coast Naphtha by first repeating Sanderson's pre-filed testimony that the Gulf Coast published price is the only objective method of valuing West Coast Naphtha, because it is published by a recognized publishing service. Exxon Reply Brief at p. 216. It points out, however, that Williams fails to note that Sanderson admitted at the hearings that, while the published Gulf Coast price may be an objective measure of Gulf Coast value, his belief that the Gulf Coast price was a suitable measure for West Coast value was his subjective judgment. *Id.* Therefore, Exxon asserts, there is no factual basis whatsoever for the attempt of Williams and Unocal/OXY to claim that their proposal to continue using the published Gulf Coast Naphtha price to value West Coast Naphtha is more objective than the methodology presented by Tallett on behalf of Exxon, which is based entirely on objective published prices for gasoline and jet fuel. *Id.* at p. 217.

1573. Similarly, Exxon states that there is no basis for Williams's reliance on the claim in Sanderson's pre-filed testimony that the use of a published Gulf Coast Naphtha price to value West Coast Naphtha is "the most consistent with the valuation of the other Quality Bank cuts." *Id.* (quoting Exhibit No. WAP-33 at p. 2). Exxon notes that Sanderson conceded at the hearings that all of the Quality Bank cuts except Naphtha and VGO are valued on the West Coast using West Coast prices, and that, if the Commission accepts the unanimous proposal of the parties to value West Coast VGO on the basis of the West Coast VGO price, all of the Quality Bank cuts other than Naphtha will be valued on the West Coast using West Coast prices. *Id.* For this reason, Sanderson conceded at the hearing, contrary to his pre-filed testimony, that it would be most consistent to use a West Coast value rather a Gulf Coast value for Naphtha if one can be derived. *Id.*

1574. In Exxon's view, Williams's legal arguments in support of continued use of a Gulf Coast Naphtha price are also without merit. *Id.* at. p. 218. For example, Exxon asserts, Williams's reliance on a 1994 statement by the Commission that it had "strictly held to posted spot prices instead of formulæ or adjusted prices to establish relative prices for the Alaska North Slope crude components" is obviously out of date. *Id*. (quoting *Trans Alaska Pipeline System*, 67 FERC at p. 61,531). As all parties have recognized, Exxon states, the Commission's "no adjustments to market prices" policy was specifically rejected on review eight years ago by the Circuit Court in *OXY* and abandoned by the

Commission on remand. *Id*.

1575. Nor is there any basis, according to Exxon, for Williams's suggestion that the *OXY* decision only applies when there is no reliable published price for a cut in either market, and that otherwise the TAPS Carriers's Tariff recognizes that the published price in one market may be used to value the cut in both markets. *Id.* Exxon asserts that the Circuit Court clearly rejected this argument in *Tesoro*, stating that its decision in *OXY* "would be breached if the availability of an adequate non-adjusted benchmark for [Naphtha on] the Gulf Coast prevented the use of an adjusted benchmark for [Naphtha on] the West Coast." *Id*. (quoting *Tesoro*, 234 F.3d at 1293).

1576. Sanderson, according to Exxon, failed to support his contentions that the Gulf Coast Naphtha price was an appropriate proxy for the value of Naphtha on the West Coast based upon his claim that, because crude oil prices on the two coasts were "similar," the prices of Naphtha and other feedstocks should also be "similar" on both coasts. Exxon Initial Brief at p. 219. Moreover, Exxon states that, even if Williams had been able to support this claim, the similarity of prices posited by Sanderson would not be sufficient to meet the requirements for reasoned decision making established for this proceeding by the Circuit Court in Exxon. Exxon Reply Brief at p. 220. Exxon claims that Sanderson based his theory primarily on his contention that the price of ANS crude on the West Coast was similar to the price of Isthmus crude on the Gulf Coast. Exxon Initial Brief at p. 219; Exxon Reply Brief at p. 220. However, Exxon states, there was no direct evidence of any actual linkage between these prices. *Id.*

1577. Exxon declares that Sanderson admitted at the hearing that the market dynamics for VGO are quite different on the Gulf Coast and West Coast due to the substantially larger Gulf Coast demand for VGO for the production of heating oil for markets in the Northeast and Midwest. Exxon Reply Brief at p. 223. In addition, Exxon notes, Sanderson admitted that strict environmental restrictions on sulfur have increased the cost of processing VGO on the West Coast and thereby reduced its value; a problem that does not arise with Naphtha because all of the sulfur in Naphtha is removed by hydrotreating on both coasts before the Naphtha is processed into reformate in order to protect the reformer catalyst. *Id.*

1578. Sanderson's theory, by his own admission, according to Exxon, did not work for VGO in either 2000 or 2001 where the VGO price differential between the two coasts varied widely. Exxon Initial Brief at p. 223. In those years, Exxon points out, the VGO price was influenced by sharp spikes in the price of gasoline. *Id*. Further, Exxon asserts, the evidence shows that, contrary to Sanderson's theory, the price differential between crude oil prices and VGO fluctuated widely over time on both coasts even when smoothed out by the use of a 12-month moving average. *Id.* What the VGO price data actually show, according to Exxon, is that – directly contrary to Sanderson's theory – VGO prices on the West Coast have closely tracked the price of gasoline on the West

Coast, not the price of crude oil, with the result that VGO prices on the West Coast have generally been higher in recent years than VGO prices on the Gulf Coast. Exxon Reply Brief at p. 224. Further, Exxon notes that Sanderson's theory does not work for other feedstocks such as Heavy Distillate, Isobutane, or Butane. Exxon Initial Brief at p. 223.

1579. Indeed, Exxon asserts, the evidence shows that, contrary to Sanderson's theory, there were wide fluctuations in the differentials between the prices of all the Quality Bank cuts and crude oil prices on the West Coast and the Gulf Coast. *Id.* It states that Exhibit No. EMT-533, which compares the differential between the Gulf Coast price of each of seven Quality Bank cuts and the price of Isthmus crude on the Gulf Coast with the differential between the West Coast price of the same cut and the West Coast price of ANS crude, shows that there was no similarity at all between the price differentials on the Gulf Coast and the price differentials on the West Coast. *Id.* at p. 223-24. Exxon also states that this fact is confirmed by a regression analysis performed on its behalf which showed there was no significant correlation between the price differentials on the two coasts. *Id.* (citing Exhibit No. EMT-534).

1580. Further Exxon argues, the evidence[599] also shows that, notwithstanding any alleged similarity of crude oil prices on the two coasts, both intermediate petroleum product prices and finished petroleum product prices have varied widely between the two coasts. *Id*. at p. 224. For example, Exxon states, the evidence shows that the average annual differential between the price of VGO on the West Coast and the price of VGO on the Gulf Coast ranged from a negative 1.0 in 1996 to a positive 3.5 in 2000, and that the monthly average price differentials also fluctuated widely from month to month between the two coasts. *Id.*

1581. Furthermore, asserts Exxon, even were Sanderson correct that "similar" crude oil prices should result in "similar" prices for intermediate feedstocks, the so-called "similarity" that he posited between Gulf Coast Naphtha prices and the value of West Coast Naphtha would not meet the requirements for reasoned decisionmaking established by the Circuit Court. Exxon Reply Brief at p. 226. Exxon notes that Williams concedes that Sanderson did not contend that the value of Naphtha was actually ever the same on the two coasts. *Id*. At most, notes Exxon, Sanderson argued that crude oil and VGO prices gave him some guidance as to the value of Naphtha on the West Coast, and that, based on that guidance, he believed that the value of Naphtha on both coasts should be 'similar' in the long run. *Id.* Indeed, explains Exxon, Sanderson contended that it would be sufficient if two prices "may average out over ten or more years" even though they

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[599] In support, Exxon cites Exhibit Nos. BPX-35, EMT-14, EMT-453, EMT-477, EMT-478, EMT-479, EMT-480, EMT-481, EMT-482, PAI-176. Exxon Initial Brief at pp. 223-24.

"may vary widely from year to year." *Id*. at pp. 226-27 (quoting Transcript at p. 8830).[600]

1582. The theory presented by both Williams and Unocal/OXY that the availability of transportation would link the West Coast Naphtha price to the Gulf Coast price is also invalid, according to Exxon. Exxon Initial Brief at p. 225. First, Exxon argues, this theory plainly does not support the use of the same price to value Naphtha on both the Gulf Coast and the West Coast. *Id.* Instead, in Exxon's view, transportation costs would only constrain or limit the price of West Coast Naphtha to some value above the Gulf Coast price based on the transportation differential for shipping Naphtha to the West Coast. *Id.* Therefore, according to Exxon, the transportation differentials claimed by Williams and Unocal/OXY would, at best, only support a cap on the price of West Coast Naphtha analogous to the "governor" proposed by Ross on behalf of BP. *Id.*

1583. Further, Exxon states, the evidence shows the transportation cost differentials for Naphtha proposed by Sanderson and Culberson were too low. *Id.* at pp. 225-26. For example, Exxon notes that Sanderson's overall Naphtha transportation differential of $1.30/barrel (3.1¢/gallon) was based on the difference between the Worldscale shipping cost from Venezuela to Los Angeles and the Worldscale shipping cost from Venezuela to Houston. *Id*. at p. 226. According to Exxon, however, Sanderson acknowledged that this estimate of the transportation differential was a subjective estimate based on his judgment and a variety of assumptions. *Id.* Exxon also notes that Sanderson's estimate was based solely on Los Angeles, did not take into account barriers to entry that would impose additional costs on shipments of Naphtha to the West Coast, and that he conceded that the differential would be larger for other destinations on the West Coast.[601] *Id.*

1584. Second, Exxon asserts, there is no valid factual basis for Culberson's claims regarding either the magnitude or the effect of transportation costs on West Coast prices. *Id.* at p. 227. Exxon notes that Culberson himself admitted that his estimate of the cost of transporting Naphtha from the Caribbean to the West Coast was significantly below the actual average transportation rates publicly reported by Platts, and that it was based solely on his speculation that cheaper rates might be obtainable based on rates in other parts of the world and that there should be no transport differential between the Gulf Coast and

[600] Exxon notes that Sanderson conceded that any linkage between the price of crude and the price of a petroleum product was "not a rigid relationship" that would permit the Commissions to compute a West Coast Naphtha price. Exxon Reply Brief at p. 226, n.133 (quoting Transcript at pp. 9056-57).

[601] Exxon notes the following barriers to entry: the cost of building additional storage and terminal facilities, the higher risks associated with the longer lead time for shipments to West Coast markets, and the lack of market liquidity that makes hedging more difficult. Exxon Initial Brief at p. 226.

the West Coast. *Id*. Asserts Exxon, the evidence showed that the rates for shipping to the West Coast were actually nowhere near as low as Culberson had assumed and suggested in his prepared testimony. *Id*. Indeed, Exxon states, Culberson testified at the hearing that March 2003 tanker rates were significantly higher and that any opinion about future rates would be total speculation. *Id*. at pp. 227-28. It points out that Culberson's conclusion that West Coast Naphtha values must be at, or near, the Gulf Coast Naphtha price was based squarely on speculation about future transportation rates that they view is clearly invalid. *Id*. at p. 228. Nor, according to Exxon, did Culberson take into account a number of other costs that would be incurred in any movement of Naphtha to the West Coast, such as the higher risk involved in longer shipments to the smaller West Coast market, the cost to the refinery of changing its crude slate, and the lack of tank and terminal facilities on the West Coast.[602] *Id.*

1585. Finally, Exxon argues, both Sanderson's and Culberson's theories are directly undercut by evidence in the record[603] that there have been substantial and persistent differences between prices on the West Coast and Gulf Coast for virtually all intermediate and finished petroleum products. *Id*. at pp. 228-29. If West Coast and Gulf Coast petroleum prices were in fact linked by transportation in the manner suggested by Williams and Unocal, Exxon submits, the substantial and persistent differences between West Coast and Gulf Coast prices for both intermediate and finished petroleum products would not exist. *Id.* at p. 229. In Exxon's opinion these price differentials only serve to highlight the inappropriateness of the Quality Bank's use of a Gulf Coast price to value West Coast product. *Id*.

1586. Although Sanderson criticized the O'Brien and Tallett West Coast Naphtha

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[602] Equally lacking in merit, in Exxon's view, was Culberson's assertion that the absence of imported volumes to the West Coast supported his claim that the Gulf Coast and West Coast markets were linked by transportation. *Id.* at p. 228, n.89. In support of this position, explains Exxon, Culberson pointed to import data which, when properly analyzed, showed that imports to the West Coast were not driven by the existence of transportation differentials. *Id.* Further, Exxon notes that Culberson's import data demonstrated that petroleum products, and particularly unleaded regular gasoline, did not move to the West Coast even during periods of high West Coast product prices. *Id.* Finally, Exxon states that Culberson's speculation about the availability of imported volumes from the West Coast of South America or the Far East proved nothing as to the reasonableness of using a Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at pp. 228-29, n.89.

[603] In support, Exxon cites Exhibit Nos. BPX-35, EMT-14, EMT-453, EMT-477, EMT-478, EMT-479, EMT-480, EMT-481, EMT-482, PAI-176. Exxon Initial Brief at pp. 228-29.

methodologies on the ground that, by setting the value of West Coast Naphtha based on the price of West Coast gasoline, they attributed all of the higher West Coast refining margin to Naphtha, Exxon points out that Sanderson conceded that his approach would do precisely the opposite – attribute none of the higher West Coast refining margin to West Coast Naphtha. *Id.* Moreover, Exxon notes that while Sanderson admitted that refining margins for finished petroleum products are higher on the West Coast in relation to crude oil prices, neither he nor Culberson presented any evidence regarding actual West Coast refining margins for intermediate feedstocks like Naphtha to support Sanderson's theory that none of the higher West Coast refining margin should be attributed to Naphtha.[604] *Id.* at p. 230.

1587. Exxon claims that the evidence shows the higher West Coast refining margins were likely to result in correspondingly higher West Coast Naphtha values. *Id.* It notes that Culberson testified that he believed the entire margin was not being captured at the refinery, but rather that some of it may be captured elsewhere. *Id.* Exxon suggests that one place where it is captured may be via an increase in the value of gasoline feedstocks like Naphtha. *Id.* Similarly, Exxon notes, Sanderson admitted that West Coast Naphtha contracts showed that during periods of gasoline price volatility, sellers of Naphtha on the West Coast were able to capture a large portion of the higher refining margin. *Id.* at. pp. 230-31.

1588. Furthermore, according to Exxon, Sanderson's theory was not based on any evidence regarding actual refining margins, but only upon inferences drawn by him from price differentials (West Coast less Gulf Coast) for two selected feedstocks, LSR and VGO, and for certain finished petroleum products. *Id.* p. 231. However, it claims, Sanderson admitted that the price differentials were a reflection of market forces, including both supply and demand factors, unique to each specific product and may not have anything to do with refining margins. *Id*. For example, Exxon notes, Sanderson acknowledged that LSR had a lower value on the West Coast, not because of anything to do with refining margins, but because stricter environmental regulations on the West Coast have severely limited the ability of West Coast refiners to use LSR in the production of gasoline, and because, unlike on the Gulf Coast, there is no petrochemical demand for LSR on the West Coast. *Id*. Therefore, Exxon asserts that Sanderson's refining margin did not work at all for LSR. *Id.*

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[604] Exxon views this omission as particularly noteworthy in Sanderson's case because he admitted that when he worked for a California refinery in the 1980s advising traders on potential purchases of Naphtha and other feedstocks, he used linear programming models to determine the value of Naphtha to the refinery based on the value of the gasoline that could be made from the Naphtha less the cost of processing and blending the Naphtha into gasoline. Exxon Initial Brief at p. 230, n.90.

1589. Exxon also notes that Sanderson admitted that market dynamics for VGO were different on the Gulf Coast and West Coast due to the use of VGO on the Gulf Coast in the production of heating oil. *Id*. Further, points out Exxon, he admitted that environmental regulations regarding sulfur also affect the markets for VGO differently on the two coasts. *Id.* at pp. 231-32.

1590. In addition, Exxon asserts, Sanderson omitted a number of price differentials for other products that undercut his theory, including Propane, Isobutane, normal Butane, MTBE, low sulfur VGO, and high sulfur fuel oil from his analysis. *Id*. p. 232. When those additional products are taken into account, Exxon asserts, the conclusion that Sanderson purports to draw – that finished petroleum products (such as gasoline) have a higher price differential than feedstocks (such as Naphtha) – was shown to be wholly without foundation. *Id.*

1591. Sanderson's analysis, Exxon also states, was undercut by the fact that the price differentials on which he relied varied significantly over time. *Id*. For this reason, Exxon states, Sanderson admitted that his reasoning also did not work for VGO for the years 1999 through 2001 when the differential between the West Coast price of VGO and the Gulf Coast VGO price went up sharply along with the price differential for regular unleaded gasoline. *Id*. In fact, according to Exxon, there was no factual basis for any of Sanderson's conclusions about the alleged relationship between the Gulf Coast-West Coast price differential for VGO and the Naphtha price differential between the two coasts of zero which he advocated. *Id*. at pp. 232-33.

1592. Exxon contends that Williams argues that the Gulf Coast Naphtha price should continue to be used to value West Coast Naphtha because the CARB gasoline requirements introduced in 1996 have lessened the demand for Naphtha on the West Coast. Exxon Reply Brief at p. 231. It asserts that this provides no support for the continued use of Gulf Coast prices to value West Coast Naphtha and, in fact, would only further confirm that use of the Gulf Coast Naphtha price is not an appropriate proxy for valuing West Coast Naphtha because the markets for Naphtha on the Gulf Coast and the West Coast have different demand characteristics. *Id.*

1593. Further, although Williams argues that the California Air Resources Board requirements have "curbed the demand for Naphtha" and thereby made Naphtha less valuable to refiners on the West Coast, Exxon claims, Williams provides no evidence at all as to how much the value of West Coast Naphtha was affected by this change in the marketplace, or how this change affected the relationship between the value of Naphtha on the two coasts. *Id.* Accordingly, Exxon asserts that this argument provides no useful guidance regarding either the "actual market value" of West Coast Naphtha or whether the Platts Gulf Coast Naphtha price "bear[s] a rational relationship to the actual market value" of West Coast Naphtha. *Id*. at pp. 231-32 (quoting *Exxon*, 182 F.3d at 42).

1594. There was also no evidence, according to Exxon, to support Sanderson's claim that the stringent benzene and aromatics requirements for CARB gasoline in California have made Naphtha less valuable on the West Coast as shown by the allegedly low utilization levels for catalytic reformers on the West Coast since 1994. Exxon Initial Brief at p. 233. Exxon asserts that Sanderson's claim about low utilization levels for West Coast reforming capacity was directly contradicted by a report prepared by Sanderson's firm, Purvin & Gertz, which stated that reforming capacities in California were utilized at about 90% during the year 2000, a fact that was also confirmed by Sanderson's colleague, Michael Sarna.[605] *Id.* at pp. 233-34. In addition, states Exxon, the West Coast Naphtha contracts show that the value of West Coast Naphtha has increased substantially since the California Air Resources Board requirements went into effect in May 1996. Exxon Reply Brief at p. 232.

1595. Further, continues Exxon, the evidence shows that prior to the introduction of the California Air Resources Board requirements, most California refiners had already installed the equipment required to remove benzene from the reformate made from Naphtha. Exxon Initial Brief at p. 234. As a result, Exxon states, California refineries are not limited in their use of Naphtha to produce CARB gasoline. *Id*. And for this reason, claims Exxon, Sorenson testified, he would strongly disagree with anyone suggesting that Naphtha lost value on the West Coast due to the California Air Resources Board requirements. *Id.*

1596. Additionally, Exxon also states, Sanderson's theory failed to take into account that the additional costs that California refineries have had to incur to produce CARB gasoline have resulted in significantly higher prices for it than for conventional gasoline. *Id*. at p. 235. More specifically, Exxon asserts, the evidence shows that the price of CARB gasoline has been $2.67/barrel (or 6.35¢/gallon) higher on average than the price of regular unleaded gasoline on the West Coast over the period May 1996 (when the California Air Resources Board requirements went into effect) through 2001. *Id.* The mere fact that some additional costs must be incurred to process Naphtha into CARB gasoline does not, according to Exxon, mean that Naphtha has lost value as compared to its value in producing conventional gasoline. *Id.*

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[605] Exxon states that, later in his testimony, Sarna attempted to diminish this fact by asserting that the 90% reformer utilization rate reported by Purvin & Gertz was a calendar day figure and that the stream day utilization rate would be lower. Exxon Initial Brief at p. 234, n.92. It asserts that that claim made no sense because, by definition, the calendar day utilization rate can never be higher than the stream day rate, which represents operation of the unit under optimal conditions, while the calendar day includes downtime for maintenance and other unexpected problems. *Id.* Accordingly, the calendar rate will only equal the stream day rate if the unit is operating at full capacity every day of the year, and it can never be higher. *Id.*

1597. Furthermore, Exxon argues, the evidence clearly shows that Naphtha has other qualities that are valuable in the production of CARB gasoline. *Id.* According to Exxon, the aromatics in the reformate made from Naphtha result in "very high octane," and higher octane makes the gasoline more valuable. *Id*. In addition, continues Exxon, reformate made from Naphtha has a low Reid Vapor Pressure, a zero olefin content, and a zero sulfur content, all of which make reformate a particularly valuable feedstock for making CARB gasoline. *Id.* Exxon points out that, as a result of these, a study of "refining options" available to California refineries done by Sanderson's firm, Purvin & Gertz, showed that a refinery on the West Coast making 100% CARB gasoline would be expected to use a higher percentage of reformate in its gasoline pool than a refinery on the Gulf Coast producing 100% reformulated gasoline. *Id.* at pp. 235-36. Exxon asserts that this study squarely contradicts both Williams's and Sanderson's claim that Naphtha has lost value on the West Coast due to the requirements for producing CARB gasoline. *Id*. at p. 236.

1598. Exxon asserts that the weakness of Williams's argument is graphically demonstrated by Williams's extensive reliance on a 1999 paper about the possible future effects of new gasoline specifications that were scheduled to go into effect in Europe in 2000 and 2005, and the possibility that those new specifications might affect the use of reformate made from Naphtha by European refineries.[606] *Id.* at p. 235. It notes that Williams's own witness conceded that the European refining industry and gas markets are markedly different than those in the U.S. *Id*. Given these many differences, Exxon argues, the conjectures in Exhibit No. WAP-266 about the possible future impact of new European gasoline specifications on the use of reformate made from Naphtha by European refineries plainly have no probative value whatsoever in this case, and Williams's extensive reliance on that paper in its initial brief only highlights the lack of evidentiary support for its position. *Id*. at pp. 235-36.

1599. Nor, according to Exxon, will the fact that new California Air Resources Board standards are scheduled to go into effect cause Naphtha to lose value on the West Coast. Exxon Initial Brief at p. 236. As Sorenson made clear, states Exxon, the benzene reduction equipment already in place will be able to handle the new California Air Resources Board standards*.* *Id.* Moreover, explains Exxon, as Sanderson's own exhibit (Exhibit No. WAP-273) shows, the new California Air Resources Board specifications actually increase the maximum amount of aromatics allowed from 30% to 35% a change that should make Naphtha, which has a high aromatics content, more valuable under the

[606] I noted during the hearing that Exhibit No. WAP-266, a 1999 paper about the possible future use of Naphtha by European refiners, "has little probative value" to the matters at issue in this case and that no witness "verified the facts" in that paper. Transcript at pp. 13516-17, 13523.

new California Air Resources Board specifications. *Id.*

1600. Finally, even if Sanderson's claim that the introduction of the CARB gasoline requirements made Naphtha relatively less valuable on the West Coast were true, Exxon argues that claim would still provide no support for Williams's position that the Platts Gulf Coast Naphtha price should be used to value West Coast Naphtha. *Id.* Regardless of their impact on the value of West Coast Naphtha, Exxon asserts that the CARB gasoline requirements plainly do not tie the value of West Coast Naphtha to the price of Gulf Coast Naphtha. *Id.* Sanderson's argument, therefore, provides no support whatsoever for the use of the Platts Gulf Coast price to value West Coast Naphtha because, Exxon states, it wholly fails to show that "the chosen proxy bear[s] a rational relationship to the actual market value" of West Coast Naphtha. *Id*. (quoting *Exxon*, 182 F.3d at p. 42).

1601. Exxon also disagrees with Petro Star's contention that any methodology that values West Coast Naphtha above the Platts Gulf Coast Naphtha price would impose an unfair financial burden on Petro Star. *Id*. at p. 237. The sole purpose of the Quality Bank is to make the shipper whose product is devalued economically indifferent to the diminution of his stream, not, in Exxon's view, to require shippers to subsidize Petro Star. *Id*. (citing *OXY*, 64 F.3d at p. 684). Exxon argues that the truth is that Petro Star has been receiving an unfair and inappropriate financial subsidy at the expense of the producers for many years because, in Exxon's view, the West Coast Naphtha cut has been undervalued by the Quality Bank, and there is no justification whatsoever for perpetuating that subsidy. *Id*. It points out that Boltz, Petro Star's own witness, testified that the Commission should value the Naphtha cut on the West Coast on the basis of the methodology that best captures its market value and not based on any possible financial effect on Petro Star. *Id.*

1602. Furthermore, continues Exxon, Petro Star substantially overstated the financial impact of valuing the West Coast Naphtha cut on the basis of West Coast market conditions. *Id*. It points out that Boltz acknowledged that Petro Star would be readily able to mitigate the financial impact of valuing West Coast Naphtha at a higher level simply by reducing the quantity of jet fuel that it produces from Naphtha. *Id.* at pp. 237-38. Exxon also notes that Boltz conceded that Petro Star's contention that West Coast Naphtha should be valued on the basis of the Gulf Coast Naphtha price was inconsistent with its position that the Quality Bank should value every one of the other West Coast cuts on the basis of West Coast prices. *Id.* at p. 238.

1603. Petro Star's hardship claim is also inconsistent, in Exxon's view, with the 1993 Settlement Agreement to which Petro Star was a signatory. *Id*. (citing Exhibit No. EMT-613). The 1993 Settlement Agreement, explains Exxon, set forth a methodology to calculate the value of West Coast Naphtha based on the Platts Los Angeles pipeline spot price of regular gasoline adjusted by the monthly price differential between Naphtha and gasoline on the Gulf Coast – a formula that tied the West Coast Naphtha value to the price of West Coast gasoline. *Id.* Exxon notes that the West Coast Naphtha value under the 1993 Settlement Agreement was even higher than it would be under any of the gasoline-based valuations proposed by the parties in this proceeding.[607] *Id.* Therefore, the alleged financial burden of an appropriate West Coast Naphtha valuation on Petro Star provides, in Exxon's opinion, no valid ground for continuing to use the Platts Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at pp. 238-39.

1604. The evidence also shows, states Exxon, that Williams's Alaskan subsidiary, Williams Alaska Petroleum, has been taking advantage of the substantial undervaluation of the West Coast Naphtha cut by extracting significant volumes of Naphtha from the TAPS crude stream. *Id*. at p. 239. According to Exxon, Williams extracts this Naphtha not for the purpose of producing gasoline or jet fuel, but solely for the purpose of exporting the Naphtha from Alaska to the Far East. *Id*. In this manner, according to Exxon, Williams arbitrages the below-market Quality Bank West Coast Naphtha value in clear contravention of the Quality Bank's purpose. *Id.* Moreover, continues Exxon, Williams has publicly announced its intention to extract even larger amounts of Naphtha from TAPS in the future for sale in the Far East and the West Coast, and to electric power generators and other refineries in Alaska. *Id*. This arbitrage opportunity is made possible solely because, asserts Exxon, by valuing all of the Naphtha in the TAPS crude stream at the published Gulf Coast Naphtha price, the Naphtha in the TAPS stream has been significantly undervalued on the West Coast. *Id.*

1605. Exxon states that Williams's and Unocal/OXY's argument that, because reforming Naphtha's price on the Gulf Coast is elevated by its use as a petrochemical feedstock, the use of a published Gulf Coast price to value West Coast Naphtha is not valid. Exxon Reply Brief at p. 227. Exxon asserts that this argument would not establish that the Gulf Coast Naphtha price is an appropriate proxy for the value of Naphtha on the West Coast, because it assumes that the markets for Naphtha on the Gulf Coast and the West Coast have different demand characteristics. *Id*. at pp. 227-28.

1606. Furthermore, continues Exxon, the theory that the Gulf Coast Naphtha price might be elevated due to petrochemical demand does not meet the standard established in the *Exxon* decision because, according to Exxon, even were there some added value due to

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[607] Exxon cites Exhibit No. EMT-432 at p. 4 (showing average value of West Coast Naphtha under 1993 Settlement Agreement of $26.57/barrel) and compares it with Exhibit No. EMT-431 at p. 4 (showing average value of West Coast Naphtha under the O'Brien valuation methodology of $26.29/barrel) to support this assertion. Exxon Initial Brief at p. 238, n.93. Exxon also cites Exhibit No. EMT-433 at p. 4 (showing average value of West Coast Naphtha under Tallett valuation methodology of $25.49/barrel) to support this statement. *Id.*

petrochemical demand as a result, it clearly does not establish that the Gulf Coast Naphtha price "will correlate consistently within some specified range" with the value of West Coast Naphtha. *Id.* at p. 228 (quoting *Exxon*, 182 F.3d at p. 42). Exxon states that this is particularly true as there are many other factors, such as the greater supply of Naphtha on the Gulf Coast from nearby sources in the Caribbean, which tend to reduce the price of Gulf Coast Naphtha, and the much higher prices of West Coast gasoline and jet fuel, which elevate the value of Naphtha on the West Coast. *Id.*

1607. According to Exxon, this conclusion is also confirmed by Tallett's regression analysis, which shows that nearly all of the variation in Gulf Coast Naphtha prices can be explained by changes in the gasoline and jet fuel prices. *Id*. at p. 229. Exxon notes that this means that, at a maximum, no more than about 3% of the variation in the Gulf Coast price of Naphtha might be caused by all other market factors, including the demand for Naphtha as a petrochemical feedstock. *Id.*

1608. Exxon asserts that the fact that petrochemical usage does not significantly influence the demand for reformer-grade Naphtha on the Gulf Coast is further confirmed by the fact that the prices for Gulf Coast Naphtha follow very closely the movements in Gulf Coast gasoline prices, including both peaks and troughs, and there is no "non-coincident spiking." *Id*. Moreover, notes Exxon, the evidence shows that the small variations between the Gulf Coast prices of Naphtha and gasoline are almost entirely explained by movements in the Gulf Coast price of jet fuel. *Id.* at pp. 229-30. According to Exxon, this evidence squarely refutes Williams's argument that petrochemical demand props up the Gulf Coast price of Naphtha during periods of low gasoline prices; for it demonstrates that it is jet fuel demand, not petrochemical demand, which props up the price of Naphtha during periods of low gasoline prices. *Id.* at p. 230. Finally, states Exxon, neither Williams nor Unocal/OXY cite any evidence supporting their claim that the demand for petrochemical products produced from Naphtha such as ethylene and benzene influence the price of reformer-grade Naphtha on the Gulf Coast. *Id*. To the contrary, Exxon claims that the evidence shows that there is a very low correlation between the prices of either ethylene or benzene and the price of Naphtha on the Gulf Coast. *Id.*

1609. In Exxon's view, there is also no merit to the argument of Unocal/OXY (based on Culberson's testimony) that, in view of the fact that Naphtha is imported into the Gulf Coast and the potential exists for similar shipments of Naphtha to the West Coast, one can infer from the absence of imports of Naphtha on the West Coast that the market value of Naphtha on the West Coast is no higher than the Gulf Coast Naphtha price. *Id*. at p. 236. First, Exxon asserts, this theory does not support the current practice of using the Gulf Coast price to value Naphtha on the West Coast. *Id.* Exxon notes that Unocal/OXY concede that, even assuming that Culberson's theory were otherwise valid, his import theory only suggests that the West Coast price of Naphtha can only exceed the Gulf Coast price by an amount sufficient to compensate for the cost of importing the Naphtha to the West Coast. *Id*. Accordingly, the lack of imports on the West Coast does not tell what either the West Coast price should be or that the West Coast price should be identical to the Gulf Coast Naphtha price. *Id*.

1610. Exxon argues that the inference that Unocal/OXY attempt to draw from the lack of West Coast imports is also contrary to the evidence. *Id*. According to Exxon and as Culberson testified, the evidence shows that very little Naphtha is imported on the West Coast because West Coast refineries are generally able to satisfy their demand for Naphtha from internal sources and do not require imports of Naphtha to produce gasoline or jet fuel.[608] *Id*. at pp. 236-37.

1611. In his rebuttal testimony, notes Exxon, Culberson attempted to avoid the obvious conflict between this balance of the supply and demand for Naphtha on the West Coast and his import theory by arguing that West Coast refiners could still choose to import naphtha if its price were less than the internally generated value of Naphtha and by changing the refinery's crude slate. *Id*. at p. 238. However, states Exxon, the record shows that Culberson seriously underestimated or wholly ignored a number of costs that a refiner would have to incur in order to take advantage of any available imported Naphtha. *Id*. Among other things, continues Exxon, Culberson ignored the fact that a refiner switching to a different crude would also be changing both the amount and the quality of all the other products produced through the distillation process. *Id.* The evidence also shows, explains Exxon, that West Coast refineries typically purchase a significant quantity of crude under long-term purchase contracts and vessels are scheduled months in advance, with the result that switching crude slates can involve a considerable amount of time and expense. *Id*.

1612. Exxon argues that Culberson also completely ignored a number of significant barriers that limit imports on the West Coast. *Id*. For example, states Exxon, Culberson ignored the higher risks involved in shipments with longer transit times to the smaller West Coast market. *Id*. Further, notes Exxon, Culberson also ignored the fact that, as a result of the balance between supply and demand on the West Coast, West Coast refineries have not constructed the tankage and terminal facilities that would be required to import substantial quantities of Naphtha. *Id*. at p. 239. As a result of these barriers, Exxon asserts that a West Coast refiner would not purchase imported Naphtha unless the price was so much lower for an extended period of time that the refiner would be compensated for all the costs and opportunity costs that would be incurred to import

[608] Exxon argues that Culberson's analysis is also undercut by his reliance on Energy Information Administration import data, which, it claims, was shown at the hearing to use different, subjective categories and to be unreliable. Exxon Reply Brief at p. 237, n.138.

Naphtha.[609] *Id*.

1613. Exxon points out that Culberson's theory also is directly undercut by the fact that there have been substantial and persistent differences between prices on the West Coast and Gulf Coast for virtually all intermediate and finished petroleum products. *Id.* at pp. 240-41. If West Coast and Gulf Coast petroleum prices were in fact equalized by the potential for imports in the manner suggested by Culberson, Exxon argues that the substantial and persistent differences between West Coast and Gulf Coast prices for both intermediate and finished petroleum products would not exist. *Id.* at p. 241. In Exxon's view, these persistent price differentials clearly demonstrate that it is inappropriate to use a Gulf Coast price to value a West Coast product. *Id*.

1614. Culberson's conclusion, Exxon insists, that the Commission should infer that the value of West Coast Naphtha does not exceed the Gulf Coast Naphtha price from the absence of Naphtha imports on the West Coast is squarely refuted by the West Coast Naphtha contracts. *Id*. Exxon maintains that these contracts provide the best available direct evidence of the value of West Coast Naphtha. *Id*. It points out that those contracts consistently valued West Coast Naphtha at levels that were significantly higher than the Platts Gulf Coast Naphtha price, thereby directly refuting Culberson's theory that it is appropriate to infer from the lack of Naphtha imports on the West Coast that the value of West Coast Naphtha does not exceed the Gulf Coast Naphtha price.[610] *Id*. at p. 242.

1615. Equally devoid of merit, in the view of Exxon, is Unocal/OXY's argument that intermediate petroleum products such as Naphtha do not have West Coast/Gulf Coast price differentials that are as high as the West Coast/Gulf Coast price differentials for finished petroleum products. *Id*. This argument is based on Exhibit No. BPX-162 which

[609] Exxon claims that the effect of these barriers to imports was confirmed by the two Stillwater reports, Exhibit Nos. EMT-385 (Stillwater report on MTBE Phase-Out in California) and EMT-489 (Stillwater report on California Strategic Fuels Reserve). Exxon Reply Brief at p. 239, n.139.

[610] Exxon asserts that Unocal/OXY are wrong in arguing that the contract studies validate the use of Gulf Coast pricing because the average price found in the contracts is not more than two cents above the average Gulf Coast price for the period prior to 1999. Exxon Reply Brief at p. 242, n.141. Although the disparity between the average contract price and the Gulf Coast price is not as large during the earlier period, Exxon maintains that the Gulf Coast price is still well below the contract price during the 1994-1998 period. *Id.* Furthermore, Exxon states that what is required is not a methodology that may function in certain selected years, but a methodology that will function reasonably at all times, and the evidence is clear that the use of the Gulf Coast price produces the largest disparity for the overall 1994-2001 period. *Id.*

Exxon asserts was contrived by Ross in an effort to avoid the obvious deficiencies in his theory that intermediate petroleum products have lower West Coast/Gulf Coast price differentials than finished petroleum products. *Id.* at pp. 242-43.

1616. Exxon argues that Exhibit No. PAI-176 shows that there is no discernible pattern among the price differentials for intermediate and finished products, and thus no factual basis for Unocal/OXY's argument that West Coast/Gulf Coast price differentials are higher for finished products than they are for intermediate products. *Id*. at p. 243. Further, states Exxon, when the long-term average price differentials shown on this exhibit were replaced by annual average West Coast/Gulf Coast price differentials for the same intermediate and finished products (Exhibit No. PAI-202), it became readily apparent that the price differentials for most of these products – and for the intermediate and finished products as a group – have been changing over time, with the result that the conclusions that one might draw about relative price differentials in one year would be very different from the conclusions that one might draw in another year. *Id*.

1617. During the hearing, notes Exxon, Ross attempted to modify Exhibit No. PAI-176 by arbitrarily reclassifying a number of products that were obviously inconsistent with his theory. *Id.* For example, explains Exxon, in order to avoid the obvious conflict between his theory and the high West Coast/Gulf Coast price differential for Isobutane, Ross first reclassified Isobutane along with three other Quality Bank cuts into a third category, natural gas plant products, in an effort simply to eliminate those products from the analysis. *Id*. at pp. 243-44. According to Exxon, however, it is undisputed that Isobutane is an important intermediate feedstock in the production of gasoline. *Id.* at p. 244. Similarly, continues Exxon, in a further effort to salvage his theory, Ross reclassified MTBE from an intermediate product to a finished product, notwithstanding the undisputed fact that MTBE is a blendstock that is an important ingredient in the production of gasoline. *Id.*

1618. As a result of Ross's contrived reclassification of those intermediate petroleum products that were inconsistent with his theory, Exxon asserts, Exhibit No. BPX-162 does not accurately reflect the West Coast/Gulf Coast price differentials for either intermediate or finished petroleum products. *Id*. at pp. 244-45. Rather, according to Exxon, what the evidence in fact shows about West Coast/Gulf Coast price differentials is that each petroleum product has its own special market characteristics and pricing pattern. *Id*. at p. 245. For example, notes Exxon, the low West Coast/Gulf Coast price differential for LSR is explained by the fact that LSR is worth much less on the West Coast because of its high Reid Vapor Pressure, which significantly curtails its use as a gasoline feedstock on the West Coast, particularly during the summer months, coupled with the demand for LSR on the Gulf Coast as a petrochemical feedstock. *Id*. By contrast, states Exxon, it is undisputed that Naphtha doesn't have the same problem with Reid Vapor Pressure that LSR does, with the result that the LSR differential has no relevance to the Naphtha valuation question. *Id.*

1619. Similarly, argues Exxon, the relatively low West Coast/Gulf Coast price differential for VGO is largely a result of the demand for VGO on the Gulf Coast for use in the production of heating oil for markets in the Northeast and Midwest, a demand that is not present on the West Coast, coupled with strict environmental restrictions on sulfur on the West Coast that have increased processing costs for VGO on the West Coast and thereby reduced its value. *Id*. at pp. 245-46. Neither of these factors applies to Naphtha, notes Exxon, because Naphtha is not used in the production of heating oil, and because all of the sulfur in Naphtha is removed by hydrotreating on both coasts before the Naphtha is processed into reformate in order to protect the reformer catalyst. *Id*. at p. 246. Therefore, states Exxon, the evidence shows that the West Coast/Gulf Coast price differentials for each Quality Bank cut are determined by market factors that are unique to each cut and may have no application to Naphtha. *Id*.

2. Phillips

1620. Phillips argues that it would be inconsistent to continue to use the Platts Gulf Coast Naphtha price to value West Coast Naphtha when all the other cuts will have separate Gulf Coast and West Coast values. Phillips Initial Brief at p. 15. Further, states Phillips, when this inconsistency is combined with the undisputed fact that the Gulf Coast and West Coast markets are economically distinct (with different supply and demand profiles for Naphtha and the gasoline it is used to make), it is clearly not acceptable to use the Gulf Coast price as a proxy for the West Coast Naphtha value. *Id*. In Phillips's opinion, the overwhelming weight of the evidence demonstrates that continued use of the Gulf Coast price would be unjust and unreasonable, and the parties proposing to continue using that price to value West Coast Naphtha have utterly failed to rebut this evidence or otherwise show how doing so could conceivably meet the uniformity and reasoned decision making standards set by the Circuit Court. *Id.*

1621. The *OXY* decision, Phillips states, requires the assignment of accurate and relatively uniform values to all cuts. *Id*. Yet, asserts Phillips, the use of the Gulf Coast price to value West Coast Naphtha is patently inconsistent with the method used to value all other cuts – that is, using an adjusted or unadjusted proxy from the local market area. *Id*. Phillips points out that Sanderson conceded that the most consistent approach would be to separately value Naphtha on the West Coast using a West Coast value if one can be derived. *Id.* at pp. 15-16.

1622. In Phillips's opinion, the only way for this inconsistent approach to Naphtha to meet the uniformity requirement of *OXY* is if the proponents could show that the non-uniformity nevertheless permitted a West Coast Naphtha valuation consistent with the valuation of all other cuts. *Id*. at p. 16. But, according to Phillips, this would require record evidence proving that there is some demonstrable, continuing close correlation between the Naphtha value on the Gulf Coast and that on the West Coast. *Id*. Phillips asserts that there is no such evidence. *Id.* To the contrary, explains Phillips, the record is replete with admissions and empirical evidence that the two markets are quite different and that the Naphtha prices in the two markets also are quite different. *Id.*

1623. Phillips points out that Sanderson conceded that the Gulf Coast and West Coast markets are different markets, with different market forces, different supply and demand profiles and different environmental regulations that affect the supply of gasoline feedstocks and blendstocks like Naphtha. *Id.* at pp. 16-17. Because the primary use of Quality Bank (or reformer-grade) Naphtha on both coasts is to make gasoline, Phillips states, the value of Naphtha on each coast is largely based on its value in making the gasoline sold on that coast. *Id.* at p. 17. It notes that Sanderson agreed with this point when he said that "what a refiner would be willing to pay for naphtha is its value when made into gasoline, less a margin for his processing the naphtha and blending it into gasoline." *Id*. (quoting Transcript at p. 8818). But, explains Phillips, gasoline is priced very differently on the two coasts, with West Coast prices generally higher, and Sanderson admitted that there is consistently a differential between the two that ranges from 2.5¢ to 18¢/gallon. *Id.*

1624. According to Phillips, neither Sanderson nor Culberson could quantify the size of the difference between the published Gulf Coast price and actual West Coast Naphtha values or suggest any way the Commission could adjust for the differences*.* *Id*. at p. 18. Phillips states they could only rest on the unsubstantiated hope that over the long term the prices would be similar. *Id.* However, Phillips asserts, the record overwhelming establishes that the differences are significant, that they fluctuate widely and that they are certainly much higher than the 0.5¢/gallon that required a processing cost adjustment for Light Distillate. *Id.* Phillips argues that all four contract analyses presented in this hearing showed West Coast Naphtha prices that exceed the published Gulf Coast price by several cents per gallon. *Id.* at pp. 18-19. In addition, according to Phillips, all four alternative methodologies for calculating West Coast Naphtha values presented in this proceeding result in West Coast Naphtha values that frequently exceed the published Gulf Coast Naphtha value by several cents per gallon. *Id.* at p. 19.

1625. Given the uncontroverted differences in value between the published Gulf Coast Naphtha prices and actual West Coast Naphtha values, Phillips claims that *OXY* teaches that it is inappropriate to value West Coast Naphtha based on published Gulf Coast prices. *Id*. To satisfy the *OXY* uniformity requirement, Phillips states, West Coast Naphtha should be valued based on published West Coast prices less processing costs, and their proposal is the only one that meets this requirement. *Id*.

1626. Although the witnesses supporting the use of a Gulf Coast price to value West Coast Naphtha acknowledge that the published Gulf Coast price will not be the same as the value of Naphtha on the West Coast, Phillips notes that they advocate the continued use of the Gulf Coast price based on their assertion that the Gulf Coast and West Coast values will be similar. *Id*. Phillips points out that Sanderson acknowledged that, in his judgment, the Gulf Coast Platts assessment would be a suitable proxy for the West Coast value was a subjective one, and that he said that, while there may be differences from time to time, he believed the two would be similarly priced over the long term. *Id.* After acknowledging that price differentials between the two coasts for other cuts had varied for eight to ten years without evening out, Phillips notes that Sanderson still considered it reasonable to use a method that had large year-to-year variations as a proxy. *Id*. at p. 20.

1627. Sanderson's assertions regarding the reasonableness of the use of the Gulf Coast Naphtha price to value West Coast Naphtha suffer, argues Phillips, from the same defect as the reasoning rejected by the Circuit Court in *Exxon*. *Id.* Just as it was not good enough in the *Exxon* case for the Resid proxy value to be "within the range" of the calculated Coker feedstock values, Phillips asserts, Sanderson cannot rely on the hope that differences in Gulf Coast and West Coast Naphtha prices may even out over the long run. *Id*. (quoting *Exxon*, 182 F.3d at p. 42). Phillips points out that the Circuit Court ruled in Exxon that "a limited and unquantified relation" between the cut and the proposed proxy is not enough. *Id.* (quoting *Exxon*, 182 F.3d at p. 36). Here, as there, Phillips states, nothing "guarantees" that the value of the proxy and the cut "will correlate consistently within some specified range." *Id*. (quoting *Exxon*, 182 F.3d at p. 42).

1628. According to Phillips, Sanderson offered no evidence that the values will be similar, could only offer hope that they would be, and presented nothing other than unsupported opinions to counter what Phillips views as overwhelming evidence that the values would not be similar. *Id.* Phillips asserts that Sanderson based his claim that West Coast Naphtha prices should be similar to those on the Gulf Coast over the long term on the supposition that these prices are linked via a very convoluted relationship through crude oil. *Id.* at pp. 20-21. It notes that Sanderson claimed this linkage existed because of “the refiner's ability to substitute crude oils of different naphtha content for naphtha purchases, then naphtha prices also would be linked through the crude oil substitution mechanism.” *Id*. at p. 21 (quoting Exhibit No. WAP-1 at p. 10). Phillips, however, asserts that this link is too vague and is unsupported by facts and, therefore, cannot support the consistent and quantifiable relationship between the Naphtha prices on the two coasts that was set as the standard by the Circuit Court in *Exxon*. *Id.*

1629. Even were the Gulf Coast pricing advocates able to show "an observed rough correlation in price" over some significant period, Phillips suggests, that would not have sufficed absent a demonstration that the values continuously move in synch with each other. Phillips Reply Brief at p. 19 (citing *Exxon*, 182 F.3d at p. 41). Not only was no such showing made, Phillips states, the evidence in the record demonstrates that the use of the Gulf Coast proxy materially undervalues West Coast Naphtha and any "similarity" in value is the result of haphazard coincidence rather than a continuing rational relationship between the values themselves. *Id*.

1630. Phillips states that the parties supporting a West Coast value offered direct proof of the value of West Coast Naphtha through the Naphtha contracts and the opinions of experts. *Id.* Apart from Dudley, whose attempt, it claims, was not credible, Phillips states, their experts carefully avoided any effort to calculate a West Coast value for Naphtha. *Id.* Moreover, unable to explain why the West Coast contracts consistently showed values far higher than the proxy, Phillips notes that all but Culberson also declined to do an independent analysis of the contract data. *Id.* Phillips states that the reason for their reluctance is apparent from Culberson's work: No matter how hard he tried to find reasons to exclude contracts from his analysis, the remaining data still showed West Coast values far above the proxy price. *Id*.

1631. Because they lack affirmative proof that the Gulf Coast proxy actually correlates with the West Coast Naphtha value, Phillips explains, the advocates of Gulf Coast pricing sought to rely on theories that they claimed suggested that the prices should not be too far apart. *Id*. at p. 20. It argues that that was the point of the "crude equalization theory" as well as the several attempts to limit West Coast Naphtha values to some the Gulf Coast proxy plus the transportation and other costs required to bring Gulf Coast Naphtha to the West Coast. *Id.* Phillips suggests that offering theories as to why the prices might not be too far apart is a far cry from establishing a rational relationship between them, and it insists that the welter of admissions in the hearing and briefs regarding the differences between the markets make it clear that no such relationship exists. *Id.*

1632. In *Tesoro*, Phillips explains, the court described three factors that it found relevant to the question of whether it is just and reasonable to continue to use the published Gulf Coast prices to value West Coast Naphtha: (1) the level of ANS deliveries to the Gulf Coast; (2) whether the "No Adjustment Policy" has been abandoned; and (3) whether use of published Gulf Coast prices undervalues West Coast Naphtha. Phillips Initial Brief at p. 22. It claims that the evidence submitted in this hearing addressed these three factors, and, according to Phillips, shows that all three propositions retain their validity even after a full evidentiary hearing. *Id.* at pp. 22-23.

1633. At the hearing, explained Phillips, the TAPS Carriers presented evidence showing that (1) there have been no Gulf Coast ANS deliveries since July of 1999, and (2) less than 3% of all ANS was delivered to the Gulf Coast for a year and a half prior to that time. *Id*. at p. 23. This evidence was uncontroverted, according to Phillips, and no witness even attempted to explain how the Gulf Coast Naphtha price retains any relevance to ANS Naphtha values when no ANS is delivered to the Gulf Coast. *Id*.

1634. Phillips contends that the *Tesoro* court found that the Commission's no adjustment policy had been abandoned, and that the Circuit Court made it clear that the policy would not in any event pass muster as a justification for departing from the required uniformity in treatment of the cuts. *Id.* Since that time, according to Phillips, the Commission has done nothing that could be said to have reinstated that policy. *Id*. On the contrary, Phillips asserts, the parties now have agreed to value West Coast VGO on the West Coast, which constitutes an even greater shift away from the policy. *Id.*

1635. A considerable portion of the Naphtha phase of the hearing, Phillips states, was devoted to the differences between Gulf Coast and West Coast Naphtha markets and values. *Id.* at p. 24. Although the quantification of those differences was contested, Phillips asserts, the only supportable conclusion that can be reached regarding the market differences is that there are significant differences in Gulf Coast and West Coast Naphtha markets and, therefore, significant differences in Naphtha prices. *Id*. As a result, Phillips states, the record supports the same conclusion that was presented in a single untested affidavit in *Tesoro* – that use of the published Gulf Coast price significantly undervalues West Coast Naphtha*.* *Id*.

1636. It is incontestable and uncontested, in Phillips's view, that the Gulf Coast and West Coast petroleum and refining markets are separate markets with different product prices. *Id.* Phillips states that this is the reason that the Quality Bank attempts to derive product prices on both the Gulf Coast and West Coast for each of the other Quality Bank cuts. *Id.*

1637. According to Phillips, the most complete description of the differences in the markets came during the cross-examination of Sanderson. *Id.* It notes that he agreed that the two markets were different with respect to: (1) supply and demand profile; (2) environmental regulations; (3) the ability to build or expand refinery capacity to meet increasing demand; (4) ability to address supply disruptions; (5) size of refining base; (6) price volatility; and (7) size of market supplied*.* *Id.* Phillips states that the testimony of every other witness who testified on this issue was generally in accord.[611] *Id*. at p. 25.

1638. The evidence also is incontestable, according to Phillips, that the differences in the market forces at work cause there to be significant differences between the Gulf Coast and West Coast prices for all products that do have prices reported on both coasts. *Id.* Phillips states that there are numerous exhibits presented by parties on all sides of the issue that include price information that support this proposition. *Id.* According to it, Exhibit No. PAI-176 has a comprehensive set of data for a large number of products*.* *Id.* Phillips notes that this exhibit has monthly price data for 13 different products on the Gulf Coast and West Coast for the years 1992 to 2001, and explains that it shows average price differentials for three different periods: (1) 1992-2001; (2) 1992-98; and (3) 1999-2001. *Id.* As this chart illustrates, explains Phillips, only one product, High Sulfur

[611] Phillips cites the following witness testimony in support of this claim: O'Brien, Exhibit No. PAI-33 at pp. 4-5; Tallett, Exhibit No. EMT-11 at p. 14; Baumol, Exhibit No. EMT-144 at pp. 21-22; Ross, Exhibit No. BPX-8 at p. 3; Culberson, Transcript at p. 10207-09; and Dudley, Transcript at pp. 10045-46. Phillips Initial Brief at p. 25, n.8.

VGO, had West Coast minus Gulf Coast price differentials that averaged within 0.5¢/gallon over one of the periods, and that was only for the 1992-98 time frame. *Id.* at p. 27. When the entire 1992-2001 time frame is considered, Phillips notes, High Sulfur VGO was, on average, worth 1.02¢/gallon more on the West Coast than on the Gulf Coast. *Id.* Furthermore, continues Phillips, in looking at the 39 price differentials shown on this chart, only 3 (7.6%) were less than 2¢/gallon, and only 6 (15.4%) were less than 4¢/gallon. *Id.*

1639. Because of these short-term fluctuations, Phillips argues, the Commission cannot rely on any smoothing effects of looking only at long-term average price differentials. Phillips Reply Brief at p. 24. It states that the method adopted by the Quality Bank must be just and reasonable as applied each month, and not just over long periods of time. *Id.*

1640. Phillips claims that the proponents of the status quo attempt to avoid the implications of the price differential data by creating artificial divisions of products such as "finished products," "gas liquids products," "intermediate products," "other products." Phillips Reply Brief at p. 23. It states that, no matter how the data is grouped and displayed in order to show different patterns of price differentials, these divisions are meaningless for this proceeding, and there are significant price differentials for almost every product. *Id*. (citing Exhibit Nos. BPX-162, WAP-39, and WAP-221).

1641. While the data for other products does not reveal what the price differentials should be for Naphtha, Phillips contends, they do reflect that there are very different supply and demand factors at work in the two markets. *Id.* at p. 24. It states that, because the differences cause wide fluctuations in the market differentials for all other petroleum products, there is every reason to believe that the same is true for Naphtha. *Id*. Therefore, according to Phillips, it is extremely unlikely that Gulf Coast Naphtha prices could reflect West Coast Naphtha values in any but the most haphazard manner. *Id.*

1642. Phillips states that another uncontested fact is that Naphtha primarily is made into gasoline, and that the price of gasoline is very important to the value of Naphtha. Phillips Initial Brief at p. 27. It notes that Sanderson testified to this effect when he stated that the Naphtha cut under discussion is a reformer grade Naphtha used primarily to make gasoline and that its value on the West Coast is very closely related to this use. *Id.* at pp. 27-28. According to Phillips, the other witnesses who testified on this issue were all in accord.[612] *Id.* at p. 28.

[612] Phillips cites the following witness testimony in support of this assertion: O'Brien, Exhibit No. PAI-33 at p. 3; Toof, Exhibit No. EMT-1 at pp. 25-26; Tallett, Exhibit No. EMT-11 at pp. 16-17; Ross, Exhibit No. BPX-8 at p. 2; Culberson, Transcript at p. 10338; Dudley, Transcript at p. 10107. Phillips Initial Brief at p. 28, n.10.

1643. There also was uncontested quantitative evidence, asserts Phillips, showing a close relationship between Naphtha prices and gasoline prices. *Id.* Phillips notes that Exhibit No. EMT-459 provides monthly Gulf Coast Naphtha and Unleaded Regular Gasoline prices for the time period 1994-2001 that show that the two prices track closely, a fact corroborated by the statistical analysis conducted by Tallett on the relationship between the two prices on the Gulf Coast. *Id.*

1644. There are, according to Phillips, two categories of evidence that quantify the extent to which West Coast Naphtha values exceed the published Gulf Coast prices. *Id.* at p. 29. The first category, states Phillips, consists of the approximately 300 Naphtha contracts that were produced in discovery in this proceeding. *Id.* Four analysts, according to Phillips, including Culberson (who supports use of Gulf Coast Naphtha prices to value West Coast Naphtha), reviewed these contracts. *Id.* at pp. 29-30. Notwithstanding the differences in the four analyses that were presented at the hearing, Phillips asserts, each shows that the West Coast Naphtha prices exceed Gulf Coast prices by at least 6¢/gallon during 1994-2001 and by considerably more than that in 1999-2001. *Id*. at p. 30. These differences, states Phillips, are similar to or exceed the difference in values alleged in *Tesoro*, which was $2.71/barrel or 6.45¢/gallon. *Id.*

1645. Phillips states that another source of evidence quantifying the difference between Gulf Coast published prices and West Coast Naphtha values is the various alternative West Coast Naphtha valuation methodologies presented by the various parties. *Id*. at p. 31. One striking aspect of all the approaches is, according to Phillips, that even though the various proposals vary widely, they all show significant differences between Gulf Coast and West Coast prices. *Id*. Thus, no matter which approach the Commission believes best captures West Coast Naphtha prices, Phillips asserts that approach supports the conclusion that Gulf Coast prices should not be used to value West Coast Naphtha. *Id*.

1646. Exhibit No. SOA-28, Phillips suggests, shows that the Dudley methodology – which Phillips states has an extremely weak factual basis – is on average very close to the Gulf Coast published price for the 1994-2001 time period.[613] *Id*. at p. 32. However, notes Phillips, even the Dudley methodology varies from the Gulf Coast published price by more than 1¢/gallon in both the 1994-1998 and 1999-2001 time frames. *Id*. Further, Phillips points out, every other proposed methodology results in West Coast Naphtha prices that are at least 2¢/gallon above the Gulf Coast price for every time frame studied. *Id.* The ungoverned O'Brien and Tallett methodologies provide the best indications of

[613] Phillips notes that the Sanderson/Culberson proposal in Exhibit No. SOA-28 at p. 2 is the Gulf Coast published price to which they are referring. Phillips Initial Brief at p. 32 and p. 33, n.12.

actual West Coast values in Phillips's view, and they show differences ranging from 4.5¢/gallon to 15¢/gallon above the published Gulf Coast price, depending on the time period considered. *Id.*

1647. Phillips argues that the parties opposing the continued use of the Gulf Coast price have presented a prima facie case that use of the Gulf Coast price is unjust and unreasonable. *Id.* at p. 35. It asserts that the proponents of the Gulf Coast price failed to carry their burden of going forward with evidence supporting continued use of the Gulf Coast price to value West Coast Naphtha. *Id.* In attempting to deny the undeniable fact that West Coast market values are significantly different from Gulf Coast market prices, Phillips notes, the proponents argue that, unlike all the other Quality Bank cuts, Naphtha has similar values on both coasts. *Id.* It also states that the proponents assert that only Naphtha fails to track the higher product prices – particularly gasoline – that generally prevail on the West Coast. *Id*.

1648. Responding to testimony from Sanderson,[614] Phillips argues that use of the Gulf Coast price to value West Coast Naphtha is not more objective than the West Coast-based proposals. *Id.* at p. 36. While the published Gulf Coast price certainly is an objective price, according to Phillips, the assertion that this Gulf Coast price accurately reflects the value of Naphtha on the West Coast is subjective. *Id.* Sanderson acknowledged that this was the case, admitting that "my analysis by necessity has to be subjective." *Id.* at pp. 36-37 (quoting Transcript at p. 8837). Phillips states that this admission utterly destroys Sanderson's claim of the superiority of using the Gulf Coast price. *Id.* at p. 37. By contrast, notes Phillips, every West Coast Naphtha proposal is based on objective prices. *Id.*

1649. Phillips points out that Sanderson's principal theory as to why Naphtha prices on the two coasts should be similar is that these prices are linked through refiner's substitution of crude oil with different Naphtha content and the direct linkage of crude prices on the two coasts. *Id.* It argues that a claim of such a generalized, unquantifiable similarity would not satisfy the Circuit Court. *Id. at* p. 38. At some level of generality, explains Phillips, there is a linkage between the price of any petroleum product and crude oil, and Sanderson admits that there is not a fixed relationship between Naphtha and crude oil prices that would allow the Commission to develop an exact Naphtha price. *Id.* In order to be just and reasonable, states Phillips, the proxy price used to value West Coast Naphtha must be more than approximately equal to the value of West Coast Naphtha, it must provide a value that is consistent with the other Quality Bank cuts and which consistently and reasonably tracks the value of West Coast Naphtha over the long term. *Id*.

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[614] *See* Exhibit No. WAP-33 at p. 3.

1650. In addition, Phillips claims, it is apparent that Sanderson's theory is factually incorrect. *Id*. If crude price equalization on the two coasts caused Naphtha prices on the two coasts to equalize, then, according to Phillips, the same should be true for other cuts as well. *Id*. However, Phillips states, if the price data submitted in this proceeding reveal anything, they reveal that prices for other products on the two coasts are neither similar nor even approximately the same. *Id.* According to Phillips, Exhibit No. PAI-176 demonstrates that there are significant differences in prices between the West Coast and the Gulf Coast with regard to a wide variety of products. *Id.* In Phillips's opinion, Sanderson's crude equalization theory provides no explanation for why only Naphtha prices on the two coasts would be equal. *Id.*

1651. Moreover, Phillips states, the data Sanderson presents does not support his conclusion that crude prices on the two coasts have equalized. *Id*. First, notes Phillips, he used different crudes on each coast as the centerpiece of his argument. *Id*. at pp. 38-39. Phillips explains that, as ANS is not sold on the Gulf Coast, Sanderson chose to compare it to Isthmus crude, which is sold on the Gulf Coast, but not on the West Coast. *Id.* at p. 39. It notes that Sanderson claimed that the qualities of these two crudes were similar, but it became apparent on cross-examination that there are a number of significant differences.[615] *Id.* In addition, notes Phillips, Sanderson agreed that ANS Naphtha has a higher N+A than Isthmus Naphtha. *Id.* Because Sanderson conceded these differences in qualities would cause refineries to value the two crudes differently, Phillips asserts that a comparison of the prices of these two crudes does not necessarily demonstrate that crude prices on the two coasts have equalized. *Id.*

1652. Finally, Phillips claims, it is not even accurate to say that the prices of ANS on the West Coast and Isthmus on the Gulf Coast have equalized. *Id*. Phillips notes that Exhibit No. PAI-207, which shows the differences in the prices of these two crudes for the time period 1994 through 2001, shows that ANS has become more valuable relative to Isthmus, but does not show that the two prices have equalized. *Id.* Rather, Phillips asserts, the prices of the two crudes are generally different, and those price differences are subject to large swings.[616] *Id.*

1653. In support of the continued use of Gulf Coast prices to value West Coast Naphtha, Phillips notes, Culberson asserts that Gulf and West Coast prices are linked by demand and transportation factors. *Id*. at p. 40. Further, continues Phillips, Culberson testified

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[615] According to Phillips, Sanderson conceded that ANS has a lower API gravity, less sulfur, and more Isobutane, VGO and Resid than Isthmus. Phillips Initial Brief at p. 39 (citing Transcript at pp. 9045-49).

[616] Phillips notes that Exhibit No. PAI-207 shows that, in 2000 and 2001, there was a swing of over $3/barrel in the relative prices of ANS and Isthmus crudes. Phillips Initial Brief at p. 39 (citing Transcript at pp. 9051-52).

that, if Gulf and West Coast Naphtha prices are not aligned, then Naphtha produced in West Coast refineries could be displaced by imported Naphtha. *Id.* They explain that Culberson goes on to assert that there have not been significant imports of Naphtha into the West Coast from the Caribbean and that he concludes from this assertion that this means West Coast Naphtha should not be valued above Gulf Coast Naphtha. *Id.*

1654. Phillips states that Sanderson similarly points to an alleged lack of imports of Naphtha into the West Coast to support his position. *Id*. He claims, according to Phillips, that the lack of imports into the West Coast indicates that West Coast refiners were not using significant amounts of naphtha to meet gasoline demand. *Id.*

1655. Whatever the merits of the abstract theory that market prices ought not to exceed the cost of alternative supplies plus the costs of acquiring them, Phillips argues, this theory cannot support a decision that the published Gulf Coast Naphtha prices should be used to value West Coast Naphtha. *Id.*

1656. Both Culberson and Sanderson acknowledge, according to Phillips, that it is more costly to transport Naphtha from the Caribbean to the West Coast than to the Gulf Coast. *Id*. at p. 41. Their calculations, which Phillips asserts contain many flaws, show that it costs from 2.7¢/gallon to 3.1¢/gallon more to transport Naphtha from the Caribbean to the West Coast than to the Gulf Coast. *Id.* (citing Exhibit Nos. UNO-7 at p. 24, WAP-33 at p. 15).

1657. Phillips notes that Culberson and Sanderson assert that, if West Coast Naphtha prices had exceeded their calculated transportation cost differentials, imports would have come into the West Coast and disciplined the West Coast prices. *Id.* It claims that the "flip side of this argument," however, is that West Coast Naphtha prices can exceed Gulf Coast prices by amounts less than these supposed transportation cost differentials and not attract any imports. *Id.* As a consequence, explains Phillips, Culberson is incorrect when he stated that the lack of Caribbean imports to the West Coast means that the West Coast Naphtha's price is not higher than the Gulf Coast price over a sustained period of time. *Id.* At most, Phillips states the import data means that the value of Naphtha on the West Coast has not exceeded the Gulf Coast price by more than the transportation differential between the two coasts. *Id.* Thus, continues Phillips, the transportation cost differential does not cause the prices on the two coasts to be equal but, at best, acts as a cap on what the difference in prices can be between the two coasts. *Id.* Phillips states that Sanderson admitted that this is a fair interpretation of the significance of the transportation cost differential. *Id.*

1658. Even Culberson's admittedly low estimate, points out Phillips, shows a transportation differential of 2.7¢/gallon. *Id*. at p. 42. Phillips asserts that this would allow the value of West Coast Naphtha to be up to 2.7¢/gallon higher than the published Gulf Coast price. *Id.* Phillips argues that such a difference would be significant under the test established by the Circuit Court in *Tesoro* and could not support the continued use of the published Gulf Coast price. *Id.*

1659. Another fundamental problem, in the view of Phillips, with Culberson's and Sanderson's theory is that it depends on a determination of the relative costs associated with transporting Naphtha from the Caribbean to the Gulf Coast and the West Coast. *Id.* at p. 43. Phillips points out that there is no publicly available objective cost calculation to show what the transportation costs might be, and no simple way to perform a calculation. *Id.* Indeed, Phillips notes that Exhibit No. PAI-178 shows that Culberson's and Sanderson's calculations do not agree. *Id*. Ross, continued Phillips, who performed a similar calculation to support his proposed governor, made three different calculations in his pre-filed testimony, and then further refined his calculation on the stand. *Id.* at pp. 43-44. It states that these calculations all used different assumptions and all reached different results. *Id*. at p. 44.

1660. Furthermore, Phillips asserts, even the transportation calculations that they finally settled on, 2.7¢/gallon (Culberson) and 3.1¢/gallon (Sanderson), were clearly "lowball" estimates. *Id.* As such, Phillips argues that these estimates understate the price differentials that would be required to attract imports to the West Coast. *Id.*

1661. Phillips states that Culberson's transportation cost calculations are deeply flawed and deserve no consideration whatsoever. *Id*. First, notes Phillips, Culberson has based his calculation solely on published spot tanker rates for the period of January 11 through May 9, 2002. *Id*. (citing Exhibit No. UNO-15 at pp. 2-3; Transcript at p. 10294). It points out that Culberson could not provide any explanation for why the Commission should look to this period, and he admitted that this time period is not representative of previous time periods. *Id*. In Phillips's view, this concession is critical, because Culberson's import data was from the years 1999-2001, which does not match up with the January-May 2002 time period on which his transportation cost calculation was based. *Id*.

1662. Second, even under the limited time period that he chose, Phillips states, Culberson used a lower spot tanker rate that he developed on his own rather than the published spot tanker rates for transportation from the Caribbean to the Gulf Coast. *Id.* at pp. 44-45 (citing Exhibit No. UNO-7 at p. 23; Transcript at pp. 10273-83, 10294-95). Also, Phillips asserts, Culberson included such irrelevant routes as Singapore to Japan, Baltic Sea to the Mediterranean, Asian Gulf to India and Asian Gulf to Japan. *Id*. at p. 45. For that reason, Phillips argues, Culberson's use of an average of these rates cannot be relied upon to give an accurate picture of the transportation costs at issue here. *Id.*

1663. Moreover, explains Phillips, when Culberson was asked why he applied his artificially low transportation cost rate from 2002 – which he agreed was lower than the published rate – to earlier time periods, he replied that "it was a deliberate exercise to see if you could get movements with very low rates." *Id*. (quoting Transcript at p. 10285). The problem with this, asserts Phillips, is that, in reality, Caribbean refiners in the 1999-2001 time period could not ship cargoes at Culberson's artificially low rate. *Id.*

1664. Unlike Culberson, states Phillips, Sanderson did use actual published spot tanker rates for the years that import data were available, and he did include a higher cost for West Coast trips, which results in Sanderson having a higher estimate of the transportation cost differential than Culberson. *Id*. at p. 46. Phillips asserts that like Culberson, however, Sanderson still ignored significant barriers to entry and the risk that price differentials would decrease in the two to three weeks that it takes to transport Naphtha from the Caribbean to the West Coast. *Id.*

1665. The import theory proposed by Sanderson and Culberson, Phillips contends, does not need to be considered in a theoretical vacuum, without any way of validating who is wrong and who is right. *Id*. It states that the record contains a considerable amount of empirical data demonstrating that West Coast/Gulf Coast price differentials far exceed the levels that Sanderson and Culberson have hypothesized. *Id.*

1666. In Phillips's opinion, perhaps the best evidence as to whether West Coast Naphtha prices are capped by the Gulf Coast price plus the 2.7 to 3.1¢/gallon transportation estimates made by Culberson and Sanderson are the prices paid in real transactions by West Coast Naphtha purchasers. *Id*. at pp. 46-47. Exhibit No. SOA-28 shows, according to Phillips, that Naphtha contract prices for the 1999-2001 time period for which Culberson submitted import data were from 11.6¢/gallon to 13.7¢/gallon above Gulf Coast prices, depending upon which contract analysis is considered. *Id*. at p. 47. Further, notes Phillips, the average differential above the Gulf Coast price was in the 6¢/gallon to 9¢/gallon range for the full 1994-2001 time frame, depending upon which contract analysis is used. *Id.*

1667. Phillips points out that these differentials are approximately four times higher than the 2.7¢/gallon to 3.1¢/gallon transportation cost differences calculated by Culberson and Sanderson. *Id*. Clearly, states Phillips, the purchasers under these contracts did not share the view of Culberson and Sanderson that they should pay no more than Gulf Coast plus 2.7¢ to 3.1¢/gallon. *Id*. Argues Phillips, the differentials stands as uncontroverted proof that the Culberson/Sanderson theory about the levels of imports and transportation costs do not in fact (1) support using the Gulf Coast price or (2) undercut the higher West Coast Naphtha values calculated under alternative methods proposed by Phillips or Exxon. *Id*.

1668. Were Platts Gulf Coast Naphtha price assessments a reliable indicator of the value of West Coast Naphtha, according to Phillips, one would expect that West Coast refiners would use them as an index for the price of Naphtha on the West Coast, but they do not. *Id*. It notes that Sanderson admitted that the West Coast refiner for whom he worked did not pay any attention to the Gulf Coast price when pricing West Coast Naphtha transactions, and the hundreds of West Coast Naphtha contracts produced make the same point. *Id.* Phillips argues that almost none of them even refer to the Platts Gulf Coast assessments, and the few that do give strong support to the fact that the value on the West Coast was higher. *Id*. at p. 48.

1669. According to Phillips, there are only three West Coast Naphtha contracts included in the various contract analyses that have a price referenced to Gulf Coast Naphtha. *Id*. The first, states Phillips, is the contract that Ross relied upon to justify his governor proposal. *Id.* Phillips explains that Ross testified that there was a cap in this contract equal to the Gulf Coast Naphtha price plus 7.05¢/gallon, or $2.96/barrel. *Id.* Phillips points out that this is about 2 1/2 times the differentials calculated by Culberson and. Sanderson. *Id.*

1670. Phillips states that the second such contract (Exhibit No. PAI-183) involved shipment in a tanker whose loading port was in Aruba. *Id.* Thus, explains Phillips, it represents an import from the Caribbean to the West Coast of the type hypothesized by Culberson and Sanderson. *Id.* However, notes Phillips, the price of this Naphtha was the Gulf Coast price plus 5.5¢/gallon. *Id.* Explains Phillips, this is approximately twice the differentials calculated by Culberson and Sanderson. *Id.*

1671. The third contract (Exhibit No. UNO-42) is priced, according to Phillips, at Gulf Coast Naphtha plus 2.75¢/gallon, which is much closer to Culberson's and Sanderson's differentials. *Id*. However, notes Phillips, the specifications on the same page of the contract show that the product has a boiling range of from 72°F to 189°F. *Id.* Phillips explains that this means that the material being sold was almost entirely Quality Bank LSR, which has a much lower value than Quality Bank Naphtha. *Id.* Quality Bank Naphtha is worth more than Quality Bank LSR, according to Phillips, and would have commanded a much higher differential. *Id.*

1672. Phillips states that another flaw in the no import theory is that it ignores the fact that most West Coast refiners produce most of the Naphtha that they need from the crude that they refine, and thus their supply and demand for Naphtha is in balance. *Id.* at p. 49. Phillips explains that this limits the volume of Naphtha that West Coast refiners acquire from third parties on the West Coast or elsewhere. *Id.* Contrary to the Culberson/Sanderson theory, Phillips contends, the West Coast refiners's supply/demand balance is the most fundamental reason why import volumes are not higher. *Id.*

1673. According to Phillips, while Culberson acknowledges the implications of this fact, he argues, nonetheless, that even if refiners produce all the Naphtha that they need, they could still choose to buy Naphtha instead of making it if the value of the Naphtha that they make is significantly higher than the price of Naphtha on the Gulf Coast plus transportation. *Id.* Phillips notes that Culberson asserts that this could be accomplished by substituting cheaper crude oils that produce lower Naphtha fractions. *Id.* The problem with this argument, explains Phillips, is that there are significant costs associated with substituting cheaper crudes that produce lower Naphtha fractions. *Id.* at p. 50. It notes that Culberson admitted that changing the crude slate does not change just the amount of Naphtha refined from the new crude, but also the amount of other products produced by the crude, as well as their quality, and states that the cost of all of these changes would need to be factored in as well before a refiner would choose to substitute a cheaper crude for ANS and import Naphtha from the Gulf Coast. *Id.* Culberson agreed that crude substitution imposes these additional costs, notes Phillips, and testified that the Naphtha price would have to be such that it enticed this substitution. *Id.* Finally, Phillips states that neither Culberson's, Sanderson's nor Ross's transportation cost differentials account for these costs. *Id.*

1674. Phillips explains that Culberson further bases his opinion regarding the value of West Coast Naphtha on a related point he makes based on statistics involving imports from Western South America. *Id.* Phillips states that Culberson asserts that, because there are imports of Naphtha from Mexico, Colombia, Ecuador, Peru and Chile to the Gulf Coast, but not to the West Coast, and because it costs more to transport Naphtha through the Panama Canal from the West Coast of South America to the Gulf Coast than it does to the West Coast of the United States, this must mean that the Naphtha price on the Gulf Coast is higher than the value of Naphtha on the West Coast. *Id.* It argues that this theory is not supported by the import data in Exhibit No. UNO-5 on which Culberson relies. *Id.* at p. 51. First, notes Phillips, it is not possible to tell from the categories of products reported by the EIA whether a cargo is reformer-grade Naphtha or some other product, so it really is not possible to tell if these countries are sending Quality Bank Naphtha comparable products to the Gulf Coast or the West Coast and, if so, in what amounts. *Id.*

1675. Second, Phillips points out, of the countries listed by Culberson, Exhibit No. UNO-5 shows that, by far, the greatest volume of imports to the Gulf Coast are from Mexico and Colombia. *Id.* It is, in Phillips's view, disingenuous of Culberson to characterize these countries as being on the West Coast of South America because the major ports and refining industries in both countries are located on the Caribbean and imports to the Gulf Coast from ports in these countries that are located on the Caribbean do not have to pass through the Panama Canal. *Id.* As these ports are closer to the Gulf Coast than the West Coast, Phillips states, it is cheaper for these imports to go to the Gulf Coast, and in no way can those shipments be considered to support Culberson's theory. *Id.* at pp. 51-52.

1676. Third, explains Phillips, by far the greatest amount of imports to the Gulf Coast from these countries is in the "Naphtha for Petrochemical Feedstock Use" category. *Id.* at p. 52. This is the true, according to Phillips, not only for Mexico and Colombia, but also for Ecuador and Peru, which are located on the West Coast of South America. *Id.*

Because it is undisputed that there is no petrochemical industry on the West Coast, Phillips states, it is not surprising that such cargoes would go elsewhere. *Id*.

1677. Fourth, the data on Exhibit No. UNO-5 at pp. 14-28 with respect to PADD V (West Coast) shows, in the opinion of Phillips, that not only did the countries identified by Culberson not export any Naphtha to the West Coast, but they also exported almost no products of any kind to the West Coast. *Id*. Further, according to Phillips, Exhibit No. UNO-5, at pp. 14-28, shows that there were no West Coast imports of any products from Mexico, Columbia or Chile, while Ecuador had one West Coast shipment of "Special Naphtha" and Peru had two West Coast shipments of "Unfinished Oils." *Id.* Phillips concludes that the virtually complete absence of imports of any kind of product from these countries suggests nothing more than that those countries do not view the West Coast as a market for any product, including Naphtha. *Id.*

1678. Unocal/OXY, Phillips states, also rely on data regarding Far East imports to support the use of Gulf Coast Naphtha pricing. Phillips Reply Brief at p. 35. It explains that Unocal/OXY make two arguments from this data: (1) it costs less to transport Naphtha from the Far East to the West Coast than to the Gulf Coast, so Gulf Coast imports from the Far East must indicate that Gulf Coast Naphtha prices are higher than West Coast prices, and (2) Far East imports can discipline Naphtha prices on the West Coast at prices lower than required for imports from the Caribbean. *Id.*

1679. According to Phillips, Unocal/OXY's first point is not supported by the data that they cite. *Id.* at p. 36. It points out that Exhibit No. UNO-4 is nothing more than a map, and states that, while Exhibit No. EMT-455, at pp. 6-30, does have detailed data regarding Gulf Coast Naphtha imports, the data show, however, that all of the Naphtha imported into the Gulf Coast from the Far East was Naphtha for petrochemical use and not reforming grade Naphtha. *Id.* Because there is no petrochemical industry on the West Coast, Phillips asserts, the fact that Naphtha for petrochemical use goes from the Far East to the Gulf Coast does not have much relevance to the value of reforming grade, i.e., Quality Bank Naphtha on the West Coast. *Id.*

1680. Phillips also argues that the second point is unsupported. *Id*. From the limited data on Naphtha imports shown in Exhibit No. EMT-449, Phillips contends, it is impossible to conclude that three cargos of Far East Naphtha (only two of which are reforming grade) imported over a six year period can discipline West Coast Naphtha prices, particularly because there is no data in the record on the Far East Naphtha market supply, demand, prices, or transportation costs to the West Coast. *Id.*

1681. Further, Phillips notes, Unocal/OXY also point to the fact that there have been significant West Coast imports of jet fuel from the Far East. *Id.* at p. 37. It notes that Unocal/OXY believe this means there also could be imports of Naphtha as well. *Id.* Again, Phillips contends, this speculative theory does not support the conclusion that

Gulf Coast Naphtha prices represent an appropriate proxy for West Coast Naphtha, and maintains that, in order to evaluate the potential for West Coast Naphtha imports from the Far East, it is necessary to have data on alternative Naphtha markets in the Far East and how they compare with West Coast markets. *Id.* Without this data, Phillips states, it is impossible to know what impact imports of Naphtha might have on the West Coast, regardless of what the volume of jet fuel imports from the Far East has been. *Id.*

1682. Finally, even were Unocal/OXY's arguments regarding Far East Naphtha imports to be accepted, Phillips suggests that all they say is that there is some general link between Gulf Coast Naphtha prices and West Coast Naphtha values. *Id.* It asserts that none of the arguments raised by Unocal/OXY indicates that Gulf Coast Naphtha is a good proxy for West Coast Naphtha or would be acceptable under the *OXY* and *Exxon* decisions. *Id.*

1683. Phillips explains that another theory advanced by Sanderson and Culberson is that Naphtha has lost its value on the West Coast due to the stringent aromatics and benzene limitations in the California Air Resources Board specifications for gasoline. Phillips Initial Brief at pp. 52-53 (citing Exhibit No. WAP-8 at pp. 11-12, 16-19; Transcript at pp. 12060-61). As an initial matter, notes Phillips, Sanderson provides no quantification of how much value he asserts Naphtha has lost, or what the value of Naphtha was on the West Coast before the implementation of the California Air Resources Board requirements. *Id.* at p. 53. As a result, states Phillips, his theory does not provide (1) any support for the proposition that West Coast Naphtha should be based on published Gulf Coast prices, or (2) any useful guidance as to the value of Naphtha on the West Coast. *Id.*

1684. Second, Phillips asserts that the theory is wrong. *Id.* It notes that Sorenson explained that most California refiners, including his own, already have installed the equipment necessary to take benzene out of the reformate they make from Naphtha. *Id.* As a result, continues Phillips, California refiners do not discount the value of Naphtha on the basis of its high benzene and aromatics content because they can be handled. *Id.* Sorenson stated that, therefore, he would disagree with the claim that Naphtha had lost its value on the West Coast due to the imposition of California Air Resources Board requirements. *Id.*

1685. Phillips concedes that the benzene treatment equipment installed by California refineries imposes additional costs on their production of CARB gasoline, but, according to Phillips, the CARB gasoline these refiners produce commands a much higher price than conventional gasoline. *Id.* at pp. 53-54. It states that Exhibit No. EMT-399 shows that, from the time that the CARB II gasoline regulations went into effect in 1996 to the end of 2001, the price of that gasoline has been, on average, \$2.67/barrel higher than the price of West Coast conventional gasoline. *Id.* at p. 54. Given this significant price advantage, over 6¢/gallon, for CARB gasoline, Phillips asserts that the fact that refiners have had to incur some additional costs to process their Naphtha into CARB gasoline does not mean that Naphtha has lost its value in making CARB gasoline compared to its value in making conventional gasoline. *Id.*

1686. Furthermore, continues Phillips, Naphtha has other qualities that are valuable in making CARB gasoline. *Id.* For example, reformate made from Naphtha has high octane and, as Sorenson testified, California refiners find octane to be a valuable commodity. *Id.* Phillips notes that O'Brien testified that reformate also is almost free of both olefins and sulfur, and has a very low Reid Vapor Pressure. *Id.* The California Air Resources Board specifications have strict limitations on olefins, sulfur, and Reid Vapor Pressure, and Phillips explains that reformate's low levels of these specifications makes it valuable for producing CARB gasoline. *Id.*

1687. Given the above, Phillips states, it is not surprising that in a study performed by Sarna, a hypothetical West Coast refinery making only CARB gasoline used more reformate than the hypothetical Gulf Coast refinery used in the same study. *Id.* (citing Exhibit No. EMT-382 at p. 7). The study also showed, continues Phillips, that the West Coast refinery used more reformate than any other blendstock in the production of CARB gasoline. *Id.* It also notes these results are inconsistent with Williams's assertion that Naphtha has lost its value on the West Coast. *Id*.

1688. Phillips argues that, even though the California Air Resources Board may implement new standards for gasoline in the future, Naphtha would not lose its value. *Id*. at p. 55. It notes that Sorenson testified that the new CARB III standards can be met with the benzene equipment that is in place and that the CARB III aromatics specification actually has been increased to allow more octane to be produced from reformers. *Id.* Exhibit No. WAP-273, notes Phillips, shows that the aromatics cap has increased from 30% under CARB II to 35% for CARB III. *Id.* In Phillips's opinion, this increase in the amount of aromatics allowed should, if it has any effect, cause reformate to become even more valuable under CARB III than it is under CARB II. *Id*.

1689. Even had the introduction of the CARB specifications reduced the demand for Naphtha on the West Coast somewhat, Phillips argues that this alone would not mean that it is appropriate to use Gulf Coast prices to value West Coast Naphtha. Phillips Reply Brief at p. 34. It notes that nowhere have the proponents of Gulf Coast pricing provided any quantification of how CARB specifications may have reduced the value of Naphtha on the West Coast or how that compares with the Gulf Coast price of Naphtha. *Id.* at pp. 34-35. Without any such quantification, Phillips argues, the mere assertion that CARB specifications have caused demand for Naphtha on the West Coast to decline cannot be relied upon to demonstrate that Gulf Coast prices reflect West Coast Naphtha values to the same degree of accuracy as the proxy prices for the other cuts. *Id.* at p. 35.

1690. Phillips notes that the final argument advanced by Sanderson in support of the continued use of the published Gulf Coast Naphtha price is his assertion that the West Coast/Gulf Coast price differential for Naphtha falls somewhere between the West Coast/Gulf Coast price differentials for LSR and VGO. Phillips Initial Brief at p. 55. However, Phillips points out that Sanderson admitted "there's a wide range between the differentials between LSR and VGO," and so this argument cannot demonstrate that the Gulf Coast price is an adequate proxy for the West Coast value. *Id.* (citing Transcript at p. 8833).

1691. Sanderson again failed to present facts to support his assertion, opines Phillips. *Id.* In particular, it notes, Sanderson has not supported his theory that the West Coast/Gulf Coast Naphtha differential is lower than the West Coast/Gulf Coast VGO price differential.[617] *Id.* at pp. 55-56. To the contrary, according to Phillips, the evidence that Sanderson cites supports the opposite conclusion. *Id.* at p. 56.

1692. Phillips states that the primary evidence relied upon by Sanderson to support his position is Exhibit No. WAP-48, which, it explains, contains Sanderson's estimate of the relative contribution of Naphtha and VGO to the West Coast gasoline pool. *Id.* Further, states Phillips, the Exhibit shows the capacity and utilization of Fluid Catalytic Converter units (units that process VGO) for the years 1994-2001 and compares that to the capacity and utilization of reforming units that process Naphtha for the same time period.[618] *Id.*

1693. It is impossible, Phillips maintains, to reach any conclusions about West Coast/Gulf Coast price differentials, however, from the data presented. *Id.* It advances two reasons for this: First, a product's market value is determined by supply and demand factors, but the data in Exhibit No. WAP-48 does not show the interrelationship between supply and demand for either Naphtha or VGO. *Id.* at pp. 56-57. Thus, Phillips states, Sanderson's estimate of the relative volumetric contribution of VGO and Naphtha to the West Coast gasoline pool says nothing about which product will be more valuable. *Id.* at

[617] There is no dispute, according to Phillips, that the West Coast/Gulf Coast price differential of Naphtha is higher than the West Coast/Gulf Coast LSR price differential. Phillips Initial Brief at p. 56, n.18. All witnesses agreed that LSR's high Reid Vapor Pressure causes it to have problems on the West Coast, and that Naphtha does not have this Reid Vapor Pressure problem. *Id.*

[618] Sanderson argues, according to Phillips, that this Exhibit demonstrates that (1) VGO contributed more volume to the West Coast gasoline pool than did Naphtha, (2) Fluid Catalytic Converter unit capacity increased on the West Coast while reforming capacity declined, and (3) reforming capacity on the West Coast was underutilized. Phillips Initial Brief at p. 56. From this, states Phillips, Sanderson concludes that "the analysis indicates that the West Coast less Gulf Coast price differential for Naphtha should be below that of VGO." *Id.* (quoting Exhibit No. WAP-33 at p. 18).

p. 57.

1694. The second reason why Exhibit No. WAP-48 tells nothing about West Coast/Gulf Coast differentials, Phillips claims, is that it contains absolutely no information about Naphtha or VGO on the Gulf Coast. *Id.* It states that a comparison of statistics between VGO and Naphtha on the West Coast might conceivably support an inference regarding which of these two products has a higher price on the West Coast, but it says nothing about which product will be valued more highly on the West Coast than on the Gulf Coast. *Id.*

1695. According to Phillips, evidence presented by Williams suffers from a similar defect. Phillips Reply Brief at p. 29. It asserts that data regarding the relative amounts of VGO and Naphtha processed on the West Coast do not reflect the demand for those products, but rather the supply, and point out that it is not possible to tell which product has a higher price based on which one is processed more. *Id*. Phillips explains that much more VGO is processed on the West Coast than Isobutane, because much more VGO is contained in crude oil than Isobutane and, therefore, there is a greater supply of VGO than Isobutane. *Id.* Nevertheless, they state that the price of Isobutane is higher than VGO on the West Coast, and the West Coast/Gulf Coast price differentials for Isobutane also are much higher than for VGO. *Id.* (citing Exhibit No. PAI-176 at pp. 10, 14).

1696. While Sanderson did not provide any information about Naphtha and VGO on the Gulf Coast, Phillips claims to have adduced some evidence during cross-examination, to wit: Exhibit No. PAI-213. Phillips Initial Brief at p. 57. It states that the Exhibit provides a comparison of utilization rates for the years 1994-2001 for the Fluid Catalytic Cracking[619] units that process VGO and the reforming units that process Naphtha, and notes that Sanderson testified that he found utilization rates to provide some indication of demand for the two products. *Id*. at pp. 57-58. According to Phillips, the Exhibit shows that utilization rates for cat crackers on the West Coast in 2001 are over 5% lower than on the Gulf Coast, which it suggests, if anything, that demand for VGO is lower on the West Coast than on the Gulf Coast. *Id.* at p. 58. By contrast, Phillips points out, the utilization rate for reforming units on the West Coast is much closer (within 2%) to the Gulf Coast for 2001. *Id.*

1697. Furthermore, Phillips notes that Sanderson acknowledged that Naphtha produced from a VGO hydrocracker requires more expensive processing than straight run Naphtha, because VGO first must be processed in a hydrocracker before it can be run through the reformer. *Id.* at p. 60. If West Coast refiners are more willing than Gulf Coast refiners to invest in a hydrocracker and then incur the increased costs to run VGO through a

[619] Sometimes called an FCC unit, other times referred to as a cat cracker. Transcript at pp 10781, 10788.

hydrocracker to produce more Naphtha, this suggests, in Phillips's view, that there is a relatively greater demand for Naphtha than VGO on the West Coast than on the Gulf Coast, because West Coast refiners are willing to expend considerable funds to convert their VGO into Naphtha. *Id.* at pp. 60-61.

1698. Phillips also argues that the evidence regarding utilization rates of reformers and cat crackers does not necessarily prove anything about demand, and instead may again be more an indication of supply. Phillips Reply Brief at p. 30. It states that the record reflects that ANS production has declined significantly since the early 1990s.[620] *Id.* To the extent that refiners have replaced medium ANS with heavy California, South American and Far Eastern crudes that contain more VGO and less Naphtha,[621] Phillips asserts, this would cause refiners to have a lesser supply of Naphtha and a greater supply of VGO than they did in the early 1990s. *Id.*

1699. The evidence submitted by Williams, Phillips argues, does not show what crudes have replaced ANS or what their Naphtha contents may be. *Id.* However, given the reduction in the supply of ANS, it contends that the reduction in reformer utilization rates could simply reflect that West Coast refiners are now refining crudes that contain less Naphtha than before. *Id.* at pp. 30-31. Far from reflecting a reduction in demand for Naphtha, it asserts, this would indicate a reduction in supply, which would make Naphtha more valuable relative to VGO, not less. *Id.* at p. 31.

1700. There is other evidence in the record, according to Phillips, that also supports the conclusion that demand for VGO is not greater than demand for Naphtha on the West Coast. *Id*. It notes that, as the proponents of Gulf Coast pricing have pointed out, West Coast refiners have invested in expensive hydrocrackers to a greater degree relative to the amount of crude they process than have Gulf Coast refiners, and explains that these hydrocrackers have been used to process VGO into "hydrocracker Naphtha" that then can be processed through a reformer to make reformate. *Id.* Phillips explains that these units, as Sanderson admitted, have higher capital and operating expenses than reformers, and asserts that, if there were a greater demand for VGO than Naphtha, one would not expect

[620] Phillips explains that the total ANS shipped from Valdez is shown on Exhibit No. EMT-243 as the PSVR "Common Stream" barrels. Phillips Reply Brief at p. 30, n.16. It states that Exhibit No. EMT-243 shows that these barrels declined from about 51.5 million in December 1993 to about 31 million in December of 2001, approximately a 40% decline in total barrels/month. *Id.*

[621] Phillips notes that the assays of the individual North Slope streams, Exhibit Nos. EMT-627 through EMT-631, show that the heavier crudes have less Naphtha than the lighter crudes. Phillips Reply Brief at p. 30, n.17. It states that Exhibit No. PAI-203 also shows that the heavier Oriente and Maya crudes have less Naphtha than ANS. *Id.*

to see the refiners making the large capital and operating cost expenditures required to convert their VGO into Naphtha. *Id.*

1701. Phillips suggests that the other evidence cited by Williams to support the proposition that VGO has a greater West Coast/Gulf Coast price differential than Naphtha is even less compelling than the evidence on relative amounts of VGO and Naphtha that have been processed on the West Coast. *Id.* It argues that Exhibit Nos. WAP-39 and WAP-221 merely show the average of the West Coast/Gulf Coast price differentials, including differentials under the various West Coast Naphtha proposals raised in this proceeding, over the years 1994-2001. *Id*. at pp. 31-32. Phillips asserts that the charts do not show any actual price differentials for Naphtha because there is no published West Coast Naphtha price. *Id.* at p. 32.

1702. Exhibit No. WAP-44 does not show, as Williams argues, according to Phillips, that there was a lack of demand for Naphtha during periods of high VGO prices. *Id.* It also asserts that the Exhibit does not show that Naphtha supplies were unimportant to West Coast refiners's gasoline demand. *Id.* Phillips notes that the exhibit does not show any data regarding VGO at all; therefore it cannot say anything about a demand for Naphtha relative to demand for VGO. *Id.* at pp. 32-33. Further, Phillips notes that, because the chart does not show how Naphtha produced by refiners on the West Coast is being used, it says very little about Naphtha demand, and certainly cannot be used to support the contention that "naphtha supplies were not instrumental to West Coast refiners to meet gasoline demand." *Id*. at p. 33 (quoting Williams Initial Brief at p. 37).

1703. Finally, Phillips takes exception to Williams's final argument that the ideal West Coast Naphtha cut is from 208°F - 330°F. *Id.* It states that this argument is somewhat convoluted, and that it is difficult to understand the point being made. *Id.* Phillips suggests that nothing in Williams's argument addresses the question of whether the West Coast/Gulf Coast VGO price differential is greater than the Naphtha differential. *Id.*

1704. However, Phillips asserts that, to the extent that Williams is implying that the "ideal" Naphtha cut contains some Full Range Naphtha and thus has a lower value than the Heavy Naphtha whose price is quoted by Platts, it is misstating the facts. *Id*. Phillips maintains that the ideal cut does not transcend the Heavy Naphtha and Full Range Naphtha cuts, and points out that the 208°F - 330°F ideal cut describe by Williams is contained entirely within the Heavy Naphtha cut that starts at 180°F and ends in the high 300s°F. *Id*. If anything, Phillips contends, the Heavy Naphtha cut specifications in Platts are for a lower-valued product than the Williams's ideal 208° - 330°F cut, not a higher valued product as Williams suggests. *Id.* at pp. 33-34.

1705. Phillips explains that Williams and Unocal/OXY argue that the Gulf Coast price of Naphtha is higher than the West Coast price because there is petrochemical demand for Naphtha on the Gulf Coast that does not exist on the West Coast. Phillips Reply Brief at

p. 25. It asserts that, in doing so, Williams and Unocal/OXY have misapplied economic theory in advancing this argument. *Id*. Phillips states that, while all other things being equal, increased demand for a product would increase its price, all other things are not equal between the Gulf Coast and the West Coast. *Id.* at pp. 25-26. It points out it is uncontroverted that, in addition to having a petrochemical industry, the Gulf Coast market has a much larger refining capacity and also routinely receives Naphtha imports. *Id.* at p. 26. Thus, Phillips explains that the Gulf Coast also has a much greater supply of Naphtha than the West Coast, and this tends to drive the price of Naphtha down there. *Id.*

1706. The only way to know definitively, according to Phillips, whether the petrochemical demand on the Gulf Coast causes Gulf Coast Naphtha values to be elevated compared to the West Coast would be to prepare a detailed study of all of the various supplies and demands for Naphtha in each market. *Id*. at p. 26. It states that no such study was entered into the record, and that, as a result, there is no evidence in the record that petrochemical demand on the Gulf Coast causes a higher Naphtha price on the Gulf Coast than on the West Coast. *Id.* Moreover, Phillips contends that the contract data in this record provides strong empirical evidence that, in fact, the opposite is true. *Id*.

1707. Phillips argues that Williams's additional assertion that that the use of Naphtha on the Gulf Coast for aromatics extraction gives it a premium over the use of reformate in gasoline is the result of equally fuzzy economic thinking. *Id*. at p. 27. If, in fact, a refiner still has a supply of Naphtha after the demand for reformate to make gasoline is satisfied, then that refiner, Phillips claims, may use the Naphtha for aromatics extraction even though it would receive a higher value from the Naphtha it uses in gasoline production. *Id.*

1708. Unocal/OXY, Phillips declares, are wrong to recommend that the Commission ignore the evidence regarding barriers to importation of Naphtha to the West Coast. Phillips Reply Brief at p. 37. It notes that Unocal/OXY, in making the argument that there still is substantial capability on the West Coast to import gasoline blendstocks and feedstocks, and that Naphtha could be imported as well, miss the point. *Id*. at pp. 37-38. While conceding that there are terminal and tankage facilities on the West Coast that could handle Naphtha imports, Phillips points out that, when there is a high demand for imports of a number of gasoline feedstocks and blendstocks, but insufficient facilities to handle all of those imports, the costs associated with the imports increase and there is a greater separation between West Coast prices and prices in other markets. *Id.* It notes that one of the Stillwater studies performed for the California Energy Commission makes this exact point.[622] *Id.*

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[622] Phillips claims that, after noting that there are, in fact, "prolonged price excursions above world market plus" the cost of transportation, the report concludes that "the only remaining explanation" is that "import options are indeed restrained by physical

1709. Ultimately, asserts Phillips, the advocates of retaining the use of the Gulf Coast Naphtha price are forced to acknowledge that there are significant price differences between products on the Gulf Coast and on the West Coast and that the West Coast Naphtha contracts show significantly higher prices than those published on the Gulf Coast. Phillips Initial Brief at p. 61. According to it, they assert that the three-year time period from 1999-2001, when the price differences were the highest, was anomalous and that, therefore, the data from this time period should be ignored by the Commission. *Id.* at p. 62. Phillips states that this argument suffers from a number of defects including that, while it is true that the data from 1999-2001 show more elevated price differences between the West Coast and the Gulf Coast, there also were significant price differences in the earlier 1992-1998 time period. *Id*.

1710. Moreover, Phillips states, the assertion that this is an anomalous time period that can be ignored implicitly suggests that: (1) something other than market forces was at work; (2) the anomaly was short lived; and (3) the anomaly is unlikely to occur again in the future. *Id.* at p. 63. According to Phillips, none of these assumptions is correct. *Id*.

1711. Proof that use of the Gulf Coast price substantially undervalues West Coast Naphtha, Phillips declares, comes from the evidence that Williams makes significant sales of Naphtha to the West Coast and the Far East. *Id.* at p. 65 (citing Exhibit Nos. PAI-187, PAI-188, EMT-374; Transcript pp. 8892-94, 8897-98, and 8902-06). In order to make such sales, Phillips explains, Williams must refine Naphtha from ANS crude, and transport it by rail to Anchorage and then by tanker to the West Coast or Japan. *Id*. That Williams can make more money from such sales than from simply returning the Naphtha to TAPS and receiving the Quality Bank price means, in Phillips's opinion, that the Quality Bank West Coast Naphtha price is too low. *Id.*

1712. Phillips disagrees with Unocal/OXY's argument that the West Coast gasoline market is not competitive. Phillips Reply Brief at p. 39. It asserts that Culberson's testimony should be given no weight because of his lack of expertise in the economic field. Id. Furthermore, it states that Culberson's opinion is based on an extremely brief, superficial examination of market conditions on the West Coast that cannot constitute a responsible analysis of competitive issues. *Id.* (citing Exhibit No. UNO-7 at p. 6).

1713. Unocal/OXY overreach when they characterize the market in California as not being competitive, according to Phillips. *Id.* It states that, while the "Preliminary Report

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reasons (terminal capacity) and commercial factors (price volatility)." Phillips Reply Brief at p. 38 (quoting Exhibit No. EMT-489 at p. 101).

to the [California] Attorney General"[623] may indicate that there is greater competition in other parts of the country than in California, and may point out certain factors that reduce competition, nowhere does it conclude that there is not workable competition in California. *Id*. Phillips points out that Pulliam testified, using the standard adopted by the Department of Justice for measuring market concentration, that the California market is only moderately concentrated. *Id*. It further notes that Pulliam testified that "many, many industries throughout the U.S. are moderately concentrated, and competition works throughout those industries." *Id*. at pp. 39-40 (quoting Transcript at p. 7588A).

3. BP

1714. BP states that Naphtha currently is valued on both the West and Gulf Coasts using Platts Gulf Coast reported price. BP Initial Brief at p. 5. When the Commission made that decision in 1993, BP acknowledges, it made sense, but today, nearly a decade after that decision, things have changed, and those changes have made it inappropriate to value West Coast Naphtha using a Gulf Coast price. *Id.* With the change in the valuation of VGO to the Platts West Coast VGO reference price,[624] BP states that it no longer is just and reasonable to value West Coast Naphtha on the basis of a Gulf Coast price. *Id.* It asserts that it is extremely important to value Naphtha on a consistent basis with VGO, because both their values are driven by their use in making gasoline. *Id.*

1715. Further, BP claims, fundamental differences between the Gulf Coast and the West Coast markets support using a West Coast-based price assessment, if reliable, instead of a Gulf Coast price assessment for valuing the West Coast naphtha component. *Id.* at p. 6. It points out that the Gulf Coast petrochemical market for Naphtha isn't replicated on the West Coast, and that this difference leads to differences in the Naphtha value on the two coasts. *Id.* Because the Quality Bank will value West Coast VGO on a West Cost basis going forward, BP asserts, the Quality Bank should make a corresponding change to the valuation of West Coast naphtha. *Id.* at p. 7.

4. Williams

1716. It is Williams's position that the current Naphtha value[625] is and continues to be

[623] Exhibit No. WAP-199.

[624] BP argues that any danger that the West Coast VGO price could be manipulated by one party at the expense of another has been eliminated. BP Initial Brief at p. 6.

[625] Williams uses the term "Current Naphtha value" to mean both the use of Platts Gulf Coast Naphtha price quote before Platts introduced the Heavy Naphtha price quote and the Platts Gulf Coast Heavy Naphtha (waterborne) price quote starting in March

just and reasonable. Williams Initial Brief at p. 17. According to Williams, Exxon, Phillips, Alaska and BP have not shown that the current valuation of the Naphtha component is unjust and unreasonable. *Id.* It asserts that they have not even made the threshold showing that there have been changed circumstances that warrant revisiting the current valuation method that has been used since the commencement of the distillation methodology. *Id.* Williams states that, if anything, any changed circumstances support the continued use of the Gulf Coast Naphtha price quote to value the West Coast Naphtha component. *Id.* Moreover, Williams notes, the alternative proposals advanced by Exxon and Phillips, respectively, are unquestionably unjust and unreasonable. *Id.*

1717. Simply stated, argues Williams, neither Phillips's nor Exxon's witnesses provide any evidence of changed circumstances warranting a change in the current methodology to value the West Coast Naphtha component. *Id.* Further, notes Williams, their witnesses did not even allege any changed circumstances since the adoption of use of the Gulf Coast published Naphtha price to value the West Coast Naphtha cut. *Id.* at pp. 17-18. Williams points out that O'Brien testified in his direct testimony that there have been no material changes in the West Coast and Gulf Coast markets. *Id.* p. 18 (citing Exhibit No. PAI-33 at p. 6).

1718. In addition, Williams states, Exxon also did not assert, nor did it provide any evidence of, changed circumstances.[626] *Id.* Similarly, Williams notes that Tallett does not address any changed circumstances in his pre-filed testimony. *Id.* In his direct testimony, according to Williams, Tallett does state: "[I]t is my understanding that in subsequent proceedings the [Commission] has abandoned its so called 'no adjustment to market prices' approach and has instead approved the use of adjusted prices." *Id.* (quoting Exhibit No. EMT-11 at p. 13). However, notes Williams, Tallett did not characterize that as a changed circumstance warranting a change in the methodology and it points out that the relevant portion of Tallett's testimony is titled "There is no Evidence That 'Changed Circumstances.'" *Id.* at pp. 18-19 (quoting Exhibit No. EMT-133 at p. 35). Further, notes Williams, when Tallett was asked what changed circumstances have occurred since October 2000 that would support a view that the Gulf Coast Naphtha price is no longer the appropriate value for West Coast Naphtha, he said there were none. *Id.* at pp. 19-20 (citing Transcript at pp. 6654-57).

1719. According to Williams, in his pre-filed direct testimony, Ross does not address

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2003. Williams Initial Brief at p. 17, n.10.

[626] Williams states that Toof's only mention of changed circumstances occurs in his pre-filed testimony addressing Ross's reference to changed circumstances in gasoline since 1996. Williams Initial Brief at p. 18, n.11 (citing and quoting Exhibit No. EMT-123 at pp. 35-36).

any changed circumstances warranting a change in methodology. *Id.* at p. 20. In his answering testimony, Exhibit No. BPX-27, it notes, Ross addresses changed circumstances in the gasoline markets as they relate to Tallett's proposed methodology asserting that the relationship, looking at gasoline differentials, between the Gulf Coast and West Coast has changed, a factor not accounted for by Tallett. *Id.*

1720. Williams asserts that one has to be wary of any proposal that uses West Coast gasoline prices because extra precautions need to be taken to ensure that the increasing margin of West Coast gasoline compared to Gulf Coast gasoline is not attributed to Naphtha. *Id.* at pp. 20-21. It state that both Tallett's and O'Brien's proposals do exactly that. *Id.* at p. 21. Williams explains that it is in this context that Ross goes on to state:

> [T]here obviously have been changed circumstances that have altered the historic relationship between Gulf Coast gasoline and West Coast gasoline. While it may have been valid to link West Coast Naphtha value to Gulf Coast Naphtha prices and the differential between West Coast and Gulf Coast gasoline prices in 1993, it certainly is not today.

Id. at p. 21 (quoting Exhibit No. BPX-27 at pp. 10-11). From this testimony, Williams concludes, Ross is focusing on the proposals and their use of West Coast gasoline and not on the value of Naphtha between the two coasts. *Id.* at p. 21. Further, Williams points out, Ross did not believe that the Naphtha values increased along with increased in gasoline prices, and that he apparently believed that, if there were a market for Naphtha on the West Coast, its value would have declined during the same period. *Id.* Williams states that Ross's conclusion that there have been no changed circumstances that affect the value of Naphtha is consistent with the record evidence supporting the continued use of the Gulf Coast Naphtha price to value the West Coast Naphtha component of the Quality Bank.

1721. Thus, it is Williams's position that there has been no evidence submitted of changed circumstances that warrant abandoning the methodology used to value Naphtha since the inception of using a distillation methodology for the Quality Bank. *Id.* at p. 22. In its *Tesoro* decision, explains Williams, the Circuit Court did not rule that changed circumstances had occurred or that its remand of the proceeding to the Commission precluded further consideration of this threshold first step in the evidentiary process of trying to change a methodology that has, in effect, been found to be just and reasonable. *Id.* Rather, states Williams, the Circuit Court held that, on the face of its complaint, Tesoro had alleged changed circumstances of a nature sufficient to require the Commission to consider and address whether changed circumstances had occurred that warranted looking at whether the methodology to value Naphtha should be changed. *Id.* (citing *Tesoro*, 234 F.3d at p. 1293).

1722. Williams notes that both Phillips and Exxon argue, despite the fact that their own witnesses testified that there were no changed circumstances, that the near complete cessation of ANS deliveries to the Gulf Coast is proof that Gulf Coast prices can no longer be used to value West Coast Naphtha. Williams Reply Brief at pp. 24-25. It argues that this assertion has been rendered meaningless by the evidence, as Ross testified, that the Platts Gulf Coast Heavy Naphtha (cargo) price assessment now being used to value the Gulf Coast and the West Coast Naphtha components of the Quality Bank is approximately equivalent to ANS plus $4.00/barrel on the West Coast. *Id.* at p. 25 (citing Transcript at p. 9979). Therefore, it asserts, the Gulf Coast Naphtha price is directly linked to ANS on the West Coast and, if there is a concern, this alleged changed circumstance is easily accounted for by simply substituting the West Coast published price for ANS + $4.00/barrel as the methodology for valuing West Coast Naphtha. *Id.*

1723. Both Phillips and Exxon also claim, states Williams, that the prices in the West Coast contracts produced in this proceeding constitute a changed circumstance based on the higher prices in the Naphtha contracts. *Id.* Williams states that Exxon would, at the least, have to show that the 2001 contracts are different from the contracts during the period 1994 – 2000 in light of the testimony that Tallett gave that his baseline year for changed circumstances was 2000, and it asserts that Exxon made no such showing. *Id.* at p. 26. According to Williams, Phillips cannot overcome O'Brien's testimony that there have been no changed circumstances since 1994 when the Commission began using the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.*

1724. Williams states that Phillips not only raises the difference in the product markets, it also pointed to the various proposals resulting in different values as a changed circumstance. *Id.* It suggests that there are two fatal flaws in this claim: first, Williams states that a person could simply skew the results of the valuation in order to support a changed circumstance based on that person's own results designed to achieve a high value for West Coast Naphtha when it is in that person's or party's economic interest; second, it states that the support that Phillips points to in *Tesoro* (234 F.3d at p. 1293) undermines Phillips's and Exxon's position that the Circuit Court, in that ruling, already decided that changed circumstances exist and that use of the Gulf Coast Naphtha price to value West Coast Naphtha is no longer appropriate. *Id.* at pp. 26-27. Further, Williams states, Tallett disavowed using the approach used in the *Tesoro* case. *Id.* at p. 27. Similarly, notes Williams, in 1998 O'Brien thought the *Tesoro* result unreasonable because it valued Naphtha higher than gasoline. *Id.*

1725. However, Williams points out that, because there was no evidentiary hearing on Tesoro's complaint, evidence of changed circumstances has to be presented in this proceeding. Williams Initial Brief at pp. 22-23. It declares that no evidence was presented here and that, therefore, the proponents have failed to clear the first of their three burden of proof hurdles. *Id.* at p. 23.

1726. Williams asserts, in support of its argument that the Gulf Coast and West Coast have different supply and demand characteristics,[627] that Exxon grossly misstates Sanderson's testimony in claiming that Sanderson stated that he would never suggest to anyone that they rely on Gulf Coast Naphtha prices to value West Coast Naphtha. Williams Reply Brief at pp. 27-28. Instead, Williams states that, when asked what prices he would advise his client to rely on to assess the risk of selling Naphtha on the West Coast, Sanderson clearly stated he would advise this client to rely on "a basket of prices, including the Gulf Coast [Naphtha] price." *Id.* at p. 28 (quoting Transcript at p. 9331).

1727. Exxon attempted to use testimony by Sanderson, according to Williams, that he did not rely on published Gulf Coast Naphtha prices when purchasing West Coast Naphtha. *Id.* at pp. 28-29. Williams argues that this testimony does not support Exxon's argument that the Gulf Coast Naphtha price is not a suitable proxy for the West Coast price in the 1993 through 2003 timeframe. *Id.* at p. 29. It contends that Sanderson clearly testified that the crude oil prices on the two coasts have been equalized since 1997. *Id.* Prior to that time, particularly in the 1980s when he was employed as the manager of economics and planning, Williams states, Sanderson indicated that crude oil prices on the West Coast, and therefore Naphtha prices on the West Coast, would have been below the Gulf Coast price. *Id.* Therefore, it maintains, the Gulf Coast Naphtha price would not have been germane to West Coast Naphtha transactions in the 1980s when Sanderson worked as the manager of economics and planning. *Id.*

1728. Williams explains that the Platts Gulf Coast waterborne Naphtha price was not created for the TAPS Quality Bank. Williams Initial Brief at p. 23. According to Williams, the reasonableness, robustness and reliability of this price quote for reforming grade Naphtha on the Gulf Coast has not been questioned or challenged since the time of its approval by the Commission and the Circuit Court for use in the TAPS Quality Bank. *Id.* It states that, in pre-filed testimony, Sanderson testified that Platts waterborne Naphtha price is a reliable indicator of reforming-grade Naphtha prices on the Gulf Coast: "In my experience, industry participants rely on the Platt's waterborne naphtha price quotation when an independent assessment of reforming-grade naphtha prices is needed as in the case of the TAPS Quality Bank." *Id.* at p. 23-24 (quoting Exhibit No. WAP-1 at p. 4).[628]

[627] Williams maintains that Exxon's claim that there are different supply and demand characteristics on the Gulf Coast and West Coast constitutes an admission that Tallett's Gulf Coast relationship is not the same as the West Coast relationship and that, therefore, his regression formula is inapplicable and thus an unacceptable way of calculating the West Coast Naphtha value. Williams Reply Brief at p. 27, n.10.

[628] Williams also cites to Exhibit No. WAP-1 at p. 11. Williams Initial Brief at p. 24.

1729. No party, Williams notes, has contested the viability, reliability and robustness of the continued use of Platts Gulf Coast Naphtha price for valuing the Gulf Coast Naphtha component of the Quality Bank. *Id.* at p. 24. Therefore, Williams asserts, there is no issue as to reasonableness of the price and its continued use to value the West Coast Naphtha component of the Quality Bank should the decision be that (i) no changed circumstances exist that warrant discontinuing use of the Platts Gulf Coast waterborne Naphtha price on either the Gulf Coast or the West Coast, (ii) the current methodology should be continued because the record evidence does not support a finding that this valuation is no longer just and reasonable, and (iii) (should the assessment reach this point) that the record evidence shows that none of the proposals to replace the current valuation methodology are just and reasonable. *Id.*

1730. Williams asserts that the continued use of the Platts Gulf Coast waterborne Naphtha price on the Gulf Coast and on the West Coast is not affected by Platts February 2003 introduction of a Heavy Naphtha price quote, which the Quality Bank Administrator implemented in March 2003 for the TAPS Quality Bank. *Id.* According to Williams, no party opposes the switch to Platts Gulf Coast Heavy Naphtha waterborne price quote for valuing Gulf Coast Naphtha and its use to value the West Coast Naphtha component of the Quality Bank so long as the current methodology continues to be used for the West Coast Naphtha component.[629] *Id.* at p. 24-25. It notes that the Quality Bank Administrator's reason for making the change was based on the new price quote being more closely aligned with the properties of Quality Bank Naphtha. *Id.* at p. 25.

1731. A basic premise of the TAPS Quality Bank, Williams states, is to use objective price quotations from independent services to value the intermediate feedstocks whenever possible.[630] *Id.* at p. 26 (citing *Trans Alaska Pipeline System*, 65 FERC at p. 62,287; Exhibit No. WAP-33 at p. 3). It states that Sanderson testified that this approach gives an

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[629] Williams states that its position that Platts Gulf Coast Heavy Naphtha (waterborne) price quote is acceptable does not extend to averaging the two prices as the Quality Bank Administrator recommends. Williams Initial Brief at p. 25, n.16.

[630] Williams explains that the TAPS Quality Bank distillation methodology values the various components as intermediate feedstock or products and not as finished products. Williams Initial Brief at p. 26, n.17. Thus, notes Williams, if there is no published price for the intermediate feedstock/product, then a published price for a finished product made entirely or essentially from that intermediate feedstock/product is used with the appropriate adjustment for processing and any other necessary adjustment to transform that finished product price into an intermediate feedstock/product price on a consistent basis with the other Quality Bank components. *Id.* Williams points out that this is not necessary because a published intermediate feedstock price exists for Naphtha. *Id.*

objective, rather than a subjective, method to use in valuing a cut. *Id.* at p. 26-27. In addition, continues Williams, the Quality Bank provides for the use of a price used on one coast to be used for valuation purposes for that component on both coasts if the other coast loses the price quote that had been used. *Id.* at p. 27.[631] Thus, asserts Williams, the Naphtha component has been valued consistently with these two basic tenets from the advent of using the distillation based methodology for the TAPS Quality Bank at Pump Station No. 1, at Golden Valley and at the Valdez Refinery. *Id.* As no published price quote exists for Naphtha on the West Coast, explains Williams, the published price quote on the Gulf Coast has also been used on the West Coast. *Id.* Further, notes Williams, these premises and the use of Platts Gulf Coast Naphtha price quote to value both the Gulf Coast and West Coast Naphtha components were not appealed. *Id.* Therefore, Williams asserts that it was effectively approved and found just and reasonable by the Circuit Court in *OXY* and was not reversed by the Circuit Court in either *Tesoro* or *Exxon*. *Id.*

1732. Williams states that it is unquestioned that there is no current West Coast Naphtha price quote. *Id.* (citing Exhibit No. WAP-1 at p. 4). In addition, notes Williams, there has been no such price quote since the Quality Bank switched to the distillation methodology. *Id.* Thus, asserts Williams, use of Platts Gulf Coast Naphtha price quote, and now Platts Gulf Coast Heavy Naphtha waterborne price quote, is the only proposal based solely on intermediate feedstock Naphtha price quotes from an industry-recognized, independent price assessment source and therefore consistent with the prices used to value the other Quality Bank components. *Id.* at p. 28.

1733. Contrary to Phillips's and Exxon's statements that Sanderson presented no evidence to support his theory, Williams asserts, the record evidence supporting its claim that Naphtha prices on the two coasts are linked to crude oil prices and, therefore, must be similar because crude oil prices of similar quality have equalized is compelling. Williams Reply Brief at pp. 34-35. It declares that Exhibit Nos. EMT-382 and WAP-229 show that only part of Naphtha, in a typical West Coast refinery manufacturing CARB gasoline, comes from straight-run Naphtha, with the balance of the Naphtha processed is purchased as crude oil or converted through hydrocracking the VGO cut from crude oil.[632] *Id.* at p. 35. Williams contends that it is logical and fully consistent with refining

[631] Williams cites to "Amerada Hess Pipeline Corporation, *et al.* Local Pipeline Tariff Part III.G.5.a." This document, however, was not offered in evidence and is not part of the record.

[632] Williams fails, however, to cite to the specific page(s) of Exhibit No. EMT-382, a multi-page exhibit, in which it finds support. Moreover, Exhibit No. WAP-229 involves a summary of the contract analyses performed by Tallett, Pulliam and O'Brien and, therefore, does not serve as proof of the point claimed by Williams.

economics to look to the crude oil price relationships between the West Coast and Gulf Coast to establish the relationship between Naphtha and VGO prices on the two coasts as Sanderson has done because we cannot look to Naphtha prices alone to verify this relationship. *Id.* It states that crude oil prices and VGO bear this relationship out. *Id.* According to Williams, it is clear from the record that VGO prices are similar and on average varied by only 0.9¢/gallon over the 1992 through 2002 period. *Id.*

1734. Williams notes that Sanderson testified that he would not expect the price relationships between intermediate feedstock prices on the two coasts that are not produced primarily from crude oil to be similar in price. *Id.* It states that Sanderson also testified that the price relationships of these commodities do not have any bearing on the price relationships between crude oil and Naphtha on the two coasts. *Id.* at pp. 35-36. Williams states that Sanderson also made a careful distinction between finished product prices and intermediate feedstock prices on the two coasts, and he was careful to explain that finished product prices are higher on the West Coast than the Gulf Coast because of the unique nature of the finished product markets on the West Coast leading to higher refining margins on the West Coast. *Id.* at p. 36.

1735. Exxon tries to blur this distinction, Williams states, by arguing that these higher refining margins on the West Coast should be attributed to the price of Naphtha and that the price of Naphtha is tied to the price of gasoline and not the price of crude. *Id.* Williams asserts that, the fact that the price of Naphtha is closer to the price of gasoline than the price of crude oil supports Sanderson's position that it is a suitable proxy for West Coast Naphtha. *Id.* It notes that Sanderson testified that the presence of a petrochemical industry on the Gulf Coast creates additional demand for Naphtha, thus elevating the price relative to what it would otherwise be, and argues that the robust demand for Naphtha on the Gulf Coast is substantiated by the fact that the Gulf Coast demand for it outstrips its supply from refineries requiring substantial volumes of imports. *Id.* at pp. 36-37. Williams believes that the price of Naphtha on the Gulf Coast must be sufficiently elevated to attract these imports. *Id.* at p. 37.

1736. According to Williams, since 1997, crude oil has been imported on the West Coast due to the decline of ANS as well as other West Coast (California) crude production. Williams Initial Brief at p. 28. It states that crude oil supply costs for the Gulf and West Coasts are similar and that this has caused crude oil prices to equalize. *Id.* at p. 29 (citing Exhibit No. WAP-1 at p. 7). Williams notes that Sanderson explained that this means prices are similar over a period of time. *Id.* (citing Transcript at p. 9398). In addition, notes Williams, because "West Coast refiners are importing increasing volumes of crude oil from several of the same crude oil suppliers as Gulf Coast refiners," Sanderson testified that "[t]he Gulf Coast and West Coast crude oil markets are linked." *Id.* (quoting Exhibit No. WAP-1 at p. 5). That does not mean, states Williams, that "prices are exactly the same" or that the "crude markets on the two coasts are identical." *Id.* (quoting Transcript at pp. 9029–30). Williams notes that Sanderson concluded that the

West Coast and Gulf Coast crude oil markets are linked because of the similarity in prices for delivered crude oil over an extended period of time. *Id.* at p. 30 (quoting Exhibit No. WAP-1 at pp. 8-9).

1737. The linkage of the Gulf Coast and West Coast crude markets, according to Williams, has significant implications with respect to the price of Naphtha on both the Gulf Coast and West Coast. *Id.* at p. 31. It points out that Sanderson testified that, because of this linkage, the price of Naphtha won't vary much between the Gulf and the West Coasts. *Id.* Williams explains, further, that the Platts Gulf Coast Naphtha price is a reasonable proxy for valuing Naphtha on the West Coast because the Platts price quote "values naphtha as an intermediate feedstock . . . [and] a refiner always has the option of running a crude oil with a higher naphtha content in lieu of acquiring naphtha as a feedstock." *Id.* at p. 32. (quoting Exhibit No. WAP-1 at p. 5).

1738. Williams states the additional demand for reforming Naphtha as a petrochemical feedstock on the Gulf Coast means that the price of reforming Naphtha on the Gulf Coast is elevated relative to what it would otherwise be. *Id.* at pp. 33-34 (citing Exhibit Nos. WAP-1 at p. 10, BPX-27 at p. 29). But, asserts Williams, there is no similar petrochemical demand on the West Coast. *Id.* at p. 34 (citing Transcript at p. 9028). It notes that Ross testified that about 70% of Heavy Naphtha in PADD III (Gulf Coast) is used for gasoline and about 30% is used in petrochemical and other applications. *Id.* (citing Transcript at pp. 9763, 6789). Further, continues Williams, both Tallett and O'Brien acknowledged that the aromatics extraction capacity on the Gulf Coast was approximately 12.4% of total reforming capacity. *Id.*

1739. It is reasonable to conclude, according to Williams, that the use of reforming grade Naphtha on the Gulf Coast to produce reformate for extraction of aromatic petrochemicals such as benzene, toluene and xylenes commands a premium over the reformate value in gasoline resulting in an elevation of the Gulf Coast Naphtha prices. *Id.* Otherwise, Williams states that the aromatic petrochemicals would not be extracted from the gasoline blending pool on the Gulf Coast. *Id.* Even an occasional use of reforming-grade Naphtha on the Gulf Coast as an ethylene cracker feedstock provides, Williams states, a floor for the reforming-grade Naphtha price on the Gulf Coast. *Id.* In support it refers to Exhibit No. EMT-89 at p. 2 which, it claims, shows that, during the winter months, the differential between Heavy Naphtha and conventional gasoline on the Gulf Coast did not drop as much. *Id.*

1740. Williams also states that the influence of the petrochemical markets on the Gulf Coast Naphtha price also helps to explain the narrower differential between gasoline and Naphtha on the Gulf Coast and the resulting higher Naphtha price. *Id.* at p. 34. It further explains that the Gulf Coast petrochemical demand and resulting higher Naphtha value also helps to explain why O'Brien's formula for valuing Naphtha appears to predict Gulf Coast prices. *Id.* at p. 35. (citing Exhibit No. WAP-133).

1741. On reply, Williams states that it believes that Exxon is wrong when it asserts that the use of Naphtha as a petrochemical feedstock on the Gulf Coast has no impact on the value of Quality Bank Naphtha. Williams Reply Brief at p. 29. In addition, it asserts that Exxon's statement concerning which aromatics are used to manufacture petrochemicals is also incorrect. *Id.* at pp. 29-30. According to Williams, the record evidence clearly indicates that 14.7% of the Quality Bank Naphtha cut is used in the production of aromatic petrochemicals such as benzene, toluene, and xylenes on the Gulf Coast. *Id.* O'Brien agrees with the magnitude of this estimate. *Id.* at pp. 30-31.

1742. In Williams's view, it is beyond question that the petrochemical demand for Naphtha on the Gulf Coast elevates the value of Naphtha while the lack of petrochemical demand for Naphtha on the West Coast coupled with much stricter benzene and aromatic restrictions for much of the gasoline produced on the West Coast lowers its value. *Id.* at pp. 33-34. When coupled with the increased value of Naphtha on the Gulf Coast of approximately 1¢/gallon as a result of using Platts Gulf Coast Heavy Naphtha (cargo) price assessment, this means, according to Williams, that the Gulf Coast Naphtha value is and continues to represent a just and reasonable value for the West Coast Naphtha component of the Quality Bank. *Id.* at p. 34.

1743. Williams explains that Sanderson's review of VGO, Naphtha and LSR prices on the Gulf Coast and VGO and LSR prices on the West Coast led him to conclude as follows:

> I remain convinced that reforming-grade naphtha should be valued as an intermediate feedstock consistent with other intermediate feedstocks produced primarily from crude oil and used primarily to make gasoline on the West Coast rather than through a subjective methodology that unfairly and improperly attributes the refiner's margin from gasoline production and marketing to naphtha, only one of the intermediate feedstocks used to make gasoline.

Williams Initial Brief at p. 35 (quoting Exhibit No. WAP-33 at p. 10). Based on this review, continues Williams, Sanderson also

> conclude[ed] that the relative value of the naphtha on the two coasts should fall between the values of VGO and LSR on the two coasts. In other words, the difference between the value of naphtha on the West Coast less the Gulf Coast naphtha price is higher than the LSR price differential (where the West Coast price is below the Gulf Coast price) and lower than the VGO price differential (where the West Coast VGO prices are currently above the Gulf Coast).

Id. (quoting Exhibit No. WAP-33 at p. 19).

1744. With the advent of CARB gasoline in California, Williams argues, it is not surprising, and in fact should be expected, that VGO's role in gasoline production would be enlarged while Naphtha's would diminish. *Id.* at p. 36. Williams points out that Exxon witness Tallett concurred with the increased importance of VGO with respect to making CARB gasoline. *Id.* (citing Exhibit Nos. WAP-33, 49).

1745. VGO prices on the West Coast and Gulf Coast have tracked each other, notes Williams, except for the extreme United States gasoline market disruptions in 2000 (due to Coker outages.) *Id.* (citing Exhibit No. WAP-224). Williams states that, as one might expect, Exhibit Nos. WAP-219 and WAP-224 show that a switchover in VGO price tracking on the two coasts occurred after 1996, which reflects VGO's increased importance to making CARB gasoline in California. *Id.* at pp. 36-37. However, notes Williams, over the 1992 through 2002 period, the price differential between VGO on the two coasts has averaged 0.9¢/gallon. *Id.* at p. 37.

1746. In contrast with VGO, Williams claims, LSR prices are significantly lower on the West Coast than on the Gulf Coast for two principal reasons. *Id.* at pp. 37-38 (citing Exhibit Nos. WAP-33 at p. 11, WAP-219, EMT-94). First, notes Williams, the high Reid Vapor Pressure of LSR and the isomerate manufactured from LSR make these components difficult to blend into CARB gasoline which has a very low Reid Vapor Pressure specification. *Id.* at p. 38. Because the Reid Vapor Pressure specifications change between the summer season (during which the Reid Vapor Pressure specifications are more severe) and the winter season in California, Williams explains, the demand for LSR is significantly curtailed during the summer season. *Id.* Without an alternative demand for LSR, Williams points out, such as a petrochemical feedstock, the LSR price is severely depressed. *Id.* Second, and conversely, states Williams, while there are also Reid Vapor Pressure limitations on the Gulf Coast (although not as severe as California), the increased demand for LSR as a petrochemical feedstock on the Gulf Coast acts to elevate LSR's price relative to the West Coast where no such demand exists. *Id.*

1747. Therefore, based on the uses of VGO, Naphtha and LSR in making gasoline, particularly CARB gasoline, on the West Coast, Williams asserts that the Naphtha value should fall between the prices of VGO and LSR. *Id.* It claims that this is true as well on the Gulf Coast. *Id.* Because all these intermediate prices are published on the Gulf Coast and, on average, and except during periods of severe disruptions, the VGO prices have been close on both coasts, Williams concludes, Platts Gulf Coast Naphtha price is representative of and should on average approximate the West Coast Naphtha price. *Id.*

1748. According to Williams, switching to CARB II gasoline on the West Coast, particularly in California, easily the largest gasoline market on the West Coast, has had a significant impact on the demand for Naphtha and thus its value in making gasoline. *Id.*

at p. 39. It notes that CARB gasoline made up approximately 71% of the West Coast gasoline production in 2000. *Id.* (citing Transcript at p. 12110).

1749. Two of the principal goals of the California Air Resources Board in establishing Phase II gasoline specifications, according to Williams, were to reduce the aromatic hydrocarbon content and the benzene content in California gasoline. *Id.* at pp. 39-40 (Exhibit No. WAP-228 at pp. 2-3). It points out that ANS Naphtha happens to be rich in both benzene and aromatic hydrocarbons. *Id.* at p. 40 (citing Exhibit No. WAP-278 at p. 6). The net result of these changes is that less reformate can be blended into the CARB gasoline pool, according to Williams, and thus less Naphtha is needed. *Id.* When compared to 1994 Naphtha throughput on an equivalent basis,[633] explains Williams, Naphtha demand on the West Coast has declined by approximately 23,000 barrels/day. *Id.* Even more revealing, notes Williams, is the fact that during this same time period, reforming capacity decreased by about 64,000 barrels/day. *Id.* (citing Transcript at p. 11028). Were Naphtha prices what O'Brien and Tallett claim they should be, Williams asserts, it is inconceivable that reforming capacity would have decreased and Naphtha throughput would have declined. *Id.* at pp. 40-41. Even with the decreased reforming capacity, Williams points out that reformer utilization still is not 90%.[634] *Id.* at p. 41. In contrast, continues Williams, Exhibit No. WAP-226 shows that both capacity and throughput have increased for VGO during the same time period, thereby demonstrating the increased importance of VGO in the manufacture of CARB gasoline and the decreased importance of Naphtha in making it. *Id.*

1750. Williams suggests, therefore, that the Gulf Coast Naphtha price, and particularly the Platts Gulf Coast Heavy Naphtha (waterborne) price, is representative of the price of Naphtha on the West Coast in that it clearly does not undervalue West Coast Naphtha. *Id.* at pp. 43-44. It asserts that there is no evidence in this record that shows any changed circumstances which have altered the relationship of Naphtha on the two coasts such that the use of the Gulf Coast Naphtha price is no longer just and reasonable. *Id.* at p. 44.

1751. Phillips wrongly states that Sanderson provided no quantification of the loss of value of Naphtha because of the CARB requirements, Williams argues. Williams Reply Brief at p. 41. It asserts that Sanderson did state that he believed the reduction to be 1.3¢/gallon, and that such a reduction in value is to be expected because of CARB

[633] Williams explains that the term "equivalent basis" means dividing the actual throughput each year by the reforming capacity that existed in 1994. Williams Initial Brief at p. 40, n.29.

[634] Williams explains that, with the introduction of CARB gasoline in 1996, reformer utilization in California dropped significantly to 66%. Williams Initial Brief at p. 41, n.30.

requirements resulting in restricted cut points for straight-run Naphtha which reduces the volume of it processed through the reformer resulting in a reduction in the value of reformate made from straight-run Naphtha. *Id.*

1752. Exxon isolates data from Exhibit No. EMT-382, Williams claims, to try to distort what the Exhibit shows in an attempt to bolster Tallett's calculated high Naphtha value. *Id.* It notes that Exxon asserts that a study of refining options available to California refineries done by Sanderson's firm, Purvin & Gertz, showed that a refinery on the West Coast making 100% CARB gasoline would be expected to use a higher percentage of reformate in its gasoline pool than a refinery on the Gulf Coast producing 100% reformulated gasoline. *Id.* Williams states that Exxon claims that this study squarely contradicts Sanderson's claim that Naphtha has lost value on the West Coast due to the requirements for producing CARB gasoline. *Id.* at pp. 41-42. In fact, according to Williams, Exhibit No. EMT-382 shows the lower contribution of straight-run reforming Naphtha (Quality Bank Naphtha) on the West Coast consistent with Sanderson's testimony that the CARB gasoline regulations have reduced the volumetric contribution of Quality Bank Naphtha. *Id.* at p. 42. Williams asserts that the volumetric comparison that is relevant to the valuation of Quality Bank Naphtha is the relative volumetric contribution of straight-run Naphtha produced from crude oil on the two coasts. *Id.*

1753. In addition, Williams notes, Phillips and Exxon try to rely on testimony from Sorenson to indicate that CARB gasoline has no effect on West Coast refineries because, as Exxon claims, "Sorenson made clear, the benzene reduction equipment already in place will be able to handle the new CARB standards." *Id.* at pp. 42-43. While that may address handling benzene at one refinery, Williams asserts, Exxon's and Phillips's statements and Sorenson's testimony do not address the fact that the volume of straight-run Naphtha that is run through reformer is reduced due to the change in cut points of the Naphtha cut. *Id.* at pp. 43-44. In addition, it states that they do not address other refineries, particularly those that run more ANS than the Phillips Los Angeles refinery. *Id.* at p. 44. Williams argues that there is no record support for the industry as a whole because Sorenson had no knowledge of any other refineries with respect to handling benzene and aromatics; nor did he know if they installed their environmental equipment on a 100% ANS basis. *Id.*

1754. Williams notes that, even at the Phillips Los Angeles refinery, Sorenson testified that "[t]o give ourselves flexibility, we have undercut the naphtha to the reformer and we blend back heavy material into the back end of gasoline." *Id.* (citing Transcript at p. 13254). It points out that this is for a refinery that in 1997 ran no ANS and now is only sometimes running 20–30,000 barrels/day of ANS. *Id.* (citing Transcript at pp. 13250-51). According to Williams, this represents only up to 15-23% of that refinery's crude slate. *Id.* Thus, since this refinery runs so little ANS, Williams asserts, its data, and therefore Sorenson's testimony, are not reflective of, and thus irrelevant to, a refinery running 100% ANS. *Id.*

1755. In addition, Williams argues, Exxon erroneously states that the shift to CARB III specifications will increase the maximum amount of aromatics allowed from 30% to 35% and make Naphtha more valuable. *Id.* at p. 45. It asserts that Exxon did not take into account that the benzene standard is being lowered from 1.2% to 0.8%. *Id.* Sorenson, Williams claims, testified that, had he altered the CARB II gasoline specification and used the lower benzene level for CARB III gasoline instead, the result would have been a higher percentage of the reformate being processed through the benzene saturation unit. *Id.* It believes that it is obvious that Exxon also forgot that ANS has a very high level of benzene and benzene precursors which also impacts negatively the ANS Naphtha ability to be processed through a reformer. *Id.*

1756. Contrary to the statements of Exxon and Phillips concerning his transportation differential analysis, Williams asserts, Sanderson's testimony that the Gulf Coast Heavy Naphtha quote is a just and reasonable valuation for West Coast Naphtha is supported by his transportation analysis in two key areas. Williams Reply Brief at pp. 37-38. First, Williams states, Sanderson uses his analysis of the relative costs of transporting Naphtha to the Gulf Coast from the Caribbean and to the West Coast from the Caribbean to test the reasonableness of the West Coast Naphtha valuation proposals. *Id.* at p. 38. It contends that the proposals of Tallett and O'Brien clearly fail this test as, during periods of extreme gasoline supply shortfalls and high gasoline prices which these proposals attribute to their Naphtha values, no measurable increase in Naphtha imports was observed. *Id.* Additionally, they state that Sanderson uses his analysis of crude oil transportation costs to illustrate the mechanism by which prices for crude oils of similar qualities on the two coasts have equalized. *Id.* at pp. 38-39.

1757. Williams argues that Exxon's argument that it costs 16¢/barrel more to ship Arabian Light crude oil to the West Coast than it does to ship it to the Gulf Coast ignores the key fact that 16¢/barrel or 0.4¢/gallon is de minimis with respect to the Gulf Coast and West Coast refiner's total cost of crude. *Id.* at p. 39. It notes that Sanderson testified that the transportation calculated by Turner Mason and published by Platts is unreliable. *Id.*

1758. Exxon's argument that Sanderson's analysis was deficient because he did not study all of the crude oils on the Gulf Coast and West Coast, Williams insists, is without merit. *Id.* at p. 40. It explains that Sanderson testified that the prices of different quality crudes even on the same coast would be different, and that the important consideration from a crude oil price perspective is that crude oils of similar quality are similarly priced on the two coasts. *Id.* at pp. 40-41. Furthermore, Williams argues that the question of whether crude oil suppliers from the Middle East can divert supplies sold to one coast to the other once a sale has been made to one coast or the other has no relevance to the relationship of crude oil prices on the two coasts. *Id.* at p. 41.

1759. Williams notes that Phillips argues that the fact that Williams makes significant sales of Naphtha to the West Coast and the Far East proves that use of the Gulf Coast price substantially undervalues West Coast Naphtha. *Id.* at p. 46. It explains that Phillips refers to this as an example of Williams's "arbitrage" of the difference between the Gulf and West Coast values of Naphtha. *Id.* Williams asserts that Phillips's statement and argument represent a blatant disregard for and misstatement of the record evidence. *Id.* First, Williams claims, the Naphtha sold is Full Range Naphtha, not Quality Bank Naphtha. *Id.* It notes that Sanderson testified that it is the fact that Williams's Naphtha is made up of between 23% and 35% LSR that enables Williams to make the Naphtha sale. *Id.* According to Williams, it is the low West Coast LSR price and not the use of the Gulf Coast Naphtha price that makes the sales possible. *Id.* at p. 47. Therefore, and contrary to Phillips's statement, Williams maintains these sales do not mean that the Quality Bank West Coast Naphtha price is too low. *Id.*

5. Unocal/OXY

1760. Unocal/OXY submit that, not only has the existing method not been shown to be unjust and unreasonable, but the evidence submitted by Unocal/OXY, Petro Star and Williams proves that continued use of Gulf Coast prices to value West Coast Naphtha is just and reasonable. Unocal/OXY Initial Brief at pp. 4-5. Moreover, continue Unocal/OXY, the proponents of change have not demonstrated that their respective proposals are just and reasonable. *Id.* at p. 5. Further, they note that the proponents of change have not satisfied their burden of showing changed circumstances. Unocal/OXY Reply Brief at p. 16.

1761. The parties opposing the continued use of Gulf Coast pricing to value West Coast Naphtha, Unocal/OXY claim, have cited the following evidence of changed circumstances: (a) abandonment of the "no adjustment" policy, (b) significant disparity between Gulf Coat prices and West Coast Naphtha value, (c) disappearance of ANS shipments to the Gulf Coast, (d) the impact of the CARB requirements and the run-up in gasoline prices beginning in 1999, and (e) the change in the way West Coast VGO is valued. *Id.* at pp. 16-17.

1762. The 1993 abandonment of the Commission's no adjustment policy does not constitute a changed circumstance that precludes continued use of a Gulf Coast price to value West Coast Naphtha, according to them. *Id.* at p. 17. They point out that, in addition to the no adjustment policy, the basis for the 1993 ruling also rested on the "single market pricing" policy, which requires that the published prices in one market be used to value products in both markets if there are no published prices in one of the markets.[635] *Id.* Unocal/OXY assert that this policy remains part of the Quality Bank

[635] Unocal/OXY cite *Trans Alaska Pipeline System*, 65 FERC at p. 62,289; *Trans Alaska Pipeline System*, 66 FERC at p. 61,418, in support.

Tariff and that no party has requested that it be changed. *Id.* at p. 18. They contend that the policy could potentially apply to all cuts in the Quality Bank, and that it is merely a coincidence that only the Naphtha cut meets the criteria of having a published price in only one market at this time. *Id.*

1763. Unocal/OXY contend that the proponents of change have not shown that there is any changed circumstance or new evidence respecting the single market pricing policy. *Id.* They note that the policy was adopted when there was a price quote for Naphtha in only one of two markets and that this situation has not changed. *Id.* Further, they explain that when the policy was adopted, there were separate price series for most intermediate and finished products on the two Coasts, and that has not changed either. *Id.*

1764. All arguments regarding the alleged disparity between West Coast Naphtha value and the Gulf Coast Naphtha price are based on guess work, supposition, or subjective judgments, according to Unocal/OXY. *Id.* at p. 19. They state that there is no hard evidence that West Coast Naphtha's market value is higher than that on the Gulf Coast, because there is no West Coast market price. *Id.* Further, they disagree with Exxon, Phillips and Alaska that the contracts presented here provide evidence of Naphtha's value. *Id.* Unocal/OXY believe that the evidence is anecdotal at best and certainly does not establish a West Coast Naphtha market value. *Id.* Finally, they assert that the contract evidence does not establish that a changed condition exists. *Id.*

1765. Unocal/OXY concede that ANS deliveries to the Gulf Coast, which were small in 1993, have virtually disappeared. *Id.* at p. 21. However, they assert that this is not by itself enough to change the existing Naphtha valuation if the use of Gulf Coast prices does not undervalue West Coast Naphtha. *Id.* According to them, when the Commission prescribed the use of single market pricing for Naphtha, Gulf Coast deliveries of ANS constituted somewhat less than 20% of deliveries. *Id.* (citing *Tesoro*, 234 F.3d at 1292). They argue that, if the use of Gulf Coast prices produced a just and reasonable value when 80% of the Naphtha cut was delivered to the West Coast and only 20% went to the Gulf Coast, then the use of Gulf Coast prices should still be just and reasonable when 100% of the cut is delivered to the West Coast. *Id.* Gulf Coast prices do not undervalue West Coast Naphtha, Unocal/OXY assert, and, therefore, the reduction in Gulf Coast deliveries does not constitute a significant change. *Id.*

1766. Ross, according to Unocal/OXY, suggests that the agreement of the parties to change the basis for valuing VGO from using Gulf Coast prices to using West Coast prices published by OPIS is a changed circumstance requiring a new Naphtha valuation. *Id.* at p. 22. They explain that Ross's rationale is that both Naphtha and VGO are closely related because of their role in the manufacture of gasoline, and that they should therefore be valued "on a consistent basis." *Id.* However, Unocal/OXY state that this is not a substantial enough change to call into question the current basis for valuing Naphtha. *Id.* They point out that there is no West Coast Naphtha price published by OPIS that could be used to put Naphtha and VGO on a consistent basis. *Id.* If a West Coast value is adopted based on either of the formulae sponsored by O'Brien or Tallett, they note, even then, if Ross's governor were also adopted, Naphtha and VGO will not be on any more of a consistent pricing basis than they would be if no change were made. *Id.* Unocal/OXY state that, in that case, Naphtha would be valued based on a formula with numerous data inputs; VGO would be valued based on a single, unadjusted published price. *Id.* By contrast, they point out that if no change to Naphtha is made, then both will be valued based on unadjusted, published prices. *Id.* Thus, Unocal/OXY believe that the "consistent basis" argument would seem to favor retention of the current pricing. *Id.*

1767. Unocal/OXY claim that the record reflects that Exxon, Phillips, and BP have all conceded that there have been no changed circumstances that would undermine the basis for the Commission's single market pricing policy adopted in 1993. *Id.* at pp. 22-23. They state that Tallett admitted in sworn testimony filed with the Commission as recently as 2000 that he had supported single market pricing and the use of Gulf Coast prices to value West Coast products in the Quality Bank, and that nothing specifically had changed since that time. *Id.* at p. 23. Tallett, they further claim, testified that "there is no evidence that 'changed circumstances' have undermined Naphtha's value on the West Coast." *Id.* (citing Exhibit No. EMT-133 at p. 35).

1768. Further, Unocal/OXY point out, O'Brien testified that there had been no changes that would affect the Commission's decision to use single market pricing for Naphtha: "I testified that there have been no material changes in the West Coast or Gulf Coast Naphtha markets since the time the Commission held that all Naphtha should be valued based on the Gulf Coast price. That continues to be the case today." *Id.* (citing Exhibit No. PAl-33 at p. 6). Finally, they note that Ross testified that, while there had been changes that altered the relationship between Gulf Coast gasoline and West Coast gasoline, these changes did not affect the Naphtha relationship on the two coasts. *Id.* (citing Exhibit No. BPX-27 at pp. 10-11).

1769. Unocal/OXY point out that, because there is no published West Coast price for Naphtha, in trying to derive a value for West Coast Naphtha, no party's proposal can be proven to represent the true price of Naphtha on the West Coast. Unocal/OXY Initial Brief at p. 5. Significantly, according to Unocal/OXY, without proof of the actual value of Naphtha on the West Coast, it is difficult to conclude that the continued use of Gulf Coast prices to value this cut is no longer just and reasonable. *Id.* They assert that, even after an extended hearing, no empirical evidence has been adduced as to the actual price of Naphtha on the West Coast. *Id.* According to Unocal/OXY, while the Naphtha sales contracts come closest to providing such evidence, they are a sparse and imperfect sample. *Id.* And while the contracts may provide evidence of value as between the parties involved in the transaction, Unocal/OXY argue, they do not provide evidence of the actual West Coast market value of Naphtha. *Id.* Therefore, assert Unocal/OXY, whatever conclusions are made on this record respecting the value of West Coast Naphtha, the continued justness and reasonableness of the existing use of Gulf Coast prices must rest instead on the subjective opinion of the expert witnesses who testified on this issue. *Id.* at pp. 5-6. Unocal/OXY's position is that these opinions fail to demonstrate that the West Coast value of Naphtha is higher than the Gulf Coast value of Naphtha over any sustained period of time in any significant amount. *Id.* at p. 6.

1770. According to Unocal/OXY, the current method of valuing West Coast Naphtha is the only method that is completely objective and not subject to manipulation or distortion, a primary concern of the Commission when it adopted the current method. *Id.* (citing *Trans Alaska Pipeline System,* 65 FERC at p. 62,289). While Ross asserts that a separate West Coast price is required because all of the other cuts will have a separate West Coast price, Unocal/OXY maintain, that is not reason enough to require a change in the current method, absent evidence that the existing Gulf Coast price undervalues West Coast Naphtha. *Id.* Unocal/OXY state that the evidence submitted at trial, taken as a whole, does not prove that West Coast Naphtha is undervalued by the use of Gulf Coast prices. *Id.* (citing Exhibit Nos. UNO-7 at p. 2, WAP-33 at p. 2).

1771. In Exhibit No. UNO-1, note Unocal/OXY, Culberson uses EIA shipping data to show that there are very few imports of Naphtha into the West Coast, while there are very substantial imports into the Gulf Coast. *Id.* Unocal/OXY explain that he reasoned that, were Naphtha valued higher on the West Coast than it is on the Gulf Coast, then there would be shipments of Naphtha into the West Coast from the same origins that currently make shipments into the Gulf Coast. *Id.* at pp. 6-7. Further, note Unocal/OXY, his reasoning is based on the linkage between geographically separated markets provided by the global trade in petroleum products. *Id.* at p. 7.

1772. Unocal/OXY explain that data on Naphtha imports, and imports of other refined products, are collected by the EIA and made available in public reports. *Id.* They note that Naphtha used for refining is reported under two categories, "Petrochemical Naphtha" and "Unfinished Oils," the latter of which includes other feedstocks as well as Naphtha. *Id.* Over the past three years, according to Unocal/OXY, the Gulf Coast has imported over 85,000 barrels/day of Petrochemical Naphtha and 220,000 barrels/day of Unfinished Oils. *Id.* By contrast, Unocal/OXY point out, the West Coast has imported only about 1,000 barrels/day of Petrochemical Naphtha and 29,000 barrels/day of Unfinished Oils. *Id.* When the 29,000 barrels/day of Unfinished Oils is broken down to the category of "Naphtha and lighter," explain Unocal/OXY, the data show only a few import shipments each year: five in 1996, six in 1997, one per year in 1998, 2000, and 2001, and none in 1999. *Id.* According to Unocal/OXY, these data, showing that there are no West Coast Naphtha imports in most months, affirm Culberson's testimony that West Coast refineries import very little Naphtha. *Id.*

1773. The origin of the Naphtha which is shipped to the Gulf Coast includes the Far East and sources on the western side of South America, according to Unocal/OXY. *Id.* at p. 8. For these origins, they allege, it would be cheaper to deliver the cargo to the West Coast than to land it on the Gulf Coast, yet the Naphtha from these origins bypasses the West Coast, transits the Panama Canal, and lands on the Gulf Coast. *Id.* This is significant, in Unocal/OXY's view, because, they believe, if Naphtha had a higher value on the West Coast than on the East Coast, that higher price would attract imports from the same Far Eastern and South American origins that ship to the Gulf Coast. *Id.* Unocal/OXY point out that Caribbean origins and eastern South America are the major source for Naphtha imported to the Gulf Coast, and the additional cost to export to the West Coast, as compared to exporting to the Gulf Coast, is quite low. *Id.* Therefore, state Unocal/OXY, Culberson concludes that the absence of imports of Naphtha into the West Coast market indicates that there is not a higher West Coast Naphtha price over a sustained period of time. *Id.* Unocal/OXY note that both Ross and Tallett agree with the essential elements of this reasoning. *Id.* at p. 9. Because all the world's regions are connected by transport, Unocal/OXY state, the price of products in one region will not exceed for long the cost of imports from others. *Id.* (citing Exhibit No. BPX-27 at p. 14).

1774. Unocal/OXY note that Ross's view differs from Culberson's only with respect to how far below the cost of imports the West Coast Naphtha value may be. *Id.* They point out that Ross assumed that the West Coast value exceeds the Gulf Coast value by some amount that is not enough to induce imports and bases his governor on the cost of shipping Naphtha to the West Coast from Venezuelan ports using a shipping rate that is more than twice the rate used by Culberson. *Id.* at pp. 9-10. However, according to Unocal/OXY, Ross's use of Venezuela as the origin in his model causes the shipping rates to be too high and his governor, therefore, may be based on the faulty premise that Far East product does not act as a disciplinary force on the value of Naphtha on the West Coast. *Id.* at pp. 10-11.

1775. According to them, they also disagree with Phillips's and Exxon's criticism of the transportation costs developed by Culberson and Sanderson. Unocal/OXY Reply Brief at p. 53. They assert that Phillips and Exxon fail to understand that Culberson was only attempting to calculate the relative transportation cost difference to land a cargo on the West Coast as opposed to the Gulf Coast from the same point of origin. *Id.* For that reason, they note, his analysis was not an attempt to calculate exact shipping costs as part of a recommendation on how to value Naphtha. *Id.* at pp. 53-54. They explain that Culberson believed that "Naphtha on the high seas originating in the Pacific could be shipped more cheaply to the West Coast than to the Gulf Coast, and could be diverted to the Gulf Coast or West Coast, respectively, if prices dictate." *Id.* at p. 54. Unocal/OXY state that Culberson then tried to calculate the marginal cost to divert these shipments to the West Coast in order to respond to higher West Coast prices. *Id.*

1776. The lack of West Coast imports, Unocal/OXY argue, cannot be explained away by the fact that Naphtha demand at West Coast refineries is satisfied by internally generated Naphtha. Unocal/OXY Initial Brief at p. 11. They explain that, if Naphtha on the West Coast were in fact valued substantially higher than Gulf Coast Naphtha, refiners would choose to import the cheaper Naphtha rather than generate it internally. *Id.* Refiners use sophisticated computer programs to optimize their operations, according to Unocal/OXY. *Id.* Further, they continue, refiners generally have between 30% and 50% of their feedstock purchases available for spot purchases. *Id.* at pp. 11-12. This, according to Unocal/OXY, gives them the ability to constantly reassess their operations to take advantage of cost savings and marketing opportunities, including the availability of cheaper imported Naphtha. *Id.* at p. 12.

1777. The lead time needed to make the "make-or-buy" decision, Unocal/OXY claim, is typically only approximately three weeks and could be as short as several days for a cargo that is already in transit. *Id.* They further point out that a refinery could also reduce its need for Naphtha by increasing output from the cat cracker, which produces gasoline precursors from VGO, a change that would require very little lead time. *Id.* Therefore, maintain Unocal/OXY, Tallett's insistence that the balance between demand and supply on the West Coast explains the absence of imports does not address the operational flexibility and profit maximization that characterize refinery operations. *Id.* Not only does the ability to adjust crude slates explain why refiner self sufficiency does not prevent imports, Unocal/OXY state, it also explains why Naphtha has the same value to refiners on both coasts. *Id.* at p. 13.

1778. Unocal/OXY note that Ross was questioned concerning the Naphtha import issue, and particularly about where the additional demand or "room" for West Coast Naphtha would come from if refiners already satisfy their demand from their own crude oil. Unocal/OXY Reply Brief at p. 63. They state that Ross acknowledged that, as Culberson described, refiners can adjust their crude slate to purchase crude oils that produce less Naphtha and thereby make room for additional supplies, and note that, even in the short run, "room" would be made by substituting cheaper imported Naphtha for the volumes of Naphtha currently being purchased locally, as evidenced by the contracts. *Id.* at p. 64. They continue to explain that this, in turn, would cause local suppliers to drop their prices to try to recapture market share, and they would keep prices low after recapture due to the discipline of potential imports. *Id.*

1779. For the longer term, according to Unocal/OXY, the cheap Naphtha would force refiners to make the kinds of make-or-buy reassessments described by Culberson, using their computer models. *Id.* They claim that the refiners would either use the cheaper Naphtha to increase their gasoline production, and thereby drive out existing gasoline imports, or they would substitute cheaper crude oils that produce less Naphtha, and increase their profit margins. *Id.* Unocal/OXY state that Ross concluded that "the fact that the West Coast naphtha market is physically in supply and demand balance" does not prevent imports, or stop them from having an effect on price, and that the West Coast market is an opaque market, which has not reached an efficient equilibrium between supply and demand. *Id.* (quoting Transcript at p. 9988).

1780. Unocal/OXY assert that there are no barriers to entry that would explain the almost complete absence of any significant amount of Naphtha imports to the West Coast. Unocal/OXY Initial Brief at p. 13. They maintain that import data show an occasional shipment of Naphtha to the West Coast from Caribbean origins, western South America, and the Far East, which demonstrates the possibility of Naphtha imports from these sources. *Id.* More importantly, according to Unocal/OXY, the import evidence for other refined products contrasts sharply with the evidence for Naphtha. *Id.* at p. 14. In support, Unocal/OXY cites record evidence of the flow of gasoline, gasoline blend stocks, jet fuel and VGO into the West Coast from the Gulf Coast when the price of West Coast gasoline spikes which they assert has the effect of moderating the rise in gasoline prices on the West Coast. *Id.* at pp. 14-15.

1781. According to Unocal/OXY, this flow of gasoline and gasoline blend stocks tends to prove the point that Gulf Coast prices will discipline West Coast prices, even in a less than fully competitive gasoline market. *Id.* at p. 14. The flow of jet fuel and VGO is important to Naphtha values, according to Unocal/OXY, for three reasons. *Id.* at p. 15. First, state Unocal/OXY, it illustrates the phenomenon of market linkage described by Culberson. *Id.* Second, continue Unocal/OXY, it identifies that the Far East is a low cost source of supply for refined products destined for the West Coast. *Id.* Third, explain Unocal/OXY, it illustrates that market entry barriers would not impede Naphtha imports if there were a sufficient price differential to attract imports from the Caribbean. *Id.* With respect to the issue of entry barriers for Naphtha imports, Unocal/OXY note that jet fuel shipments use the same kind of "clean" tankers which are used for Naphtha and that the evidence shows that the West Coast infrastructure can handle imports of Naphtha. *Id.* (citing Transcript at pp. 8612, 8616; Exhibit No. BPX-79).

1782. Contrary to the claims of Exxon and Phillips, Unocal/OXY argue that the existence of separate West Coast and Gulf Coast pricing series for virtually all refined products other than Naphtha does not indicate that it is no longer just and reasonable to continue using Gulf Coast prices for West Coast Naphtha. *Id.* at p. 16. Unocal/OXY explains that separate pricing is not a new development and that there were different West Coast and Gulf Coast price series for refined products at the time the Commission adopted the Gulf Coast price to value West Coast Naphtha. *Id.* Accordingly, they suggest, this argument does not establish a basis for changing the Commission's prior ruling. *Id.*

1783. Unocal/OXY also assert that the existence of different price series does not prove that Gulf Coast prices undervalue West Coast Naphtha. *Id.* They claim that the prices used by Exxon and Phillips are selective, leave out some products, and, even for the products that are selected, do not show that West Coast prices are always higher. *Id.* at pp. 16-17. For example, Unocal/OXY point out that West Coast prices for N-butane and LSR are generally lower, and lower on average, than Gulf Coast prices. *Id.* at p. 17 (citing Exhibit No. EMT-14). Further, the West Coast/Gulf Coast differential for VGO is close to zero, indicating little variation on average for VGO between the two coasts. *Id.* (citing Exhibit No. PAI-56 at p. 3).

1784. A more complete depiction of price series for various products, according to Unocal/OXY, clearly shows that finished products such as gasoline, jet fuel, and diesel consistently have higher West Coast prices, but that intermediate products such as high and low sulfur VGO, and light cycle oil do not. *Id.* at pp. 17-18 (citing Exhibit No. BPX-162). Further, claim Unocal/OXY, Naphtha is considered an intermediate product and should display the same price behavior as VGO and LSR. *Id.* at p. 18 (citing Transcript at pp. 9682-83; Exhibit No. UNO-7 at p. 7). Finally, according to Unocal/OXY, the margins for intermediate products are the same on both coasts. *Id.*

1785. Unocal/OXY also take exception to criticism suggesting that Culberson claimed that the Gulf Coast Naphtha price is equal to the West Coast Naphtha price. *Id.* They assert Culberson's did not so testify; that his testimony was that there might be day to day variations between the two, but that over time average Gulf Coast prices would not undervalue West Coast Naphtha. *Id.* at pp. 18-19 (citing Exhibit No. UNO-7 at p. 5).

1786. The high West Coast/Gulf Coast price differentials for finished products, according to Unocal/OXY, are an indication that the West Coast market for finished products is markedly different than the Gulf Coast market for finished products. *Id.* at p. 20. They claim that the West Coast finished product market also behaves differently than the market for intermediate products, in their view. *Id.*

1787. Unocal/OXY contend that the West Coast gasoline market is not workably competitive because it is dominated by California where competition is constrained. *Id.* at p. 20 (citing Exhibit No. UNO-7 at p. 6). They point out that this constraint is caused by the CARB gasoline requirements which are not required in other markets, geographical isolation of the market, barriers to entry by new refiners and to expansion of existing refining facilities, and dominance of the market by a small number of large producers. *Id.* Unocal/OXY state that these factors have caused the price of gasoline in California, particularly in recent years, to exceed the prices in all other parts of the country by a substantial difference. *Id.* at pp. 20-22 (citing Exhibit Nos. WAP-199, EMT-489).

1788. In contrast to the West Coast market, Unocal/OXY point out that the Gulf Coast market is large, diverse and highly competitive, containing 30% of U.S. petroleum refining capacity and 75% of the petrochemical capacity. *Id.* at p. 22 (citing Exhibit No. UNO-1 at p. 7). Unocal/OXY explain that the Gulf Coast does not have the CARB gasoline restrictions, high taxes, or the environmental and permitting restrictions for new construction that apply in California. *Id.* An important feature of the Gulf Coast market, according to Unocal/OXY, is the petrochemical industry, which creates a demand for Naphtha that supplements the refinery demand. *Id.* (citing Exhibit Nos. PAI-33 at p. 4, BPX-8 at p. 3). Unocal/OXY state that the petrochemical demand, existence of Naphtha imports, and a significant Naphtha trade create a price support for Naphtha on the Gulf Coast that is absent from the West Coast. *Id.* (citing Exhibit Nos. BPX-67 at p. 31, PAI-33 at p. 4). They assert that the existence of the petrochemical demand for Naphtha on the Gulf Coast leads to the conclusion that Gulf Coast Naphtha may have a higher value than West Coast Naphtha. *Id.* at pp. 22-23 (citing Exhibit Nos. UNO-1 at p. 14, WAP-33 at p. 10, BPX-27 at p. 29).

1789. Unocal/OXY disagree with the position of Exxon and Phillips that the differences between the Gulf Coast and the West Coast markets require that different prices be used to value intermediate products, such as Naphtha, in each market. *Id.* at p. 23. As noted previously, they state that the price series for intermediate products tend to show either rough price equivalence between the two markets or that Gulf Coast prices are higher. *Id.* at pp. 23-24 (citing Exhibit Nos. EMT-94, EMT-480, EMT-93, EMT-429 at p. 3, EMT-453, UNO-62, BPX-27 at p. 10). Thus, claim Unocal/OXY, not only do LSR and VGO prices not follow gasoline trends in terms of West Coast/Gulf Coast differentials, they sometimes move in the opposite direction. *Id.* at p. 24.

1790. These price relationships, Unocal/OXY contend, answer a major argument of the opponents of single market pricing that market linkage and imports do not sufficiently discipline prices to justify the continued use of single market pricing. *Id.* (citing Exhibit Nos. EMT-76 at p. 11, EMT-84 at pp. 24, 29, 38-39). Unocal/OXY assert that this argument is easily answered and explain that market constraints cause the prices of finished products such as gasoline and jet fuel to remain high notwithstanding substantial imports, because supply is constrained and demand is high and growing. *Id.* Because that market is not workably competitive, continue Unocal/OXY, end refiners are taking advantage of that fact to hold prices high and increase their margins. *Id.*

1791. Unocal/OXY concede, however, that there is no evidence that the market for intermediate products is similarly constrained or not workably competitive. *Id.* at pp. 24-25. Nonetheless, Unocal/OXY maintain, upon closer examination, the argument falls apart. *Id.* at p. 25. They point out that VGO prices were higher on the West Coast for only a brief period, 1999-2002, and that prior to 1999 they were lower and have returned to that “pattern” starting in 2003. *Id.* Furthermore, according to Unocal/OXY, 1999-2002 was an anomalous period in the California gas market because of stringent air quality controls on gasoline, the spiking of natural gas prices in 2000-2001, manipulation of electric energy markets causing electricity prices to reach unprecedented levels, and several long and significant outages at California refineries. *Id.* (citing Exhibit Nos. UNO-7 at pp. 10-12, BPX-27 at p. 11, BPX -37).

1792. These conditions, Unocal/OXY assert, not only caused large increases in gasoline prices over this period, but they also caused the price of VGO to increase. *Id.* At the same time, according to them, the same conditions that caused gasoline and VGO prices to go up would cause the value of Naphtha to decrease. This, explain Unocal/OXY, is because the demand for reformate, and hence the demand for Naphtha, went down as a result of the constraints. *Id.* at pp. 25-26 (citing Exhibit No. BPX-27 at p. 12).

1793. Unocal/OXY note that Phillips and Exxon assert that California refiners have installed treatment equipment to remove benzene precursors from reformer feed, and that the higher prices that CARB gasoline commands have allowed them to recover the cost of these capital improvements. Unocal/OXY Reply Brief at pp. 67-68. This argument, according to them, fails to consider the evidence produced by Sanderson that, since the introduction of CARB requirements in 1996, Naphtha demand on the West Coast has declined, and reforming capacity has decreased by some 64,000 barrels/day. *Id.* at p. 68. They argue that if Naphtha were important in the production of CARB gasoline, then reformer capacity would not have declined. *Id.*

1794. In reply to arguments that CARB gasoline requirements are a changed circumstance, Unocal/OXY concede that it is true, but assert that the result was a decrease in value for Naphtha, and hence does not constitute new evidence that would call into question the Commission's prior rulings on Naphtha. Unocal/OXY Reply Brief at p. 20.

1795. Unocal/OXY explain that there are two competing views concerning how to value Naphtha. Unocal/OXY Initial Brief at p. 26. One view, state Unocal/OXY, is that its value is linked to the value of the end product, gasoline; because Naphtha's primary use on the West Coast is to make gasoline. *Id.* The other view, according to Unocal/OXY, is that Naphtha's value is best measured by determining its costs to produce it from crude oil. *Id.* The first view, espoused by Exxon and Phillips, results in a higher value for Naphtha on the West Coast, note Unocal/OXY. *Id.* (citing Exhibit Nos. EMT-11 at pp. 16-17, EMT-84 at pp. 13, 22, PAI-33 at p. 8). The second view, espoused by Unocal/OXY, results in Naphtha being valued the same on the West Coast as it is on the Gulf Coast, because crude oil costs are the same on both coasts and the cost of extracting Naphtha is the same. *Id.* (citing Exhibit No. WAP-1 at p. 10).

1796. According to Unocal/OXY, the second view is the logical choice because Naphtha itself is an intermediate product used to manufacture gasoline and not an end product, and, therefore, a refiner would regard Naphtha as a cost item like other feedstocks or blendstocks. *Id.* at pp. 26-27. Naphtha and other feedstocks are valuable because refiners can turn them into gasoline; but starting with the price of gasoline and working backward to derive a value for a feedstock is, in Unocal/OXY's view, a very subjective way to attempt to set a value. *Id.* at p. 27. In fact, state Unocal/OXY, a value set in this manner is going to differ depending on who is deriving the value, whereas starting with the cost of crude oil and adding the costs to extract the Naphtha is more objective. *Id.*

1797. Unocal/OXY note that several exhibits purport to show, in graphical form, the relationship between crude, Naphtha, and unleaded regular gasoline for both the Gulf and West Coasts. *Id.* (citing Exhibit Nos. EMT-476, EMT-536, EMT-541). Because Naphtha is processed from crude oil, and then used to manufacture gasoline, Unocal/OXY explain, it is not surprising that its price line falls between the crude oil and gasoline price lines. *Id.* They note that the question is whether the price line for Naphtha on the West Coast should be closer to crude oil or closer to gasoline. *Id.* Unocal/OXY point out that Exhibit No. EMT-536 places the Naphtha line close to the crude line, while Exhibit No. EMT-541 pushes the West Coast Naphtha line up close to the unleaded regular gasoline line. *Id.*

1798. Exhibit No. EMT-536 provides the correct representation, declare Unocal/OXY. *Id.* They assert that, as in Exhibit Nos. EMT-568 and EMT-569, which compare crude, VGO, and unleaded regular gasoline for the West Coast and Gulf Coast, respectively, there should be no major differences between Exhibit Nos. EMT-476 and EMT-536, except for the unleaded regular gasoline line. *Id.* at pp. 27-28. Unocal/OXY explain that the West Coast crude-Naphtha-unleaded regular gasoline graph would look much like the VGO graphs, except the Naphtha line would be farther above the crude line than the VGO line is because it costs more to process Naphtha from crude than VGO. *Id.* at p. 28 (citing Transcript at pp. 12051-52). According to Unocal/OXY, the main difference between Exhibit Nos. EMT-568 (West Coast VGO) and EMT-576 (West Coast Naphtha) is that the West Coast price of VGO did rise in the anomalous period (after 1999) due to refinery upsets constraining the supply of VGO. *Id.*

1799. Conversely, Unocal/OXY argue that Exhibit No. EMT-541 (a Tallett graph) is not an accurate representation. *Id.* In Unocal/OXY's view, it pushes the Naphtha price much too close to the unleaded regular gasoline price, transferring value or margin that belongs to the finished product to Naphtha, and thereby overvaluing Naphtha. *Id.* In addition, Unocal/OXY point out that, if Naphtha were actually priced that high, it would be priced above the cost of imports, and "refiners would have switched their crude oil slate and imported naphtha." *Id.* (quoting Transcript at p. 12057).

1800. On both the Naphtha and VGO sets of graphs, Unocal/OXY note, the West Coast unleaded regular gasoline line is much higher above the crude line than it is on the Gulf Coast. *Id.* According to Unocal/OXY, this means that the unleaded regular gasoline line will be higher above the Naphtha line on Exhibit No. EMT-536 than it is on Exhibit No. EMT-476. *Id.* They explain that this anomaly results from the much higher margins reflected in finished product prices, such as unleaded regular gasoline, on the West Coast, as described in the 1999 California Attorney General's Report. *Id.* at pp. 28-29 (citing Exhibit No. WAP-199).

1801. Unocal/OXY assert that the major problem with deriving a Naphtha value from the price of gasoline lies in the process of deducting the costs, including profit margin, from the price of gasoline. *Id.* at p. 29. They point out that most refiners are not anxious to reveal their profit figures and yet the 1999 Report to the California Attorney General identified very high margins on California gasoline. *Id.* (citing Exhibit No. WAP-199 at pp. 4-5, 39). Unocal/OXY note that the same report states that these margins are much higher than margins in other parts of the United States. *Id.* Further, explain Unocal/OXY, margins are assigned to the finished products and not to the intermediate products, because intermediate products are regarded as costs incurred to produce the finished product. *Id.* They state that a refiner would have no interest in raising the price of an intermediate product with a margin over cost, as he would be charging that margin to himself. *Id.* Instead, according to them, whatever margin can be earned is assigned to the finished product and passed on to the buyer. *Id.* Thus, if one were to attempt to value Naphtha starting with the price of gasoline, Unocal/OXY assert, it would be necessary to "strip these margins out of the finished product prices before intermediate product values are determined." *Id.* (citing Exhibit No. BPX-27 at p. 17).

1802. In addition, Unocal/OXY explain, even though essentially all of it is used on the West Coast to make gasoline, Naphtha is only one of several products that go into the gasoline pool, and it is blended to make reformate, which in turn accounts for only about one quarter of the West Coast gasoline pool. *Id.* (citing Exhibit No. BPX-67 at p. 5). In Unocal/OXY's view, VGO is more important in terms of its contribution to the gasoline pool. *Id.* at pp. 29-30. They note that a study done by Sanderson estimated that Naphtha contributed about 400,000 barrels/day to the West Coast gasoline pool, while VGO produced about 500,000 barrels/day, or 25% more. *Id.* at p. 30 (citing Exhibit Nos. WAP-33 at pp. 17-18, WAP-48). Further, Unocal/OXY explain, the requirements to produce CARB gasoline have imposed limits on aromatics, thereby limiting the amount of reformate in gasoline and causing the lower utilization rates for reformers that prevailed in the 1990's and a lower value for Naphtha. *Id.* (citing Exhibit No. UNO-7 at p. 15; Transcript at pp. 12060-61).

1803. The significance of these facts, according to Unocal/OXY, is that Naphtha does not appear to have been in high demand on the West Coast, based on low reformer utilization rates, at a time when West Coast gasoline prices relative to the rest of the country were at an all time high. *Id.* Compared to their Gulf Coast values, Unocal/OXY argue, West Coast Naphtha should trend with West Coast LSR and VGO, not gasoline, and should be below VGO but above LSR. *Id.* Particularly significant, in Unocal/OXY's view, is the fact that Naphtha imports did not occur when the price of California gasoline spiked in 1999 to 2001. *Id.* Imports of other refined products surged, explain Unocal/OXY, but there were still no imports of Naphtha. *Id.* Unocal/OXY assert that the absence of Naphtha imports at this time shows that the value of Naphtha is below that of import and possibly below that of Gulf Coast Naphtha as well. *Id.* at pp. 30-31. (citing

Exhibit No. UNO-1 at p. 14).

D. THE RELEVANCE OF THE WEST COAST NAPHTHA CONTRACTS

1. Exxon

1804. Exxon argues that the record demonstrates that West Coast Naphtha contracts provide the best available evidence of the actual market value of Naphtha on the West Coast in that they show how actual buyers and sellers in the marketplace have valued West Coast Naphtha. Exxon Initial Brief at p. 241. It claims that the contracts also confirm the reasonableness of the Tallett methodology and the unreasonableness of many of the other proposed methodologies, and points out that Phillips and Alaska share this view. Exxon Reply Brief at p. 247.

1805. According to Exxon, the West Coast Naphtha contracts are particularly relevant because they provide the only available direct evidence of the actual market value of Naphtha on the West Coast. Exxon Initial Brief at p. 241. It is undisputed, states Exxon, that the transactions reflected in the West Coast Naphtha contracts are arms-length purchases and sales of Naphtha between well informed, sophisticated parties, each of which had a strong business incentive to negotiate the most favorable deal possible. *Id.* at p. 242. Further, according to Exxon, all of the witnesses with economic training who testified at the hearing stated that the West Coast Naphtha contracts provide the best available evidence of the actual market value of Naphtha on the West Coast. Exxon Reply Brief at p. 247.

1806. Exxon states that the West Coast Naphtha contracts also are highly relevant because they reveal the manner in which actual buyers and sellers of Naphtha have determined the price to be paid for Naphtha on the West Coast. Exxon Initial Brief at p. 243. For example, continues Exxon, it is significant that not a single one of the nearly 300 contracts priced West Coast Naphtha on the basis of an unadjusted Gulf Coast price. *Id.* at p. 243. In contrast, notes Exxon, approximately 80% of the West Coast Naphtha contracts set the price of Naphtha based on the price of West Coast gasoline less a cost differential. *Id.* at p. 244. This strongly supports, according to Exxon, those Naphtha valuation methodologies, including the methodologies proposed by Exxon, Phillips, and Alaska, that tie the value of West Coast Naphtha to the value of gasoline on the West Coast. *Id.*

1807. Similarly, states Exxon, it is revealing that only two out of the hundreds of West Coast Naphtha contracts produced in this case set the price of West Coast Naphtha on the basis of a Gulf Coast Naphtha price plus a premium. *Id.* Moreover, Exxon notes, only one contract employed a pricing mechanism based on the Gulf Coast price that was in any way analogous to the governor or price cap proposed by BP, and that the particular price cap produced by the pricing formula in that contract was nearly double the size of the governor proposed by BP. *Id.* at pp. 244-45. Exxon concludes that, to the extent that the contract relied upon by Ross has any relevance, it shows that his proposed governor results in a Naphtha value that is much too low. *Id.* at p. 245.

1808. Further, notes Exxon, even those parties that argue that the contracts should be given no weight, at times, recognize their value and rely upon the contracts to support their positions. Exxon Reply Brief at p. 248. For example, Exxon states, Williams, which argues that the contracts are not relevant for determining the value of Naphtha on the West Coast, uses them to substantiate the Dudley valuation proposal; that the ANS + $4.00 proposal is supported by one of the contracts; that the N+A adjustment is not valid because the contracts don't have one; and that the contracts inform us about whether there is a spot market for Naphtha on the West Coast. *Id.*

1809. Unocal/OXY, which generally contend that the "the contracts do not provide reliable evidence of value," also rely on the contract data to support their contention that the Platts Gulf Coast Naphtha price, if used in conjunction with the Ross governor, would have provided reasonable results in the 1994-1998 period, according to Exxon. *Id.* And while both BP and Petro Star also generally oppose the use of the contracts, they too rely on the contracts to support particular proposals, arguing that the contracts cannot be used to evaluate the various validation proposals while using them to support the use of ANS + $4.00 proposal. *Id.* at pp. 248-49.

1810. In assessing the evidentiary significance of the contracts, Exxon argues that it is also important to keep in mind that no party has advocated that the contract data be used directly to value West Coast Naphtha. *Id.* at p. 249. Rather, explains Exxon, the contracts have consistently been presented only as useful evidence for judging the relative merits of the various Naphtha valuation proposals at issue in this case – a proposition which cannot credibly be disputed. *Id.*

1811. Exxon argues that, although criticized by Unocal/OXY, BP, and Petro Star on the ground that they represented only a small percentage (on the order of 1%) of the total Naphtha that is produced on the West Coast, the evidence demonstrates that this criticism was not well founded. Exxon Initial Brief at p. 245; Exxon Reply Brief at p. 250. In the first place, states Exxon, the evidence is clear that statisticians regularly rely on very small samples in a wide variety of commercial, governmental, and research applications. Exxon Initial Brief at p. 245. It notes that Toof testified that a statistician would consider a one percent sample as being fairly significant. *Id.* Further, while agreeing that it is always preferable to have more data, Exxon maintains that the amount of data provided by the West Coast contracts was more than sufficient to provide good quality data. *Id.*

1812. In addition, Exxon asserts that the evidence shows that the volume of sales reflected in the contracts is actually larger than the volumes that are often relied upon by

Platts and OPIS in making their price assessments for certain of the other Quality Bank products. Exxon Reply Brief at p. 251. For example, Exxon notes that Culberson stated at the hearing that the volumes reflected in the West Coast Naphtha contracts were greater than the total volume of trades behind the Quality Bank reference prices for both Propane and Isobutane, and that he did not know if the volume of trades behind the Quality Bank reference prices for VGO, Normal Butane, or LSR were greater or less than the volumes represented in the Naphtha contracts. *Id.* Similarly, Exxon states, Pulliam testified that the analyst who does the Platts VGO price assessment believed that the volume of trades behind the Quality Bank reference price is in the range of a couple of percent of the total, which is comparable to the percentage of West Coast Naphtha reflected in the contracts. *Id.* at pp. 251-52.

1813. Exxon also argues that Petro Star's argument that the limited size of the West Coast Naphtha market means that it is not likely that a refiner could find a buyer for Naphtha for a price near the price in the contracts is without merit. *Id.* at p. 252. It suggests that the contracts themselves provide direct and conclusive proof that West Coast refiners have in fact found buyers for Naphtha at the prices found in the contracts. *Id.*

1814. The further argument of Petro Star and BP that the contracts should be disregarded because they reflect sporadic rather than routine transactions, Exxon maintains, is also contrary to the facts. *Id.* It points out that several witnesses testified that there are a number of asphalt refiners on the West Coast who cannot process their Naphtha, with the result that there is a constant source of Naphtha for sale on the West Coast. *Id.* In addition, explains Exxon, the long term nature of many of the contracts, including the large contract between Companies 4 and 13 upon which Ross relied, and the large number of contracts entered into by both Company 31 and Company 41, demonstrates that Naphtha is frequently purchased to meet long term refinery requirements. *Id.*

1815. Likewise deficient, in Exxon's view, is BP's criticism that the contract studies are incomplete because they do not include transactions between traders. *Id.* Exxon asserts that BP's claim is directly at odds with its own contention that the actions of brokers and traders do not contribute to a transparent market, because they tend to do their work in secret. *Id.* If that claim by BP is true, Exxon states, transactions between traders would not be expected to shed much light on the market price, and there would be no basis for BP's criticism of the contract studies on the ground that they do not include such transactions. *Id.* at p. 253. Exxon also suggests that BP's claim is misleading because, although the contracts do not include strictly trader-to-trader transactions, there are many transactions involving Company 43, a West Coast trader. *Id.* In addition, Exxon states, the record shows that the contracts align very closely with the prices used by West Coast Naphtha traders. *Id.* For example, explains Exxon, Culberson's interview notes (Exhibit No. UNO-9) show that traders have had no difficulty in ascertaining the value of West Coast Naphtha in the regular course of business despite the fact that there is no published price. *Id.*

1816. Moreover, according to Exxon, the evidence demonstrates that the buyers involved in these contracts were particularly well informed buyers from very large firms who are regular participants in the Naphtha market and were thus highly unlikely to be vulnerable to any systematic overpricing of their purchases of Naphtha. Exxon Initial Brief at p. 246. It explains that, if the value of the other 99% of the West Coast Naphtha that is produced and used internally by refiners were not at least as high as the price of the Naphtha sold by contract, market forces would certainly be expected to cause producers to sell more of their Naphtha to obtain the higher sales price. *Id.*

1817. Exxon also asserts that extensive statistical studies performed on the pricing formulæ used in the West Coast Naphtha contract studies verify their validity as a means of accurately predicting the value of West Coast Naphtha and verify that prices in the West Coast Naphtha contracts are not the product of a dysfunctional market. *Id.* at pp. 246-47. In addition, Exxon claims that sensitivity analyses performed by Toof clearly demonstrate that regardless of which of several factors[636] associated with the West Coast Contract studies were taken into account, the average West Coast Naphtha value fell within the range of $24.39 to $25.53/barrel for the period January 1992 to December 2001. *Id.* at pp. 247-48.

1818. The Naphtha contracts are also helpful, in Exxon's view, in validating that the West Coast Naphtha valuation proposals presented by Tallett and O'Brien produce reliable results. *Id.* at p. 248. It explains that, because the West Coast Naphtha valuation methodology proposed by Tallett produces results that are very close to the market prices reflected in the West Coast Naphtha contracts, his valuation methodology is reasonable and appropriate. *Id.* at p. 249.

1819. The contract studies presented by the other witnesses also validate the conclusion, according to Exxon, that the Tallett methodology provided an average contract price that

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[636] The factors Exxon refers to are as follows: volume weighting the contracts (Exhibit No. EMT-356); using both Pulliam's "Spec" and his "Potential" contracts instead of just his "Spec" contracts (Exhibit No. EMT-357); using Seattle unleaded regular gasoline prices instead of West Coast unleaded gasoline prices as the pricing benchmark (Exhibit No. EMT-358); adding a time variable into the regression analysis (Exhibit No. EMT-359); and using various alternative dates within each month to determine the appropriate contract price in those instances in which the contract pricing date was indeterminate (Exhibit Nos. EMT-363, EMT-364, and EMT-365). Exxon Initial Brief at pp. 247-48. By comparison, according to Exxon, the average Platts Gulf Naphtha value for this same period was $22.47, $2 to $3/barrel below the range for West Coast Naphtha contract price. *Id.* at p. 248.

was nearly identical to the average price for that period derived from the West Coast contracts.[637] *Id.* Moreover, continues Exxon, even when the contracts were analyzed on a company specific basis, they supported Tallett's methodology. *Id.* at p. 250. For example, states Exxon, Ross's review of the Tosco contracts, which he labeled as reliable, showed that Tallett's methodology produced the closest fit when the analysis was done on a weighted average basis.[638] *Id.*

1820. Exxon also argues that BP's and Williams's criticism that the West Coast Naphtha contract data are suspect because they are different in certain respects from the pricing information that Platts and OPIS rely on is also without merit. Exxon Reply Brief at p. 254. Exxon states that for the limited purpose of testing the various valuation proposals, the contracts plainly provide the best evidence. *Id.*

1821. Furthermore, in Exxon's view, the record reflects that the West Coast Naphtha contracts provide more information than Platts or OPIS have available to them in making their assessments. *Id.* It points out that the pricing services do not have access to actual contract data; the only information that they get is what people tell them. *Id.* Moreover, Exxon notes, Ross conceded in a 1995 affidavit that the OPIS and Platts price assessments are sometimes based on small amounts of market data with transactions occurring only once a month. *Id.* According to Exxon, this also was confirmed by Sanderson, who testified, in 1994, that the West Coast VGO prices reported by OPIS were largely hypothetical and based on surveys of what participants thought the prices could be and not on actual transactions. *Id.* at pp. 254-55. Finally, Exxon notes, Pulliam

[637] Exxon cites the following in support of this assertion: Exhibit Nos. SOA-28, EMT-380, EMT-381, PAI-156, UNO-52. Exxon Initial Brief at p. 249. According to Exxon this negates Culberson's claim that the other witnesses inclusion of certain contracts in their analyses undermined the usefulness of the contracts. *Id.* at p. 249, n.96. Similarly lacking merit, states Exxon, were the claims of Ross and Culberson regarding the monthly variability of the prices in the contracts. *Id.* It was demonstrated at the hearing, according to Exxon, that there also is significant variability on a monthly basis in the West Coast prices reported by Platts and OPIS. *Id.* Moreover, Exxon notes that neither Ross nor Culberson made any allowance for the fact that the Platts and OPIS prices are reported for specific locations, whereas the contract analyses were done on a more general basis. *Id.*

[638] Exxon claims this analysis also undermines Williams's claim regarding the Company 31 contracts and their alleged impact on the reliability of the contract data. Exxon Initial Brief at p. 250, n.97. It also notes that the weakness of Williams's claim in this regard is also demonstrated by the fact that the Company 41 contracts produce results comparable to the Company 31 contracts and by the fact that the Company 31 contracts were often priced at or below the contracts of other companies, including Williams's. *Id.*

testified that crude oil traders believe that their information is often better than the published information. *Id.* at p. 255.

1822. Exxon asserts that BP's further argument that the contract studies should have excluded long term contracts because Platts uses spot assessments sounds particularly insincere given that Ross relied heavily on one long term contract to validate his governor proposal. *Id.* If a single long term contract can be relied upon by Ross to validate his proposed governor, then, in Exxon's opinion, the entire collection of contracts can certainly be relied upon to assess the reasonableness of that and other proposed methodologies. *Id.*

1823. Similarly, Exxon finds that Williams's argument that the West Coast Naphtha contracts are virtually meaningless because they include some longer term contracts as well as spot transactions is in direct conflict with its own witness's reliance upon other Platts price assessments that include term contracts. *Id.* at p. 256. It notes that Sanderson based his argument in favor of using the Platts Gulf Coast Naphtha price as a proxy for the value of West Coast Naphtha on a comparison of the reported prices of ANS crude oil on the West Coast and Isthmus crude oil on the Gulf Coast. *Id.* Exxon also notes that Sanderson conceded, at the hearing, that much of that crude oil is traded pursuant to term contracts, not cash spot transactions. *Id.* Therefore, asserts Exxon, the argument made by Sanderson for using the Platts Gulf Coast Naphtha quotation to value West Coast Naphtha is thus based squarely on published prices that include term contracts as well as spot transactions. *Id.*

1824. There also is no basis, according to Exxon, for BP's criticism that the studies of the West Coast Naphtha contracts done by Pulliam, Tallett, and O'Brien made no adjustments to the contract data. *Id.* It notes that BP acknowledges that both Platts and OPIS exercise editorial discretion in making adjustments to their price assessments. *Id.* at pp. 256-57. Exxon argues that there is nothing improper about this procedure, and it adds that it is appropriate for the Quality Bank to rely on these independent pricing services for product valuations. *Id.* at p. 257. Nevertheless, Exxon asserts, the fact that the contract studies presented in this case make no such adjustments should be praised, not criticized. *Id.* Exxon explains that the contract studies do not depend on any price assessor's opinion, but reflect instead the actual value of West Coast Naphtha bought and sold by actual market participants. *Id.* Therefore, states Exxon, the contract prices are actual market prices, not hypothetical assessments arrived at by uninvolved third parties. *Id.* Far from being useless, claims Exxon, the contract studies are, in fact, a superior measure of the true market price than the subjective appraisal of the price assessment services. *Id.*

1825. Exxon also asserts that BP's further argument that price reporting contributes to transparency and is a step towards a competitive market overstates the case. *Id.* In making this argument, states Exxon, BP relies extensively on two Platts statements regarding its services and the impact those services have on energy markets. *Id.* It points out that the usefulness of those statements is undercut to some degree by the very fact that Platts felt compelled to issue them. *Id.* Exxon also notes that BP fails to mention that Platts was accused of playing a key role in causing those crises because the prices that it reported were so inaccurate. *Id.* at pp. 257-58.

1826. Additionally, Exxon argues, BP's transparent market theory is wholly without any legal, economic, or factual support. *Id.* at p. 258. It states that the information available to buyers and sellers of Naphtha on the West Coast from a wide variety of sources is fully comparable to the information available to buyers and sellers in other competitive markets. *Id.* For that reason, Exxon asserts, there is no factual basis for Ross's contention that the incremental benefit of having a single additional item of pricing information – a published Platts or OPIS price assessment – would fundamentally transform the West Coast Naphtha market from opaque to transparent and would attract a large volume of imports. *Id.*

1827. Exxon contends that, in an effort to avoid larger differentials between the values produced by their proposed methodologies and the values found in the West Coast Naphtha contracts during the 1999-2001 period, Unocal/OXY, Williams and BP all argue that the West Coast Naphtha contracts from that period should be discounted. *Id.* at p. 259. Although the arguments made in an effort to achieve this result differ, it is Exxon's position that there is no merit to any of them. *Id.*

1828. Williams and Unocal/OXY contend, according to Exxon, that the fact that the prices in the West Coast Naphtha contracts were substantially higher than Gulf Coast Naphtha prices during the 1999 to 2001 period should be ignored because 85% of the contract volumes during the 1999-2001 period were from four participants, and because a single purchaser purportedly purchased nearly 80% of the volumes in 2001. *Id.* As a matter of basic economics, Exxon states, this argument makes no sense. *Id.* It explains that, in view of the fact that the price at which a product is sold is determined by the relative strength of the buyer and seller in the marketplace, unduly high prices would only be expected where sellers have greater market power than buyers. *Id.* at p. 260. In the situation postulated by Williams and Unocal/OXY where a few large buyers predominate, Exxon argues, basic economics would dictate that those purchasers would command lower prices. *Id.* Therefore, according to it, the prices found in the contracts might be unduly low, not too high. *Id.* at pp. 259-60.

1829. Additionally, Exxon notes, the purchasers of West Coast Naphtha are not primarily small firms who might be at a disadvantage in negotiations; instead more than 90% of the purchases of Naphtha on the West Coast were made by BP, Amoco, Exxon and other large firms who would be expected to be able to negotiate extremely favorable prices. *Id.* at p. 260. Thus, there is no logical economic basis, concludes Exxon, for the contention of Williams and Unocal/OXY that purchases by a few large companies would be expected to result in inflated prices. *Id.*

1830. Exxon asserts that Williams's and Unocal/OXY's arguments are also based on incomplete analyses of the West Coast Naphtha contract data, particularly as related to Williams's contentions that Company 31 became a dominant purchaser, going from 23.6% of West Coast Naphtha purchases in 1999 to 83.3% of the purchases in 2001, and that the prices which Company 31 paid were significantly above the prices of other participants during this time frame. *Id.* at p. 261. It claims that the evidence makes clear that the data on which Williams and Unocal/OXY rely for these assertions (Exhibit Nos. WAP-200, WAP-202) do not include a number of the larger contracts. *Id.* For example, continues Exxon, those exhibits do not include the long term contract between Companies 4 and 13 which Williams admits is the largest volume contract among all the West Coast Naphtha contracts. *Id.* That contract was for 200,000 barrels/month, or 2.4 million barrels/year, so that, states Exxon, even if only the Heavy Naphtha portion of the contract is considered, it involved 1.68 million barrels/year of Heavy Naphtha. *Id.* Including just this one large-volume contract would, Exxon claims, change the percentages depicted in Exhibit Nos. WAP-200 and WAP-202. *Id.* at p. 262. For example, Exxon explains that adding the additional 1.68 million barrels of Heavy Naphtha to the total of 1.30 million barrels included in the Exhibit No. WAP-200 for 2001 would have sharply reduced Company 31's percentage of the West Coast Heavy Naphtha contract purchases from 83.3% to 36.4%. *Id.* Additionally, notes Exxon, the back-up data for the Williams's charts shows that there were a number of different buyers and sellers in the West Coast Naphtha market. *Id.* In light of this evidence, Exxon asserts, Company 31's share of the West Coast market was not a matter of special significance to the contract studies. *Id.*

1831. There also is no factual basis, according to Exxon, for Williams's claim that Company 31 paid prices for West Coast Naphtha that were above what other companies paid. *Id.* at pp. 262-63. Exxon asserts that Company 41, another party with an interest in the outcome of this proceeding and a major purchaser of West Coast Naphtha in 1999 and 2000, had contract prices that were higher than the prices paid by Company 31 on both a straight and volume-weighted basis over the 1999-2001 period. *Id.* at p. 263. Similarly, Exxon notes that in both 1999 and 2000 Company 31's contracts were often priced lower than Williams's contracts. *Id.* Exxon asserts that this evidence squarely refutes Williams's claim that Company 31 paid higher prices for Naphtha. *Id.*

1832. Exxon claims that BP acknowledges that Naphtha contract values for 1999-2001 closely track the prices of finished products, especially gasoline, and capture the gasoline price spikes that occurred on the West Coast. *Id.* Nevertheless, Exxon notes, BP still argues that the Commission should give less weight to the West Coast Naphtha contracts for those years based on Ross's theory that there were price anomalies that might not have existed in a transparent market. *Id.* at pp. 263-64. Exxon opines that BP's argument regarding the weight to be given the 1999 to 2001 contracts fails because there is no economic or factual justification for Ross's transparent market theory. *Id.* at p. 264.

1833. According to Exxon, the concerns of Williams, Unocal/OXY, and BP that the contract studies contain subjective judgments and were thus prone to possible manipulation also are without foundation. *Id.* at pp. 264-65. In the first place, Exxon asserts, the undisputed evidence clearly refutes Williams's allegation that there was an attempt by the analysts to coordinate their studies so that they were based on the same set of contracts. *Id.* at p. 265. Exxon states that Toof expressly testified that he and Tallett did not rely on O'Brien's analysis in any way, and, while they compared the Tallett study against the Pulliam study in order to identify differences and check the accuracy of their results, they made no attempt to duplicate Pulliam's analysis. *Id.* According to Exxon, this is also confirmed by the fact that Tallett's contract study did not use the same set of contracts as either the O'Brien or the Pulliam studies. *Id.*

1834. Similarly, Exxon asserts, the argument of Williams and Unocal/OXY that the Naphtha contract analyses involved subjective judgments due to some contract's ambiguous product identification and pricing terms provides no ground for disregarding the contract studies, as the evidence clearly shows that any differences in how the contracts or their pricing terms were classified were immaterial to the results obtained. *Id.* at pp. 265-66. Exxon states that this was demonstrated at the hearing by a series of sensitivity tests which analyzed several variations of the data – including using alternative dates within each month where contract pricing was indeterminate – to assess the effect of any differences on the results of the Tallett and Pulliam studies. *Id.* at p. 266. It notes that the results clearly showed that no matter how one varies the contract data, the Tallett and Pulliam contract analyses come out with results that are very similar and are always about $2 to $3/barrel higher than the Gulf Coast Naphtha price. *Id.*

1835. Additionally, Exxon argues, Williams's and Unocal/OXY's alleged concerns about subjectivity in the contract analyses are refuted by Culberson's contract study, which produced results that are highly comparable to those produced by the other contract analyses. *Id.* at pp. 266-67. According to Exxon, Culberson acknowledged at the hearing that, despite the differences in the four contract studies that were put together by Tallett, Pulliam, O'Brien, and Culberson, the contract studies all follow the same pattern, and the results for both the 1994-1998 period and the 1999-2001 period were reasonably close. *Id.* at p. 267. Exxon points out that Culberson's study, which Unocal/OXY describes as taking a conservative approach, resulted in the highest overall West Coast/Gulf Coast price differential of all the contract analyses for the period 1994-2001. *Id.* Culberson's study thus strongly confirms, in Exxon's view, the significant price differentials found by all the contract studies between the value of West Coast Naphtha and the Gulf Coast Naphtha price, and puts to rest any possible concerns about subjectivity or manipulation of the contract data. *Id.*

1836. Exxon asserts that there is no merit whatever to BP's argument that the contract data are flawed because the range of monthly price variation found in the contracts appears wider than the variability reflected in the petroleum product price assessments published by Platts and OPIS. *Id.* According to Exxon, this argument is premised on a distinction that Ross drew at the hearing between what he called monthly price variability and what he termed monthly price volatility. *Id.* It states that, although BP argues that its measure of monthly price variability is more appropriate, it cites no record support whatsoever for that assertion and its attempt to apply its theory results in a meaningless apples-to-oranges comparison.[639] *Id.* at pp. 267-68.

1837. There is absolutely no record support for the idea that Ross's definition of monthly price variability has any value as a measure of price variability, and BP cites nothing that even remotely supports its assertion that this measure is the appropriate tool to use, Exxon maintains. *Id.* To the contrary, it claims, the definition of monthly price variability created by Ross doesn't explain what the price variability is during the month. *Id.* Nor, states Exxon, is there any basis for the contrived distinction that Ross purported to draw between the terms variability and volatility, which are generally regarded as synonyms and used interchangeably. *Id.* at pp. 268-69.

1838. The evidence also makes clear, states Exxon, that the measure of monthly price variability used in the BP exhibits is different from the more traditional measure of monthly price variability, which Ross defined as volatility. *Id.* at p. 269. As a result of the averaging of the reported daily high and low price assessments (which are themselves a blend of the underlying data), Exxon explains, the monthly spread produced using Ross's definition of variability is necessarily much more narrow than the spread produced by averaging the highest high and lowest low prices for the month. *Id.*

2. Phillips

1839. According to Phillips, over 300 "West Coast Naphtha" contracts were produced in discovery in this proceeding. Phillips Initial Brief at p. 65. It is Phillips's position that these contracts provide the best evidence of the value of West Coast Naphtha. *Id.* While it agrees that the contracts cannot be used to establish a West Coast Naphtha value for use in the Quality Bank, Phillips asserts they can be used to evaluate proposed proxies for the West Coast value. *Id.* at pp. 65-66. In addition, Phillips states, the contracts can be used

[639] Platts and OPIS, Exxon states, report both a high and a low price assessment for each day (or for some products, each week). Exxon Reply Brief at p. 268. It explains that Ross obtained his measure of monthly price variability by averaging the daily high price assessments for each month and the daily low price assessments for the month, and from these two averages derived a spread that he called the price variability for that month. *Id.* Exxon states that this calculation equates mathematically to the average spread between the high and the low daily assessment. *Id.*

to test various arguments about the issues that have been raised by the parties. *Id.* at p. 66.

1840. Phillips claims that these contracts represent the only direct evidence in the record as to what the value of Naphtha is on the West Coast and explains that, as such, they are the only evidence of the prices that actually were paid for Naphtha in arms-length transactions on the West Coast. *Id.* at p. 68.

1841. Sanderson, according to Phillips, urges that the Commission ignore the contracts because the volume of Naphtha represented by them is too small to have any relevance. *Id.* To support this assertion, explains Phillips, Sanderson presented Exhibit No. WAP-229, which shows that the contracts represent only about 1% of all Naphtha processed on the West Coast. *Id.* Culberson makes essentially the same argument, states Phillips, despite presenting his own contract analysis. *Id.* Ross also attacks use of the contracts, but, notes Phillips, he does not assert that the sample is too small, only that the West Coast market is an opaque market because there are no published prices. *Id.* Ross goes on, continues Phillips, to declare that the contract prices are higher than they would be in a transparent market where there are published prices. *Id.* According to Phillips, all of these arguments are without merit. *Id.*

1842. Phillips states that, because the contract data is inconsistent with their theories on West Coast Naphtha values, BP, Williams, Unocal and Petro Star all argue that the Commission should ignore this powerful direct evidence.[640] Phillips Reply Brief at p. 41. It notes that BP goes so far as to argue that the data from the hundreds of contracts, which represent sales of millions of barrels of Naphtha for hundreds of millions of dollars, are useless. *Id.* Further, it notes that, in contrast with the witnesses who testified in support of the relevance of the contracts, the witnesses opposing their use were not trained economists. *Id.*

1843. Williams acknowledges, according to Phillips, that the Naphtha contracts do have some probative worth as to the value of Naphtha on the West Coast when it relies on the contracts to argue that N+A does not have value on the West Coast. *Id.* at p. 42. Indeed, Phillips states, Williams introduced its own contract analysis, Exhibit No. WAP-267, in the N+A phase of the hearing. *Id.* That Williams is willing to use the contracts when it believes that they help its case undercuts its efforts, in Phillips's view, to argue that the

[640] Phillips notes that Petro Star's argument that the contracts are irrelevant runs contrary to the testimony of its own witness, Dudley, who agreed that "it would be useful to look at the naphtha contracts." Phillips Reply Brief at p. 41, n.19 (citing Transcript at p. 10108).

contracts should be ignored when they are inconsistent with Williams's position. *Id.*

1844. While it is true that the Naphtha contracts involve only about 1% of the Naphtha processed on the West Coast, Phillips argues, that does not detract from the fact that they represent substantial amounts of sales – millions of barrels and hundreds of millions of dollars. Phillips Initial Brief at p. 68. Baumol – who, notes Phillips, is an economist and well qualified to analyze the significance of market data, unlike Sanderson and Culberson – testified this is not an artificial market, but a very real one. *Id.* at pp. 68-69. Further, states Phillips, Baumol went on to testify that many business people want to enter that kind of market for the profits it offers. *Id.* at p. 69.

1845. Phillips notes that Baumol explained that if the contract values did not represent the approximate value of Naphtha on the West Coast then it was because buyers were being fooled into overpaying systematically year after year and that he found that possibility highly implausible.[641] *Id.* In addition, states Phillips, Pulliam, another economist, agreed with Baumol and testified that he found the contract data, the most direct evidence for establishing the value of Naphtha on the West Coast and the best information for appraising the valuation proposals. *Id.*

1846. According to Phillips, Baumol was asked, if Naphtha contracts represented all of the arms-length sales, but only 1% of the volume of Naphtha processed, "can the market price of that 1 percent be used to establish the value of the 99 percent of the naphtha which is not being sold" and answered that it could, but perhaps not to six decimal places.[642] *Id.* at p. 71. Phillips states that Baumol explained that the two markets are economically, if not legally, one. *Id.* This is because, according to Phillips, at any point in time, a refiner has a choice of either using its Naphtha internally, or engaging in a purchase or sale transaction with a third party. *Id.* If the price at which a refiner could buy or sell Naphtha varied significantly from its internal value, then, asserts Phillips, the refiner would have every incentive to buy or sell that Naphtha instead of using it internally. *Id.* It points out that Baumol believes that, even though this connection may be imperfect, it is "more perfect than simply transferring a Gulf Coast price to the West Coast because nobody there is voting with their feet. It is more representative than putting in a Gulf Coast governor on the West Coast because there, nobody is voting with

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[641] Phillips states that the reason Baumol did not believe there was systematic overpayment for Naphtha under the contracts is because he considered the parties to the contracts to be sophisticated and large companies that would not be misled that way. Phillips Initial Brief at pp. 69-70. It was counsel for BP, claims Phillips, who challenged Baumol's assertion that BP is a sophisticated buyer and is reasonably well informed about Naphtha prices on the West Coast. *Id.* at p. 70.

[642] Phillips cites Transcript at p. 5159.

their feet." *Id.* (quoting Transcript at p. 5160). Further, notes Phillips, Baumol testified that the "market is not an artificial market. It is not a negligible market, and it is a market in which . . . knowledgeable parties, are there deciding on prices which have to be, in their opinion, representative of the value of naphtha in that arena for other uses." *Id.* (quoting Transcript at p. 5161).

1847. Phillips notes Pulliam was in agreement with Baumol on this point and stated:

> [T]he participants that are involved in these transactions are in the same market as . . . the 99 percent of the volume that is not moving through these third party transactions. The people that are purchasing the naphtha [via contract] are doing the same things with it that . . . the 99 percent that is being . . . internally transferred and consumed in the refinery. And there is opportunity here for parties who do use it internally to sell to parties who are interested in buying.

Id. at p. 72 (quoting Transcript at pp. 7584-85). Further, Phillips states, when asked whether economists would rely on contracts to represent the value of a product, even when most of the product is used internally instead of being bought and sold, Pulliam responded: "Yes . . . [t]hat's precisely the thing that economists in economics would look to. Those transactions represent the price at which markets are coming into balance, where supply and demand are coming into balance. That to an economist is evidence of the market value." *Id.* (quoting Transcript at pp. 7578A-79A).

1848. According to Phillips, each witness who analyzed the West Coast Naphtha contracts provided a consistent explanation of how he made decisions regarding those which he used, demonstrating that the choices made were, in fact, not arbitrary.[643] *Id.* at p. 73. It asserts that it is not necessary to address opposing parties's concerns in detail regarding choice of contracts for analysis. *Id.* In Phillips's opinion, the best defense against the attacks lies in the fact that each of the four contract analyses, all of which used different sets of contracts, reaches remarkably similar results. *Id.* at pp. 73-74. It explains that, despite the differences in approach among the witnesses, the four independently performed contract analyses show that Naphtha prices exceeded Gulf Coast prices to approximately the same degree for each of the time periods analyzed and that this should give the Commission confidence in the results of the analyses. *Id.* at p. 74.

1849. BP recognizes, Phillips maintains, the lack of a valid economic theory to support its contention that the contracts are not relevant and, therefore, attempts instead to

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[643] In support, Phillips cites Transcript at pp. 5912-17, 6601-04, 7295-96. Phillips Initial Brief at p. 73.

establish a legal standard that would exclude the contracts without considering whether as an economic matter they provide useful information. Phillips Reply Brief at pp. 42-43. It suggests that this is a preposterous argument, and notes that no evidence, other than the prices reported by Platts or OPIS, could meet BP's standard. *Id.* at p. 43. Thus, Phillips explains, BP is suggesting that, when considering the theoretical arguments of Culberson, Sanderson and Ross, no West Coast refiner would ever pay more for Naphtha than the Gulf Coast price plus a small amount (2.7 to 3.5¢/barrel) representing transportation cost differentials, the Commissions should ignore the fact that there are approximately $300-$400 million dollars worth of sales of Naphtha on the West Coast at much higher average prices. *Id.*

1850. Phillips also asserts that BP's reliance on the *OXY* decision to support its argument is misplaced as nothing in *OXY* or the other Circuit Court opinions suggests that the Commission cannot use empirical data, such as the contracts, to determine that the continued use of Gulf Coast prices would undervalue West Coast Naphtha, or that use of BP's governor also would undervalue West Coast Naphtha. *Id.* at pp. 43-44. It contends that those decisions discuss the methodologies used to value Quality Bank cuts, not the evidence that is used to evaluate the reasonableness of the proposed methodologies. *Id.* at p. 44.

1851. BP theorizes, according to Phillips, that contract prices in an opaque market likely will be higher than they would be in a transparent market. *Id.* It explains that Ross's assertions on this matter are incorrect and likely stem from his unfamiliarity with economic theory. *Id.* There is no reason to believe, states Phillips, that the contract prices are significantly different from what they would be if there was a published West Coast price. *Id.* Phillips asserts that the somewhat concentrated nature of the purchasers of Naphtha and the fact that there are a number of sellers who do not make gasoline and hence have no alternative but to sell their Naphtha would suggest, if anything, that the prices paid for Naphtha might be below what they might be in a perfectly competitive market. *Id.* at pp. 44-45. This is the exact opposite of Ross's contention, declares Phillips. *Id.* at p. 45.

1852. Phillips posits that BP makes a further error in that, after discussing its theory that an opaque market can affect pricing, it assumes that the West Coast Naphtha market is almost completely opaque. *Id.* According to Phillips, this “leap” from the absence of a published Platts West Coast price assessment to an extreme exaggeration of what BP calls the "scarcity of information in the West Coast naphtha market" is unwarranted. *Id.* (quoting BP Initial Brief at p. 15). More importantly, according to Phillips, BP's assertions regarding the availability of information are incorrect. *Id.* It suggests that many sources of information are available to the West Coast refiners, including: (1) sources and availability of supply, (2) prices, and (3) availability and cost of imports. *Id.* at pp. 45-46. Further, it asserts that the West Coast refiners who purchase and sell Naphtha all have sophisticated computer models that tell them the internal value of the

Naphtha that they are purchasing and selling. *Id.* at p. 46. Therefore, Phillips contends that West Coast refiners know what prices they are paying and receiving for Naphtha. *Id.*

1853. Thus, Phillips contends that BP is wrong when it asserts that the West CoastNaphtha contracts were negotiated in the dark without any relevant information. *Id.* While there were no published Platts West Coast assessments, it states, the contracts were negotiated by sophisticated parties who are not in the business of giving money away and who had extensive amounts of data available to them in determining the prices to be paid under the contracts.[644] *Id.* at pp. 46-47. Thus, Phillips maintains, there is no reason to believe that the contract prices deviate to any significant extent from what they would have been if there were a published Platts West Coast assessment, and certainly no reason to believe that the prices on average are significantly higher than they would have been had there been a published price. *Id.* at p. 47.

1854. Phillips disagrees with BP's and Unocal/OXY's contention that the contracts for the 1999-2001 time period should not be considered. *Id.* It states that BP and Unocal/OXY argue that the contracts from this period are corrupted by gasoline price irregularities and that, in general, the Naphtha West Coast/Gulf Coast price differentials should be similar to the differentials for intermediate products, as Ross classifies them. *Id.* at pp. 47-48. Phillips asserts that Ross's theory, supported by BP, that in a transparent market prices would have been lower during this time period because of arbitrage opportunities to import Naphtha does not hold water. *Id.* at p. 47. It states that the 1999-2001 contracts are the most recent and most numerous, and thus most useful, and contends that, far from being corrupted by gasoline price irregularities, they demonstrate the extent to which West Coast Naphtha prices were influenced by gasoline price fluctuations. *Id.* at pp. 47-48. Given that West Coast Naphtha is made into gasoline, Phillips maintains that it is not at all surprising that Naphtha prices would reflect movements in the gasoline market, and this fact certainly does not constitute grounds for rejecting the contracts from 1999-2001. *Id.* at p. 48.

1855. BP's second argument, according to Phillips, should be rejected on much the same grounds. *Id.* It explains that Ross's hypothesis is that West Coast/Gulf Coast Naphtha price differentials should be similar to the differentials for intermediate products, as he classifies them. *Id.* It notes that, because the Naphtha contracts, during the 1999-2001 time period, tracked gasoline price differentials more than VGO differentials, BP asserts that the Naphtha contract prices must be unreliable. *Id.* Phillips claims that this turns

[644] Phillips points out that sophisticated market participants would likely not base their decisions solely on Platts in any event. Phillips Reply Brief at p. 47, n.21. It explains that participants realize that Platts might not accurately reflect all the current transactions, and states that they would look first to their internal values and then test the market by seeking quotations from other participants. *Id.*

reason on its head. *Id.*

3. Alaska

1856. Alaska argues that third party purchase and sales transactions, such as those reflected in the Naphtha contracts, represent the price at which supply and demand are coming into balance and that this is evidence of the market value to an economist. Alaska Initial Brief at p. 3. Further, explains Alaska, the published price assessments that the Quality Bank currently uses to value distillation cuts likewise constitute the publishers's assessments of the prices at which third party transactions are occurring or could occur. *Id.*

1857. While the Naphtha contract data thus are consistent with published price data as indicia of market value, Alaska states, there is a significant difference in their applications. *Id.* It points out that Platts and OPIS continuously collect information to assess and publish current market values on a daily or weekly basis, whereas the discrete set of Naphtha contract data collected in this case was intended to be used only to test the validity of the parties's proposed methodologies for valuing Naphtha in the Quality Bank. *Id.* Alaska asserts that the relevance of the contracts for the purposes of this case is not to publish an assessment of precise market value on any given day or week, but to see how the various methodologies performed relative to transactional information over longer periods of time. *Id.* For that purpose, Pulliam concluded, and Alaska agrees, one is justified in relying heavily on the contracts. *Id.* at p. 4.

1858. During the 1994-1998 period (or 1993-1998 for Culberson), states Alaska, the Pulliam, Tallett, and Culberson analyses[645] all found the contract prices to average a few cents per gallon above Platts Gulf Coast price, and during the 1999-2001 period, all found the contract prices to average about 11 to 14¢/gallon above Platts Gulf Coast price. *Id.* Alaska notes that O'Brien's analysis yielded a numerical average only for the entire 1994-2001 period, and his result – 9.4¢/gallon above Platts Gulf Coast price – is within about a penny and a half per gallon or less of the Culberson (1993-2002) and Tallett

[645] Alaska notes that Sanderson did not do his own contract analysis but examined what would happen under Tallett's analysis if all non-spot transactions were deleted. Alaska Initial Brief at p. 4, n.4. It asserts that those deletions made virtually no difference for the 1994-1998 period and reduced the contract/Gulf Coast differential from 12.65 to 10.16¢/gallon for the 1999-2001 period. *Id.* Alaska explains that the, apparently, greater effect of the deletions on the entire 1994-2001 period is an artifact of averaging because the deletions eliminated over half of the contract volume in the later years but hardly any volume in the early years. *Id.* Sanderson's average over 1994-2001 gave relatively greater weight to the early data, when West Coast and Gulf Coast Naphtha values were closer, than to the later data, when they were more divergent. *Id.*

results. *Id.* at pp. 4-5. While at first glance Pulliam's results for the entire 1994-2001 period appear lower, at 6.1 to 6.5¢/gallon above Platts Gulf Coast price, Alaska explains that this is due to a different method of aggregating the price data, not to a significant difference in the underlying findings.[646] *Id.* at p. 5.

1859. Alaska argues that these robust contract data are useful in several ways to test the various Naphtha valuation proposals. *Id.* It points out that the primary focus in this case was direct comparison between the Naphtha values predicted by those proposals and the Naphtha values derived from the contracts. *Id.* Thus, according to Alaska, the O'Brien and Tallett methods performed better than any of the others over the entire 1994-2001 time period, and dramatically better during the last three years. *Id.*

1860. Further, notes Alaska, other contract data also shed light on the validity of the competing proposals. *Id.* The O'Brien and Tallett methodologies are based primarily on West Coast gasoline prices, which, according to Alaska, is consistent with how Naphtha is priced in the contracts. *Id.* Further, continues Alaska, the prices of nearly 80% of the Naphtha contract volumes were directly tied to a West Coast gasoline price. *Id.* at pp. 5-6. In contrast, Alaska points out, only 2.3% of the volume was priced with reference to Gulf Coast Naphtha prices, despite some parties's claims that West Coast Naphtha should be valued at Gulf Coast Naphtha prices or that West Coast Naphtha values are subject to a governor that is tied to the price of Naphtha on the Gulf Coast. *Id.* at p. 6.

1861. Alaska also claims that the contracts allow the latter claim to be tested using statistical techniques. *Id.* If Ross's assertion was correct – that the option of importing Naphtha limits the value of Naphtha on the West Coast to no higher than import parity – then Alaska asserts, "we would expect that the spread between the naphtha contract prices and West Coast gasoline prices would *increase* whenever a gasoline-derived value for naphtha on the West Coast would otherwise exceed import parity." *Id.* (quoting

[646] Alaska explains that Pulliam derived a Naphtha price for each month by taking the volume-weighted average of the contract prices in effect for that month. Alaska Initial Brief at p. 5, n.5. When he compared these monthly prices to the various methodologies over a multi-year period, Alaska states, Pulliam used a straight average of the monthly comparisons during the period in question. *Id.* According to Alaska, this caused his average for the entire 1994-2001 period to fall close to the middle between his average figures for the early part of the period and for the later part of the period. *Id.* In contrast, points out Alaska, the other witnesses aggregated their price data either by volume-weighting all the data or by not using any volume weighting. *Id.* Because there were both more transactions and more Naphtha volume in the later part of the 1994-2001 period than in the early part, the later data had relatively more impact on those witnesses's overall averages for the entire 1994-2001 period, and consequently their overall averages are closer to the average figures for the later part of the period. *Id.*

Exhibit No. SOA-1 at p. 15) (emphasis in original). When Pulliam tested this hypothesis using a regression analysis, Alaska points out, he found that the Naphtha/gasoline price spread did not increase as Ross's theory would predict. *Id.* Instead, according to it, the results were the opposite of his theory. *Id.*

1862. Because the Naphtha contract data contradict the positions of parties who want the Quality Bank to keep valuing West Coast Naphtha using Gulf Coast prices or to use a Gulf Coast-based price cap, Alaska explains that those parties have devised several attacks on the reliability of the contract data, none of which, it believes, has merit. *Id.* Alaska argues that the number of Naphtha contracts analyzed is sufficient for the purposes of testing the parties's proposed Naphtha valuation methodologies. *Id.* at p. 7. It cites Pulliam's testimony who stated that, in his opinion, in view of the number of contracts, the transactions and the volume of Naphtha involved, the contracts may be relied upon for purposes of testing the parties's proposed valuation methodologies. *Id.* Further, it notes that Pulliam believed he had quite a bit of data to work with, particularly for the last three years. *Id.* Alaska notes that Pulliam's analysis involved 175 contracts, including 94 contracts in the last three years, involving 15 different sellers, and 12 different buyers, with an average of six contracts in effect each month during that period. *Id.*

1863. It is unlikely that the contracts collected in this case, Alaska conceded, constituted 100% of the transactions during the time periods studied, which raises questions of the randomness and validity of the sample. *Id.* It notes that Pulliam explained that randomness of a sample is a method used to ensure that a sample is not biased and that he had no reason to believe that the contract sample obtained in this case was biased. *Id.* at pp. 7-8. Further, according to Alaska, in this case, the nature of the buyers and sellers also gave Baumol a high level of confidence in the pertinence of the sample. *Id.* at p. 8.

1864. Furthermore, Alaska explains, Pulliam performed a sensitivity test for bias in the Naphtha contract sample. *Id.* This test, according Alaska, examined the possibility that the actual average West Coast Naphtha contract price in the 1999-2001 period, including the unknown transactions that were not obtained in this case, as well as the transactions that were obtained, might equal -- rather than substantially exceed -- the average Gulf Coast Naphtha price. *Id.* The result, noted Alaska, was that the average West Coast Naphtha price, from the contracts which were obtained, so greatly exceeds the Gulf Coast price that, to offset that differential, the average price of the missing contracts would need to be so low as to simply not be plausible. *Id.* Alaska asserts that none of the contracts that Pulliam reviewed had prices nearly that low. *Id.*

1865. Beyond the question of sample bias among the Naphtha contracts themselves, Alaska notes, there is a somewhat different question concerning the fact that only a small percentage of the Naphtha produced and used on the West Coast is bought and sold in third party transactions. *Id.* The issue, according to Alaska, is whether or not the market price of the 1% that is sold can validly be used to value the remaining 99%. *Id.* at pp. 8-9. Both economic theory and specific knowledge about the refining industry make clear, in Alaska's opinion, that the answer is an unequivocal yes. *Id.* at p. 9.

1866. Refiners, Alaska contends, constantly attempt to optimize their operations in order to stay profitable in the face of an array of choices and often use linear programming models. *Id.* For example, notes Alaska, with respect to the volume of Naphtha produced in a refinery, Culberson acknowledged that the options include changing the crude slate, changing the boiling ranges or cut-points in the crude unit, changing the cut-points in the Coker and hydrocracker, and importing VGO feedstock. *Id.* Further, explains Alaska, Sanderson testified that the West Coast refiner for whom he previously worked used Naphtha from its own crude runs and also Naphtha purchased from the outside, depending on which was more economical at any given time. *Id.*

1867. In the first part of the period for which Naphtha contracts were obtained, notes Alaska, Gulf Coast Naphtha prices tended to be close to the West Coast contract prices, and all of the proposed methodologies yield West Coast Naphtha values that average within a few cents per gallon of the contract prices. *Id.* at pp. 11-12. In the latter part of the period, continues Alaska, the contract prices tended to greatly exceed Gulf Coast Naphtha prices, and only the O'Brien and Tallett proposals yield West Coast Naphtha values close to the contract prices. *Id.* at p. 12. This, according to Alaska, reflects the fact that gasoline prices on both coasts were relatively close during the earlier years and then diverged during the later years. *Id.*

1868. According to Alaska, Ross claimed that the West Coast Naphtha market is an opaque market and that, therefore, West Coast Naphtha prices reflected in the contracts are probably higher than they would be if a company like Platts published a price assessment for West Coast Naphtha. *Id.* at p. 13. Notes Alaska, Ross claims that were there such a published Naphtha price assessment, that is if the market were transparent, West Coast Naphtha would not exceed import parity. *Id.*

1869. Ross's theory, according to Alaska, grossly exaggerates the role of published price assessments in the universe of market information. *Id.* It notes that he defines "opaque market" to mean "a market where there's little information available." *Id.* (quoting Transcript at p. 8219). Yet, explains Alaska, Baumol noted that, while most people have limited information, buyers and sellers of Naphtha are well informed, and do not need a published price to negotiate the best deals possible. *Id.* at pp. 13-14. Further, Alaska points out that even Ross admits that West Coast refiners have access to such information as the shadow price of Naphtha in computer models, the prices of Naphtha in the Caribbean and the Gulf Coast export markets, and to brokers operating in the West Coast market who are in touch with the refineries on a continuing basis. *Id.* at p. 14. Pulliam, according to Alaska, pointed out that a trader for one such broker who was interviewed estimated West Coast Naphtha prices that were very close to the prices calculated from the Naphtha contracts analyzed by Pulliam. *Id.*

1870. The additional piece of information that Ross contends makes all the difference – a Platts or OPIS price assessment – is, in Alaska's view, nothing more than what the assessor can find out as a result of phone calls. *Id.* Further, notes Alaska, sometimes such published assessments are based on very limited market transactions. *Id.* While there may be some incremental benefit to having that piece of information, Alaska argues, there is simply no basis for concluding that the absence of a published assessment in the West Coast Naphtha market has the material effect on Naphtha prices that Ross asserts. *Id.* It points out that traders themselves believe their information is often better than the published information. *Id.* at pp. 14-15.

1871. Alaska also states that BP makes several incorrect assertions regarding the its position on the opaque markets issue. Alaska Reply Brief at p. 3. First, it claims, BP states that Pulliam referred to the West Coast Naphtha market as opaque. *Id.* In fact, asserts Alaska, Pulliam testified that it is not at all opaque and information on the West Coast market is readily available. *Id.* Second, Alaska takes issue with BP's comments that there were few participants in the West Coast, arguing that there were at least ten refiners making gasoline on the West Coast and were thus potential ultimate purchasers of Naphtha during the time periods studied. *Id.* Third, Alaska argues, the record clearly shows that there are regular buyers of Naphtha on the West Coast and not only sporadic buyers, as BP claims. *Id.* at pp. 3-4. Further, Alaska asserts, a large volume of Naphtha, more that half of the contract volume during the 1999-2001 period, is purchased under term contracts. *Id.* at p. 4. According to Alaska, these contracts are, by definition, not used to meet immediate unplanned needs, as BP states. *Id.*

1872. BP errs in asserting that the contract analyses are not useful for evaluating proposed Naphtha valuation methodologies because they did not use exactly the same techniques to estimate market values as do Platts and OPIS, according to Alaska. Alaska Reply Brief at p. 5. It asserts that the different techniques are just slightly different methods for achieving a common result, namely, determining the prices at which actual market transactions in a product occur. *Id.* Alaska maintains that, if Platts published a price assessment for West Coast that was used to compare the proposed methodologies, Pulliam would expect similar results to those from his contract analysis. *Id.* Further, Alaska asserts, use of the contract data to test proposed methodologies is not inconsistent with how the Quality Bank uses the Platts and OPIS price assessments. *Id.* at pp. 5-6. Finally, Alaska claims, Pulliam's conclusions are supported by the fact that the contracts and published price assessments for ANS crude are "very close." *Id.* at p. 6.

1873. In response to the criticisms made by several parties that Pulliam's analysis is subjective, open to manipulation, or should not have included term contracts, Alaska argues, his approach was, in fact, objective and inclusive, made use of all relevant data, and used a volume-weighted approach for each month in question. *Id.* It rejects the assertion that a more filtered, subjective approach, such as that used by Platts, is more appropriate, noting that the purpose of Pulliam's analysis was not to arrive at precise, day-to-day calculations of the market value of Naphtha, but instead his purpose was to look at the market value over a longer period of time. *Id.* at pp. 6-7. Alaska asserts that it is absurd for parties to ask the Commission to ignore the fact that one proposed methodology deviates from actual market (contract) prices by an average of more than 14¢/gallon while another deviates by less than a penny per gallon. *Id.* at p. 7.

1874. Alaska further suggests that a party who does not find Pulliam's analysis valid could look at the contract data in Exhibit No. SOA-12 for validation that 95.5% of the contract Naphtha volume, between 1999 and 2001, was sold at prices above the Gulf Coast price, while over 60% of the Naphtha volume was sold within 2¢/gallon of the prices predicted by the O'Brien methodology. *Id.* In Alaska's view, these disparities cannot be filtered away as BP and Williams suggest. *Id.*

1875. BP argues, according to Alaska, that the contracts data is not useful because of their high degree of price variability when compared to the published price assessments. *Id.* This comparison is, Alaska states, misleading because, although BP claims to have compared underlying contract data with data underlying the price assessments, it did not and could not do that. *Id.* at pp. 7-8. Alaska points out that BP compared the data underlying the contracts with the actual price assessments from Platts, because the underlying data for the Platts assessments is not available. *Id.* at p. 8. Further, Alaska explains, because the Platts assessments themselves are averages, they necessarily show less variability than the underlying contract data. *Id.*

1876. The valid comparison, according to Alaska, is between the variability of the Platts and OPIS assessments and the variability of Pulliam's price estimates. *Id.* Alaska asserts that, because Pulliam's estimate is a single number, while those of Platts and OPIS are ranges, the "average monthly price variability" under Pulliam's analysis is zero as compared to several cents per gallon in the case of the Platts and OPIS assessments. *Id.* at pp. 8-9. It concedes that this comparison is not very meaningful, but states that it is more meaningful than BP's comparison. *Id.* at p. 9.

1877. Alaska asserts that, contrary to BP's theory, there is no pattern for price differentials that reliably distinguishes intermediate from finished products. *Id.* For example, explains Alaska, during 1992-1998, the differentials for unleaded regular gasoline and jet fuel (two finished products) were very similar, at 5.99 and 5.57¢/gallon respectively; while during 1999-2001 those two differentials were highly dissimilar, at 13.55 and 7.75¢/gallon respectively. *Id.* Moreover, notes Alaska, BP's classifications are biased: the differentials for blendstocks MTBE and feedstock isobutane strongly contradict the tidy pattern BP tries to create if they are correctly classified as intermediate products. *Id.* at pp. 9-10. Consequently, states Alaska, BP calls MTBE a finished product and assigns Isobutane to a third category, "gas plant products," so its pattern is preserved. *Id.* at p. 10. Alaska also finds BP's argument turns the scientific method backward, and explains that, if observations and data gathered do not support the theory, then, according to the scientific method, it is the theory that should be questioned and not the data. *Id.*

1878. BP and other critics of the contract data have stressed that refining on the West Coast experienced instability, disruptions, and anomalies during 1999-2001, states Alaska. *Id.* According to Alaska, it should not then be a surprise that the price patterns BP claims to see in the previous years do not persist into 1999-2001 period. *Id.* In Alaska's view, it is precisely during changing market conditions that the performance of the proposed Naphtha valuation methodologies is most meaningfully measured, and it is not relevant that the prices may be the result of disruptions or anomalies. *Id.* The only relevant question, asserts Alaska, is how well do the proposed methodologies track the market prices in the real world of change. *Id.*

1879. Petro Star is mistaken, explains Alaska, in its claim that there is no market demand for Naphtha on the West Coast. *Id.* at p. 12. It points out that most of the Naphtha sold under the contracts analyzed by Pulliam comes from refineries that do make gasoline, have no internal requirement for Naphtha, and therefore must sell it. *Id.* Alaska asserts that there is no evidence that refiners need to pay or are willing to pay a premium for convenience or that convenience is even a relevant consideration for refiners. *Id.*

1880. The changes to the contract analyses that have taken place during the course of the proceeding reflect the witness's desire to be as accurate as possible, according to Alaska. *Id.* at p. 13. They do not, it maintains, indicate that the analysis is subjective and ambiguous, nor do they indicate a conspiracy among the analysts. *Id.* at pp. 12-13. According to Alaska, the changes resulted from the fact that the analysts received more complete information about the transactions being analyzed or were correcting errors. *Id.* at pp. 13-14.

1881. Alaska explains that Williams cited the differences in price data contained in Pulliam's versus O'Brien's contract analyses as evidence of subjectivity in them. *Id.* at p. 14. Rather than indicating subjectivity, Alaska asserts, they reflect the difference in methods that the witnesses's used to apply a pricing formula based on delivery dates. *Id.* Further, notes Alaska, both methods are valid, and the choice does not make a significant difference in the results. *Id.* According to Alaska, Williams also criticized the analysis of Pulliam and O'Brien because, for some contracts, they used different volumes. *Id.* at p. 15. Alaska points out that this is not a reflection of their different interpretations of the contracts; rather it reflects that O'Brien had information on actual volume delivered and Pulliam used the volume stated in the contract. *Id.* It asserts that the quantitative impact of this deviation was immaterial; the difference between the contracted and delivered volumes for the 30% of contracts where that information is available was 7%. *Id.* at pp. 15-16.

1882. Unocal/OXY also err, according to Alaska, in characterizing the fluctuating gasoline reference prices in the contracts as ambiguous. *Id.* at p. 14. In Alaska's view, Pulliam's analysis appropriately managed these fluctuations and was not distorted by them. *Id.* It explains that Pulliam's analysis compared monthly averages of these contract reference prices with monthly averages from the valuation methodologies being evaluated in order to avoid timing mismatches. *Id.* at pp. 14-15. In addition, notes Alaska, Pulliam performed a sensitivity analysis that showed that the intra-month fluctuations do not have a material impact on the results of his analysis. *Id.* at p. 15.

1883. Alaska further notes that Unocal/OXY criticize the contract analysis suggesting that there is ambiguity concerning the classification of the product being sold. *Id.* at p. 16. It explains that this issue of classification was recognized by the analysts, and that they accounted for it by analyzing two sets of contracts each and running tests on the impact of the classification decision made by the analysts. *Id.* Alaska points out that the classification decisions were conservative and resulted in lower West Coast Naphtha values than would have otherwise resulted, and also points out that four other witnesses, including Unocal/OXY's, made independent classification decisions as part of their contract analyses and that those results were consistent with Pulliam's and O'Brien's. *Id.*

1884. Unocal/OXY also argue, according to Alaska, that the contract transactions are dominated by four large participants and involve few others. *Id.* at p. 17. It answers that this merely reflects the reality of the West Coast Naphtha market. *Id.* While conceding that the buyer side of the market appears more concentrated than the seller side, Alaska asserts, this market structure would tend to cause prices to be lower than they would be otherwise. *Id.* Alaska also notes that the total number of participants is substantial: 15 different sellers and 12 different buyers during 1999-2001. *Id.*

1885. Williams criticizes, Alaska points out, the contract analyses because it perceives that one company's contracts (Company 31) have a disproportionate impact on the total results, noting that the average spot contract price drops if Company 31's data is deleted from the analyses. *Id.* Alaska argues that this is meaningless, because one could just as easily criticize the analyses for producing too low a price by dropping the contracts of a company whose data are below the average. *Id.* The point of the analyses, according to Alaska, is to use all the data available and not to eliminate data that runs counter to a party's interests. *Id.* It also argues that Williams overstates the significance of Company 31's data on the outcome of the analysis. *Id.* While Williams states that the percentage of purchases attributed to Company 31 went from 23.6% in 1999 to 83.3% in 2001, Alaska explains, the average West Coast Naphtha contract price was 12.7¢/gallon above the Gulf Coast Naphtha price in 1999, and 14.1¢/gallon above the Gulf Coast price in 2001. *Id.* at pp. 17-18. Further, notes Alaska, in 2000, when Company 31's percentage of purchase was only about half the 2001 percentage, the difference was 14.3¢/gallon, slightly higher than the 2001 figure. *Id.* at p. 18.

4. BP

1886. In order for the Quality Bank to properly compensate those shippers injecting higher-quality crude into TAPS and to properly debit those shippers injecting lower-quality crude into TAPS, BP asserts that the Quality Bank methodology must remain internally consistent. BP Initial Brief at p. 7. BP points out that the Circuit Court has said that the "[Commission] must accurately value all cuts -- not merely some or most of them -- or it must overvalue or undervalue all cuts to approximately the same degree." *Id.* at pp. 7-8 (quoting *OXY*, 64 F.3d at p. 693). In other words, states BP, internal consistency is an essential goal of the Quality Bank. *Id.* at p. 8. Therefore, it is BP's position that the development of a West Coast Naphtha methodology must be guided by this consistency principle. *Id.*

1887. According to BP, witnesses and parties who consider the West Coast contracts useful suggested that their only practical use is as a yardstick to determine the validity of a proposed West Coast methodology for valuing Naphtha on the West Coast. *Id.*; BP Reply Brief at p. 7. In BP's view, the only way that the West Coast Naphtha contracts could properly play such a role is if they were consistent with the other prices used in the Quality Bank. BP Initial Brief at p. 8. In other words, explains BP, values derived from West Coast contracts must bear sufficient similarity to the prices that are used to measure the value of the other Quality Bank cuts for them to be useful in judging the validity of the proposed West Coast naphtha valuations. *Id.* It argues that the evidence presented in this case conclusively shows that the contracts and the values that the witnesses have assigned to them are not consistent with reported prices, and that, therefore, the contracts are not a useful yardstick for considering the merits of the West Coast Naphtha valuation proposals. *Id.*

1888. The preferred method of valuing the Quality Bank cuts, states BP, is through the use of prices that are reported by either Platts or OPIS, two price-reporting services.[647] *Id.* at p. 9. It explains that both Platts and OPIS survey the markets that they are trying to assess to determine the value of a particular product in the particular market at a particular moment. *Id.* BP states that the Platts and OPIS independent, unbiased assessments are the foundation of the Quality Bank methodology and notes that these reporting services provide a valuable role in the industry because their unbiased assessments allow industry participants to consider pricing information when planning their business, including their contracting decisions. *Id.* According to BP, these services attempt to provide the industry with price transparency. *Id.* at pp. 9-10. It notes that Ross agreed with Platts assessment of the important role that published prices play in the market. *Id.* at p. 10.

[647] BP cites Transcript at pp. 9740-41; Exhibit Nos. PAI-33 at p. 3, WAP-1 at pp. 4-5 in support. BP Initial Brief at p. 9, n.6.

1889. BP states that the EIA also has discussed the importance of publicly available prices in ensuring an appropriate supply/demand balance in oil markets. *Id.* It notes that spot market prices are relatively transparent and provide a clear signal about supply and demand characteristics of a market. *Id.* Further, explains BP, the EIA has recognized the importance that published prices play in market activity, stating that they enhance a market participant's ability to assess the market price level. *Id.* at pp. 10-11. BP states that, in its view, Exxon, Phillips and Alaska underestimate the importance that transparency plays in the petroleum market. BP Reply Brief at p. 10.

1890. According to BP, the editors for Platts and OPIS exercise editorial discretion in assessing the prices that they report. BP Initial Brief at p. 11. For example, continues BP, Platts does not adhere blindly to the use of weighted average prices to determine reported prices even in liquid markets and believes there is an important role for independent, analytical scrutiny, rather than simple volume weighted calculation, especially in thinly traded markets which can be subject to manipulation. *Id.* It asserts that the Naphtha market on the West Coast meets anyone's definition of thinly traded. *Id.*

1891. BP states that component cuts for ANS are valued based on published prices determined from markets characterized by transparency. BP Reply Brief at p. 11. By contrast, it points out that the West Coast Naphtha contracts were entered into in a market that lacks published prices and is opaque. *Id.* It asserts that this significant difference is fatal to the use of the Naphtha contracts as a yardstick for evaluating any methodology. *Id.*

1892. Reported prices play an important role in developing an efficient, well-functioning energy market and Platts is a significant contributor to the operation of the energy market, BP claims. BP Initial Brief at p. 12. It notes that Toof testified that the classic definition of a transparent market is one where all participants have perfect knowledge of information relevant to the transaction at hand. *Id.* (citing Transcript at pp. 6362-63). By contrast, notes BP, in an opaque market, the parties to a transaction would have little or no information. *Id.* at pp. 12-13. It points out that Toof and Ross agreed that the Gulf Coast Naphtha market, with its reported prices, is closer to being transparent than the West Coast Naphtha market, which lacks reported prices. *Id.* at p. 13.

1893. Phillips and Alaska, BP states, attempt to undermine the importance of transparency in the Naphtha market by claiming that enough information is available to the Naphtha contract participants for the contract prices to be a useful yardstick for evaluating the naphtha methodologies. BP Reply Brief at p. 13. It points out that this information, such as their own internal production value, their own negotiated Naphtha contracts, and a Gulf Coast Naphtha price, fails to provide market participants with information equivalent to that available in a transparent market with published prices. *Id.* at pp. 13-14. BP considers this information to be an incomplete subset of all Naphtha contracts and prices that falls far short of published price information. *Id.* at p. 14. It states that the information that refiners can glean from their computer models cannot replace published prices and only reveals a maximum price and notes that it tells the refiners nothing about the best price they should be able to achieve. *Id.*

1894. According to BP, the West Coast Naphtha contract prices were formed in an environment that lacked supply availability information, supply sources information, and complete price information. BP Initial Brief at p. 15. Because of that, asserts BP, there are few potential market participants who actually participate in the market and they do so only sporadically to meet emergent Naphtha supply needs. *Id.*

1895. BP states that Platts and OPIS survey the market to develop their price assessments, exercise editorial discretion, and are independent. *Id.* at p. 18. Further, explains BP, they look at spot transactions and not long-term contracts. *Id.* It asserts that Pulliam's, Tallett's, and O'Brien's Naphtha contract analyses are different. *Id.* BP points out that Pulliam acknowledged that one difference is that, although his contract analysis looks strictly at the terms of the contracts, Platts surveys the market and ordinarily does not look at individual contracts. *Id.* at pp. 18-19. It explains that this prevents individual deals from taking on a disproportionate value if only one player is in the market at a specific time. *Id.* at p. 19. Other players may value Naphtha at a lower value or not have a need for Naphtha at the time, notes BP, but would purchase at a lower price, if transparency permitted the potential buyer to determine that additional quantities would be available at that price. *Id.* Surveying the price level at which a transaction would occur, argues BP, rather than valuing the product based on one particular transaction, helps prevent overvaluation. *Id.*

1896. Another difference between the price-reporting service values and the contract values, according to BP, is the impact of long-term transactions. *Id.* BP notes that all of the contract analyses included long-term transactions. *Id.* It states that Platts does not look at long-term transactions generally and bases its values on the immediate estimated value. *Id.* For any West Coast Naphtha contracts analysis to be comparable to the reported prices, BP asserts, the analysis should have considered only spot assessments and excluded term contracts. *Id.* at p. 20. Otherwise, explains BP, formula values negotiated at a specific point in time will continue to affect the valuation at later points in time when market conditions may have changed. *Id.*

1897. Moreover, states BP, the data in the contracts analyzed by Pulliam have not been filtered to isolate them to a particular jurisdiction. *Id.* Unlike Platts, BP notes, neither Pulliam's, Tallett's, nor O'Brien's analysis adjusted prices to ensure consistency of location. *Id.* Further, BP explains, none of the analysts made the same adjustments that Platts would have made. *Id.* For example, continues BP, Platts makes various adjustments to values determined for its product prices according to industry knowledge, experience, and current market conditions and none of the West Coast contract analyses do anything like that. *Id.* Instead, according to BP, each simply reflects a compilation of particular transactions made with imperfect knowledge in an opaque market. *Id.* It argues that this provides one more indication that the contract analyses are not comparable to the price reporting services's product price assessments that underlie the Quality Bank. *Id.*

1898. BP notes that at least two techniques can measure the variation on a monthly basis in a product's price. *Id.* at p. 21. One measure, according to it, compares the absolute highest and lowest values in a month for the product; and the other compares the difference in the product's average high and average low prices for the month, the measure that Ross defined as monthly price variability. *Id.* The second measure, according to BP, is the appropriate tool to use to compare the reported prices to Pulliam's contract analysis. *Id.*

1899. Pulliam priced out the Naphtha contracts, BP states, using monthly average prices instead of trying to determine an exact contract price on a given day because he lacked data to make exact determinations for all of the contracts. *Id.* Further, explains BP, many of the Naphtha contracts's pricing terms were based on the reported price of gasoline minus a constant and were referenced to the delivery date for the Naphtha. *Id.* Therefore, states BP, instead of trying to price each contract out to match the delivery date using daily gasoline prices, Pulliam used the monthly average gasoline price. *Id.* at pp. 21-22. To appropriately compare those contract prices with the Platts and OPIS reported prices used in the Quality Bank, explains BP, Ross developed charts that describe what he called the price variability for the reported prices and then compared the range of the average high prices and average low prices with the range of the average high and average low prices that Pulliam developed in his contract analysis. *Id.* at p. 22.

1900. BP comments that the contract monthly price variability is well out of proportion to the published price series monthly price variability. *Id.* at p. 24. It notes that even Pulliam recognized that, were West Coast prices for Naphtha published, the range of Naphtha values for published price assessments "would be narrower" than what Pulliam's contract analysis yielded. *Id.* (citing Transcript at p. 7510). BP's conclusion is that the contract values are simply not comparable to the published price series, cannot be trusted as a reliable indicator of the value of Naphtha on the West Coast, and are not a useful yardstick. *Id.* It views any conclusions drawn from the contract data set as flawed. *Id.*

1901. As support for the proposition that the contract analyses provide a good yardstick for appraising the Naphtha valuation proposals, BP notes, the contract supporters point to the claimed similar values that each analysis produces and argue that, therefore, the methodologies must be sound and useful. BP Reply Brief at p. 19. BP disagrees with this conclusion for four reasons: (1) the results should be similar, (2) the contracts are still an inappropriate yardstick to use to evaluate Naphtha valuation methodologies, (3) neither participant diversity nor volumes transacted resolves the problems of an opaque market, and (4) the techniques used in the contract analyses are different than the techniques used by the reporting services. *Id.*

1902. First, BP asserts, it is not surprising that the analysts's results are similar as analyses of the same contracts should produce similar, if not identical, results. *Id.* It believes that this establishes only the similarity of the methodologies and the precision of the calculations, not the appropriateness or usefulness of the calculations. *Id.*

1903. Second, BP argues, even if one assumes that the contracts were formed in a market that is comparable to the markets that underlie the other Quality Bank cuts's reference prices the contract analyses would still be an inappropriate yardstick for judging methodological suitability. *Id.* Despite the contract supporters's claims of consistency among contract analyses's results, BP maintains, there are noticeable variations between the analyses's end results. *Id.* BP point out that, for the 1994-2001 period, the contract analyses range from 6.1¢/gallon above the Gulf Coast Naphtha price for the Pulliam contract analysis to 9.93¢/gallon above the Gulf Coast Naphtha price for the Culberson contract analysis. *Id.* at p. 20. It explains that both the Tallett and O'Brien methodologies produce results that surpass the Gulf Coast Naphtha price by 9¢/gallon during that period. *Id.* BP further notes that the data indicate that the contract analyses themselves are subjective in calculating the Naphtha contract values, as they vary widely depending on the criteria chosen for each analysis. *Id.* It states that every contract analysis used a different subset of the contracts based on the witnesses's personal choices about what to include. *Id.* BP maintains that, contrary to the contract supporters's argument that a comparison of the various contract analysis results supports their use as a measuring tool, a comparison of the resulting values cuts squarely against the contract analyses's reliability and appropriateness. *Id.*

1904. Third, BP points out, the contract supporters argue that the contracts represent transactions from a variety of sources with all of the major West Coast players represented. *Id.* It notes that the supporters claim that participant diversity and the supposedly substantial volumes transacted prove that the contracts are representative of the West Coast value of Naphtha. *Id.* BP argues that neither of those factors resolves the problems of an opaque market and argues that regardless of participant numbers or volumes transacted all of the Naphtha contracts were formed under conditions that are not comparable to the market conditions that underlie the Quality Bank reference prices. *Id.* In BP's view, because their underlying data source does not represent Naphtha prices that would be found in a transparent market, their reliability is weakened. *Id.* at p. 21.

1905. Fourth, BP states, the techniques used in the contract analyses are different than the techniques used by the reporting services. *Id.* It notes that the reporting services exercise editorial discretion, look at spot transactions only, and do not use contracts. *Id.* BP explains that price is influenced by other contractual terms including the contract's length. *Id.* In contrast, BP notes, the contract analyses look at long-term contracts and make valuation determinations from the individual contracts and points out that the contract analyses did not filter the data to ensure consistent pricing location in keeping with the reporting services techniques. *Id*.

1906. Moreover, BP maintains, drawing conclusions from the contract data is dangerous because the data set in this case is incomplete. *Id.*; BP Initial Brief at p 24. BP notes that Pulliam admitted that Platts picks up transactions between traders, while the contract analyses performed in this case would not pick up those types of transactions. BP Initial Brief at p 24. Without these transactions, claims BP, the contract analyses data set is only a subset of those transactions that should be considered. *Id.* at pp. 24-25. This fact coupled with the many differences in the techniques used to generate the Naphtha values reflected in the contract analyses means, according to BP, that the contract analyses are generating values that are not consistent with – and likely substantially different from – the values that would be generated by a reported pricing series. *Id.* at p. 25.

1907. BP notes that the contract supporters (Exxon, Phillips and Alaska) claim that the contracts's pricing mechanisms were not formed in a dysfunctional market, and explain that the contract supports assert that 1999-2001 did not produce anomalous gasoline prices, that anomalies were not distorting the contract values during this period, and that the data from that period is relevant. BP Reply Brief at p. 23. As to this claim, BP states:

> They base this assertion on several flawed arguments. First, they assert that since the contract values produce results similar to various formulas' results, this similarity indicates that the contract values are reliable for 1999-2001. For example, they argue that the contract values are similar to: (1) 1993 settlement values produced; (2) Mr. Kutola's rule of thumb; (3) Mr. Ross' analysis of contract data when adjusted for quality and volume weighting; and (4) the values generated as a function of crude oil and gasoline prices. Second, they argue that gasoline price spikes in 1999-2001 were matched by price spikes in other products. They also assert that price differentials for all products existed for the entire 1994-2001 period, not just 1999-2001, indicating that it is not anomalous for [the] West Coast to have greater differentials than the Gulf Coast and that the intermediate products' prices followed gasoline price spikes.

Id. at pp. 23-24, n.5 (citations omitted).

1908. Further, BP asserts, the supporters believe that the market characteristics that were present in 1999-2001 are likely to continue and cannot be considered anomalous. *Id.* at pp. 23-24. It argues that these assertions ignore the evidence establishing that the 1999-2001 period was characterized by large price swings, related to gasoline price anomalies, that hadn't happened in earlier periods. *Id.* at p. 24. BP suggests that the unstressed 1994-1998 contracts are more likely to be representative of West Coast naphtha values in a transparent market. *Id.*

1909. According to Ross, BP claims, there was greater gasoline price stability and fewer gasoline price anomalies on the West Coast during the 1994-1998 period than during the 1999-2001 period. BP Initial Brief at p. 25. According to it, this is important when considering whether the Naphtha contracts offer any value as a predictor of West Coast Naphtha values because, explains BP, the Naphtha contract prices are linked to gasoline prices, so that some of the contract prices went up starting in 1999. *Id.* BP points out that, according to Ross, this would not have happened in a transparent market. *Id.* It also notes that the Stillwater report, Exhibit No. EMT-385, chronicles the dysfunctional market conditions that were present in 1999-2001, and explains that the report indicates the market conditions in 1999-2001 were very different from those in 1994-1998 and that the gasoline market on the West Coast suffered from supply-demand imbalances in the later period. BP Reply Brief at p. 24. Thus, BP concludes, the contracts during the 1999-2001 period are corrupted by gasoline price irregularities and are less reliable as an indicator of Naphtha value on the West Coast.[648] BP Initial Brief at p. 26.

1910. BP notes that Ross further testified that it is problematic to look at the "contract line" over the entire 1994-2001 period because "it's distorted by the events of 1999 through 2001." *Id.* (citing Transcript at p. 9667). These events indicate that if any of the contracts or contract analyses are to be considered, according to BP, the contract data and analyses related to the 1994-1998 period would be closer to a Naphtha value in a transparent market than contract data and analyses related to the 1999-2001 period. *Id.* BP asserts that including the data from the 1999-2001 period in an analysis would result in values that are less likely to be representative of naphtha in a transparent market. *Id.*

1911. Ross acknowledged, according to BP, that Naphtha and VGO would not move in sync all the time, but claimed that, on average, they would show similar patterns. *Id.* at p. 28. The 1999-2001 contracts deviate from the VGO values and the values of the other intermediate products, explains BP. *Id.* Further, BP states, even if the 1999-2001 period characteristics continue, the contracts still would not represent the West Coast value of Naphtha in a transparent market. BP Reply Brief at p. 27. In a transparent market, it argues, the West Coast Naphtha value would not track the elevated gasoline prices because many of the disruptions that have led to higher gasoline prices would not affect intermediate feedstock (such as Naphtha) values. *Id.*

1912. The record shows, in BP's view, that the anomalous conditions during 1999-2001 corrupted the contracts and elevated their values in lockstep with gasoline, when the intermediate product values would not have been affected. *Id.* at pp. 27-28. It argues that

[648] BP also cites Exhibit No. WAP-199, a report to the California Attorney General that Pulliam co-authored, as further evidence that there were pricing irregularities on the West Coast which became more severe in 1999. BP Reply Brief at p. 25.

this relationship further undermines the appropriateness of using the contracts as a yardstick for the Naphtha valuation proposals. *Id.* at p. 28. Nevertheless, asserts BP, if the contracts are used as a yardstick, the 1994-1998 data is more reliable than the 1999-2001 data, because the 1994-1998 period did not suffer from the extreme price spikes that plagued the later period. BP Initial Brief at p. 28.

5. Unocal/OXY

1913. Unocal/OXY's position is that the Naphtha contracts analyzed in this proceeding provide some relevant and useful information about West Coast Naphtha, but that they do not provide a basis for determining West Coast Naphtha values. Unocal/OXY Initial Brief at p. 31. Further, Unocal/OXY believe, Exxon, Phillips and Alaska place too great an emphasis on the value of the contracts because it is in their economic interest to do so. Unocal/OXY Reply Brief at pp. 68-69.

1914. The contract data, Unocal/OXY state, validate the continued use of Gulf Coast pricing if consideration of the contract data is limited to the period of 1992-1998, as even Pulliam conceded. *Id.* at p. 69. They also point out that the contract pricing during the anomalous period shows evidence of various market defects that render the data unreliable. *Id.* Therefore, Unocal/OXY conclude, the contracts do not provide a basis for refuting the continued use of Gulf Coast pricing. *Id.*

1915. Unocal/OXY assert that the private contracts relating to West Coast Naphtha sales do not provide reliable evidence of the West Coast value of Naphtha for several reasons. *Id.* First, they state, the number of contracts is too small, comprising less than two percent of West Coast Naphtha volumes. Unocal/OXY Initial Brief at p. 31. Second, continues Unocal/OXY, the small sample of contracts was dominated by no more than four large participants. *Id.* at pp. 31-32 (citing Exhibit Nos. WAP-200, WAP-202, SOA-34, SOA-35, SOA-36, SOA-37).

1916. In addition, Unocal/OXY note, the sample of contracts is heavily weighted for the period 1999 through 2001, a period of extremely high volatility in California gasoline prices, characterized by anomalous conditions described earlier. *Id.* at p. 32. While the contracts spanned the period from 1988 through March of 2002, Unocal/OXY point out, 61% of the volumes included were in the 1999-2001 period. *Id.* Accordingly, Unocal/OXY claim, the entire sample was heavily influenced by a single large buyer who entered the market in 1998 and dominated the market in 2001. *Id.* They concede, in their reply brief, that a small sample size does not by itself render the data unusable, but claim that a small sample is more susceptible to distortion, manipulation and anticompetitive effects. Unocal/OXY Reply Brief at p. 76. Unocal/OXY assert that the pre-1999 contract data has not been tainted in this manner and is usable, but that the post-1999 data is tainted and thus is unusable. *Id.*

1917. Unocal/OXY also assert that there are other indications that the market in the West Coast was not competitive during the period 1999-2001 as indicated by several "red flags." Unocal/OXY Reply Brief at p. 73. They point out that a 1999 report to the California Attorney General cautions that the gasoline market has become more concentrated, that in-state refiners have been the primary beneficiaries of California's higher prices, and that the market is characterized by a relative lack of competition. *Id.* Also, they note, Ross has characterized the West Coast Naphtha market as opaque, which prevents the exchange of information on price and quality, and that Culberson has characterized the West Coast gasoline market as not workably competitive. *Id.* at p. 74. Finally, they point out that the Stillwater report describes the California gasoline market as increasingly unstable and subject to extreme volatility. *Id.* (citing Exhibit No. EMT-385 at p. 15).

1918. Because of the above problems on the West Coast, Unocal/OXY contend, the Commission should be careful not to base its decision on evidence that has been distorted by these non-competitive considerations. *Id.* Specifically, they assert that the pricing evidence from the 1999-2001 contracts should be disregarded. *Id.* at pp. 74-75. They also argue that the degree of sophistication attributed to the parties to the contracts does not obviate that possibility of market manipulation. *Id.* at p. 75.

1919. In addition, state Unocal/OXY, the contracts were often ambiguous with respect to the terms describing the quality of the material traded. Unocal/OXY Initial Brief at p. 32. Approximately 30 different terms were used to describe the Naphtha being sold, which, Unocal/OXY assert, created ambiguity as to whether the Naphtha described in the contracts was comparable to Quality Bank Naphtha. *Id.* (citing Exhibit No. UNO-7 at pp. 38-39). They claim that, as there is no precise definition of Naphtha commonly used in the industry, deciding whether a particular contract dealt with Quality Bank Naphtha or something else involved a large degree of subjective judgment. *Id.* Consequently, explain Unocal/OXY, each of the experts who analyzed the contracts did not analyze exactly the same set of contracts. *Id.* at pp. 32-33 (citing Exhibit Nos. EMT-133, PAI-154, PAI-224, SOA-1). Unocal/OXY continue, there were also a large number of very small volume transactions produced by Phillips, representing 200 barrel truck sales that Unocal/OXY's witness Culberson excluded, because they did not represent a true market value. *Id.* at p. 33.

1920. Unocal/OXY also claim that, not only were the quality terms ambiguous, but the pricing terms also were uncertain in most of the contracts, as the prices specified some deduction from a published price for a delivery date that was not specified in the contracts. *Id.* at p. 34. Typically, explain Unocal/OXY, the price is a three or five day average of published prices before and after delivery, less a deduction. *Id.* Rather than use these prices, Unocal/OXY state, O'Brien and Pulliam used monthly average prices for all such contracts, whether they had delivery data or not, and Tallett only used monthly average prices in the absence of delivery date information. *Id.* Prices for West Coast gasoline, the most frequently used pricing reference, continue Unocal/OXY, fluctuate widely during any given month. *Id.* Therefore, Unocal/OXY agree with Culberson that use of monthly average prices as a substitute for 3-day or 5-day averages could cause serious price distortion and that they should be excluded for that reason. *Id.*

1921. Because the contracts do not reflect the market value of Naphtha on the West Coast, they provide, in Unocal/OXY's view, no compelling evidence that West Coast Naphtha should be valued higher than Gulf Coast Naphtha. *Id.* They explain that, focusing on the 1999-2001 period, which represent a majority of the volumes in the studies, one dominant purchaser consistently paid materially higher prices than other purchasers, one paid consistently lower prices, and others were in the middle. *Id.* at pp. 34-35. Further, state Unocal/OXY, the largest purchasers rarely bought at the same time, meaning that there was no or very little competition to set prices. *Id.* at p. 35. The monthly prices paid by buyers reflected average differences of 15.6¢/gallon, and, therefore, state Unocal/OXY, there was no market clearing price during those months. *Id.* Unocal/OXY conclude that this means that the market was far from transparent. *Id.*

1922. Although the contracts do not provide evidence of the market value of West Coast Naphtha, Unocal/OXY contend, they provide isolated or anecdotal evidence respecting West Coast Naphtha transactions, particularly for the pre-1999 time period. *Id.* They assert that the evidence introduced by O'Brien, Pulliam, Tallett, and Culberson validates the continued use of Gulf Coast pricing. *Id.* (citing Exhibit Nos. EMT-380, EMT-381, PAI-154, PAI-224, SOA-15, SOA-16). For the period prior to 1999, Unocal/OXY state, three of these studies (Pulliam's, Tallett's, and Culberson's) show that the unadjusted average price of the Naphtha contracts is no more than two cents above the average Gulf Coast price for the period. *Id.* at pp. 35-36 (citing Exhibit Nos. SOA-25, EMT-380, UNO-20). They also maintain that, in light of the fact that Platts does not even include contracts such as those included in these studies when it develops a price assessment, differences of this magnitude are inconsequential. *Id.* at p. 36. Furthermore, Unocal/OXY point out, Culberson testified that, when contracts for Naphtha are made on the Gulf Coast, they often include a price that includes an adjustment of a penny or two from the referenced Platts price. *Id.* The much larger differentials between the contract prices and Gulf Coast prices shown for the 1999-2001 period, in their view, should be ignored because the contract sample is dominated by a very small number of purchasers operating in a non-transparent market during an aberrational period of extreme gasoline price volatility. *Id.* By contrast, explain Unocal/OXY, the pre-1999 period is not compromised by these features, and the data are therefore more reliable. *Id.*

1923. In addition, Unocal/OXY assert, problems with nomenclature cause counter-intuitive results that call into question the validity of the contract data. *Id.* at p. 37. They note that Ross testified that Full Range Naphtha should command a lower price than Heavy Naphtha. *Id.* Yet, Unocal/OXY note, when Tallett's Heavy Naphtha study is compared to his All Accepted Contracts study some interesting results are evident. *Id.*

(citing Exhibit Nos. EMT-380, EMT-381). According to Unocal/OXY, the straight average of contract prices for the All Contracts set is higher than the straight average for the Heavy Naphtha set. *Id.* Unocal/OXY explain that the pricing anomaly occurs in individual contracts as well: Ross identified three specific contracts that priced both Heavy Naphtha and Full Range Naphtha in the same contract, and set the prices equal. *Id.* Based on the foregoing, it is Unocal/OXY's position that the contracts for West Coast Naphtha transactions do not provide credible evidence that West Coast Naphtha has a higher value than Gulf Coast Naphtha. *Id.*

1924. Moreover, Unocal/OXY assert that the results of the contract analysis are inconsistent. Unocal/OXY Reply Brief at p. 77. They state that Pulliam testified that Exhibits Nos. SOA-24 and SOA-28 support the O'Brien methodology because "it came closer to the contract prices than any of the Gulf Coast based methodologies." *Id.* at pp. 77-78 (quoting Transcript at p. 7449). However, Unocal/OXY note, Pulliam eventually conceded that the Sanderson/Culberson method was closest for 1994-1998 and Tallett's method came closest if the whole period was considered. *Id.* at p. 78. Further, Unocal/OXY state, Pulliam ultimately agreed that the O'Brien method only produced the closest match during the 1999-2001 period, a period which Unocal/OXY calls "anomalous." *Id.* They note that Pulliam continued to defend the O'Brien method at the hearing, even though he acknowledged that the 1999-2001 period was characterized by refinery outages, supply constraints, elevated gasoline prices, and a relatively less competitive market. *Id.*

1925. Unocal/OXY state that, as the contract analyses are more or less consistent in terms of their overall pricing averages, all pose the same problem that Pulliam confronted. *Id.* They note that all the proposed methodologies plus the existing valuation method can claim some legitimacy from some part of the contract analyses. *Id.* Unocal/OXY argue that the contract analyses do not, however, all support a single consistent methodology throughout the period and assert that, because they don't, they are not robust and the contract analyses is of only questionable utility in this proceeding. *Id.*

6. Williams

1926. Williams asserts that no party to this proceeding considered any West Coast Naphtha contracts relevant to this proceeding or likely to provide any probative evidence in its pre-filed direct testimony. Williams Initial Brief at p. 44. It suggests that the subsequent attempts by proponents of a change to the valuation method for West Coast Naphtha to use these contracts to show their proposals are sound are misguided and argues that the hearing record reflects that the Naphtha contracts do not serve any such purpose nor do they provide any relevant or probative evidence going to the value of Naphtha on the West Coast. *Id.*

1927. According to Williams, O'Brien, Pulliam, and Tallett attempted to coordinate their testimony to show the extreme subjectivity of this analysis and to indicate the potential for manipulation of the limited West Coast Naphtha contract data. *Id.* at p. 45. It cites Exhibit Nos. PAI-82, PAI-156, and PAI-157 as proof that the three analysts were constantly changing their testimony so that eventually they would all use the same set of contracts, noting that O'Brien's data points kept changing as contracts were removed from his Heavy Naphtha contract analysis, and others were added in.[649] *Id.* Williams argues that this was particularly true of O'Brien's attempt to align his data points with those of Pulliam because they both supported the Phillips's proposal. *Id.* at pp. 45-46.

1928. Williams suggests that a problem with Pulliam's analysis is that he elected to ignore the actual pricing contained in a number of the West Coast Naphtha contracts; instead using a monthly average price. *Id.* at p. 47. They note that, even though Pulliam presented various rationalizations for doing this, he had to agree that this approach skewed the results.[650] *Id.* Williams points out that Pulliam admitted that Exhibit No. WAP-194, which graphs the variations in Pulliam's Naphtha contract values from month-to-month, shows that the actual monthly average is not at a consistent point in the monthly range. *Id.* Pulliam's answer was that it is volume-weighted, according to Williams, so it reflects the average price paid for all the transactions in the month. *Id.* at pp. 47-48.

1929. The other specific difference in contract interpretations and their impacts, Williams contends, is shown on Exhibit No. WAP-195, involving a contract between Company 32 and Phillips that both O'Brien and Pulliam included in their equivalent contract analyses. *Id.* at p. 48. It claims that Pulliam used 40,000 barrels because he said it was the volume specified in the contract, while O'Brien used 50,895 barrels which Pulliam understood to be the number of barrels that was actually delivered under that

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[649] In Williams's opinion, Pulliam's changes were the result of his not being sufficiently trained to do such contract analyses. Williams Initial Brief at p. 45, n.33. Further, Williams notes, Tallett, through a series of changes to his contract analysis, brought his contract analysis closer to his, as well as O'Brien's, calculated Naphtha values. Williams Initial Brief at p. 45, n.34.

[650] Williams notes that Pulliam attempts "to wiggle off the hook" by explaining that he ran some sensitivity tests "that allegedly show how little things would change if actual contract pricing was used." Williams Initial Brief at p. 47, n.37 (referring to Exhibit No. SOA-23). It asserts that the problem with the sensitivities is the same fundamental flaw with Pulliam's entire contract analyses, i.e., his failure to analyze the contracts correctly and accurately in the first instance results in his conclusions being suspect. *Id.*

contract for that month.[651] *Id.* Thus, notes Williams, there was a variation, for this particular transaction, of 20 to 25% in volume. *Id.* Therefore, Williams notes that, as Pulliam testified, O'Brien will have a higher average price in this case than he would. *Id.* Williams explains that this difference underscored another problem with the contract analyses: the persons performing them did not have the actual volumes delivered under all the contracts. *Id.* Consequently, it contends, Pulliam conceded that, because his analysis is volume weighted, as the volume of the contract varies, his answer would also vary. *Id.* at pp. 48-49.

1930. The other area of concern where questions arise with respect to the contracts, according to Williams, is the impact on the contract pricing results which a single company can potentially have. *Id.* at p. 49 (citing Exhibit No. WAP-200). It explains that this Exhibit shows that, from 1999-2001, a single company which started purchasing Naphtha in 1998 became the dominant purchaser; going from 23.6% of the contract purchases in 1999 to a staggering 83.3% of the contract purchases in 2001. *Id.* While Pulliam testified that he did not think there was any special significance to this, the issue as to the impact is magnified because that same company (Company 31) was one of two companies that paid the highest prices for Naphtha during this period. *Id.* at pp. 49-50 (citing Exhibit Nos. WAP-8, WAP-141, WAP-230, WAP-231). Yet, Williams notes, Pulliam placed no significance on Company 31's suddenly dominant role in Naphtha purchases. *Id.* at p. 50.

1931. In reply, Williams states, the underlying bases of the analyses of the Naphtha contracts produced in this proceeding renders any conclusions dubious. Williams Reply Brief at p. 50. It notes that Phillips points to the congruence of the results as its reason for arguing that criticism of the contract analysis is without merit. *Id.* However, Williams points out, part of the similarity of the results was derived by O'Brien and Pulliam to a greater extent, and Tallett (with the assistance of Toof) to a lesser extent, because of their attempts at reconciliation of the results so that the contracts relied upon and the results there from were in closer harmony. *Id.*

1932. Sanderson testified, Williams claims, that companies such as Platts who report price assessments limit their assessments to cash spot transactions. Williams Initial Brief at p. 50. According to Williams, this renders Pulliam's contract analysis, as well as those of O'Brien and Tallett, inconsistent with other Quality Bank price assessments. *Id.* at pp. 50-51. It states that the consequence of this is shown in Exhibit No. WAP-230 which, it claims, shows that, for the period 1994-2001, the total average daily volume of Heavy Naphtha contracts (according to Tallett's contracts analysis) is 1,100 barrels/day and for

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[651] Williams notes that Pulliam admitted that he made a data entry error with respect to the contract volume that he used for this particular contract. Williams Initial Brief at p. 48, n.38.

the period 1999-2001 it is only slightly higher, 1,260 barrels/day. *Id.* at p. 51. Williams calls this volume "a drop in the bucket," amounting to no more than 0.4% of the Naphtha throughput, when compared to the overall throughput of 337,000 barrels/day of straight run Naphtha in reformers. *Id.* Williams states that, also as shown on Exhibit No. WAP-230, the spot volumes for these two periods are reduced by approximately 25% and 33%, respectively, or below 1,000 barrels/day in both instances, when Company 31's volumes are removed. *Id.* Thus, on the basis used by Platts and other independent reporters of petroleum intermediate feedstock prices (spot transactions), it states, this almost non-existent volume renders the Naphtha contracts virtually meaningless with respect to a meaningful indication of the value of Quality Bank West Coast Naphtha. *Id.*

1933. In Williams's view, the fact that these small volumes have no relevance is buttressed by O'Brien's deposition testimony (incorporated into Sanderson's pre-filed rebuttal testimony) concerning the subject, in which he stated that these contracts do not represent a market price, because they make up only a very small portion of the total Naphtha processed through West Coast refineries. *Id.* at pp. 51-52. At his deposition regarding his answering testimony, Williams notes that O'Brien quantified substantial contract volume, stating he would consider substantial volumes to be 40-50,000 barrels/day and that to establish a market you would need that kind of daily trade. *Id.* at p. 52. Thus, even if one disregards this small volume of spot contracts, which is all that Platts would have to rely on in giving an assessment, Williams states, the highest total daily volume of all the Heavy Naphtha contracts for the most recent three years (1999-2001), is 1,260 barrels/day, which does not even come close to O'Brien's threshold to establish a market price. *Id.*

1934. Williams asserts that Exxon improperly references the Naphtha contracts as demonstrating "that Naphtha sellers have been able to extract a substantial portion of any higher West Coast refining margin." Williams Reply Brief at p. 49. In doing so, Williams notes, Exxon relied upon incomplete Sanderson testimony. *Id.* at pp. 49-50 (citing Transcript at pp. 11224, 11230). It argues that, if one looks at the complete Sanderson testimony, it is clear that that Exxon's assumption applies at best to no more than 1% of the Naphtha volume on the West Coast (the volume represented by the Naphtha contracts) and not to the other 99% of the West Coast Naphtha. *Id.* at p. 50.

1935. In Williams's opinion, the West Coast Naphtha contracts that were used in the various analyses show five points that are not subject to subjective adjustment or interpretation: (1) the West Coast Naphtha market is not robust, which is consistent with the West Coast Naphtha supply/demand being in balance; (2) most recent cargoes ported are more of a Full Range Naphtha cut tailored to meet CARB gasoline specifications; (3) the largest volume contract, "the Contract that Ross relies on," contains ANS + $4.00/barrel in the pricing formula; (4) only one contract has any N+A adjustment, and that was a penalty provision; and (5) the spot contract volume is minuscule. Williams Initial Brief at p. 53.

1936. Williams notes that Exxon states that "the reasonableness of the West Coast Naphtha values determined by [Tallett's] methodology is strongly confirmed by the fact that [Tallett's] West Coast Naphtha values are very close to the actual West Coast Naphtha prices found in the West Coast Naphtha contracts." Williams Reply Brief at p. 55 (quoting Exxon Initial Brief at p. 263). It asserts that the fallacy in Exxon's argument is that those contracts reflect how Naphtha is priced for small volume sales and thus do not reflect its value. *Id.* Williams argues that pricing Naphtha at a discount to unleaded regular gasoline is the mechanism buyers and sellers use to price small volume purchases and ensure that the price of Naphtha is indexed to other petroleum commodities to reduce the financial risk to both buyer and seller of a price change in Naphtha. *Id.* at pp. 55-56. It maintains however, that the fact that contract Naphtha prices are related to gasoline prices through a price discount to gasoline does not have a bearing on the valuation methodology. *Id.* at p. 56. Williams notes that Sanderson explained that the ability to hedge

> can be built into the transaction. For instance, if you sell naphtha based on a discount to unleaded gasoline or to CARB gasoline, you can hedge in that way. Because then if the gasoline price falls, the naphtha value falls, so the refiner gets that advantage or the receiver gets that advantage. The producer does not.

Id. (quoting Transcript at pp. 9200-01).

7. Petro Star

1937. According to Petro Star, Phillips, Exxon and Alaska assert that the West Coast Naphtha contracts examined by O'Brien, Tallett, and Pulliam corroborate the methodologies proposed by O'Brien and Tallett and repudiate the fairness of the current methodology. Petro Star Initial Brief at p. 3. It argues that the contracts accomplish none of those objectives. *Id.* In particular, Petro Star states, there is little, if any, reason to believe that the prices reflected by the contract transactions fairly represent the value of the vast bulk of Naphtha produced in or imported to the West Coast.[652] *Id.*

1938. Petro Star states that the proponents of higher West Coast Naphtha valuations

[652] Petro Star states that the issues concerning the Naphtha contracts break down into questions concerning whether the contracts are likely to shed light on the value of Naphtha as it is produced and used on the West Coast and those concerning precisely what the contract data show, assuming that they are useful. Petro Star Initial Brief at p. 3, n.4. It notes that its brief focuses only on the former question and does not duplicate the detailed criticisms of the contract analyses presented by Williams and Unocal/OXY. *Id.*

proffer a number of arguments why the Naphtha contracts are representative of Naphtha generally, but none of those arguments changes the fact that the contracts represent only a tiny fraction of the West Coast Naphtha volume. Petro Star Reply Brief at p. 3. It asserts that, most importantly, none of them surmount the fact that Naphtha typically is not bought and sold as a commodity on the West Coast. *Id.*

1939. Explains Petro Star, almost all Naphtha that is used on the West Coast is distilled from crude oil by the refineries that use it to manufacture gasoline and/or jet fuel. Petro Star Initial Brief at p. 4. According to it, Naphtha is, therefore, typically neither bought nor sold as such, and the cost of Naphtha to the refiner is the cost of crude oil plus the cost to distill the crude. *Id.* Petro Star states that the "typical" West Coast Naphtha barrel thus arrives at the refinery gate as a crude oil component, whether from California, Alaska or elsewhere. *Id.* It points out that the refinery distills crude oil, further processes most of the Naphtha to produce gasoline blendstocks, and uses most of the remainder to manufacture jet fuel. *Id.* The refinery sells finished gasoline and jet fuel, not Naphtha states Petro Star *Id.*

1940. Further, according to Petro Star, a typical catalytic reformer on the West Coast processes from 30,000 to 40,000 barrels of Naphtha per day. *Id.* at p. 5. It states that refiners buy crude oil to distill the Naphtha they need to fill their reformers or make jet fuel. *Id.* Notes Petro Star, approximately 337,000 barrels/day of Naphtha typically are distilled from crude oil on the West Coast and used according to the general pattern described above. *Id.*

1941. By contrast, according to Petro Star, refiners buy Naphtha, as opposed to crude oil, very occasionally, and in small quantities. *Id.* at p. 5. For example, notes Petro Star, Pulliam's combined contract (i.e., both "Spec" and "Potential" Naphtha) indicated that annual Naphtha contract volumes for the period 1994 through 2001 ranged from a low of 1260 barrels/day in 1998 to a high of 7190 barrels/day in 2000. *Id.* In other words, states Petro Star, even if a single refiner operating a typical 30,000-40,000 barrel/day catalytic reformer had purchased all of the Naphtha sold under the contracts in 2000, it still would have refined three-fourths of its Naphtha feed from crude oil. *Id.* In fact, points out Petro Star, the largest Naphtha purchaser in 2000 bought 30.3% of the total, or approximately 2200 barrels/day.[653] *Id.*

[653] Petro Star states that it focuses on Pulliam's contract analysis because he testified most extensively about the issue of whether the contract data were representative of Naphtha purchased as crude oil and refined internally. Petro Star Initial Brief at p. 5, n.5. It explains that the contract analyses performed by Tallett and O'Brien did not involve sample sizes that were materially different from Pulliam's. *Id.* Consequently, in Petro Star's view, the arguments it makes regarding the contracts analyzed by Pulliam apply equally well to Tallett's and O'Brien's analyses. *Id.*

1942. These small volumes of Naphtha represent a very limited number of transactions, in Petro Star's opinion. *Id.* For the entire West Coast, notes Petro Star, Pulliam's combined contract database includes 175 contracts over the entire period 1994 through 2001, somewhat less than two per month on average. *Id.* Even during the more recent period 1999 through 2001, Petro Star states, there are only 94 contracts, or fewer than three per month. *Id.* Petro Star argues the Naphtha contracts do not represent a large enough sample to accurately reflect all of Naphtha refined on the West Coast. *Id.* More importantly, states Petro Star, the vast bulk of West Coast Naphtha is not involved in the same kind of transaction as the Naphtha traded under the contracts. *Id.* at p. 6.

1943. Pulliam acknowledged, Petro Star suggests, that a random sample must be representative of the population from which it is drawn to be valid. *Id.* However, states Petro Star, he opined that Naphtha contract prices are representative of the value of Naphtha that was purchased as crude oil and refined rather than sold. *Id.* Petro Star explains that Pulliam looked to the stock market to explain why, claiming that the value of a stock to the owner who does not sell on any given day is represented by the value (selling price) of the one percent that is traded on a given day. *Id.* Pulliam explained, continues Petro Star, that he believes that a refiner that uses Naphtha internally only does so after deciding not to sell it. *Id.*

1944. In fact, asserts Petro Star, once Pulliam's implicit assumptions are tested against the realities of refining economics, the stock market analogy better illustrates why the contracts are not representative of the value of West Coast Naphtha. *Id.* at p. 7. It indicates that Pulliam's theory is that 99% of the Naphtha that does not trade is valued at the same price as the 1% that was sold, according to Petro Star, because any one of the non-selling shareholders could have sold his or her stock at that same price. *Id.* Petro Star states that Pulliam assumes that the reverse, if any refiner wanted to sell, it could find a buyer for its Naphtha at or near the prices in the contracts analyzed by Pulliam, also is true. *Id.*

1945. According to Petro Star, this is unlikely to be the case, because the Naphtha market essentially is in balance on the West Coast. *Id.* Consequently, according to Petro Star, refiners have a choice: they can either buy Naphtha or they can buy crude oil. *Id.* There is no dispute that refiners typically build their refineries to process crude oil, and the one thing that the contract data unequivocally show, states Petro Star, is that demand for purchased Naphtha is very limited. *Id.* Indeed, asserts Petro Star, none of the reasons that O'Brien recounted for why large refiners might trade Naphtha back and forth are routine. *Id.* Moreover, notes Petro Star, Tallett testified that, if you imported a cargo of gasoline into California, you would hope to sell it for a reasonable price, but if you imported Naphtha you might or might not find people that would pay a reasonable price. *Id.* at pp. 7-8. Petro Star states that O'Brien similarly testified that a few isolated California refiners sell Naphtha outside California because there is no local market. *Id.*

Finally, notes Petro Star, each of the small refiners that Pulliam reported closed in spite of being fully capable of producing Naphtha. *Id.* (citing Exhibit WAP-199 at p. 22.)

1946. At best, asserts Petro Star, the most that the price of the 1% can indicate is the value of the small volume of Naphtha that is traded as a commodity rather than purchased as crude oil. Petro Star Reply Brief at p. 4. According to Petro Star, the contract proponents's arguments that the Naphtha contracts are broadly representative rests on the mistaken assumption that all of the Naphtha on the West Coast is constantly in play in a vibrant Naphtha market. *Id.* Thus, states Petro Star, Baumol tacitly assumes that the prices contained in the Naphtha contracts are indeed widely available when he testified that, if a refinery uses Naphtha internally that could be sold at a price higher than its internal value, then the refiner could be subject to a shareholder derivative suit. *Id.* Moreover, notes Petro Star, Baumol's hypothetical rests on the high prices being persistent. *Id.* If in fact there were persistent high prices available for Naphtha, Petro Star argues, there would be imports of Naphtha into the West Coast and it states that Baumol testified he also believed that would be true. *Id.* However, asserts Petro Star, deals for Naphtha sales are struck so infrequently that it would be rash to assume that because Company A got a high price for Naphtha, Company B could get the same high price. *Id.* at p. 5.

1947. Further, notes Petro Star, Alaska argues that "specific knowledge about the refining industry" indicates that the contract data accurately reflects the value of West Coast Naphtha that is not bought and sold as a commodity. *Id.* at p. 6 (quoting Alaska Initial Brief at pp. 8-9). It notes that Alaska contends that constant refinery optimization essentially means that refineries always make the choice whether to refine Naphtha from crude and use it themselves, or to buy and sell it as a commodity. *Id.* at pp. 6-7.

1948. Petro Star also claims that Alaska cites Culberson's testimony concerning a refiners options to change the crude slate, the boiling ranges, the cut points, import VGO, and make decisions as to how to satisfy its Naphtha demand, as an example. *Id.* at p. 7. According to Alaska, notes Petro Star, these examples provide the linkage between the contract prices and the value of internally used Naphtha. *Id.* In fact, asserts Petro Star, they merely confirm that refineries buy or sell only very small volumes of Naphtha. *Id.* It states that the Alaska conceded that Sanderson's remarks only pertained to those instances where the refinery actually made Naphtha purchasing decisions when it was more economical to buy from an outside source. *Id.* Moreover, asserts Petro Star, except for VGO importing, the routine optimization decisions that Culberson described all illustrate how a refinery in the ordinary course of business trims its Naphtha supply by adjusting how it processes crude oil – not by purchasing commodity Naphtha. *Id.* at pp. 7-8. Therefore, concludes Petro Star, the knowledge relied upon by Alaska shows that Naphtha volumes sold under contract are small, precisely because almost all West Coast Naphtha is purchased and used according to a different pattern. *Id.* at p. 8.

1949. None of the contract proponents's arguments, Petro Star contends, designed to show that the small sample reflected in the Naphtha contracts is either adequate or representative have merit. *Id.* While 1% might comprise an adequate sample size under some circumstances, Petro Star maintains it doesn't in this case. *Id.* It explains that when using small samples, it is necessary to design them carefully so that they are representative of the large group of data you are sampling and not just one segment. *Id.* In the case of the Naphtha contracts, states Petro Star, just one segment of the population is picked. *Id.* Virtually none of the Naphtha used on the West Coast is traded as a commodity, notes Petro Star, but all of the data come from the one or two percent that is. *Id.*

1950. Petro Star suggests that the argument that the pricing services rely on a small number of transactions to derive their quotations to be equally unpersuasive for three reasons. *Id.* First, states Petro Star, the pricing services themselves do not believe that there is sufficient information available to support quotations for West Coast Naphtha. *Id.* Second, states Petro Star, and contrary to the premise of the argument, the pricing services do not simply extrapolate from transactional data to arrive at their prices. *Id.* For example, Platts quotes are its assessment of where Naphtha could be traded. *Id.* at pp. 9-10. If, instead of relying on contacts and exercising judgment, the pricing services had to rely on the Naphtha contracts, Petro Star argues that they frequently would have to accept the price for one or a very few individual, and frequently stale, contracts as the prevailing Naphtha price. *Id.* at p. 10. Finally, the bulk of the Naphtha contracts are term contracts, notes Petro Star, which the pricing services find to be unreliable as price indicators because they may not reflect the current market. *Id.*

1951. Market realities thus, according to Petro Star, contradict Pulliam's assumption that a refiner could find a buyer for its Naphtha at or near the prices in the contracts that Pulliam examined.[654] Petro Star Initial Brief at p. 8. There is no evidence, according to Petro Star, that any West Coast refiner uses purchased Naphtha as more than a small fraction of its reformer feed. *Id.* at p. 9. Further, states Petro Star, there is no evidence that the prices contained in the Naphtha contracts are representative of the value of

[654] Petro Star asserts that there is an additional reason why the prices in many of the contracts that Pulliam analyzed may not be representative. Petro Star Initial Brief at p. 8, n.6. It explains that term contracts, as opposed to spot contracts, may no longer reflect market prices when delivery occurs. *Id.* For this reason, states Petro Star, Platts uses spot, not term contracts, and avoids contracts where the Naphtha price is set up as a function of gasoline minus a differential and the differential doesn't change with the market on a day-to-day basis. *Id.* Petro Star points out that the majority of the contracts analyzed by Pulliam price Naphtha in this manner. *Id.* Similarly, concludes Petro Star, fewer than half of the "Heavy Naphtha" contracts analyzed by Tallett during the crucial 1999-2001 period were spot contracts. *Id.*

anything other than the very small Naphtha volumes traded under the contracts. *Id.* Thus, it concludes, the Naphtha contracts should not be used to validate or invalidate any of the methodologies at issue in this proceeding. *Id.*

1952. Petro Star explains that contract proponents argue that the Naphtha contracts must be important because they represent so many transactions, so many barrels of Naphtha, and so many dollars. Petro Star Reply Brief at p. 10. It states that these arguments emphasize that, in absolute terms, the numbers associated with purchases and sales of Naphtha on the West Coast are large. *Id.* They do not, notes Petro Star, address the fact that most West Coast refiners acquire all or almost all of the Naphtha they use without purchasing it as a commodity, and, as a consequence, the number of actual deals struck is small. *Id.*

1953. According to Petro Star, the highest number of Naphtha contracts included in any witness's study was the 192 included in Tallett's, or only 24 contracts per year on the West Coast. *Id.* It states that these were contracts for all types of Naphtha for the eight-year, 1994-2001, period. *Id.* at pp. 10-11. Petro Star explains that more contracts are available from recent years than earlier, but even during the more recent 1999-2001 period, the contract analyses include fewer than three contracts per month. *Id.* at p. 11. In addition, continues Petro Star, these 94 contracts were spread among 12 different buyers, so that, on average, each of the refineries that did buy Naphtha during the period contracted to do so fewer than three times per year. *Id.*

1954. Petro Star points out that contract proponents attempt to bolster the significance of the contracts by emphasizing the sophistication of the transacting parties. *Id.* (citing Exxon Initial Brief at p. 242). But, according to Petro Star, Baumol, Toof, and Pulliam, cited as sources for that conclusion, did not claim any knowledge about the specific business underpinnings of the Naphtha contracts. *Id.* Further, asserts Petro Star, this depiction of an active, vibrant market for Naphtha is not borne out by the evidence. *Id.* at p. 12. Petro Star concedes that some individual contracts involve careful negotiation and it probably may be assumed that careful consideration went into the negotiation of the very large volume contracts, but the same assumptions should not be made of the small lots transported by truck. *Id.* If a transaction involves only a very small volume, Petro Star asserts that even a company like BP might not bring all of its sophistication to bear upon it. *Id.*

1955. Moreover, Petro Star takes the view that, in the absence of market transparency, it appears very unlikely that Naphtha purchasers who on average enter into fewer than three contracts per year are necessarily "particularly well informed buyers . . . who are regular participants in the Naphtha market," whether or not they represent very large firms. *Id.* (quoting Exxon Initial Brief at p. 246). Indeed, Petro Star points out that Exxon asserts that Toof's own analysis showed the average Naphtha price from 1992 through 2001 was the same whether one viewed Full Range or only Heavy Naphtha contracts, or volume weighted the contracts. *Id.* Petro Star argues that it seems unlikely that keen and sophisticated Naphtha buyers and sellers would value Full Range and Heavy Naphtha the same, or make transactions at prices irrespective of volume. *Id.*

1956. Petro Star explains that Toof conducted two sets of statistical analyses that attempted to prove the validity of the contract analysis: (1) he sought to predict Gulf Coast Naphtha prices using a regression formula derived from West Coast contract Naphtha prices and unleaded regular gasoline prices; and (2) he conducted "sensitivity" analyses to investigate the results of the contract analysis if different subgroups of the contracts were used or different assumptions were made in assigning prices to the different contracts. *Id.* at p. 13. In Petro Star's opinion, neither of these approaches did anything to prove that the Naphtha contracts prices are representative of Naphtha that is refined and used within refineries. *Id.*

1957. Exxon argues, Petro Star claims, that Exhibit Nos. EMT-360 and EMT-366, which compare actual Gulf Coast Naphtha prices with those predicted by a regression formula calculated using West Coast unleaded regular gasoline prices and Pulliam's and Tallett's contract databases, show there is a close relationship between gasoline prices and Naphtha prices on both the Gulf and the West Coasts. *Id.* In Petro Star's opinion, the exhibits, at most, show the relationship between gasoline prices and the Naphtha contract prices on the West Coast, but little or nothing about the relationship between gasoline prices and the West Coast Naphtha refined and utilized within refineries. *Id.* Petro Star asserts that the Naphtha contract prices reflect different economics than those that govern internally refined Naphtha. *Id.* at pp. 13-14.

1958. Toof's sensitivity analyses, according to Petro Star, similarly are irrelevant to the question of whether the contracts are representative of West Coast Naphtha, and Exxon's conclusion that the contracts show that Naphtha's value on the West Coast is significantly higher than its value on the Gulf Coast should similarly be limited to the value of the Naphtha contracts. *Id.* at p. 14.

E. IF CURRENT NAPHTHA VALUE IS NOT JUST AND REASONABLE, WHAT METHODOLOGY SHOULD BE USED?

1. Exxon

1959. Exxon states that the evidence is overwhelming that the current Quality Bank practice of using Platts Gulf Coast Naphtha price to value West Coast Naphtha does not produce a just and reasonable result and that, therefore, the Commission needs to determine what alternative methodology should be used instead to value West Coast Naphtha. Exxon Initial Brief at p. 251. It declares that Tallett's approach is the best methodology because it is based on West Coast market prices and a proven relationship between the value of Naphtha and the market prices of gasoline and jet fuel, the two products that are produced from Quality Bank Naphtha. *Id.* Also, Exxon asserts, the Tallett methodology produces a result that, it claims, is easy to administer and not subject to manipulation by any party. *Id.*

1960. Tallett, explains Exxon, derived a simple formula to value Naphtha on the West Coast based on the published West Coast prices of regular unleaded gasoline and jet fuel. *Id.* at p. 253. Exxon asserts that this methodology is analytically sound and produces a just and reasonable result for two reasons: first, Exxon notes, the primary use for Naphtha, on both the Gulf and West Coasts, is to make jet fuel and gasoline and published prices exist on both coasts for both products; second, Exxon points out, regression analysis performed by Tallett shows that the price of Naphtha on the Gulf Coast is almost entirely explained by the published prices of gasoline and jet fuel on the Gulf Coast. *Id.* at pp. 252-53.

1961. It is undisputed, according to Exxon that the primary use of Naphtha on both the Gulf Coast and the West Coast is to make gasoline, generally via catalytic reforming of Naphtha to raise its octane. Exxon Initial Brief at pp. 253-54. Further, Exxon claims, it is undisputed that the market value of Naphtha on both the West Coast and the Gulf Coast is determined primarily by its value in producing gasoline. *Id.* at p. 254. It also is undisputed, continues Exxon, that another use of Naphtha on both the West Coast and the Gulf Coast is to take the high end of the Quality Bank Naphtha cut and blend it into jet fuel.[655] *Id.* at p. 255. As a result, states Exxon, the value of Naphtha also is influenced by the price of jet fuel. *Id.*

1962. The evidence further shows, according to Exxon, that refiners have the ability to vary the output of their refineries depending upon market conditions by changing the cut point and thereby changing the proportion of Naphtha to be made into gasoline or jet fuel. *Id.* In addition, explains Exxon, depending upon the relative prices of gasoline and jet fuel, a refiner can vary the output of its hydrocracker to produce more or less jet fuel, with a corresponding reduction or increase in the amount of hydrocracker Naphtha produced. *Id.* at p. 256. Moreover, the evidence shows that there are times when jet fuel is actually more valuable to the refiner than gasoline, and that, in those situations, refiners increase the amount of the Naphtha cut that is processed into jet fuel. *Id.* Because of these close and undisputed relationships between Naphtha, gasoline, and jet fuel, Exxon states, Tallett employed a standard linear regression analysis to determine the relationship

[655] Exxon points out that Ross, who initially contended that the use of Naphtha in jet fuel was wrong, withdrew that testimony, thereby conceding that some refiners do blend the 300°-350°F cut into jet fuel. Exxon Initial Brief at p. 255, n.99. Exxon also notes that Ross's estimate that less than 5% of Naphtha is blended into jet fuel was shown to be based on a miscalculation by Ross, and the correct percentage of Naphtha blended into jet fuel shown by Ross's own numbers was nearly 16%. *Id*

between the prices of Naphtha, regular unleaded gasoline, and jet fuel based on published prices for all three products which are available on the Gulf Coast.[656] *Id.* This regression analysis showed an almost perfect correlation between the price of Naphtha and the prices of both unleaded gasoline and jet fuel. *Id.* at pp. 256-57.

1963. Claiming to have established that the price of Gulf Coast Naphtha is almost totally explained by the price of Gulf Coast unleaded gasoline and jet fuel, Exxon argues, Tallett's analysis shows that the value of West Coast Naphtha for the period 1992 through 2001 was on average approximately $24.91/barrel, or about $2.44/barrel higher than the average Gulf Coast Naphtha during the same period. *Id.* at p. 257.

1964. It is also apparent from the evidence, according to Exxon, that Tallett's approach is a conceptually sound way to value Naphtha on the West Coast, even though Williams disputes the transferability of the approach. *Id.*; Exxon Reply Brief at p. 273. The same processes, states Exxon, are used on both the Gulf Coast and the West Coast to process Naphtha into reformate to make gasoline and for blending the high end of the Naphtha cut into jet fuel. Exxon Initial Brief at p. 257. In addition, explains Exxon, the specifications for Naphtha on the two coasts are identical, as is the pricing point (waterborne) for all of the published prices. *Id.* It follows, according to Exxon, that the same relationship that exists on the Gulf Coast between the value of Naphtha and the prices of gasoline and jet fuel should also exist on the West Coast. *Id.* at pp. 257-58. Moreover, because Tallett's regression formula is derived from the relationship between Naphtha and the prices for both gasoline and jet fuel, rather than gasoline alone, Exxon asserts, it also has the advantage of tending to reduce the impact of price spikes that arise during periods of West Coast gasoline price volatility. *Id.* at p. 258.

1965. Exxon states that the validity of Tallett's approach is corroborated by Baumol's testimony that Tallett's Gulf Coast-derived regression formula is transferable to the West Coast because it produces results similar to O'Brien's independent analysis.[657] *Id.* at pp. 259-60. It also notes that Toof's pooled data test results lend further support to the transferability of Tallett's Gulf Coast-derived regression formula to the West Coast. *Id.* at p. 260. These pooled data tests, according to Exxon, showed that there is no statistically significant difference between the relationship of Naphtha, gasoline and jet

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[656] Exxon argues that regression analysis is a standard, straight-forward means of assessing the quantitative relationship among variables. Exxon Initial Brief at p. 256, n.100. Further, notes Exxon, no party contends that Tallett's methodology is inappropriate because it uses regression analysis to value West Coast Naphtha. *Id.* Finally, Exxon notes, the Circuit Court has made clear that methods based on regression analysis cannot be summarily rejected. *Id.* (citing *Tesoro*, 234 F.3d at p. 1291).

[657] *See* Exhibit No. PAI-147.

fuel between the two coasts and no structural difference between the two markets. *Id.* at pp. 260-61. Thus, states Exxon, the pooled data test results confirmed Tallett's hypothesis that the prices of Naphtha, regular unleaded gasoline, and jet fuel are related to each other on the West Coast in the same manner as they are related on the Gulf Coast. *Id.* at p. 261.

1966. Moreover, the reasonableness of Tallett's methodology is supported, in Exxon's view, by the rule of thumb used by Kutola, an experienced Naphtha trader. *Id.* at p. 267. Exxon explains that this rule of thumb calculates typical values for Naphtha on the West Coast as being from 61.97 to 68.97¢/gallon, or from $26.03 to $28.97/barrel, depending upon the quality of the Naphtha being valued. *Id.* at pp. 267-68. Because the Naphtha produced from ANS crude is good quality Naphtha due to its high N+A, this means, notes Exxon, that the formula identified by Kutola would value the West Coast Naphtha cut produced from ANS crude at a price significantly higher than the value produced by Tallett's methodology. *Id.* at p. 268.

1967. Exxon states that the reasonableness of Tallett's methodology is also confirmed by the results derived when Naphtha's value is calculated as a function of gasoline and crude oil prices. *Id.* at pp. 269-70. Thus, explains Exxon, if the price of Naphtha is determined as a percentage of the range between the price of gasoline and the price of crude oil using Gulf Coast prices, and this same percentage is then used to calculate a West Coast price of Naphtha using the price of gasoline and the price of ANS crude oil on the West Coast, the result is very close to Tallett's average West Coast Naphtha value for the same period. *Id.* at p. 270.

1968. Criticisms of Tallett's approach are, according to Exxon, wholly without merit. *Id.* at p. 270. Its position is that the evidence clearly demonstrates the validity of the Tallett approach and supports the transferability to the West Coast of the proven relationship between the prices of Naphtha, gasoline, and jet fuel that Tallett found to exist on the Gulf Coast. Exxon Reply Brief at p. 279. Exxon states there is no merit to the suggestion that Tallett's West Coast Naphtha valuation violates the Commission's order in *Trans Alaska Pipeline System*, 90 FERC ¶ 61,123 (2000). Exxon Initial Brief at p. 270. It explains that that order dealt with how a published price for West Coast Heavy Distillate should be adjusted to account for the fact that the West Coast Heavy Distillate proxy product has a lower sulfur content than the ANS Heavy Distillate cut. *Id.* Accordingly, continues Exxon, the issue in that situation was the magnitude of the sulfur processing cost adjustment that was needed to bring the ANS Heavy Distillate cut value into line with the published proxy price. *Id.* The situation at issue here is fundamentally different, notes Exxon, because there is no market-based published reference price for Naphtha on the West Coast. *Id.* In valuing West Coast Naphtha, Exxon asserts, the task is to establish a proxy price based on some other published market price or prices, with or without any further adjustments. *Id.* at pp. 270-71. Exxon states that, for that purpose, it is obviously both necessary and appropriate to use a market-based approach rather than a cost-based approach. *Id.* at p. 271. That is precisely what Tallett did, according to Exxon, and one of the benefits of Tallett's regression formula approach is that – unlike the Naphtha valuation methodologies proposed by Ross and O'Brien – no further cost-based adjustments are required. *Id.*

1969. Contrary to the claim of O'Brien, Exxon asserts, Tallett did not use Gulf Coast prices to value West Coast Naphtha. *Id.* Rather, Exxon points out, Tallett used his regression formula to value West Coast Naphtha on the basis of published West Coast prices of regular unleaded gasoline and jet fuel. *Id.* He used Gulf Coast prices, Exxon claims, only to find the relationship – defined in his regression formula – between the value of Naphtha as a feedstock and the prices of the end-products of that process. *Id.* Exxon argues that this is a reasonable approach, because Naphtha is used for the same purposes and processed in the same manner on both the Gulf Coast and the West Coast. *Id.* Nor does Tallett's regression formula rely on any fixed price differential, notes Exxon, but on variables whose values change as prices in the West Coast market change. *Id.*

1970. Exxon takes issue with the contention that it employed a regression-based approach to valuing West Coast Naphtha because it was in its economic interest to do so. *Id.* at pp. 271-72. It states that it used a regression-based approach because it is the simplest approach to apply, and because it produces results that are consistent with other reasonable West Coast Naphtha valuations. *Id.* at p. 272. Moreover, directly contrary to the claim that Exxon's goal was a formula that would produce the highest possible West Coast Naphtha values, Exxon points out, the evidence shows that by including jet fuel prices in the formula, Exxon actually reduced the West Coast Naphtha values produced by its formula. *Id.* Further, notes Exxon, the West Coast Naphtha values produced by the Exxon regression formula were also lower than the values reached by O'Brien on behalf of Phillips and Alaska. *Id.*

1971. Responding to Sanderson's claim that higher West Coast refining margins for gasoline and other finished petroleum products in comparison with crude oil costs skew the value of Naphtha when Tallett's approach is used, Exxon exclaims that there is no evidence supporting it. *Id.* at pp. 272-73. It adds that all of the witnesses agree that

> the price of Naphtha has closely tracked the price of gasoline on the Gulf Coast, a pattern that reflects the fact that, as Mr. Sanderson's own firm has stated "full range naphtha is most often priced at a discount to unleaded regular gasoline with the differential reflecting the costs of reformer processing."

Id. at p. 273 (citations omitted). Exxon declares that there is "every reason to expect that the price of Naphtha also tracks the price of gasoline on the West Coast." *Id.*

1972. Exxon also rejects Ross's assertion that the introduction of CARB gasoline has reduced the demand for Naphtha on the West Coast. *Id.* at pp. 273-74. It declares that, contrariwise, Naphtha is more attractive since the introduction of CARB gasoline because the aromatics in reformate made from Naphtha have a high octane, and because it has a low Reid Vapor Pressure, and no olefins or sulfur. *Id.* at p. 274. Exxon adds that, also contrary to Ross's testimony, Naphtha's value is enhanced by the rising demand for gasoline on the West Coast. *Id.* Nor, it claims, have refinery outages had any impact on West Coast demand for Naphtha. *Id.* Moreover, according to Exxon, the record supports a conclusion, converse to Ross's testimony, that the price of gasoline and jet fuel governs the value of Naphtha on the Gulf Coast despite the demands of the petrochemical industry. *Id.* at pp. 274-77.

1973. Williams's argument that Tallett's regression formula is not objective is clearly incorrect, according to Exxon. Exxon Reply Brief at p. 279. It explains that Tallett's regression formula determines the value of the West Coast Naphtha cut based entirely on objective West Coast prices for regular unleaded gasoline and jet fuel which are published by Platts. *Id.* at pp. 279-80. Further, Exxon maintains, the regression formula itself is also objective in that it is derived by a standard statistical formula that that can be run on any computer, with the result that no individual's judgment is required to calculate the formula, and anyone running the same analysis will get the same answer. *Id.* at p. 280. Finally, Exxon reiterates that the conclusion that Tallett's regression formula is a reasonable and appropriate method for valuing West Coast Naphtha was objectively validated at the hearings by a number of statistical tests as well as by other evidence in the record. *Id.* Accordingly, Exxon's position is that Tallett's approach is at least as objective a way to determine the value of West Coast Naphtha as any of the alternative methodologies. *Id.*

1974. It is not disputed, according to Exxon, that prices for both gasoline and jet fuel on the West Coast have been considerably higher than the prices for gasoline and jet fuel on the Gulf Coast throughout the period at issue in this proceeding.[658] *Id.* Assuming, as Williams does, that the prices of crude oil are similar on the two coasts, Exxon argues that the higher West Coast gasoline and jet fuel prices necessarily mean that the price differentials or refining margins between the prices of gasoline or jet fuel and the price of

[658] Exxon asserts that there is no evidence to support Unocal/OXY's contention that higher West Coast gasoline prices are a result of a non-competitive West Coast gasoline market. Exxon Reply Brief at p. 281, n.174. Rather, Exxon states, the higher gasoline prices are a result of the factors discussed in the Stillwater reports. *Id.* It also states that Unocal/OXY's argument about restraints on competition is particularly disingenuous in view of the evidence showing that a significant anticompetitive factor in the California market for CARB gasoline is Unocal's patents. *Id.*

crude oil are also higher on the West Coast than on the Gulf Coast.[659] *Id.* at pp. 281-82. However, Exxon maintains, this alone says nothing about the West Coast value of Naphtha, an intermediate product that is produced from crude oil and then used to produce finished products like gasoline and jet fuel. *Id.* at p. 282. Rather, Exxon states, the critical question is whether the value of West Coast Naphtha increases with increases in the prices of West Coast gasoline and jet fuel. *Id.* At the hearing, notes Exxon, Williams did not present any empirical evidence addressing this issue. *Id.* Instead, explains Exxon, all of the evidence pertaining to refining margins on which Williams relies, including both the Muse Stancil & Company data and Sanderson's analysis of "3-2-1 crack spreads," relates only to the differential between the price of finished products (such as gasoline or a mix of gasoline and low sulfur No. 2 fuel) and crude oil prices. *Id.* Those higher West Coast price differentials or refining margins relative to the price of crude oil provide no information about the price of Naphtha. *Id.*

1975. Moreover, Exxon asserts, directly contrary to Williams's unsubstantiated claims, there is substantial evidence showing that higher West Coast prices for gasoline and jet fuel, and the resulting higher West Coast refining margins, have resulted in correspondingly higher West Coast Naphtha values. *Id.* at p. 283. For example, Exxon states, Culberson testified that, regarding the high refining margins on the West Coast, he did not believe the refiners captured the entire margin, but that some could have been captured elsewhere. *Id.* Exxon believes that some of the margin is reflected in an increase in the value of gasoline feedstocks such as Naphtha. *Id.* Moreover, continues Exxon, in view of the undisputed evidence that the Gulf Coast price of Naphtha is determined virtually entirely by the prices of gasoline and jet fuel in the same market, the appropriate conclusion to be drawn from the fact that West Coast gasoline and jet fuel prices are substantially higher than Gulf Coast gasoline and jet fuel prices is that the value of Naphtha on the West Coast is also substantially higher than the price of Naphtha on the Gulf Coast. *Id.*

1976. Exxon further argues that the weakness of Williams's position is demonstrated by the charts that were submitted to show how Naphtha and VGO values compare to the values of gasoline and crude oil on the Gulf Coast and the West Coast. *Id.* at p. 284. Exxon believes it is clear from Exhibit No. EMT-476 that the value of Naphtha on the Gulf Coast more closely tracks the price of Gulf Coast gasoline rather than the price of crude oil. *Id.* That same pattern, notes Exxon, is also shown on the charts tracking the prices found in the West Coast Naphtha contracts and the West Coast Naphtha values calculated using Tallett's methodology against the prices of West Coast gasoline and

[659] Exxon maintains that this measurement of refining margin or differential between the West Coast price of gasoline and the price of crude oil is not a measure of profitability because such a claim disregards the undisputed fact that West Coast refinery costs are also significantly higher. Exxon Reply Brief at p. 282, n.175.

crude oil. *Id.* However, Exxon explains, the pattern is not found when the Gulf Coast Naphtha price is tracked against the prices of West Coast gasoline and crude oil. *Id.* In that scenario, Exxon states, the value of Naphtha does not track the value of the products into which it is made. *Id.*

1977. The result, Exxon declares, observed in comparing Gulf Coast Naphtha prices to the West Coast prices of gasoline and crude oil also is at odds with the results that one sees when a similar analysis is done comparing VGO prices with gasoline and crude oil prices. *Id.* at pp. 284-85. In that comparison, explains Exxon, the relationship between the price of the VGO feedstock and the price of gasoline on the two coasts is much more comparable. *Id.* at p. 285. Furthermore, Exxon notes, the charts show that, in the absence of special circumstances, such as a cat cracker outage, the value of an intermediate product is more closely tied to the value of the final product (gasoline) than to crude oil prices. *Id.* Exxon concludes that this evidence further serves to contradict Williams's theory that intermediate feedstocks do not share in the increased value of the final products. *Id.*

1978. Exxon also states that Petro Star errs in criticizing Tallett for basing his regression formula on ten years of pricing data covering the entire period from 1992 through 2001 rather than using only current pricing. Exxon Reply Brief at p. 287. In fact, Exxon maintains, Tallett's regression formula does calculate the West Coast value of Naphtha using current pricing because it computes the value of West Coast Naphtha using the current published prices for regular unleaded gasoline and jet fuel on the West Coast. *Id.* Moreover, Exxon points out, it was shown at the hearing that it made no significant difference whether Tallett's regression formula was derived from the full ten years of Gulf Coast pricing data that Tallett used, or from some smaller portion of that period. *Id.* It was also demonstrated, according to Exxon, that if there was reason to believe that the underlying relationship between the prices of Naphtha, gasoline, and jet fuel had changed, Tallett's regression formula could easily be rerun to test that belief and, where appropriate, the coefficients in his regression formula could be modified. *Id.* at pp. 287-88. Exxon argues, however, that no party has introduced any evidence to show that any modification of the formula would be appropriate at this time to reflect any change in market conditions. *Id.* at p. 288.

1979. Contrary to Ross's argument, Exxon argues, that Naphtha is used as a petrochemical feedstock on the Gulf Coast does not undermine Tallett's regression formula. Exxon Initial Brief at p. 274. Exxon also disagrees with Williams's argument that the Gulf Coast's importation of Naphtha to meet petrochemical feedstock demands results in a different supply/demand situation for Naphtha on the Gulf Coast which undercuts Tallett's use of a regression formula derived from Gulf Coast prices to value West Coast Naphtha. Exxon Reply Brief at p. 288. Exxon states that Williams's argument directly undercuts the claim of Williams and Unocal/OXY that the published Gulf Coast price should be used to value West Coast Naphtha, because the availability on the Gulf Coast of Naphtha for import from nearby Caribbean sources would tend to drive down the market value of Naphtha on the Gulf Coast. *Id.* at pp. 288-89.

1980. Further, while Exxon does not suggest that there is no significant petrochemical market for Naphtha on the West Coast, it asserts that there is no evidence that petrochemical demand on the Gulf Coast significantly influences the Gulf Coast Naphtha price, as Williams asserts. *Id.* at p. 289. According to Exxon, the evidence introduced by Culberson showing the views of Naphtha traders expressly indicates that Naphtha's value as a feedstock for the manufacture of gasoline and jet fuel is higher and this creates a cap on its value as a petrochemical feedstock. Exxon Initial Brief at pp. 274-75. As a result, states Exxon, the value of Naphtha on the Gulf Coast is determined by gasoline and jet fuel, not the petrochemical industry. *Id.* at p. 275.

1981. This conclusion is confirmed, in Exxon's view, by Tallett's regression analysis, which shows that over 98% of the variation in Gulf Coast Naphtha prices can be explained by changes in the gasoline and jet fuel prices. *Id.* According to Exxon, this means that, at a maximum, only about 3% of the variation in the Gulf Coast price of Naphtha might be caused by all other market factors, including the demand for Naphtha as a petrochemical feedstock. *Id.*; Exxon Reply Brief at p. 289. Exxon goes on to suggest that the fact that petrochemical usage does not significantly influence the demand for reformer-grade Naphtha on the Gulf Coast also is confirmed by the fact that the prices for Gulf Coast Naphtha follow very closely the movements in Gulf Coast gasoline prices, including both peaks and trough, and there is no "non-coincident spiking." Exxon Initial Brief at p. 275. Moreover, Exxon notes, the small variations between the Gulf Coast prices of Naphtha and gasoline are almost entirely explained by movements in the Gulf Coast price of jet fuel. *Id.* at pp. 275-76 (citing Exhibit No. EMT-384).[660] In Exxon's view this also refutes Williams's argument that petrochemical demand on the Gulf Coast undermines the application of Tallett's Gulf Coast regression formula to the West Coast. Exxon Reply Brief at p. 290.

1982. Furthermore, Exxon claims, no evidence was introduced that would support the contention that the use of Naphtha as a petrochemical feedstock on the Gulf Coast has had any significant impact on the Gulf Coast price of Naphtha. Exxon Initial Brief at p. 276. In fact, Exxon states, the evidence shows a significant part of the Naphtha used as a petrochemical feedstock on the Gulf Coast is a different, lighter Naphtha than the heavier reformer-grade Naphtha and is used in steam crackers to produce ethylene. *Id.* Further,

[660] Exxon asserts that Exhibit No. EMT-384 squarely undercuts the claim that petrochemical demand props up the price of Naphtha during periods of low gasoline prices, for it demonstrates that it is jet fuel demand, not petrochemical demand, which props up the price of Naphtha during periods of low gasoline prices. Exxon Initial Brief at p. 276, n.101.

explains Exxon, no evidence was presented that the price of the ethylene that is produced from this lighter Naphtha has had any effect on Naphtha prices. *Id.* On the contrary, Exxon noted, Tallett demonstrated there was a very low correlation between the price of ethylene and the price of Naphtha on the Gulf Coast. *Id.* Further, the evidence showed that the ethylene steam cracking industry was a 'price taker' that would choose the least expensive of the many possible alternative feedstocks. *Id.* at pp. 276-77.

1983. There also was no showing, according to Exxon, that the price of benzene (produced from heavier Naphtha) had any impact on the price of Naphtha. *Id.* at p. 277. Only the aromatics in the reformer-grade Naphtha (benzene, toluene, xylene) are used in the manufacture of petrochemicals, explains Exxon, and this constitutes only 3 to 5% of the reformate. *Id.* This very limited use of reformer-grade Naphtha as a petrochemical feedstock on the Gulf Coast, continues Exxon, has no significant effect on the price of Gulf Coast Naphtha. *Id.* As Tallett demonstrated, notes Exxon, there also was a low correlation between the price of benzene and the price of Naphtha on the Gulf Coast. *Id.* The limited use of reformer-grade Naphtha as a petrochemical feedstock, does not, therefore, according to Exxon, distort the strong relationship between the prices of Naphtha, gasoline and jet fuel. *Id.*

1984. Also, Exxon argues, Williams's assertion that the Gulf Coast and West Coast markets for gasoline and jet fuel are different is wholly unsupported by any evidence at all. Exxon Reply Brief at pp. 290-91. The mere fact that gasoline and jet fuel are sometimes exported from the Gulf Coast to the West Coast only confirms, in Exxon's view, the undisputed fact that prices for gasoline and jet fuel are considerably higher on the West Coast than on the Gulf Coast; a fact that strongly suggests that the value of Naphtha is also considerably higher on the West Coast. *Id.* at p. 291. By contrast, notes Exxon, there is no evidence of any exports of Naphtha from the West Coast to the Gulf Coast that would support Williams's contention that Naphtha prices are higher on the Gulf Coast, and the mere lack of West Coast imports of Naphtha is the result of other market conditions and does not reveal anything about the relative price of West Coast Naphtha. *Id.*

1985. Williams's and Ross's contention that Tallett's regression formula approach did not provide a good predictor of West Coast VGO prices, according to Exxon, was not based on Tallett's regression formula for valuing West Coast Naphtha, but on an entirely different regression formula that Tallett used to compare the price of VGO against a standard crack spread formula of 2/3 the price of gasoline plus 1/3 the price of fuel oil. Exxon Initial Brief at pp. 277-78; Exxon Reply Brief at p. 291.

1986. Exxon also points out that Tallett never suggested that this Gulf Coast regression formula for VGO could appropriately be used to value VGO on the West Coast. Exxon Reply Brief at p. 292. According to Exxon, the evidence shows that the markets for VGO on the Gulf Coast and the West Coast are quite different due to the substantially larger demand for VGO on the Gulf Coast for the production of heating oil for markets in the Northeast and Midwest. *Id.* Moreover, notes Exxon, Ross conceded at the hearings that VGO is less valuable on the West Coast than it is on the Gulf Coast due to more stringent West Coast environmental requirements that make it more costly for refiners to process and use, and because, on the West Coast, there is no petrochemical demand for the olefins produced by VGO. Exxon Initial Brief at p. 278. Therefore, according to Exxon, the evidence showed that there were a number of factors – not applicable to Naphtha – that preclude use of the relationship between the prices of VGO, gasoline, and fuel oil on the Gulf Coast to value VGO on the West Coast based on the prices of West Coast gasoline and fuel oil. *Id.*

1987. Phillips and Alaska, Exxon notes, take the position that, in view of the significant differences between the markets for Naphtha on the West Coast and Gulf Coast, the West Coast Naphtha value must be based on West Coast market factors and prices rather than on Gulf Coast prices. *Id.* at p. 279. For this purpose, states Exxon, Phillips, via its witness O'Brien, supported by Alaska, propose to value the West Coast Naphtha cut on the basis of the price of regular unleaded gasoline in Seattle, less the cost of reforming and blending Naphtha into regular unleaded gasoline. *Id.* Exxon explains that O'Brien's methodology purports to take into account all of the refiner's costs, including marginal operating costs, fixed operating costs, and capital recovery costs. *Id.* As a result, notes Exxon, the value for West Coast Naphtha using O'Brien's method is somewhat higher than the value resulting from the Exxon proposal. *Id.*

1988. Exxon agrees with O'Brien's approach because it recognizes that the Gulf Coast and West Coast are different markets and that the value of Naphtha is directly linked to the value of gasoline on the West Coast, and because pricing data from West Coast Naphtha contracts supports his result. *Id.* at pp. 279-80. Notwithstanding this, Exxon points out, there are a number of problems with O'Brien's valuation methodology that make it less desirable than the Exxon proposal presented by Tallett. *Id.* at pp. 280-81. For example, notes Exxon, O'Brien's approach is highly complex, premised on a number of subjective judgments, and based on an outdated semi-regenerative reformer technology that is less efficient and produces lower yields than the continuous reformer technology that would be employed by a refiner today. *Id.* at p. 281. According to Exxon, O'Brien's reformer analysis also uses inconsistent pricing bases for valuing reformer yields. *Id.* Specifically, states Exxon, O'Brien uses a Seattle barge price for regular unleaded gasoline, while valuing the other reformer yields on the basis of the California-based prices that are used by the Quality Bank on the West Coast. *Id.* It explains that this results in a lower gasoline price and a lower value for Naphtha because the Seattle price for gasoline has been, on average, lower than the Platts Los Angeles price for gasoline. *Id.* Exxon notes also that O'Brien understates the costs of reforming Naphtha into gasoline on the West Coast by failing to use a West Coast location factor to adjust Gulf Coast costs upwards to West Coast levels. *Id.*

1989. Finally, Exxon believes that Phillips's contention that O'Brien's methodology should be preferred because it is the only proposal that is consistent with the methodology that the parties have agreed to use to value the Resid cut is also overstated. Exxon Reply Brief at p. 295. While consistency is important, Exxon asserts, it is much more important to select a methodology that generates the most reliable results than to select a methodology solely on grounds of consistency. *Id.* The goal of accurate relative values does not establish an overriding requirement of consistency or uniformity as Phillips contends; rather, according to Exxon, it only established a rule of "reasoned relative uniformity." *Id.* (quoting *Exxon*, 182 F.3d at p. 38).

1990. Exxon states that, like Exxon, Phillips and Alaska also have taken the position that the continued use of the Gulf Coast Naphtha price to value West Coast Naphtha is not just and reasonable. Exxon Initial Brief at p. 282. BP advocates, states Exxon, that the value of West Coast Naphtha be determined by the West Coast Naphtha valuation methodologies presented by either Tallett or O'Brien, but subject to the so-called "governor" proposed by Ross. Exxon Reply Brief at p. 296. The adoption of Ross's governor is opposed by Exxon, Phillips, and Alaska as being without justification and contrary to the evidence. *Id.* Exxon asserts that no party other than BP advocates its adoption. *Id.*

1991. While purporting to accept the principle that West Coast Naphtha should be based on the prices of West Coast petroleum products, Exxon maintains, Ross undercut that principle by proposing to superimpose on the resulting value of West Coast Naphtha a so-called "governor" or price ceiling. Exxon Initial Brief at p. 283. This ceiling, explains Exxon, would effectively cap the value of West Coast Naphtha to correct for alleged anomalies in the market for gasoline on the West Coast from 1999 through 2001.[661] *Id.* The size of the cap, explains Exxon, was to be based on an estimate of the additional costs that would be incurred to divert shipments of Naphtha from Venezuela to the West Coast that would otherwise go to the Gulf Coast. *Id.* Although there was no evidence that any shipments of Venezuelan Naphtha, in fact, had ever gone to the West Coast, Exxon states that the theory behind Ross's "governor" was that, if the price of Naphtha on the West Coast were to rise above the Gulf Coast price by more than $1.85/barrel (the value of the cap proposed by Ross), such shipments would occur and effectively cap the West Coast Naphtha price at that level. *Id.* In later submissions, notes Exxon, Ross made a number of modifications to his proposed ceiling that served to reduce the size of the cap from $1.85 to $1.49. *Id.* at p. 284. Exxon states this change

[661] Exxon states that Ross failed to establish any meaningful definition of the term "pricing anomaly." Exxon Initial Brief at p. 286, n.102. It notes that, during the hearing, he stated his assessment of when a pricing "anomaly" existed amounted to little more than his subjective assessment of a particular context coupled with the fact that his governor came into play. *Id.*

reflects Ross's realization that he had made errors in his calculation of transportation costs.[662] *Id.*

1992. In his reply testimony, Exxon states, Ross added a price floor to his governor in recognition of the fact that Naphtha would not move to the West Coast unless the price were at least sufficient to cover the seller's cost of producing the Naphtha from crude. *Id.* Ross set the floor at the average of the high and low published Platts West Coast prices of ANS crude plus $4.00. *Id.* This $4.00 figure was "borrowed," explains Exxon, from a West Coast Naphtha contract which employed a price floor based on the price of ANS crude oil plus $4.00 to protect the cost base of the supplier. *Id.* Continues Exxon, Ross claims that he validated this figure on the basis of (1) the differential between the price of Gulf Coast Naphtha and the price of West Texas sour crude, based on Ross's assumption that West Texas sour crude was comparable to ANS crude, and (2) the differential between the prices of Naphtha and VGO on the Gulf Coast, based on Ross's assumption that the relationship between the prices of Naphtha and VGO on both the Gulf Coast and the West Coast would be the same.[663] *Id.* at pp. 284-85. According to Exxon, Ross's governor would substantially limit the West Coast Naphtha values produced by the Exxon, Phillips and Alaska valuation methodologies. *Id.* at p. 285. It argues that the proposed governor should be rejected as unjustified and contrary to the evidence. *Id.*

1993. As noted above, Exxon states, Ross bases the governor theory on his claim that "pricing anomalies" existed on the West Coast during the 1999-2001 period. *Id.* at p. 286. It contends that the pricing data for the products claimed as support by Ross do not sustain his pricing "anomalies" claim. *Id.* For example, Exxon states, the evidence shows the prices of Butane and LSR on the West Coast were not correlated with the price

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[662] Exxon notes that Ross acknowledged that he had miscalculated the transportation cost for diverting a Venezuelan shipment of Naphtha from the Gulf Coast to the West Coast – an error which reduced his proposed governor from $1.85 to $1.29. Exxon Initial Brief at p. 284. In addition, claims Exxon, Ross conceded that he had underestimated the transportation cost by failing to take into account the lack of backhaul opportunities for shipments to the West Coast, and to compensate for this omission, Ross further adjusted his transportation cost calculation by adding an additional 20¢ to his governor, thereby increasing the size of his proposed governor to $1.49. *Id.*

[663] Exxon notes that, shortly before the beginning of the Naphtha portion of the hearing, Ross withdrew his testimony valuing the West Coast Naphtha cut, thereby leaving only that portion of his testimony dealing with the governor. Exxon Initial Brief at p. 285. In this connection, explains Exxon, Ross stated that he would accept either the West Coast Naphtha valuation presented by Tallett on behalf of Exxon or the Naphtha valuation presented by O'Brien on behalf of Phillips and Alaska, provided that they were subject to the governor which he proposed. *Id.*

of West Coast gasoline at any time during the period 1994 to 2001. *Id.* Further, it states, unlike Naphtha, the use of Butane and LSR to produce gasoline is highly seasonal in that they cannot be blended into gasoline on the West Coast during the summer because of their high Reid Vapor Pressure. *Id.* at pp. 286-87. Exxon also notes that Ross admitted that the most pronounced spikes in the prices of Butane (in January 2001) and LSR (in 2000) were caused by spikes in natural gas prices that had nothing to do with gasoline prices. *Id.* at p. 287. Further, Exxon says, LSR is imported into the Gulf Coast mostly for use as a petrochemical feedstock, while LSR has no use as a petrochemical feedstock on the West Coast. *Id.*

1994. Exxon also takes exception to Ross's attempt to support his pricing "anomaly" theory on the basis of VGO prices. *Id.* at p. 287. It asserts that Ross's attempt to validate the import theory underlying his governor based on published data for VGO imports by West Coast refineries demonstrated just the opposite – that there is little, if any, correlation between spikes in the price of VGO on the West Coast and imports of VGO into the West Coast market. *Id.* at pp. 287-88. Exxon explains that Ross's own chart of the relationship between spikes in the West Coast price of VGO and the level of VGO imports into California shows no correlation at all on its face. *Id.* at p. 288 (citing Exhibit No. BPX-84). Moreover, notes Exxon, that chart shows that West Coast VGO prices were frequently well above Ross's cost of imports, and sometimes for periods of several consecutive months. *Id.*

1995. Exxon claims that, contrary to BP's argument, what the VGO price data shows is that VGO prices on the West Coast closely track West Coast gasoline prices, including price spikes.[664] *Id.*; Exxon Reply Brief at pp. 299-300. Further, Exxon claims, the evidence shows that the price of VGO on the West Coast is generally higher than the price of VGO on the Gulf Coast, and that this was particularly true in the 1999-2001

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[664] Although the data showed a few instances in 1999 and 2000 where the price of gasoline went up and the price of VGO did not, or did not go up to the same extent, Exxon states, those instances were explained by outages of "cat crackers" or FCC units at West Coast refineries which both precluded the refinery from processing VGO into gasoline (thereby reducing the demand for VGO and making it less valuable) and reducing the refinery's output of gasoline (thereby reducing the supply of gasoline and making it more valuable). Exxon Initial Brief at p. 288, n.103 (citing Exhibit No. EMT-443); Exxon Reply Brief at p. 300. According to Exxon, these outages would not impact the value of West Coast Naphtha and, as Ross was forced to admit, might account for an increase in the value of West Coast Naphtha vis-à-vis West Coast gasoline during this period. Exxon Initial Brief at p. 288, n.103. Exxon states that the contention in Ross's pre-filed testimony that the cat cracker incidents would have lowered the demand for Naphtha, a contention which BP relies on in its brief, was thus shown at the hearing to be incorrect. Exxon Reply Brief at p. 301. Therefore, Exxon maintains, the West Coast VGO price data does not provide any support for Ross's proposed governor. *Id.*

period when West Coast gasoline prices spiked and West Coast VGO prices exceeded the Gulf Coast VGO prices by an amount greater than Ross's governor, thereby confirming that the prices of West Coast gasoline feedstocks follow the price of West Coast gasoline, including during periods of sharp increases in the price of gasoline. Exxon Initial Brief at pp. 288-89. The VGO price data, explains Exxon, thus directly refute Ross's claim that the West Coast prices of gasoline feedstocks do not respond to anomalous spikes in the price of gasoline because they are governed by the ability of West Coast refiners to import such feedstocks. *Id.* at p. 289.

1996. There also is no merit, according to Exxon, to BP's further argument that the need for Ross's governor is supported by a comparison of OPIS West Coast VGO prices with a 1993 settlement proposal that would have valued West Coast VGO on the basis of a 70/30 weighted average of the West Coast prices of regular unleaded gasoline and No. 2 fuel oil minus a deduction of 8¢/gallon. Exxon Reply Brief at p. 301. According to Exxon, the evidence shows that this 1993 settlement proposal, which Ross supported at that time, used the same 8¢/gallon deduction in valuing VGO on both the Gulf Coast and the West Coast notwithstanding the fact that West Coast refinery costs are higher than Gulf Coast costs. *Id.* at pp. 301-02. However, Exxon notes, Culberson testified in opposition to that proposal that VGO was typically priced on the Gulf Coast at "about 5 cents per gallon below the 70/30 price," while "West Coast [VGO] prices are usually 10 to 14 cents per gallon below the 70/30 price." *Id.* at p. 302 (quoting Exhibit No. EMT-493 at p. 6). Moreover, Exxon points out, the evidence shows that correcting the proposed 1993 settlement formula to use a more appropriate West Coast cost deduction of 12¢/gallon rather than 8¢/gallon largely eliminates the overvaluation that BP identifies and provides a result that is much closer to the OPIS West Coast VGO price than does the application of Ross's proposed governor. *Id.* Exxon asserts that the conclusion to be drawn from this evidence, therefore, is that the VGO formula in the 1993 settlement proposal used a cost deduction that was inadequate for the West Coast and not that any artificial price "governor" was needed to constrain the values produced by the proposed 1993 settlement gasoline-based VGO valuation formula. *Id.* at pp. 302-03.

1997. Exxon alleges that, even had anomalies in the pricing of intermediate feedstocks existed on the West Coast during the period 1999 to 2001, the governor proposed by Ross is not appropriately targeted to that alleged problem. Exxon Initial Brief at p. 289. It notes that Ross conceded the West Coast pricing anomalies addressed by his governor did not arise until 1999, and that there was no justification for applying his governor during non-anomalous periods like those that existed prior to 1999. *Id.* Nevertheless, continues Exxon, the evidence shows that his proposed governor would have been operative at least 80% of the time to determine the value of West Coast Naphtha prior to 1999. *Id.*; Exxon Reply Brief at p. 303. Further, explains Exxon, although the proposed governor would go into effect automatically in all future years, Ross conceded that, should future years look like the non-anomalous period that existed prior to 1999, there would be no need or justification for applying his governor. Exxon Initial Brief at p. 290.

Exxon contends that Ross's attempt at the hearing to avoid this problem by arguing that a pricing anomaly existed whenever his governor became operative to determine the West Coast Naphtha price was an obviously circular argument. *Id.*

1998. By using an extremely restrictive governor based on the Gulf Coast price of Naphtha plus $1.49/barrel, Exxon argues, Ross's proposed governor would also have the undesirable effect of imposing on the value of West Coast Naphtha any pricing anomalies that might arise on the Gulf Coast. *Id.* Were, for example, the price of Naphtha on the Gulf Coast to drop by reason of some event that did not affect the value of Naphtha on the West Coast, such as refinery outages, the proposed governor would inappropriately, Exxon claims, reduce the value of Naphtha on the West Coast for Quality Bank purposes. *Id.*

1999. Exxon states that, although BP is obviously aware of this fundamental flaw in Ross's proposed governor, it argues nevertheless that the governor would not do any harm and would serve as insurance during periods when there are no noticeable gasoline price spikes. Exxon Reply Brief at p. 304. It argues, however, that this would be true only if the governor did not actively intervene to determine the value of West Coast Naphtha during periods like 1994 to 1998 when there were no pricing anomalies, and thus no reason for the governor to be applied. *Id.* Exxon asserts that is most decidedly not the case with Ross's governor. *Id.* It concludes that, as the proposed governor would still apply 80% or more of the time even when there is no justification for its application, the governor is not an appropriate response to any anomalies in the pricing of intermediate feedstocks on the West Coast. *Id.*

2000. During the hearing, Exxon notes, Ross advanced, for the first time, an alternative justification for his governor based on the lack of a published price for Naphtha on the West Coast. Exxon Initial Brief at p. 291. Exxon explains that Ross argued that a lack of a published price inhibited supply and caused the price to be different, likely higher, than it would be if there were a transparent market. *Id.* Further, notes Exxon, Ross argued that his governor was an attempt to model a transparent market. *Id.* It claims that Ross offered no evidence that supported this alternative theory for his governor, and his economic analysis was directly contrary to the testimony of Baumol. *Id.* Exxon also maintains that, despite BP's attempts to justify the governor on the basis of the 'transparent market' theory, there is simply no credible evidence in the record to support the governor on that basis and overwhelming contrary evidence. Exxon Reply Brief at p. 305.

2001. Even were Ross's "transparent market" theory supportable as a matter of economic analysis, and Exxon asserts it is not, it maintains that the theory would not provide any lawful basis for valuing the Quality Bank West Coast Naphtha cut. *Id.* at p. 306. Exxon notes that the Circuit Court has ruled that all Quality Bank cuts must be assigned accurate relative values and this requires that all cuts must be valued, to the extent possible, on a reasonably consistent basis. *Id.* at pp. 306-07. It points out that every other Quality Bank cut is valued on the West Coast on the basis of its estimated actual market value to a refiner in the real world marketplace. *Id.* at p. 307. Further, according to Exxon, no cut is valued on the basis of what its value might be in an imaginary idealized market that does not reflect the market that actually exists in the real world. *Id.* Therefore, Exxon argues, BP's attempt to defend the governor on the basis of the manner in which market forces might operate in a hypothetical transparent market does not meet the *Exxon* court's valuation requirements. *Id.*

2002. Baumol's testimony, in Exxon's view, squarely refuted Ross's opinion that, as a result of the lack of a transparent market with published prices, the price of Naphtha on the West Coast is probably higher than it would be were there a published price. *Id.* Exxon states that prices are determined by relative strengths of buyers and sellers and only a seller with greater market power than a buyer can get an excessive price. *Id.* It explains that Ross presented no evidence, however, that sellers of Naphtha on the West Coast have greater market power than buyers, and claims that the evidence in the record squarely refutes that idea. *Id.* Exxon points out that purchasers of West Coast Naphtha are not primarily small firms that are easily out negotiated; rather, more than 90% of them are large firms that are unlikely to allow themselves to be subject to repeated overcharging. *Id.* at pp. 292-93. Therefore, concludes Exxon, there is no factual basis for Ross's opinion that the price of West Coast Naphtha is probably higher than it would be if there were a published market price. *Id.* at p. 293.

2003. Exxon points out that the pricing information available to both buyers and sellers of Naphtha on the West Coast is comparable to, or even better than, the information on which Platts or OPIS makes its price assessment, which is simply what an assessor can learn from phone calls and may be based on as few as one transaction in a month. Exxon Reply Brief at pp. 309-10 (citing Alaska Initial Brief at pp. 13-14). It also asserts that traders of oil products believe that their information is often better than that of the price publishing services. *Id.* at p. 310. Exxon notes that BP, itself, recognizes, in its brief, that price data published by Platts may be unsound and inappropriate to use. *Id.* In these circumstances, Exxon argues, there is absolutely no factual basis for Ross's contention that the incremental benefit of having one additional piece of price information – a published Platts or OPIS price assessment – would have the dramatic effects on the functioning of the market that are suggested by Ross. *Id.*

2004. Further, Exxon asserts, the theory supporting Ross's argument in support of the governor is directly refuted by substantial evidence in the record that, even in markets where there is a published West Coast price, the West Coast petroleum prices often exceed the corresponding Gulf Coast prices by substantially more than the amount of his governor. *Id.* at p. 313. For example, Exxon explains, the evidence shows that published prices exist on both the West Coast and the Gulf Coast for gasoline, jet fuel, VGO, propane, Isobutane, Light Distillate, and Heavy Distillate. *Id.* Nevertheless, according to

Exxon, the evidence demonstrates that West Coast/Gulf Coast price differentials substantially in excess of the $1.49/barrel transportation cost differential in Ross's governor have existed for all of these petroleum products, and those large price differentials have often persisted for long periods of time. *Id.* at pp. 313-14. Thus, Exxon concludes, Ross's claim that a published price would create a governor that would narrowly constrain West Coast/Gulf Coast price differentials is clearly not supportable. *Id.* at p. 314.

2005. Were the concept of Ross's governor valid, Exxon argues, one would expect to see actual movements of Naphtha to the West Coast at times of high West Coast prices. Exxon Initial Brief at p. 293. However, Exxon states, there is no evidence of any Naphtha cargoes actually moving into the West Coast at times of high West Coast prices. *Id.* It notes that Ross conceded that he had no evidence that any shipments of Naphtha or any other intermediate or finished petroleum product had been sent from Venezuela to the West Coast. *Id.* According to Exxon, Ross also conceded that there is very little trading in Naphtha on the West Coast, and Sanderson acknowledged that it is unlikely that Naphtha will be imported to the West Coast in the future.[665] *Id.*

2006. The substantial and persistent differentials between the West Coast and Gulf Coast prices for many petroleum products are also, in the opinion of Exxon, confirmed by the March 2002 Stillwater Report to the California Energy Commission, which stated that prolonged price differentials for petroleum products on the West Coast were a product of the insular nature of the California market, related to geography, product quality, commercial barriers and infrastructure limitations. *Id.* at pp. 294-95 (citing Exhibit No. EMT-489 at p. 101). As a result of these various physical and commercial constraints, Exxon notes, the report stated that California prices are substantially higher, sometimes for significant periods, than Gulf Coast petroleum prices plus the total cost to move goods between them, including transportation, duties, storage, time value of money, etc. *Id*. at p. 295. Therefore, according to Exxon, the Stillwater report squarely contradicts Ross's governor theory. *Id.*

2007. Further, Exxon claims, Ross's attempt to argue that the prices of jet fuel on the West Coast were capped by imports proved just the opposite. *Id.* It notes that Ross argued that East Coast, and not Gulf Coast, prices were the appropriate comparison for West Coast prices. *Id.* Even so, Exxon points out, the evidence showed that, contrary to

[665] Exxon also cites a study by Purvin & Gertz for Petróleos de Venezuela S.A., Exhibit No. PAI-185, which excluded the West Coast from its analysis of potential U.S. markets for Venezuelan crude oil on the ground that the West Coast was not a competitive market for Venezuelan crude oil and also excluded the West Coast from its analysis of potential U.S. markets for Venezuelan refined petroleum products. Exxon Initial Brief at p. 293, n.104.

the theory of Ross's governor, the West Coast price of jet fuel has exceeded the cost of imports from the East Coast by more than the value of his governor in 31 out of 72 months, or 43% of the time, between 1996 and 2001. *Id.* There also was no factual or logical basis whatsoever, according to Exxon, for Ross's attempt to dismiss all of the periods when West Coast jet fuel prices exceeded the Gulf Coast price by more than his estimated import cost as simply the result of overheated market conditions; for the very purpose of the West Coast Naphtha valuation for Quality Bank purposes is to reflect actual market conditions, not to suppress or disregard them. *Id.*

2008. Even were there some conceptual validity to Ross's idea of a governor on prices of Naphtha, the evidence clearly shows, according to Exxon, that Ross significantly understated the amount of the costs and other barriers that limit the import of Naphtha into the West Coast and the level of any such governor. *Id.* at pp. 296-97; Exxon Reply Brief at p. 314. As a result, there is no evidentiary support, argues Exxon, for the $1.49/barrel price cap imposed on West Coast Naphtha values by the governor proposed by Ross. Exxon Initial Brief at p. 297. Quite the contrary, Exxon asserts, all of the available pricing data indicates that the governor proposed by Ross is far too restrictive. *Id.*

2009. The fact that the ceiling in Ross's governor is much too low is also shown, in Exxon's view, by the undisputed fact that published West Coast prices for many petroleum products, including both intermediate and finished products, have routinely exceeded the Gulf Coast price by much more than the $1.49/barrel transportation cost differential estimated by Ross, and often for long periods of time. Exxon Reply Brief at p. 315. Exxon argues that these substantial and persistent West Coast/Gulf Coast price differentials for both finished and intermediate products well in excess of the price ceiling in the governor demonstrate beyond any serious question that the price ceiling of the governor, which is supposedly based on the cost of import, is unrealistically low. *Id.*

2010. Although Ross purported to base the size of his governor on certain shipping differentials, Exxon states, the evidence shows that he substantially underestimated the amount of those differentials and that he also failed to take into account a number of other costs that would tend to impede the flow of Naphtha to the West Coast during times of high Naphtha prices. Exxon Initial Brief at p. 298. Exxon notes that, despite the fact that Platts publishes tanker rates for shipments from both the Caribbean and Venezuela to the West Coast, Ross initially did not use those rates, but instead elected to use only the tanker rate for shipments from the Caribbean to the Gulf Coast, which he then adjusted.[666] *Id.* It states that he made no attempt to look for other published rates for

[666] Exxon explains that only on redirect examination at the hearing did Ross introduce an alternative governor based on a variable transportation differential for shipments from Venezuela to the West Coast. Exxon Initial Brief at p. 298, n.105.

shipments from Venezuela to the West Coast and Ross's adjustments were based on a series of assumptions and calculations that had no evidentiary support in the record. *Id.* at pp. 298-99.

2011. Ross's reliance solely on transportation differentials also led, in Exxon's view, to a substantial understatement of the proposed cap. *Id.* at p. 300. It asserts that the evidence makes clear that far more is involved in a decision to import Naphtha than the cost of transportation to the West Coast. *Id.* For example, Exxon explains, Ross failed to take into account that West Coast refiners typically produce all the Naphtha they need from existing crude slates. *Id.* Thus, continues Exxon, to take advantage of any available imported Naphtha, the refiner would need to switch to a different crude slate to process the imported Naphtha. *Id.* Because West Coast refineries typically purchase a significant quantity of crude under long-term purchase contracts and vessels are scheduled months in advance, Exxon states, such switching can involve a considerable amount of time and expense. *Id.* Therefore, Exxon concludes, a refiner would not purchase imported Naphtha unless the price was so much lower for an extended period of time as to compensate the refiner for all the costs and opportunity costs that would be incurred by importing Naphtha. *Id.* Exxon points out that Ross's governor made no allowance for the costs associated with changing the crude slate in order to accommodate imports of Naphtha. *Id.* at p. 301.

2012. Exxon states that BP also completely disregards these costs in its argument defending the value of the Ross governor. Exxon Reply Brief at pp. 318-19. Similarly, notes Exxon, BP's reliance on an exhibit listing 17 cargoes of Naphtha that were sent to the West Coast in its attempt to dismiss the voluminous evidence that West Coast imports are limited by barriers to entry is clearly misplaced in view of Ross's admission that every one of those 17 cargoes went to a single West Coast refiner. *Id.* at p. 319.

2013. In addition, because West Coast refineries have generally been able to meet their demand for Naphtha internally without any significant amount of imports, Exxon argues, West Coast refineries do not have the tank and terminal facilities needed to import substantial quantities of Naphtha. Exxon Initial Brief at p. 301. It claims that Ross made no allowance for the costs of additional storage or terminal facilities that would be required to handle Naphtha imports on the West Coast. *Id.* According to Exxon, the importance of this omission is confirmed by the fact that no Naphtha imports into the West Coast took place when the price of all products on the West Coast went up in 1999, 2000 and 2001. *Id.* Instead, notes Exxon, the market has responded to gasoline price spikes by the flow of gasoline into high-priced West Coast markets from adjacent markets, thereby directly moderating any gasoline price spikes. *Id.*

2014. The evidence also shows, in Exxon's opinion, that, in calculating the magnitude of his so-called governor, Ross substantially underestimated other costs that would be required to divert Naphtha to the West Coast. *Id.* at p. 302. For example, explains

Exxon, Ross initially failed to take into account the fact that, because there is no back-haul on shipments to the West Coast (unlike shipments to the Gulf Coast), chartering companies would charge substantially higher rates to divert shipments of Naphtha to the West Coast. *Id.* In addition, Exxon states, Ross failed to take into account that any shipment from the Gulf Coast to the West Coast would require very expensive Jones Act shipping using vessels built in the United States and crewed by United States citizens. *Id.* In short, concludes Exxon, Ross's transportation differential of $1.49/barrel was completely lacking in evidentiary support. *Id.*

2015. Exxon also asserts that Ross's governor failed to account for the fact that, in the real world, any discipline provided by imports would not occur instantaneously, but would occur only after weeks of validation and weeks of shipping. *Id.* In addition to the lag involved in validation of the price differential, Exxon points out that it could take an additional month to load, ship, and off-load a Naphtha cargo and still more time to reform and blend the Naphtha into gasoline. *Id.* at p. 303. Thus, explains Exxon, these real world time intervals render the shipping of Naphtha to the West Coast a slow and inefficient means of responding to temporary spikes in the price of West Coast gasoline. *Id.* Further, as a result of the considerable time required to decide on and implement a plan to import Naphtha in response to an increase in the price of West Coast Naphtha, Exxon states that the governor proposed by Ross would plainly not go into effect immediately, but only after a lag of at least a month or more. *Id.*

2016. Exxon also claims that Ross's governor did not take into account the added risks that a Venezuelan Naphtha shipper would incur if it diverted a shipment to the West Coast. *Id.* It points out that the evidence showed there is not a sufficiently robust West Coast market to ensure that a Naphtha shipper would obtain a compensatory price. *Id.* This risk is aggravated, explains Exxon, by the additional travel time needed to move product to the West Coast and the substantial delays that have frequently been experienced by shippers in transiting the Panama Canal. *Id.* Ross's transportation differential assumed that Naphtha shippers would be indifferent to all of these risk factors – an assumption Exxon argues is patently unreasonable. *Id.* at p. 304.

2017. Ross relies upon a single one of the nearly 300 West Coast Naphtha contracts – a long-term contract between companies 4 and 13 – to validate his "governor" price cap, reliance which Exxon claims is clearly misplaced. *Id.* at p. 305. It points out that the contract upon which Ross relied is the only one out of the hundreds of West Coast Naphtha contracts produced in this proceeding that has a price mechanism which is in any way comparable to his proposed governor. *Id.* at pp. 305-06. Moreover, explains Exxon, that contract did not involve the sale of Heavy Naphtha, but rather Full Range Naphtha, a product that is not equivalent to the Quality Bank Naphtha cut. *Id.* at p. 306. Further, continues Exxon, that contract contained a complex series of pricing terms, including reference to another contract, and there is no evidence as to the reasons why the contract was structured in that unusual way. *Id.* Exxon notes that Ross also admitted that he had no knowledge as to the reason for the price mechanism used in that contract. *Id.*

2018. In addition, notes Exxon, the contract upon which Ross relied provides no support at all for the magnitude of the price cap proposed by Ross. *Id.* at p. 307. In contrast to the $1.49/barrel price cap proposed by Ross, Exxon points out that the contract relied upon by Ross employed a far higher cap of 7.05¢/gallon, or $2.96/barrel – nearly twice the amount of the price cap proposed by Ross. *Id.* As a result, explains Exxon, the West Coast Naphtha prices established by that contract were either nearly the same as, or somewhat higher than, the value of West Coast Naphtha as valued by Tallett's regression analysis, depending on how the contract volumes are divided between Heavy Naphtha and LSR. *Id.* Therefore, Exxon concludes the contract on which Ross relied provides no support at all for the low West Coast Naphtha values that are produced by Ross's governor.[667] *Id.*

2019. Similarly, Exxon asserts that the evidence shows that another measure of the relative value of a gasoline feedstock on the Gulf Coast and West Coast is provided by MTBE, a clean product that is used on both coasts in the production of gasoline, is imported on the West Coast both from Venezuela and directly from the Gulf Coast, and has published prices on both coasts. *Id.* at p. 308. Exxon states that the differential between the price of MTBE on the Gulf Coast and the West Coast was in the 7.3¢/gallon ($3.07/barrel) range throughout the 1992 to 2001 period. *Id.* Insofar as this price differential reflects a more accurate measure of the true price differential between the Gulf Coast and the West Coast applicable to gasoline feedstocks, Exxon argues that the $3.07/barrel MTBE price differential further confirms that Ross's $1.49/barrel "governor" significantly understates the price differential that is needed to cause gasoline feedstocks to move into the West Coast. *Id.*

2020. During the hearings, notes Exxon, Ross suggested an alternative formula for his

[667] Exxon further explains that applying the Ross governor with the higher $2.96/barrel price cap found in that contract rather than the $1.49/barrel cap proposed by Ross to the West Coast Naphtha values determined by Tallett's regression formula would result in a reduction of the average West Coast Naphtha value for the 1994 through 2001 period from $25.48/barrel to $24.71/barrel – a reduction of 77¢/barrel. Exxon Initial Brief at p. 307, n.108. (In its brief, Exxon states that the reduction is 77¢/gallon. However, Exhibit No. EMT-440 at p. 1 shows that the comparisons are on a per barrel basis.) Exxon also states that application of the Ross governor with the $2.96/barrel cap would reduce the Tallett West Coast Naphtha value for the period 1994 through 1998 by only 8¢/barrel, while it would reduce the Tallett West Coast Naphtha value for the period 1999 through 2001 – the period of alleged anomalies – by $1.95/barrel. *Id.* By contrast, notes Exxon, application of the Ross governor with the $1.49/barrel cap reduces the average price by an average of about $3.35/barrel over the 1999-2001 period. *Id.*

proposed governor. *Id.* Under the alternative proposal, explains Exxon, instead of a fixed price cap of $1.49, Ross suggested that a variable transportation differential could be used.[668] *Id.* Although Ross continued to assert that his proposed price cap of $1.49 should be used, Exxon points out that he offered this alternative in case the Commission should prefer a monthly movable ceiling. *Id.* at p. 309. Exxon notes that Ross's price floor remained unchanged. *Id.*

2021. Ross's alternative formula for his proposed governor addresses only two of the many deficiencies in his proposal, according to Exxon. *Id.* It points out that, while he replaced his initially proposed fixed price cap of $1.49 with a variable transportation differential based on published freight rates for shipments from Venezuela to both the Gulf Coast and the West Coast, the alternative formula still does not address the most fundamental deficiencies of his governor. *Id.* First, Exxon states, he did not provide any justification for imposing a governor at all, because he provides no evidence that a governor is needed to correct for any so-called anomalies in the pricing of intermediate feedstocks, or that any price governor actually operates in the marketplace for such feedstocks on the West Coast. *Id.* at pp. 309-10. Also, although Ross's alternative formula introduces current freight rates, Exxon points out, it does nothing to take into account the many other costs that were erroneously omitted from his governor, including the need for additional storage facilities on the West Coast, or the additional risk posed by the substantial time lag involved in shipments to the West Coast. *Id.* at p. 310. Moreover, states Exxon, given that the alternative formula is essentially the same as the formula used to calculate his original $1.488 price ceiling, the obvious inadequacy of the magnitude of Ross's original price ceiling when viewed against both the West Coast Naphtha contracts and other evidence of actual Gulf Coast/West Coast price differentials is equally apparent in this alternative. *Id.*

2022. While Exxon maintains that there is no valid theoretical or evidentiary basis for the governor, in the event that the Commission was to attempt to impose some sort of price limits on the West Coast Naphtha values analogous to the proposed governor, it is also clear from the evidence that the governor would have to be fundamentally changed in certain respects. Exxon Reply Brief at p. 320. Exxon asserts that the ceiling would

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[668] Exxon states that this variable transportation differential would be computed by the Quality Bank Administrator on the basis of the Worldscale annual rate for shipments from Venezuela to Los Angeles multiplied by the Platts freight rate for shipments from the Caribbean to the West Coast, plus the Worldscale Panama Canal charge adjusted to metric tons, reduced by the Worldscale annual rate for shipments from the Venezuela to Houston multiplied by the Platts freight rate for shipments from the Caribbean to the Gulf Coast. Exxon Initial Brief at pp. 308-09. Later in the hearings, notes Exxon, Ross made additional changes to his proposed formula for the governor, including the addition of a new working capital charge. Exxon Initial Brief at p. 309, n.109.

need to be higher and there would have to be a time lag inserted. *Id.* at pp. 320-21.

2023. Similarly, Exxon asserts that the evidence shows that the differential between the Gulf Coast price of MTBE and the West Coast price of MTBE has consistently been in the range of 7.3¢/gallon or $3.07/barrel throughout the 1992 to 2001 period.[669] *Id.* at pp. 321-22. Exxon notes that this MTBE price differential is over twice the size of the $1.49/barrel price ceiling suggested by Ross. *Id.* at p. 322. It suggests that this MTBE price differential is particularly significant because, like the transparent market that Ross purports to be simulating by his governor, MTBE is a clean petroleum product with published prices on both coasts that is actually imported on the West Coast from Venezuela. *Id.* The $3.07/barrel MTBE West Coast/Gulf Coast price differential provides strong additional evidence, in Exxon's view, that the $1.49/barrel price ceiling proposed by Ross's governor is far too small, and that any price ceiling would have to be at least twice the amount suggested by Ross. *Id.*

2024. In addition, because the evidence clearly establishes that it would take a month or more for potential shippers of Naphtha to validate and respond to any spike in the price of Naphtha on the West Coast, Exxon argues that it is undisputed that no price cap created by the potential for Naphtha imports on the West Coast could possibly operate within the first month of any increase in the West Coast price of Naphtha. *Id.* It follows, according to Exxon, that any price ceiling based on potential Naphtha imports should not go into effect until after period of a least a month has passed, and then it would apply only if the West Coast/Gulf Coast price differential exceeded the amount of the price ceiling during the second month as well as the first month. *Id.* at pp. 322-23.

2025. While these changes to the governor proposed by Ross would not cure the lack of theoretical and evidentiary justification for the governor, Exxon argues, the need for these fundamental changes starkly demonstrates the complete reformulation of the governor that would be required to bring it into compliance with the evidence. *Id.* at p. 323.

2026. Turning to the Petro Star alternative proposal for valuing West Coast Naphtha presented through the testimony of Dudley, Exxon described it as being based on the relationship between Gulf Coast Naphtha prices and a weighted incremental differential between Gulf Coast and West Coast VGO prices and Gulf Coast and West Coast LSR prices.[670] Exxon Initial Brief at p. 311. The sole objective of Petro Star's proposal,

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[669] Exxon states that there was no merit to either Ross's or BP's attempt to classify MTBE as a finished product in view of the undisputed fact that MTBE is a blendstock that is an important ingredient in the production of gasoline. Exxon Reply Brief at p. 322, n.207.

[670] Exxon explains that Dudley calculated a price differential between Gulf Coast and West Coast Naphtha based on the average price differential between Gulf Coast and

claims Exxon, was to attempt to devise some method of valuing West Coast Naphtha that does not rely on finished gasoline prices. *Id.*

2027. Exxon asserts that there is no logical or evidentiary basis for Dudley's proposal. *Id.* By arbitrarily avoiding any connection between the value of Naphtha and gasoline, the principal product that is produced from Naphtha, Exxon states, Dudley simply turned his back on the product from which 90% or more of West Coast Naphtha derives its value. *Id.* at pp. 311-12. Additionally, Exxon criticizes Dudley's methodology as being plucked from thin air, because Dudley did nothing to validate it. *Id.* at p. 312. It notes that Dudley did not compare his valuation results with the West Coast Naphtha contracts or consult any petroleum product traders to validate his results. *Id.* Nor, according to Exxon, did he compare his results with the values that would have been produced by the linear programming or price differential methodologies that he himself ordinarily used to value petroleum products in the real business world. *Id.*

2028. Petro Star, according to Exxon, advances as the two strengths of the Dudley methodology that "(1) it uses current Gulf Coast Naphtha prices as a starting point, and (2) it avoids reliance on the West Coast finished gasoline market." Exxon Reply Brief at pp. 325-26 (quoting Petro Star Initial Brief at pp. 9-10). Exxon suggests that neither of these so-called strengths provides any justification for Dudley's approach. *Id.* at p. 326.

2029. In view of Petro Star's position that Gulf Coast prices should continue to be used to value West Coast Naphtha, Exxon states, it is not surprising that Petro Star regards Dudley's reliance on current Gulf Coast Naphtha prices as the starting point for valuing West Coast Naphtha as a strength. *Id.* However, Exxon asserts, Petro Star offers no evidence at all as to why using current Gulf Coast prices to value West Coast Naphtha is reasonable or appropriate, and there is overwhelming evidence that the Gulf Coast Naphtha price is not a reasonable basis for valuing West Coast Naphtha. *Id.*

2030. Exxon also notes that Petro Star offers no justification whatever for Dudley's avoidance of any reliance on West Coast gasoline prices, as it agrees that virtually all Naphtha on the West Coast is used to manufacture either gasoline or jet fuel. *Id.* Moreover, notes Exxon, Dudley testified that, when he valued West Coast Naphtha for other clients, he always used the West Coast price of gasoline as his starting point. *Id.* Indeed, Exxon states, the only reason that Dudley could offer for his avoidance of the use of West Coast gasoline prices was that he was told to do so by Petro Star. *Id.* at pp. 326-27. What the evidence shows, in Exxon's view, is that this "strength" (not using

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West Coast VGO and the average price differential between Gulf Coast and West Coast LSR. Exxon Initial Brief at p. 311. It further explains that the average VGO and LSR price differentials were then weighted on the basis of their relative contribution to the value of the ANS stream. *Id.*

prices of West Coast gasoline in his analysis) is in fact a weakness. *Id.* at p. 327. Exxon asserts that this stems from Petro Star's awareness that any valuation methodology based on the price of West Coast gasoline would lead to values for West Coast Naphtha that were well above the Platts Gulf Coast Naphtha price. *Id.*

2031. Moreover, Exxon argues, Petro Star is unable to cite any evidence that might validate either Dudley's methodology or the reasonableness of the results that it produces. *Id.* It maintains that this omission is a result Dudley's methodology producing results that were far below the Naphtha values that are produced by the Tallett and O'Brien methodologies. *Id.* Exxon also claims that Petro Star cannot simply dismiss the empirical evidence in the record regarding the market value of West Coast Naphtha on the grounds that there is no market. *Id.*

2032. Exxon also argues that Dudley's proposed methodology does not meet the requirements for reasoned decision making established for this proceeding by the Circuit Court in the *OXY* and *Exxon* decisions. *Id.* at pp. 327-28. Exxon states that Dudley presents no evidence supporting his assumption that Gulf Coast and West Coast prices for Naphtha, VGO and LSR should behave similarly because they are supplied from similar sources and are used to produce similar products on both Coasts. *Id.* at p. 328. According to Exxon, Dudley's own analysis showed that the prices of LSR and VGO do not behave similarly on the two coasts for reasons that are unique to each product. *Id.*

2033. Even accepting Dudley's assumption, however, Exxon asserts that his generalized theory of similarity between the West Coast/Gulf Coast price differentials for Naphtha, VGO, and LSR suffers from the same defect as the reasoning that was rejected by the Circuit Court in the *OXY* and *Exxon* decisions. *Id.* It claims that the Circuit Court in *Exxon* stated that there must be more than a generalized claim that two values are similar. *Id.* Rather, explains Exxon, there must be some evidence that the proposed proxy has a consistent correlation within a specific range. *Id.* Therefore, even were it true that the same general relationship exists between the values of Naphtha, VGO, and LSR on the two coasts, Exxon maintains, the resulting similarity of prices assumed by Dudley does not meet the *Exxon* court's test. *Id.* at pp. 328-29.

2034. Exxon argues that Dudley also had no logical or evidentiary basis for valuing Naphtha on the basis of VGO and LSR prices, both of which are almost always priced well below Naphtha. Exxon Initial Brief at p. 312. Indeed, notes Exxon, Dudley admitted that Naphtha prices can change regardless of what VGO and LSR prices are doing. *Id.* Moreover, states Exxon, Dudley conceded at the hearing that, had he selected any of the other Quality Bank cuts which are used to produce gasoline, the results achieved by applying his methodology would have been dramatically different. *Id.* at pp. 312-13.

2035. Further, states Exxon, Dudley acknowledged that the differential between the Gulf

Coast price and the West Coast price for each cut was a function of the specific economics applicable to that cut, that the economics of making Naphtha into gasoline are greatly different from those of LSR, and that there was no relationship between the price differential and the boiling range of a particular cut. *Id.* at p. 313. In particular, notes Exxon, Dudley acknowledged that the prices of both VGO and LSR behaved very differently on the West Coast from the way they behaved on the Gulf Coast because the costs of transforming them into gasoline are much higher on the West Coast. *Id.* Exxon points out that this was confirmed by the fact that the correlation between VGO and LSR prices on the West Coast was substantially lower than the correlation between VGO and LSR prices on the Gulf Coast. *Id.* It states that Dudley also conceded that he had never undertaken any study of the economics of transforming VGO, LSR, or Naphtha into gasoline. *Id.* at pp. 313-14.

2036. Dudley, explains Exxon, could not identify a single example of anyone in the petroleum industry who valued Naphtha or any other cut by looking at the prices of other cuts above or below it in the distillation range. *Id.* at p. 314. Neither, according to Exxon, could Boltz, Petro Star's other witness. *Id.* Similarly, Exxon states, it was undisputed that Petro Star never valued Naphtha by the method proposed by Dudley. *Id.* Indeed, Exxon notes, Dudley conceded that as a consultant in the actual business world he has always valued Naphtha on the basis of the price of gasoline using either a linear programming model or a processing cost deduction. *Id.* Likewise, states Exxon, Culberson conceded that, when he functioned as a refinery consultant, he valued Naphtha as a gasoline feedstock. *Id.*

2037. The illogic of Dudley's proposal can also be demonstrated, in Exxon's view, if one attempts to apply his approach to other Quality Bank cuts. *Id.* For example, explains Exxon, Williams presented an exhibit which set forth West Coast minus Gulf Coast price differentials for four Quality Bank cuts (Isobutane, Butane, LSR, and VGO) for which there are West Coast and Gulf Coast prices. *Id.* Using these price differentials, notes Exxon, it was impossible to predict the price of any other cut. *Id.* Exxon argues that Dudley's approach when applied in this fashion produces nonsensical results. *Id.* at pp. 314-15. For example, states Exxon, if one tried to predict the West Coast price of LSR using the weighted average of the price differentials for the other three cuts, Dudley's approach would predict that the West Coast LSR price would be 40¢/barrel higher than the Gulf Coast LSR price of $20.26/barrel, or $20.66/barrel, whereas in fact the West Coast LSR price during this period was only $17.78/barrel. *Id.* at p. 315.

2038. Exxon also asserts that Petro Star's contention that LSR and VGO are the appropriate cuts to use to value West Coast Naphtha because, like Naphtha, they are intermediate blendstocks used to produce gasoline on both coasts also completely disregards the undisputed evidence in the record that, Exxon reiterates, the West Coast/Gulf Coast price differential for each petroleum product – both finished and intermediate – is based on market dynamics that are unique to the particular product, its usage and its technical characteristics. Exxon Reply Brief at p. 329. For example, Exxon notes that, as Petro Star concedes in its brief, the negative West Coast/Gulf Coast price differential for LSR is a result of the fact that LSR has consistently been priced lower on the West Coast than the Gulf Coast, an unusual situation that is most likely caused by the fact that LSR has a high Reid Vapor Pressure in comparison to Naphtha which constrains LSR's use in summer gasoline production on the West Coast. *Id.* By contrast, Exxon states that because it is undisputed that Naphtha doesn't have the same Reid Vapor Pressure, the LSR differential provides no information on how to value West Coast Naphtha. *Id.* at pp. 329-30. Accordingly, Exxon asserts, even Petro Star must admit that LSR differentials are most probably different from Naphtha differentials. *Id.* at p. 330.

2039. Similarly, Exxon states that the evidence shows that the relatively low West Coast/Gulf Coast price differential for VGO is largely a result of the demand for VGO on the Gulf Coast for use in heating oil production coupled with the stricter West Coast environmental restrictions on sulfur that require more extensive processing of VGO, which makes VGO more expensive to use as a gasoline feedstock on the West Coast. *Id.* Exxon notes that neither of these factors applies to Naphtha, because Naphtha is not used in the production of heating oil and all of the sulfur in Naphtha is removed on both coasts by hydrotreating before the Naphtha is processed into reformate in order to protect the reformer catalyst. *Id.* The evidence thus shows, according to Exxon, that the West Coast/Gulf Coast price differentials for both LSR and VGO are determined by market factors that are unique to each of those cuts and have no application to Naphtha. *Id.* at pp. 330-31.

2040. Further, Exxon argues that the evidence shows that had Dudley used the price differentials for any of the other Quality Bank cuts that are used to produce gasoline, the resulting West Coast Naphtha values produced by his methodology would have been dramatically different. *Id.* at p. 331. Indeed, Exxon asserts that the evidence shows that it is impossible to predict the price of any other cut using the price differentials for any of the other cuts as Dudley proposed. *Id.*

2041. The manner in which Dudley chose to weight the incremental differences between West Coast and Gulf Coast prices for VGO and LSR also, according to Exxon, had no logical basis. Exxon Initial Brief at p. 315. Further, notes Exxon, the weighting factor that he used for LSR was inconsistent with his own explanation. *Id.* Exxon explains that in weighting the VGO and LSR price differentials on the basis of their relative contribution to the value of the ANS stream, Dudley looked only at the ANS crude downstream of the Petro Star and Williams refineries, an approach that would permit those refineries to influence the amount of VGO and LSR in the stream and thereby impact the Quality Bank value of Naphtha on the West Coast. *Id.*

2042. Exxon states that, although Petro Star claims that Dudley's decision to derive his West Coast Naphtha value from an approximately 4 to 1 weighted average of the West

Coast/Gulf Coast price differentials for VGO and LSR was based on the relative contributions of VGO and LSR to the TAPS stream, neither Petro Star nor Dudley has ever provided any logical justification for that weighting as an appropriate way to value West Coast Naphtha. Exxon Reply Brief at p. 331. This failure is the result of a more fundamental problem, in Exxon's view: the VGO and LSR price differentials used by Dudley have nothing to do with the value of Naphtha on the West Coast, with the result that any use of them to derive a value for West Coast Naphtha would be wholly arbitrary. *Id.* at pp. 331-32.

2043. Dudley himself, Exxon claims, testified that the sole objective of his valuation proposal was to create a formula that resulted in West Coast Naphtha being valued at the Gulf Coast Naphtha price, and that was the sole standard by which he judged the results. Exxon Initial Brief at pp. 315-16. It argues that the methodology proposed by Dudley produced nonsensical results, resulted in a substantial undervaluation of West Coast Naphtha as compared to all of the other valuation proposals for that cut, and often valued West Coast Naphtha at levels below even the Gulf Coast Naphtha price. *Id.* at p. 316. Exxon explains that, due to the large negative West Coast/Gulf Coast price differential for LSR, the average West Coast Naphtha price computed by Dudley's proposed methodology was 0.19¢/gallon lower than the Platts Gulf Coast Naphtha price. Exxon Reply Brief at p. 332.

2044. Exxon states that, at the hearing, Sanderson suggested that another alternative method for valuing Naphtha on the West Coast might be to use the market price of ANS crude plus the cost of producing Naphtha from the crude. Exxon Initial Brief at pp. 316-17. It claims that Williams presented no evidence to support this alternative valuation methodology. *Id.* at p. 317. In particular, Exxon states, although Sanderson acknowledged that Naphtha is produced in refineries using three different technologies having different costs, he presented no evidence regarding the cost of producing Naphtha by any of those technologies. *Id.* Instead, explains Exxon, Sanderson suggested that the Commission might use either the $3.60 differential between the average price of Gulf Coast Naphtha and the average price of ANS crude or the same $4.00 that Ross proposed to use as part of his price floor for West Coast Naphtha based on one contract as a proxy for the cost of producing Naphtha from crude. *Id.*

2045. Sanderson's proposed alternative, Exxon argues, is nothing more than a thinly disguised effort to value West Coast Naphtha at the Gulf Coast Naphtha price. *Id.* Indeed, Exxon asserts, this is shown mathematically by Sanderson's suggestion that the differential between the average price of Gulf Coast Naphtha (P_{GCN}) and the average price of ANS crude (P_{ANS}) could be used as the proxy for the cost of producing Naphtha from crude. *Id.* at pp. 317-18. Sanderson's formula for valuing West Coast Naphtha at the price of ANS crude (P_{ANS}) plus the cost of producing Naphtha from crude would then be $P_{ANS} + (P_{GCN} - P_{ANS})$, which, according to Exxon, equates to P_{GCN}, the price of Gulf Coast Naphtha. *Id.* at p. 318. Sanderson's proposed alternative method for valuing West

Coast Naphtha is thus, in Exxon's opinion, nothing more than an alternative way to reach a preordained result identical to his original – and patently unreasonable – proposal to value West Coast Naphtha at the Gulf Coast Naphtha price. *Id.*

2046. Exxon states that Williams confirms in its brief that this was the preordained objective of the Sanderson proposal. Exxon Reply Brief at p. 334. For that reason, explains Exxon, Williams states that ANS + $4.00/barrel is not only "consistent" with the Platts Gulf Coast Naphtha price quotation, it touts this proposed proxy on the ground that it is "equivalent" to the Gulf Coast Naphtha price. *Id.* Further, continues Exxon, Williams defends the reasonableness of Sanderson's ANS + $4.00 proposal solely on the ground that, because the Gulf Coast Naphtha price is the equivalent of ANS + $4.00, the reasonableness of using ANS + $4.00 as a proxy to value West Coast Naphtha should be judged by the same record evidence that supports the reasonableness of continuing to use the Gulf Coast Naphtha price as a proxy for the value of the West Coast Naphtha cut. *Id.* Exxon asserts that, were that the case, this proposal must be rejected because the evidence overwhelmingly demonstrates that the continued use of the Gulf Coast Naphtha price to value the Naphtha cut on the West Coast is unreasonable and unlawful. *Id.*

2047. Also, Exxon states, Sanderson's proposal to value West Coast Naphtha on the basis of the cost of ANS crude + $4.00 would be inconsistent with the valuation approach that has been adopted for every other Quality Bank cut. *Id.* at pp. 334-35. According to Exxon, all other cuts are valued on the basis of the market value of the products that are produced from that cut with, where appropriate, certain adjustments to ensure the equivalence of the Quality Bank cut and the proxy product. *Id.* at p. 335. It asserts that this is the very essence of the distillation methodology which values the crude oil based on the market price of the cuts produced when the crude is heated. *Id.* Exxon points out that no Quality Bank cut has ever been valued on the basis of the price of ANS crude plus the cost that a refiner would incur to derive that particular cut from the crude oil. *Id.* Accordingly, Exxon maintains, Sanderson's proposal to value the West Coast Naphtha cut at ANS + $4.00/barrel would clearly violate the consistency requirements of the *OXY* decision. *Id.*

2048. The absurdity of Sanderson's proposed ANS + $4.00 valuation for West Coast Naphtha is further demonstrated, in Exxon's view, by the fact that the costs to derive all of the Quality Bank cuts from ANS crude through the distillation process are roughly the same, since all of the cuts are derived from the crude oil through the same distillation process. *Id.* Were Sanderson correct, Exxon asserts, this would mean that the value of all the other Quality Bank cuts should also be ANS plus $4.00/barrel on the West Coast. *Id.* As the evidence makes very clear, notes Exxon, the West Coast market values of the other Quality Bank cuts bear no fixed relation to the price of ANS crude, but vary widely both from the price of ANS crude and from each other. *Id.* at pp. 335-36.

2049. Exxon argues that Sanderson's suggestion also is defective because he presented no evidence regarding the costs that would actually be incurred by a West Coast refinery to produce Naphtha from ANS crude. *Id.* at p. 336. Although he suggested that the Commission might use the differential between the average Platts Gulf Coast Naphtha price and the average price of ANS crude as a proxy, Exxon explains that he provided no explanation for why this differential would serve as a reasonable proxy for the costs of producing Naphtha from crude. *Id.* Nor, continues Exxon, did he even contend that the $4.00 figure, which he borrowed from the price floor used in Ross's proposed governor, actually reflects the cost of producing Naphtha from crude. *Id.* There is a complete failure of proof, concludes Exxon, regarding the essential cost element of Sanderson's proposal to value West Coast Naphtha at ANS + $4.00. *Id.* In Exxon's opinion, Sanderson's proposed ANS + $4.00 proxy thus suffers from the same lack of evidentiary support as the FO-380 less 4.5¢ proxy for Resid that the Circuit Court found to be unsupported by the record evidence in the *Exxon* decision.[671] *Id.* at pp. 336-37.

2050. Furthermore, Exxon notes, as Phillips stated in its brief, Sanderson's suggestion that $4.00 be used as a proxy for the costs that a West Coast refinery would incur to produce Naphtha from ANS crude conceals a wide variation in monthly results. *Id.* at p. 337. Assuming, as Sanderson does, that the cost of producing Naphtha from ANS crude could reasonably be approximated by the difference between the Platts Gulf Coast Naphtha price and the price of ANS crude, Exxon asserts, the evidence shows that difference has fluctuated widely from month to month from as low as 89¢/barrel up to $11.35/barrel. *Id.* It argues that the proposed use of a flat $4.00/barrel adjustment to cover this wide variation in results would therefore also violate the requirement in *Exxon* that the proxy price bear a rational relationship to the value it is supposed to represent. *Id.*

2051. Moreover, Exxon argues, it is revealing that Sanderson's suggestion of ANS + $4.00 for valuation of West Coast Naphtha is the same as the price floor proposed by Ross for West Coast Naphtha. Exxon Initial Brief at p. 318. It points out that this graphically demonstrates what Sanderson's proposed alternative Naphtha valuation was designed to do – to set the West Coast Naphtha price at or below the very minimum level at which suppliers might possibly be willing to sell Naphtha. *Id.*

2052. According to Exxon, neither Ross's testimony nor the one contract upon which he relied provides any justification for Sanderson's use of Ross's proposed price floor as a

[671] Exxon asserts that, in light of the complete lack of evidentiary support for Sanderson's suggestion that ANS + $4.00 might be used as a proxy to value West Coast Naphtha, the wholly unsubstantiated assertion by Unocal/OXY that Sanderson's suggestion "is more objective" than the supposedly "very subjective" valuation methodology presented by Tallett must be rejected as utter nonsense. Exxon Reply Brief at p. 337, n.211.

basis for valuing all West Coast Naphtha. *Id.* Exxon argues that, to the contrary, both Ross's governor proposal and the contract upon which it was based recognize that the price of ANS crude plus $4.00 represents a minimum value below which it would be unreasonable to expect the price of Naphtha to fall, and that the value of Naphtha on the West Coast would ordinarily be expected to exceed that minimum price. *Id.* at pp. 318-19.

2053. During the hearing, Exxon notes, I asked whether it might be appropriate to derive a West Coast Naphtha value using the published prices of two other petroleum products ("Product A" and "Product B") that bracketed the price of Naphtha on both the Gulf Coast and the West Coast. *Id.* at p. 320. Exxon explains that the value of West Coast Naphtha would then be determined by placing it within the range of the West Coast prices for the two bracketing products based on the position of the Gulf Coast Naphtha price within the range of the Gulf Coast prices for the same two products. *Id.* It notes that all parties agreed that there were no two intermediate petroleum products that both met the pricing requirements of bracketing the Naphtha price and could appropriately be used to derive a value for West Coast Naphtha in this fashion. *Id.* However, continues Exxon, the evidence showed that this formula could be applied using regular unleaded gasoline as Product A and crude oil as Product B, since the price of Naphtha generally falls somewhere between the price of regular unleaded gasoline – the chief product produced from Naphtha, and the price of crude oil – the product from which Naphtha is derived. *Id.* at p. 321.

2054. Similarly, explains Exxon, Judge Wilson suggested by her questioning that the value of Naphtha on the West Coast should be expected to be at or above the price of crude plus the cost of processing the crude into Naphtha (like the price floor proposed by Ross), and at or below the West Coast price of gasoline less the cost of processing the Naphtha into gasoline (like the Naphtha value calculated by O'Brien). *Id.* This would strongly suggest, according to Exxon, that the price of Naphtha should be somewhere between an upper bound determined by the West Coast price of gasoline less the cost of producing gasoline from Naphtha on the West Coast, and a lower bound determined by the price of ANS crude plus the cost of producing Naphtha from the crude on the West Coast. *Id.* Exxon suggests that the point within that range at which Naphtha would be appropriately valued might then be estimated on the basis of the relationship between the prices of gasoline, Naphtha, and crude oil on the Gulf Coast. *Id.*

2055. On the Gulf Coast over the 1994-2001 period, states Exxon, the average price of regular unleaded gasoline was $24.66/barrel, and the average price of Isthmus crude was $19.31/barrel. *Id.* During that same period, continues Exxon, the average price of Full Range Naphtha with an N+A of 40 on the Gulf Coast was $22.74/barrel, which means that the average price of heavy Naphtha with an N+A greater than 55, like the Naphtha produced from ANS crude, on the Gulf Coast during that period would have been

$23.79/barrel.[672] *Id.* at pp. 321-22. This means, claims Exxon, that the average differential between the price of regular unleaded gasoline and Isthmus crude on the Gulf Coast was $5.35/barrel, and that the average differential between the prices of ANS-type Naphtha and Isthmus crude on the Gulf Coast was $4.48/barrel. *Id.* at p. 322. It follows from these differentials, asserts Exxon, that, on average, the price of ANS-type Naphtha on the Gulf Coast was equal to the price of Isthmus crude plus 83.74% of the range between the price of gasoline and the price of Isthmus crude on the Gulf Coast. *Id.*

2056. Exxon suggests that this 83.74% figure could then be used to derive the West Coast value of Naphtha using the average published West Coast prices for regular unleaded gasoline and ANS crude. *Id.* It points out that, during the same 1994-2001 period, the average price of regular unleaded gasoline on the West Coast was $27.73/barrel, and the average price of ANS crude on the West Coast was $19.16/barrel. *Id.* This means, according to Exxon, that the average range between the price of regular unleaded gasoline and ANS crude oil on the West Coast was $8.57/barrel, and 83.74% of that range was $7.18/barrel. *Id.* at pp. 322-23. Adding this portion of the range to the price of ANS crude produces, in Exxon's calculations, an average West Coast Naphtha value of $26.33/barrel. *Id.* at p. 323. Exxon notes that this number is somewhat higher than Tallett's average West Coast Naphtha value of $25.48/barrel for the same period, and well above the average Gulf Coast Naphtha price of $22.74/barrel. *Id.*

2057. Similarly, Exxon states that, using the published average Gulf Coast price of Full Range Naphtha of $22.74/barrel with no adjustment for the higher quality of ANS Naphtha, this analysis produces an average West Coast Naphtha value of $24.65/barrel, a number somewhat below Tallett's average of $25.48/barrel. *Id.* It points out, an average of the results of the ANS-type Naphtha analysis ($26.33/barrel) and the Full Range Naphtha analysis ($24.65/barrel) produces a result ($25.49/barrel) that is virtually identical to the result for the same period produced by Tallett's methodology ($25.48/barrel). *Id.*

2058. This similarity of results is not surprising, according to Exxon, because, as Phillips correctly points out, the interpolation process that was suggested during the hearings is conceptually similar to Tallett's regression proposal, though Phillips states that Tallett's

[672] Exxon explains that the Naphtha produced from ANS crude is a more valuable Heavy Naphtha with an N+A over 55. Exxon Initial Brief at p. 322, n.111. It states that Heavy Naphtha is approximately 1¢/gallon more valuable than Full Range Naphtha, and a Naphtha with an N+A greater than 55 is approximately 1.5¢/gallon more valuable than Naphtha with an N+A of 40 (which is the value on which the Platts Gulf Coast Naphtha prices are based). *Id.* It follows, according to Exxon, that ANS Naphtha would be 2.5¢/gallon, or $1.05/barrel, more valuable than the Full Range Naphtha on which the Platts Gulf Coast price was based. *Id.*

proposal gives a more accurate result. Exxon Reply Brief at p. 340. Therefore, Exxon concurs in Phillips's recommendation to adopt the Tallett proposal rather than an interpolation proposal, because Tallett's proposal was fully addressed by all parties at the hearing and would not pose the same risk of lack of record support that the interpolation proposal would. *Id.*

2. Phillips

2059. Phillips supports the West Coast Naphtha methodology proposed by O'Brien, because Phillips believes that, out of all the Naphtha proposals, O'Brien's proposal is a cost-based methodology. Phillips Initial Brief at p. 76. It notes that O'Brien derives the Naphtha value from product prices published on the West Coast less the costs of processing Naphtha into those products. *Id.* Phillips explains that this is the way that all other Quality Bank cuts are valued when there is no published price that applies directly to the cut on the coast on which it is delivered. *Id.*

2060. O'Brien's proposal, Phillips explains, follows his methodology for valuing Resid as a Coker feedstock and is based on the fact that virtually all of the Naphtha produced by refineries on the West Coast is first processed through catalytic reformers to produce reformate, which subsequently is used as a blendstock in the production of gasoline. *Id.* at pp. 76-77. According to Phillips, O'Brien's methodology attempts to replicate the value of Naphtha in this processing. *Id.* at p. 76. It points out that the parties are in general agreement as to the basic Resid methodology, although they differ on certain of the assumptions used in that methodology. *Id.* at p. 77. Because that basic Coker feedstock methodology has been adopted by the Commission and approved by the Circuit Court, Phillips argues, using the same approach for West Coast Naphtha ensures that the Naphtha value is consistent with the Resid value and in compliance with the *OXY* uniformity requirement. *Id.*

2061. Phillips explains that the first step of O'Brien's methodology is to develop a before-cost value of Naphtha on the West Coast by first determining the product yields from running Naphtha through a reformer. *Id.* While about 85.7% of the Naphtha is converted into reformate, Phillips notes, other product yields include hydrogen gas, fuel gas, propane, isobutane, and normal butane. *Id.* As is the case with Resid, Phillips states, the reformer yields are multiplied by their product prices in order to derive a before-cost value of Naphtha. *Id.* Continues Phillips, published prices are available and used for fuel gas, propane, isobutane and normal butane, but further analysis was required to develop the reformate and hydrogen prices, which are not published. *Id.* at pp. 77-78.

2062. According to Phillips, O'Brien developed his reformate value based on the fact that the sole use of reformate is as a gasoline blendstock and derived the value of reformate using the published prices of the other blendstocks used to make gasoline as well as the price of the gasoline itself. *Id.* at p. 78 (citing Exhibit No. PAI-35.) It refers to this as the "three-component blend" formula. *Id.*

2063. Phillips concedes that some judgment is required in selecting the blend of products used to value reformate because gasoline is not uniformly made from a standard blend. *Id.* at p. 79. Instead, explains Phillips, there are a number of different blends of different blendstocks that can be used. *Id.* Notes Phillips, each refinery will choose a different blend or mix of blends depending upon the blendstocks available and the environmental restrictions that are applicable to that refinery. *Id.* In addition, states Phillips, there are a number of different types of gasoline produced on the West Coast ranging from CARB gasoline with its strict emission standards to conventional gasoline which has less strict emission standards. *Id.* Finally, notes Phillips, there are prices reported for regular and premium gasoline for all categories of gasoline differentiated by their respective octane content. *Id.*

2064. O'Brien based his Naphtha value calculation, states Phillips, on conventional regular gasoline using the Seattle reported price. *Id.* It points out that CARB gasoline and reformulated gasoline are more expensive, and are made with more complex blends that include products with no reported prices. *Id.* Further, notes Phillips, conventional gasoline is easier to make because it does not have to meet the California Air Resources Board and reformulated gasoline standards. *Id.* O'Brien chose to use the Seattle price, according to Phillips, because there is a robust market for conventional gasoline in the Pacific Northwest, whereas the California conventional gasoline market is small and shrinking. *Id.* at pp. 79-80.

2065. According to Phillips, O'Brien used a simple three-component blend of butane, LSR and reformate to make conventional regular gasoline, using percentages that allow the blend to meet applicable octane, Reid Vapor Pressure and vapor to liquid ratio specifications. *Id.* at p. 80. While this three-component blend is somewhat simplistic, Phillips claims, it is used by many refineries to make conventional regular gasoline. *Id.* Because there are reported prices for butane and LSR, Phillips argues, use of this blend allows O'Brien to perform a relatively simple calculation to determine the value of the reformate used in the blend. *Id.*

2066. Because there also is no published price for hydrogen on the West Coast, Phillips explains, O'Brien developed a hydrogen value based on the cost of manufacturing hydrogen from natural gas in a hydrogen plant. *Id.* O'Brien's calculation of the hydrogen value is the same, notes Phillips, as the calculation of the value of hydrogen that O'Brien performed for the Resid and Heavy Distillate valuation calculations. *Id.* However, according to Phillips, O'Brien faced a dilemma with respect to the question of how that hydrogen value should be adjusted to account for changes in the cost of natural gas, which is the primary cost incurred in producing hydrogen. *Id.* This dilemma, notes Phillips, results from the fact that, while hydrogen is produced as a byproduct of the processing of the Naphtha cut, it is consumed in the processing of the Resid and Heavy

Distillate cuts. *Id.* at pp. 80-81. For that reason, according to Phillips, O'Brien could not use the same approach for adjusting the cost of natural gas in calculating the value of the hydrogen produced in the reformer. *Id.* at p. 81. Under the Quality Bank methodology, states Phillips, all products of the various processes modeled by the methodology, including each of the Quality Bank cut values, are adjusted monthly in accordance with changes in published prices for that product. *Id.* Similarly, explains Phillips, the Resid valuation approach to which all parties have agreed provides that each of the Coker product prices is adjusted monthly to reflect changes in the published prices for that product. *Id.* O'Brien also adjusts all other products of the reforming process on a monthly basis in deriving his Naphtha value, notes Phillips. *Id.*

2067. In order to be consistent with how all other products produced from the various Quality Bank processes are adjusted, therefore, Phillips notes, O'Brien adjusted the natural gas component of his calculated hydrogen value on the same monthly basis in accordance with changes in the published price of natural gas. *Id.* at p. 82. Finally, states Phillips, this inclusion of the natural gas component of hydrogen in the Naphtha valuation formula is reflected in the formula shown on Exhibit No. PAI-39. *Id.*

2068. Once O'Brien determined the value of the products of the reforming process, Phillips explains, it was necessary to subtract the costs of the reforming process. *Id.* He used the same approach for this calculation, according to Phillips, as he did for his Resid and Heavy Distillate cost calculations, based on the Baker & O'Brien cost curves and fixed and operating cost data that O'Brien uses in his every day business. *Id.* (citing Exhibit No. PAI-37). Once the costs of reforming are determined, Phillips notes, the final step is to subtract those costs from the before-cost value to arrive at a cost-based value of Naphtha. *Id.* Finally, states Phillips, consistent with the treatment of costs for other cuts, the costs are adjusted annually for changes in the Nelson Farrar Operating Index. *Id.* (citing Exhibit Nos. PAI- 38, 39).

2069. Phillips argues that another reason O'Brien's proposal should be adopted is that a number of tests that have been applied to his results that validate the reasonableness of his methodology. *Id.* at p. 83. It explains that O'Brien was required to make a number of assumptions regarding a representative gasoline blend and about how reformate is valued and parties opposed to use of his methodology have attacked the assumptions underlying his method. *Id.* However, Phillips asserts, it is possible to perform a real world test of the assumptions included in O'Brien's methodology. *Id.* While there clearly are differences between Gulf Coast and West Coast Naphtha values, Phillips explains, there is nothing in the theory underlying O'Brien's cost-based methodology that limits it to West Coast Naphtha. *Id.* Naphtha also is processed into gasoline on the Gulf Coast, notes Phillips, and the three-component blend is one way that conventional gasoline can be made on the Gulf Coast. *Id.* The significant differences between the Gulf Coast and West Coast markets can be accounted for, according to Phillips, by using Gulf Coast product prices in the formula instead of West Coast prices. *Id.*

2070. As a result, states Phillips, it is possible to test O'Brien's formula by substituting Gulf Coast product and gasoline prices into that formula. *Id.* The results of this substitution show, notes Phillips, that not only are the calculated prices close to the actual prices, but O'Brien's methodology very closely follows the Gulf Coast price trends, with an r-squared value of 0.959. *Id.* at p. 84. Phillips asserts that this result means that the values resulting from O'Brien's Naphtha methodology are more than just randomly related to the value of Naphtha, and thus the methodology is in conformance with the Circuit Court's holding in *Exxon*. *Id.*

2071. Further bolstering the validity of O'Brien's method, according to Phillips, is Exhibit No. WAP-132 that shows that, on average, O'Brien's calculated value was 2.1¢/gallon lower than the actual Gulf Coast price. *Id.* Phillips states that this means the costs that O'Brien calculated as required to process Naphtha on the West Coast were on average 2.1¢/gallon higher than what actually was required to match the Gulf Coast price. *Id.*

2072. Further, Phillips explains, the 2.1¢/gallon undervaluation of Gulf Coast Naphtha that results from the application of O'Brien's methodology to the Gulf Coast provides a practical response to a number of the attacks on his methodology. *Id.* For example, to the extent that the arguments are correct that the cost of processing Naphtha is higher on the West Coast than on the Gulf Coast, Phillips claims, the 2.1¢/gallon difference between Gulf Coast prices and the results of O'Brien's methodology on the Gulf Coast shows that O'Brien has provided for greater costs in his Naphtha methodology than occur on the Gulf Coast. *Id.* at pp. 84-85. Phillips also argues that this difference similarly addresses other arguments regarding differences between the Gulf Coast and the West Coast Naphtha markets such as that refiner margins are higher on the West Coast, and that Naphtha has a lower value relative to gasoline prices on the West Coast than on the Gulf Coast. *Id.* at p. 85.

2073. At the same time that O'Brien developed a cost-based Naphtha methodology, Phillips explains, Tallett independently derived a market-based methodology. *Id.* at p. 89. Although the two methodologies come up with somewhat different values, Phillips states, they are in the same general range as can be seen from the analyses presented by Pulliam in Exhibit No. SOA-28. *Id.* Phillips argues that the fact that two completely different approaches to the same problem came up with similar answers provides additional support for each methodology. *Id.* It claims that the testimony of Baumol supports this view, noting that he testified that:

> I've seen two pieces of evidence, which I think do strongly support the transferability of the Gulf Coast derived regression [done by Tallett] to the West Coast. One is the similarity of the results it yields to [O'Brien's] results. . . . And it is essentially an entirely independent result, one I described as, I believe, disaggregation of the final product price, and it comes out with numbers very close to [Tallett's]. Now, the point is that if it

> were true that the naphtha values, for example, for the West Coast entailed earnings materially lower or materially higher than those on the Gulf Coast, I would have expected that the Tallett concluding numbers would also have been correspondingly materially higher or materially lower than the O'Brien numbers.

Id. at pp. 89-90. (quoting Transcript at pp. 5151-52).

2074. Phillips states that one criticism of O’Brien's methodology is that, for a period of several months in 2000 and 2001, the calculated Naphtha price was above the Seattle gasoline price that O'Brien used to calculate the Naphtha price and that it is unrealistic to assign a value to Naphtha that is higher than the price of the gasoline that the Naphtha is made into. *Id.* This criticism, Phillips points out, ignores that Naphtha is made into a number of products other than just gasoline – most notably hydrogen. *Id.* at p. 92. Because the value of hydrogen is highly dependent on the value of the natural gas from which it is principally made, Phillips explains, the calculated value of Naphtha can increase independently of the price of gasoline when the price of natural gas increases. *Id.* At times, notes Phillips, the Naphtha value can even increase above the price of gasoline if natural gas prices are high enough. *Id.* According to Phillips, this is exactly what happened in the case of O'Brien's methodology in 2000 and 2001. *Id.* It notes that when natural gas prices returned to more normal levels, the calculated Naphtha values moved back below Seattle gasoline prices. *Id.*

2075. That high natural gas prices were the cause of the high Naphtha prices resulting from O'Brien's methodology in 2000-2001 is also illustrated, points out Phillips, in Exhibit No. PAI-150, which breaks down each before-cost element of the Naphtha value calculated by O'Brien for each month from 1999-2001. *Id.* It explains that Exhibit No. PAI-150 shows that increases in the price of reformate, which is what is blended into gasoline, never caused the calculated Naphtha value to exceed the gasoline price. *Id.* Instead, continues Phillips, it was when the prices of hydrogen and fuel gas, which also is priced from natural gas, were higher than normal that the calculated value of Naphtha exceeded the price of Seattle gasoline. *Id.*

2076. Phillips asserts that this result is perfectly consistent with economic theory, as Baumol testified. *Id.* It also is consistent, notes Phillips, with what happens from time to time on the Gulf Coast. *Id.* Also, Phillips explains, the price data submitted in this hearing show that there have been occasions when the published price of Naphtha has exceeded the published price of regular unleaded gasoline. *Id.* at pp. 92-93. It further states that this phenomenon has occurred as recently as 2003. *Id.* at p. 93.

2077. According to Phillips, Toof and Tallett nonetheless attacked the use of a Seattle gasoline price as being inconsistent with O'Brien's use of California prices at other points in his calculations. *Id.* at p. 94. It points out that O'Brien recognized this inconsistency, but that he believed that the danger of having the California price disappear in the future justifies using the Seattle price. *Id.* However, notes Phillips, use of the Seattle price is not central to his methodology, and if the Commission believes that the Los Angeles or West Coast gasoline price would be more appropriate for purposes of consistency, such a change could easily be made without doing any harm to the methodology. *Id.*

2078. In contrast to the arguments that it is inconsistent for O'Brien to have used the Seattle gasoline price for his Naphtha value instead of a Los Angeles price, Phillips notes, Williams suggested that O'Brien should not have used the Southern California natural gas price in his Naphtha value. *Id.* Phillips explains that Williams suggested that the Seattle or Green River, Wyoming, price be used instead, and sponsored Exhibit No. WAP-211 to show how the different prices compare. *Id.* It states that that Exhibit shows that, under typical conditions, there is not much difference between using the Los Angeles, Seattle, or Green River prices. *Id.* at p. 95. However, during the natural gas crisis of 2000-01, Phillips explains, the natural gas prices in these locations started to separate, with the Los Angeles prices increasing to levels substantially higher than the Seattle prices, which in turn exceeded the Green River prices. *Id.*

2079. It is Phillips's position that the Los Angeles natural gas price should be used, at least in ordinary circumstances.[673] *Id.* Phillips explains that most of the prices that have been used in cost-based calculations for other cuts have come from the Los Angeles area, and O'Brien used Los Angeles natural gas pricing for his proposed Heavy Distillate and Resid methodologies. *Id.* The reason that O'Brien chose not to use the Los Angeles conventional gasoline price does not, according to Phillips, apply to the Los Angeles natural gas market. *Id.*

2080. Phillips states that it is aware that the Commission has concluded that California natural gas prices were manipulated during the 2000-2001 time frame when Exhibit No. WAP-211 shows a separation between Seattle and Los Angeles prices. *Id.* (citing *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange*, 102 FERC ¶ 61,317 at P 56-63 (2003)). However, Phillips asserts, these manipulation concerns do not apply to the current prices, and the Commission is taking steps to prevent manipulation of the prices in the future. *Id.* at pp. 95-96 (citing *Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council*, 97 FERC ¶ 61,294 (2001)). To

[673] Phillips explains that the Los Angeles area price that O'Brien uses is based on the reported Southern California price index, plus an additional amount to account for the cost of transporting gas from the hub where the Southern California price is reported to refineries in the Los Angeles area. Phillips Initial Brief at p. 95, n.39 (citing Exhibit No. PAI-1 at p. 13).

the extent that the Commission is concerned about future natural gas price manipulation, Phillips suggests, the Quality Bank Administrator be permitted to propose the use of a different natural gas price in the event that the Commission makes a finding that there is a problem with the reported Southern California natural gas price. *Id.* at p. 96.

2081. The criticism that O'Brien's approach to valuing hydrogen for Naphtha purposes is inconsistent with the way that O'Brien values hydrogen in his cost-based calculations for Heavy Distillate and Resid, Phillips claims, has no merit. *Id.* It argues that it is wrong to say that O'Brien calculated his hydrogen value differently in his Naphtha calculations than he did in his Resid and Heavy Distillate calculations. *Id.* To the contrary, explains Phillips, O'Brien testified that he used the same approach for Naphtha that he used for Resid and Heavy Distillate. *Id.* The only difference, according to Phillips, is in how O'Brien proposes to adjust the value of hydrogen to account for changes in natural gas prices. *Id.*.

2082. Phillips notes that hydrogen is one of many elements of the costs associated with processing Heavy Distillate and Resid. *Id.* Rather than develop separate escalation factors for each cost element, Phillips explains, O'Brien lumps all costs together and adjusts them in accordance with changes in the Nelson Farrar Operating Index. *Id.* It would add considerably to the complexity of the Heavy Distillate and Resid formulæ, states Phillips, if each element of cost were escalated separately. *Id.* at pp. 96-97.

2083. According to Phillips, O'Brien was also concerned that others might find it inconsistent if he were to vary the cost of hydrogen in his Heavy Distillate and Resid cost calculations based on the cost of natural gas, but to escalate all other costs based on the Nelson Farrar Index. *Id.* at p. 97. Nevertheless, Phillips explains, it would be administratively feasible to do so if the Commission was to prefer using an across the board hydrogen valuation method for all purposes in all cuts. *Id.*

2084. Phillips considers O'Brien's approach to the hydrogen issue to be logical. *Id.* It claims that hydrogen is one of the products of the Naphtha reforming process instead of one of the costs. *Id.* O'Brien, Phillips states, varies the value of all products of the Heavy Distillate and Resid processing and of all other products of the Naphtha processing each month based on changes in the market prices of those products, and it would be inconsistent with the way that all other products are treated if, as suggested, O'Brien were to fix the value of hydrogen in calculating the value of Naphtha while allowing all other product values to vary each month based on changes in product prices. *Id.* Phillips asserts that this is not an acceptable way of achieving an across the board hydrogen approach, as it would distort the cut values significantly. *Id.*

2085. Exhibit Nos. WAP-214 and WAP-215, Phillips suggests, show that changing the value of hydrogen so that it is valued as it was on the cost side of the Heavy Distillate and Resid calculations would not have a significant impact on the Naphtha value in most years, but it would prevent the calculated Naphtha value from exceeding the Seattle gasoline price in those months where high natural gas prices caused O'Brien's calculated value to exceed the Seattle gasoline price. *Id.* at pp. 97-98. Far from supporting the use of a fixed value of hydrogen for O'Brien's methodology, Phillips asserts that Exhibit Nos. WAP-214 and WAP-215 show why the hydrogen value should be allowed to vary each month in accordance with the cost of natural gas. *Id.* at p. 98. As explained above, notes Phillips, the high cost of natural gas in those months caused the value of Naphtha to rise above the Seattle gasoline price, as evidenced by the West Coast Naphtha contracts. *Id.* Adopting a pricing methodology that fails to reflect the fact that Naphtha's value is based in part on the price of natural gas would result, in Phillips's opinion, in a calculated Naphtha value that undervalues Naphtha in times of high natural gas prices. *Id.*

2086. Phillips states that Sanderson and Culberson both asserted that the three-component blend used by O'Brien in his methodology was not used to make gasoline and that it failed to meet environmental and industry standards. *Id.* O'Brien disagreed, noted Phillips, but he did acknowledge that this blend is one of the simpler ones used in the industry and that there are more complex blends that also are used to make gasoline. *Id.* Those more complex blends, explains Phillips, are more difficult to model, particularly since they use blendstocks for which there are no published prices. *Id.* Since the three-component blend is used to make gasoline, continued Phillips, O'Brien concluded that it would be an appropriate simplifying assumption to value Naphtha based on the use of reformate in this three-component blend. *Id.* at pp. 98-99.

2087. As an initial matter, Phillips asserts, the tests of O'Brien's methodology are particularly useful for evaluating claims about whether the three-component blend is appropriate for use in developing a value for Naphtha. *Id.* at p. 99. In particular, Phillips believes, the fact that O'Brien's methodology does such a good job tracking the price of Naphtha on the Gulf Coast provides strong evidence that use of his three-component blend does in fact accurately capture the economics of making gasoline from Naphtha. *Id.*

2088. Phillips, referring to Exhibit No. UNO-57, which it describes as a report which purports to show that the three-component blend used in O'Brien's methodology does not meet industry standards, notes that Culberson used it to attempt to show that the three-component blend does not meet Drivability Index specifications required for most gasoline sold in the United States. *Id.* At page one of his report, according to Phillips, Culberson asserts that the blend would exceed the maximum 50% and 90% evaporation points established in the Drivability Index specifications for gasoline. *Id.* at p. 100. However, asserts Phillips, the distillation data produced by O'Brien during discovery, Exhibit No. PAI-237, showed that Culberson's assertion is incorrect. *Id.* Instead, explains Phillips, that Exhibit shows that 50% of the three-component blend evaporates at 236°F, and 90% evaporates at 319°F. *Id.* When these boiling points were compared with the Drivability Index specifications set forth in Exhibit No. UNO-57, continues Phillips, they show that the three-component blend does in fact meet the 50% and 90% evaporation requirements. *Id.* Furthermore, Exhibit No. PAI-237 includes a Drivability Index calculation for the three-component blend which shows, points out Phillips, that the three-component blend has a Drivability Index of 1186, which meets all Drivability Index specifications. *Id.* at pp. 100-01.

2089. Williams also asserted, Phillips states, that the three-component blend cannot meet EPA requirements for gasoline. *Id.* at p. 101. However, Phillips argues, the record evidence shows that the three-component blend does in fact meet the applicable EPA requirements for most of the Pacific Northwest refineries that are the primary producers of conventional gasoline on the West Coast. *Id.* Phillips explains that the general EPA requirements applicable to refiners appear at 40 C.F.R. § 80.101(2004). *Id.* at p. 102. Further, notes Phillips, the requirements that apply to conventional gasoline are in Section 101(b)(3). *Id.* Under section 101(c)(2), states Phillips, refiners have been obligated to satisfy the complex model standards starting in 1998, and there is no real dispute among the parties as to the applicable standards. *Id.* It notes that the primary requirements under this standard apply to annual average exhaust toxic and Nitrogen Oxide emissions, determined pursuant to the "complex model" under 40 C.F.R. § 80.45(2004). *Id.* Further, states Phillips, section 101(b)(3) requires that each refiner must meet its "compliance baseline" for exhaust toxics and Nitrogen Oxide emissions. *Id.* Refineries have two different ways to meet the EPA emissions requirements, according to Phillips: refineries that were in operation in 1990 have an individual baseline based on their 1990 gasoline qualities; while refineries that were not in operation in 1990 must meet the statutory baseline, which is a standardized baseline that applies throughout the United States. *Id.* at pp. 102-03. In order to assist refineries in determining compliance with the complex model, notes Phillips, the EPA has developed a standard spreadsheet to perform the complex model calculations. *Id.* at p. 103. According to Phillips, this model was used by O'Brien, Sanderson and Culberson in the course of their testimony. *Id.*

2090. One of the problems associated with the attempts to determine whether the three-component blend satisfies the EPA standards is the need to have accurate data regarding the quality of reformate made from ANS Naphtha, according to Phillips. *Id.* It notes that this can be seen from page 4 of Exhibit No. PAI-167, which shows both the input and output for the EPA complex model. *Id.*

2091. As Exhibit No. PAI-167 shows, continues Phillips, in order for the complex model to be run, it is necessary to have information regarding the gasoline blend's qualities with respect to Reid Vapor Pressure, distillation information for 200° and 300°, aromatics, olefins, sulfur and benzene. *Id.* It notes that some of this information can reasonably be estimated. *Id.* For example, explains Phillips, because Naphtha must be hydrotreated to essentially zero sulfur content prior to being processed in a reformer, it is reasonable to assume that reformate has no sulfur. *Id.* Similarly, states Phillips, it is well known that butane, LSR and reformate have no olefins. *Id.* at pp. 103-04. However, asserts Phillips, the benzene and aromatics levels of the blend, which are very important to the results of the complex model, are highly dependent on the benzene and aromatics levels of the LSR and reformate in the blend. *Id.* at p. 104.

2092. Use of ANS assays, according to Phillips, can help ascertain the benzene and aromatics levels of the LSR used in the blend, but they only provide the benzene and aromatics levels of the Naphtha that is processed into reformate and not of the reformate itself. *Id.* The whole point of the reforming process, explains Phillips, is to increase the amount of aromatics and naphthenes contained in Naphtha, and, therefore, the benzene and aromatics content of reformate made from ANS Naphtha necessarily will be higher than the benzene and aromatics content of ANS Naphtha itself. *Id.* Phillips points out that exactly how much higher cannot be determined by looking at the qualities of ANS Naphtha. *Id.* It notes that there is no standard correlation available that shows how to calculate the benzene and aromatics content of reformate from the benzene and aromatics content of Naphtha. *Id.* Instead, states Phillips, it is necessary to have that data taken directly from the reformate. *Id.*

2093. Phillips explains that the challenge for the parties in this proceeding, therefore, was to find data providing reasonable approximations of the amount of aromatics and benzene that is contained in reformate made from ANS Naphtha. *Id.* Without reasonable data for these qualities, they contend that any attempt to use the EPA complex model on the three-component blend would not lead to meaningful results. *Id.*

2094. According to Phillips, three different sets of data were presented at the hearing regarding the benzene and aromatics levels of reformate made from ANS Naphtha. *Id.* at p. 105. It notes that two of those were presented by Williams (Exhibit Nos. WAP-136, WAP-140), and the third set was presented by O'Brien (Exhibit No. PAI-167). *Id.* Phillips argues that only O'Brien's data contains a reasonable estimate of the qualities of reformate made from ANS Naphtha. *Id.*

2095. Exhibit No. WAP-136, according to Phillips, shows benzene and aromatics levels of 5.5% and 61.3%, respectively, for ANS reformate, values derived from a table in PIMS model 11.0. *Id.* The problem with using this table, according to Phillips, is that the benzene and aromatics content of the reformate based on the Naphtha feedstock which is used in the PIMS model is not calculated on it. *Id.* Phillips explains that the PIMS table uses a generic level of benzene and aromatics for reformate, regardless of the benzene and aromatics content of the Naphtha that is actually being reformed. *Id.* This is an unrealistic assumption, in Phillips's view, because the benzene content of reformate is directly related to the benzene and aromatics content of the Naphtha that is being processed by the reformer. *Id.* at pp. 105-06. It notes that O'Brien further testified that the PIMS generic reformate quality data included in this table was not linked to the part of the PIMS model that he used in his calculations and that he did not rely on that generic data in any fashion. *Id.* at p. 106.

2096. Phillips notes that Sorenson's testimony, during the N+A phase of the hearing, also addressed the data that was in the PIMS model regarding benzene and aromatics content of reformate. *Id.* It explains that Sorenson confirmed O'Brien's testimony that the PIMS data table does not vary the benzene and aromatics content of reformate based on the benzene and aromatics content of the Naphtha being processed, but rather on the octane level of the reformate into which the Naphtha is being processed. *Id.* Phillips notes that Sorenson also testified that the benzene and aromatics numbers in the PIMS table were "much higher than [he had] typically seen in the reformers [on which he'd] worked." *Id.* (quoting Transcript at p. 13325).

2097. Exhibit No. WAP-136, which it states shows the results of using the above-assumed reformate qualities in EPA's complex model, is the next matter addressed by Phillips. *Id.* It states that the Exhibit shows that the complex model calculates an annual average exhaust toxics level of 210.8 mg/mile for the three-component blend. *Id.* However, it notes that, because that calculation is based on the generic PIMS reformate aromatics and benzene content, not on the actual aromatics and benzene content of reformate made from ANS Naphtha, the calculation does not reflect the exhaust toxics level that would result from using ANS reformate. *Id.* Furthermore, Phillips explains that, because the generic PIMS aromatics and benzene levels are high, the calculated exhaust toxics level of 210.8 mg/mile is too high and does not accurately reflect the exhaust toxics value for the three-component blend. *Id.*

2098. Phillips states that Williams also used Exhibit No. WAP-140 during the hearing. *Id.* at p. 107. It explains that page one of this Exhibit shows somewhat lower benzene and aromatics levels for ANS reformate than the generic PIMS levels, with contents of 4.0% and 63.7% respectively, and that note 2 shows that the source of this data is a 1991 National Petroleum Refiners Association paper, which was entered into the record as Exhibit No. WAP-139. *Id.*

2099. Exhibit No. PAI-167 at p.1, according to Phillips, shows the reformate quality data presented by O'Brien, with benzene and aromatics levels of 2.52% and 60.6% respectively. *Id.* at p. 108. This data, it explains, is somewhat lower than the data in either Exhibit No. WAP-136 or Exhibit No. WAP-140 and comes from the reformate qualities of Phillips Ferndale Refinery for the months June 2001 through December 2002. *Id.* (citing Exhibit No. PAI-167 at pp. 2-3). It states that O'Brien testified that this refinery, which is located in the Pacific Northwest and typically makes conventional gasoline, runs primarily ANS. *Id.* Phillips notes that he also testified that the Ferndale reformate was reformed more severely than the reformate in his assumed blend – to a 98.6 Research Octane instead of the 94 Research Octane assumed in O'Brien's blend. *Id.* at pp. 108-09. This means, according to Phillips, that the Ferndale reformate would have somewhat more benzene and aromatics than it would had it been processed to O'Brien's assumed 94 Research Octane. *Id.* at p. 109. It concludes that the Ferndale reformate qualities, therefore, while not perfect, provide a more reasonable approximation than those presented by Williams. *Id.*

2100. Phillips explains that using the complex EPA model calculations results in annual average exhaust toxics of 133.6 mg/mile using the Ferndale reformate qualities. *Id.* It notes that Exhibit No. PAI-167 at p. 1 also compares this figure with EPA's individual exhaust toxics baselines for the five Pacific Northwest refineries, and states that this comparison shows that the three-component blend exhaust toxics of 133.6 mg/mile are less than the 141.6 mg/mile baseline for the BP Cherry Point Refinery, which is by far the largest refinery in the Northwest, and also are less than the 134.2 mg/mile baseline for the Shell Anacortes Refinery, which is the second largest refinery in the region.[674] *Id.* at pp. 109-110. Therefore, Phillips suggests that either of these refineries could make the three-component blend and satisfy the EPA regulations. *Id.* at p. 110.

2101. According to Phillips, the primary criticism directed at O'Brien's methodology (as well as the methodology proposed by Tallett) is that "it inappropriately attributes the margin or profit refiners receive for their investments and market power in producing their most valuable refined product, gasoline, to the naphtha feedstock." Phillips Reply Brief at p. 55 (quoting Williams Initial Brief at p. 58; also citing Unocal/OXY Initial Brief at p. 28; BP Initial Brief at p. 34). It asserts that this rather vague, and unprovable, theory appears to rest on the assertion that margins between the price of crude and the price of the products sold by the refineries are higher on the West Coast than the Gulf Coast. *Id.* at pp. 55-56. Phillips explains that Exhibit No. WAP-9, which represents the data referred to by Sanderson to support his assertions about margins shows the margins in dollars per barrel of crude run. *Id.* at p. 56 (citing Exhibit No. WAP-8 at p. 5). Similarly, they point out that the "3-2-1 Crack Spread" that Sanderson also uses in his testimony on West Coast refiners's margins, calculates the margin as "a basket of conventional gasoline and low sulfur No. 2 fuel prices minus crude oil prices."[675] *Id.* (quoting Exhibit No. WAP-8 at p. 6).

[674] Phillips explains that data for the size of the Pacific Northwest refineries can be found in the Oil & Gas Journal data for Washington refineries that appears at page 10 of Exhibit No. PAI-262. *Id.* at p. 110, n.48. It states that this data shows that refinery sizes, based on barrels of crude processed per day, are as follows: BP—222,720; Shell – 148,600; Tesoro – 114,500; Phillips – 90,250; U.S. Oil – 44,350. *Id.*

[675] In addition, Phillips states that O'Brien testified that, when he refers to "refinery profit margins," he means the difference between the cost of crude oil and the price of the finished product being sold. Phillips Reply Brief at p. 56, n.25 (citing Transcript at pp. 5983-84).

2102. Thus, Phillips argues, when the advocates of Gulf Coast pricing assert that gasoline margins are higher on the West Coast than the Gulf Coast, what they are really saying is that there is a larger price differential between the price of gasoline and the price of crude on the West Coast than on the Gulf Coast. *Id.* Knowing that the margin between crude oil and gasoline is higher on the West Coast than on the Gulf Coast does not, in Phillips's view, provide an answer to the question of what the differential should be between the values of Naphtha and crude or gasoline prices. *Id.* It explains that the fact that there is a wider spread between crude and gasoline prices on the West Coast than on the Gulf Coast says nothing about where between those prices the West Coast Naphtha value falls, either on an absolute basis or in comparison to where the Naphtha value falls between crude and gasoline prices on the Gulf Coast. *Id.*

2103. Phillips notes that Unocal/OXY argue that, because Naphtha is an intermediate product used to make gasoline, the refiners would have no interest in increasing the margin of Naphtha over cost, since it would only be charging that cost to itself. Phillips Reply Brief at p. 57, n.26. It asserts that this argument is nonsense, and points out that a refiner that uses its Naphtha internally to make gasoline does not charge itself anything for the Naphtha, but simply determines its profits as the difference in price between the crude oil that it purchases and the products that it does sell. *Id.* According to Phillips, such a refiner does not establish a margin for the Naphtha that it uses internally. *Id.*

2104. There are a number of additional errors, Phillips contends, associated with the assertion that O'Brien's methodology assigns the margin associated with gasoline to Naphtha. Phillips Reply Brief at p. 57. Phillips explains that, as Exhibit No. PAI-37 shows, O'Brien has included a 20% capital recovery factor in his cost calculation that is intended to reflect a return on the capital invested in the refinery equipment, and points out that this factor was substantial, equal to 4.6¢/gallon in 1996 dollars. *Id.* It suggests that use of this capital recovery factor means that the entire West Coast gasoline margin is not being assigned to West Coast Naphtha. *Id.* at pp. 57-58. That this is an appropriate portion of the margin to assign to the return on capital is clear to Phillips because it claims that it is the same capital recovery factor that O'Brien used in determining the processing costs for Heavy Distillate and Resid. *Id.* at p. 58. It points out that the same parties complaining that O'Brien has not attributed sufficient margin to capital recovery in his Naphtha analysis (Williams, Unocal/OXY and Petro Star) accepted that as an appropriate allocation for the other three cuts. *Id.*

2105. Furthermore, Phillips maintains, Exhibit No. WAP-132 supports the conclusion that O'Brien's formula allows for a higher margin for West Coast finished products than refiners earn on the Gulf Coast. *Id.* It notes that this Exhibit, which applies O'Brien's methodology to the Gulf Coast, shows that, on average, O'Brien's formula results in a calculated Gulf Coast Naphtha price, after costs, that is 2.1¢/gallon lower than the published Gulf Coast price, and concludes that this indicates that, far from assigning the same margin to Naphtha on the West Coast that applies on the Gulf Coast, O'Brien's formula results in gasoline margins on the West Coast that are 2.1¢/gallon higher than those which prevailed on the Gulf Coast. *Id.*

2106. Phillips calls the argument regarding the relationship between Naphtha values and gasoline prices on the West Coast that is used by the proponents of Gulf Coast pricing "patently illogical." *Id.* at p. 61 (citing Williams Initial Brief at pp. 33-35; Unocal/OXY Initial Brief at p. 22). It suggests that the conclusion that the value of Naphtha on the West Coast, where it is almost exclusively made into gasoline, should not track gasoline prices as well as on the Gulf Coast, where there are other markets for Naphtha, is exactly backwards. *Id.* Phillips points out that, if Naphtha is made only into gasoline in the West Coast market, but is made into several products in the Gulf Coast market, it should track the price of gasoline more closely in the West Coast market where there are no alternative uses for Naphtha, not the Gulf Coast where other alternative uses potentially can influence the price. *Id.*

2107. According to Phillips, the Quality Bank already uses finished product prices to value two other cuts – the Light Distillate and Heavy Distillate cuts. *Id.* It explains that the proxy prices used for these cuts, jet fuel and No. 2 Fuel Oil, also have had significantly higher prices on the West Coast than on the Gulf Coast. *Id.* Phillips notes that the parties attacking O'Brien's methodology have characterized jet fuel – along with gasoline – as being "highly priced finished products." *Id.* at p. 62 (quoting Williams Initial Brief at p. 73, n.58).

2108. Having already chosen to value the Light Distillate and Heavy Distillate cuts based on finished product prices minus processing costs, Phillips asserts, the Commission cannot reject that same approach for Naphtha on the grounds that it transfers West Coast refining margins for finished products to the value of an intermediate product. *Id.* It contends that to do so would be to treat the Naphtha cut value differently from the Light Distillate and Heavy Distillate cuts, in violation of the *OXY* uniformity requirement. *Id.* Nor does it believe it is necessary to treat Naphtha differently from Light Distillate and Heavy Distillate as it points out that, in all three cases, a return on capital component is included in the cost calculation that is designed to provide for margins earned by the refiners on their capital equipment. *Id.* Because O'Brien was consistent in his use of the same 20% capital recovery factor in all his fixed cost calculations, it maintains that his approach allowed all three cuts to be valued consistently, taking into account a return on capital that the Gulf Coast pricing advocates found acceptable in other calculations that they sponsored. *Id.*

2109. Phillips indicates that it disagrees with Williams's argument that O'Brien's methodology is inconsistent with the cost-based methodologies used for the other Quality Bank cuts. *Id.* at p. 63. It states that, while it is true that gasoline is made from other products in addition to Naphtha, Williams makes no effort to explain why this difference has any impact on O'Brien's cost-based calculation. *Id.* Phillips notes that O'Brien's formula explicitly accounts for the fact that other components also are used in making gasoline, and that is why he used a three-component gasoline blend to develop his Naphtha value. *Id.* Further, it explains that O'Brien's formula backs out the value of the other components used in the blend from the price of gasoline, allowing the value of the reformate (made from Naphtha) that is used in the blend to be isolated from the values of the other products. *Id.* at pp. 63-64. Because O'Brien's formula accounts for the distinction identified by Williams, Phillips asserts, it is a distinction without a difference. *Id.* at p. 64.

2110. Williams's assertion that the Resid formulæ use only intermediate feedstock prices to value the products of the coking process while O'Brien's formula uses finished product values is not correct, according to Phillips. *Id.* It notes that both the Eight Parties and the Exxon Resid valuation formulæ use the Quality Bank Heavy Distillate price, which is a finished product price for low sulfur No. 2 Fuel Oil, minus processing costs. *Id.* (citing Exhibit No. PAI-18). Phillips also asserts that Williams's argument is based on the false premise that there is something inherently different about using intermediate product prices instead of finished product prices for proxy products, and points out that the Quality Bank has made no such distinction in the past, and there is no evidence in this record to suggest it must do so here.[676] *Id.* It contends that O'Brien's use of conventional unleaded regular gasoline as a proxy is consistent with the Quality Bank's approach of using a product as a proxy that is as close as possible in specification to the Quality Bank cut so as to minimize the amount of processing that would be required to get the cut to meet the proxy product's specification. *Id.*

2111. In addition, Phillips claims that Williams does not, and cannot, assert that there is some other finished West Coast product price that would be more appropriate to use in valuing Naphtha to make the cost-based Naphtha value more consistent with the cost-based values for Light Distillate, Heavy Distillate and Resid. *Id.* at p. 65. It argues that the record is clear that Naphtha is made almost exclusively into gasoline on the West Coast. *Id.* (citing Exhibit No. PAI-33 at p. 6). Given that, and given that it is possible to account for other products blended with reformate to make gasoline, Phillips concludes, O'Brien's proposal is entirely consistent with the way that the other cost-based adjustments are performed. *Id.*

2112. Phillips asserts that Williams should know better than to combine Exhibit No. PAI-39 and O'Brien's testimony to conclude that O'Brien's Naphtha value is in lock step

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[676] While Ross and Sanderson both tried to suggest some consistent differences in West Coast/Gulf Coast price differentials between finished products and intermediate products using graphics that were supposed to show some distinction, Phillips states, the graphics were very misleading and the supposed patterns evaporated under cross-examination. Phillips Reply Brief at p. 64, n.30.

with the price of gasoline plus a premium of 7%. *Id.* (citing Transcript at p. 5390). It states that O'Brien was careful to qualify his answers to the questions about how his formula worked by stating that the formula would follow gasoline prices only assuming that "everything else is equal." *Id.* (quoting Transcript at p. 5390). Later, Phillips notes that O'Brien explained that he gave this qualification, because his formula does not refer just to the price of Seattle gasoline, but also to a number of other products. *Id.* at pp. 65-66. As a result, it states that:

> [I]f one of these commodities or one of these prices changes, they don't change just unilaterally. All of these petroleum products and feedstocks and so forth are all related to energy values and crude oil prices. When one changes, they all tend to change, not necessarily in lockstep, but they do change.

Id. at p. 66 (quoting Transcript at p. 5960). Thus, Phillips explains that everything else is not equal, and that the value of Naphtha does not move in lockstep with the Seattle gasoline price. *Id.* Phillips asserts that this is graphically illustrated by Exhibit No. PAI-150 which shows clearly how the fluctuations in the prices of the various products of the reforming process affect the value. *Id.* It states that is in order to know how the calculated value of Naphtha changes, it is necessary to look at the prices of all the products that are included in the formula shown on Exhibit No. PAI-39, not just the Seattle gasoline price. *Id.*

2113. Furthermore, Phillips contends that Williams's focus on the 1.07 times the Seattle gasoline aspect of the formula creates the false impression that O'Brien is proposing to value Naphtha at 107% of the Seattle gasoline price. *Id.* It explains that O'Brien's formula, shown on Exhibit No. PAI-39,[677] also backs out the value of the LSR and Butane that are used in the three component blend. *Id.* Thus, it notes that, after multiplying the Seattle gasoline price times 1.07, O'Brien's formula then subtracts the LSR and Butane values used in the three-component blend, as well as the calculated processing costs. *Id.* at pp. 66-67. Williams's failure, Phillips argues, to mention these subtractions included in the formula is highly misleading. *Id.* at p. 67.

2114. Therefore, given the number of variables in his formula, Phillips maintains, the record demonstrates that O'Brien's Naphtha price does not "move [in] lockstep" with the Seattle gasoline price and certainly does not increase by $1.07 for every $1.00 increase in the Seattle gasoline price. *Id.* In support, Phillips refers to Exhibit No. PAI-176 which it states shows, among other things, O'Brien's calculated Naphtha values on a monthly basis from 1992-2001, and Exhibit No. EMT-352, which it states shows the monthly Seattle

[677] Phillips states “Exhibit No. PAI-38” in its Reply Brief. Phillips Reply Brief at p. 66. I am certain, however, that Phillips meant to refer to Exhibit No. PAI-39.

gasoline prices. *Id.* Phillips explains that a comparison of these two values, on a month-to-month basis, reflects that the two prices change at differing rates and that, indeed, on occasion, the Naphtha price can decrease when the gasoline price increases, or vice versa. *Id.* Further, Phillips notes, this is because price changes for the other products included in O'Brien's proposed Naphtha valuation formula offset the impact of the change in the Seattle gasoline price. *Id.*

2115. Phillips asserts that Williams's argument regarding the U.S. Oil refinery's ability to make that three component blend totally misconstrues O'Brien's rationale for choosing the three-component blend.[678] *Id.* at pp. 67-68 (citing Williams Initial Brief at pp. 64-67). It notes that O'Brien testified that he did not assume that his three-component blend was made solely by simple refineries like the U.S. Oil refinery. *Id.* at p. 68. Rather, according to Phillips, he assumed, in using the three-component blend, that it is a simple blend that can be made by every refinery that makes gasoline, from the most simple to the most complex. *Id.* Furthermore, Phillips notes that it is O'Brien's opinion that the three-component blend, in fact, is made by such complex refineries. *Id.* While use of the three-component blend admittedly is a simplifying assumption, Phillips contends that it is also a reasonable assumption. *Id.*

2116. Williams also wrongly points out, according to Phillips, that the U.S. Oil refinery uses isomerate to make gasoline, and asserts that O'Brien's decision not to include isomerate in his blend saved him from having to reduce his Naphtha value by the cost of an isomerization unit. *Id.* It notes that the isomerization unit is not used to process Naphtha, but instead processes LSR into isomerate to improve the octane of the LSR. *Id.* at pp. 68-69. Thus, it explains, the isomerization unit costs would have to be subtracted from the value of isomerate used in the blend, not from the Naphtha. *Id.* at p. 69.

2117. Phillips explains that any Naphtha valuation formula that included isomerate in the blend would have to follow four steps: (1) determine how much isomerate to include in the blend; (2) determine a value for isomerate, since there is no published price; (3) deduct the costs of the isomerization unit from the isomerate value; and (4) back out the isomerate value from the blend in order to determine the contribution of reformate to the gasoline value. *Id.* It asserts that the second and third steps would be complicated and controversial. *Id.* Furthermore, Phillips argues that, because it is unclear what the resulting after-cost isomerate value would be, it is unclear whether the inclusion of

[678] Phillips explains that Williams's assertions about whether the three-component blend meets EPA standards are based on inaccurate data regarding the benzene and aromatics content of reformate made from ANS Naphtha. Phillips Reply Brief at p. 67, n.32. It suggests that Williams presents its discussion of the EPA standards without ever even acknowledging that the more accurate data provided in Exhibit No. PAI-167 was entered into evidence. *Id.*

isomerate in the blend would increase or decrease the calculated value of Naphtha. *Id.*

2118. It was precisely to avoid the additional complication of valuing blending components with no published prices, such as isomerate, contends Phillips, that O'Brien used the simple three-component blend, where there are available prices for all the components except for reformate. *Id.* While it certainly is true that gasoline also is made with more complex blends, including blends with isomerate, Phillips maintains that O'Brien's methodology accurately tracks Gulf Coast Naphtha prices (albeit at a slightly lower price) provides strong evidence that his three-component blend does accurately reflect the economics of using Naphtha to make gasoline. *Id.*

2119. Phillips states that the Unocal/OXY assertion that the three-component blend should be rejected because it will not meet the air quality regulations on the West Coast and, therefore, cannot be used in California, Seattle, Phoenix or Las Vegas is irrelevant. *Id.* at p. 70. It notes that the record is clear that the Seattle conventional unleaded regular gasoline price used by O'Brien is based on a large and robust market. *Id.* (citing Exhibit No. PAI-33 at p. 9). In addition, it points out that Platts publishes both a West Coast and a Los Angeles conventional unleaded regular gasoline price. *Id.* (citing Exhibit No. EMT-349 at pp. 4-5). Therefore, Phillips maintains, there is ample evidence to support the conclusion that there are substantial trades of conventional unleaded regular gasoline on the West Coast. *Id.*

2120. Furthermore, Phillips argues that other Quality Bank cuts are valued based on proxy prices of products that are not necessarily used throughout the entire West Coast. *Id.* As examples, it refers to the use by the Quality Bank of Low Sulfur No. 2 Fuel Oil price to value Heavy Distillate even though California has implemented more restrictive CARB gasoline specifications applicable to sales in California. *Id.* (citing Exhibit No. EMT-349 at pp. 10-11). Phillips contends that the Commission has never considered, in adopting proxy prices for the Quality Bank, whether the proxy products used by the Quality Bank are sold throughout the entire West Coast. *Id.* at pp. 70-71. It asserts that it, therefore, would be inconsistent with the value of the other cuts to reject O'Brien's Naphtha value on this basis. *Id.* at p. 71.

2121. Phillips argues that Exxon’s criticisms of the O’Brien methodology are largely without merit. *Id.* Furthermore, it points out that two of Exxon’s criticisms actually would cause the calculated Naphtha value to increase. *Id.* First, Phillips notes, Exxon criticizes O'Brien's methodology for failing to employ a West Coast location factor to adjust the costs that he employs in his cost calculation. *Id.* Whatever the merits of this argument are with respect to Resid and Heavy Distillate, Phillips asserts, they demonstrably do not apply to O'Brien's Naphtha cost calculation. *Id.*

2122. According to Phillips, when O'Brien's Naphtha methodology is applied to Gulf Coast Naphtha using Gulf Coast product prices, it results in calculated prices that are on average 2.1¢/gallon below the published Gulf Coast Naphtha prices. *Id.* (citing Exhibit No. WAP-132 at p. 1). Phillips claims that this means that the costs used by O'Brien in his calculation were 2.1¢/gallon higher than they should have been if he were calculating the Gulf Coast Naphtha price, or 2.1¢/gallon higher than reflected in the prices charged by Gulf Coast refiners. *Id.* It argues that it is, therefore, wrong for Exxon to characterize O'Brien's Naphtha processing costs as representing Gulf Coast processing costs, and points out that his cost figures are higher than those incurred by Gulf Coast refiners. *Id.* at pp. 71-72.

2123. Phillips also takes exception to Exxon's criticism that O'Brien's value is "based on an outdated semi-regenerative reformer technology that is less efficient and produces lower yields than the continuous reformer technology that would be employed by a refiner today." *Id.* (quoting Exxon Initial Brief at p. 281). It notes that O'Brien explained, however, that he has used the most recent version of PIMS to obtain his yields, and that he believes that it is more appropriate and consistent with the other Quality Bank cut valuations to use the PIMS yields rather than non-PIMS yields, as Tallett has proposed. *Id.* Phillips asserts that O'Brien's use of the PIMS yields instead of Tallett's non-PIMS yields does not cause O'Brien's calculation to overstate the value of Naphtha. *Id.* It also notes that Exxon acknowledges that the more modern technology upon which Tallett relies is more efficient and has better yields than the technology assumed in PIMS. *Id.* Thus, it points out, use of this technology would reduce the assumed costs and increase the value of the products produced, which would in turn increase the calculated value of Naphtha. *Id.*

2124. It also disagrees with Exxon's criticism of O'Brien's choice of the Seattle gasoline price instead of a Los Angeles-based gasoline price, Phillips claims. *Id.* In addition, Phillips states that O'Brien explained he used the Seattle price because the Seattle market for conventional gasoline is robust and growing while the California market is small and shrinking. *Id.* at pp. 72-73 (citing Exhibit No. PAI-78 at pp. 8-9). In any event, Phillips asserts that use of a Los Angeles price would result in a higher Naphtha price since the Los Angeles gasoline prices have been higher than the Seattle prices. *Id.* at p. 73.

2125. While it is the case, concedes Phillips, that the three-component blend satisfies the individual baselines of most Pacific Northwest refineries, it also is the case that the three-component blend's annual exhaust toxics of 133.6 are well above the anti-dumping statutory baseline threshold for annual exhaust toxics, which is 104.5. Phillips Initial Brief at p. 111 (citing 40 C.F.R. § 80.91(c)(5)(iv)(2004)). The fact that the three-component blend does not meet the statutory baseline that applies in the absence of an individual refinery baseline should not make any difference, because, Phillips claims, all of the West Coast refineries were in operation in 1990 and thus have their own individual baselines. *Id.* As a result, contends Phillips, the anti-dumping statutory baseline does not apply to any of them. *Id.*

2126. To the extent that the Commission is concerned about the level of emissions under the three-component blend, Phillips suggests, there is evidence in the record that would allow the Commission to adjust O'Brien's proposal to address that concern. *Id.* Phillips explains that it is possible to install a benzene saturation unit in a refinery in order to reduce the amount of benzene in reformate to levels that will allow the refiner to lower the exhaust toxics resulting from the use of that reformate. *Id.* It notes that Sorenson also testified that use of a benzene saturation unit or another similar treatment facility is common in California. *Id.* Further, states Phillips, O'Brien presented Exhibit No. PAI-148 to show how use of a benzene saturation unit allows the three-component blend to meet the statutory baseline. *Id.* at p. 112.

2127. Phillips notes that Exhibit No. PAI-148 shows there would be two types of costs associated with the addition of a benzene saturation unit. *Id.* The first, explains Phillips, is the additional processing costs associated with the unit; the second is the decreased yield value of the products produced from the reforming process as a result of the use of the benzene saturation unit. *Id.* In combination, states Phillips, these two costs would reduce the value of Naphtha by 1.29¢/gallon in November of 2001. *Id.* Further, according to Phillips, O'Brien also determined how his Naphtha valuation formula should be changed if the Commission decides that the benzene saturation unit should be included in the cost-based calculation. *Id.* The revised formula is set out as Exhibit No. PAI-149. *Id.*

2128. The study that Culberson introduced as part of Exhibit No. UNO-57 also raised issues, states Phillips, regarding the extent to which use of the benzene saturation unit brings the three-component blend within the applicable EPA statutory baseline standards. *Id.* at p. 114. In particular, explains Phillips, the study asserts that the three-component blend would not meet EPA's emission standards even after being treated in the benzene saturation unit. *Id.* The problem with that study, asserts Phillips, is that Culberson applied the Federal Reformulated Gasoline Phase II requirements and the California Air Resources Board requirements to the three-component blend. *Id.* Phillips argues that this is inappropriate, because the three-component blend is a conventional gasoline, not a reformulated gasoline or a CARB gasoline. *Id.* It points out that Culberson conceded as much and that these standards therefore say nothing about whether the three-component blend satisfies the statutory baseline for conventional gasoline. *Id.*

2129. Independently of O'Brien, Phillips states, Tallett took a different, market-based, approach in deriving a value for West Coast Naphtha. *Id.* Phillips explains that he evaluated Gulf Coast prices to establish a relationship between published Naphtha, jet fuel and gasoline prices, and then applied that same relationship to West Coast jet fuel and gasoline prices to develop a West Coast Naphtha price. *Id.* While Phillips believes that the O’Brien methodology is more consistent with the methodologies used to value the other cuts, to the extent that the Commission determines that a market-based approach is preferable to a cost-based approach, Phillips believes, Tallett's proposal represents a rational approach to developing a market-based value. *Id.* at pp. 114-15.

2130. In reply to criticisms of the Tallett methodology, Phillips highlights the inconsistencies between the positions taken by the advocates of Gulf Coast pricing in their attacks on Exxon's proposal and their position that Gulf Coast pricing should be used. Phillips Reply Brief at p. 75. It states that Williams, Unocal/OXY and Petro Star each attack this proposal on the grounds that the Gulf Coast and West Coast markets are too different from each other for the relationship between products on the Gulf Coast to apply to the West Coast. *Id.* (citing Williams Initial Brief at p. 75; Unocal/OXY Initial Brief at p. 42; Petro Star Initial Brief at p. 20).

2131. Phillips argues that it is precisely because of the differences between the Gulf Coast and West Coast markets that the Gulf Coast price of Naphtha cannot accurately represent the West Coast value of Naphtha. *Id.* It contends that, by highlighting these differences between Gulf Coast and West Coast markets in their attacks on the Tallett methodology, Williams, Unocal/OXY and Petro Star are demonstrating why it is not appropriate to continue using the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at pp. 75-76.

2132. According to Phillips, Ross has proposed that the Commission adopt either O'Brien's or Tallett's West Coast Naphtha proposal. Phillips Initial Brief at p. 116. However, Phillips points out, Ross would then apply a governor to the calculated West Coast Naphtha value that, in reality, would continue to subject the West Coast Naphtha value to the Gulf Coast price. *Id.* Phillips states that this governor would apply uniquely to West Coast Naphtha and no other cut valuation involves any mechanism at all similar. *Id.*

2133. Phillips asserts that Ross's West Coast Naphtha proposal proved to be a moving target that changed directions several times during the proceeding as the underpinnings of the proposal came under attack. *Id.* It notes that the following changes were made: (1) withdrawal of cost-based calculation, (2) multiple changes to the governor, and (3) change in fundamental theory of what the governor represents. *Id.* at pp. 116-21.

2134. In his first round of testimony, states Phillips, Ross proposed the use of a governor set at $1.848/barrel. *Id.* at p. 117. Phillips explains that the governor is used to set a ceiling price for West Coast Naphtha, so if the calculated West Coast Naphtha value exceeded the Gulf Coast price plus $1.848/barrel, then the West Coast value would be reduced to that ceiling level. *Id.* Ross testified, according to Phillips, that his governor was based on a self-evident principle that the price of West Coast Naphtha could never exceed the price of Gulf Coast Naphtha plus the cost of shipping from the Gulf to the West Coast. *Id.* Phillips asserts that this self-evident principle changed through each round of testimony. *Id.* It notes that the value of the proposed governor decreased from $1.848/barrel to $1.29/barrel and then increased to $1.49/barrel. *Id.* Later, states

Phillips, Ross also added a floor equal to the price of ANS plus $4.00/barrel. *Id.* When Ross realized that this floor often exceeded the ceiling, Phillips notes, he added a provision that, in such event, the floor price would prevail. *Id.* Finally, when the use of a fixed governor was challenged, Phillips explains that Ross decided it would be acceptable to develop a governor that varied monthly based on changes in published transportation rates. *Id.* Phillips notes, because of these changes, Ross spent a considerable amount of time at the hearing explaining how his testimony would need to be changed as a result. *Id.* at p. 118.

2135. Phillips points out that Ross's justification for the application of his governor also changed over time. *Id.* Originally, states Phillips, Ross testified that his governor was required because of anomalies in West Coast gasoline prices that would cause the value of Naphtha to be overstated if no adjustment was made. *Id.* Initially, according to Phillips, Ross stated that the anomalous period started in 1999, later he agreed that it started in 1998. *Id.* Still later, asserts Phillips, when it became clear that his governor applied about as frequently before 1999 as it did during the so-called anomalous period, Ross backed away from his reliance on market anomalies from 1999-2001 to support the governor. *Id.* Instead, Phillips notes that, in rebuttal testimony, he refers only to intermittent increases in the price of gasoline on the West Coast that he believes are not attributable to any corresponding increase in the value of West Coast Naphtha. *Id.* at pp. 118-19. Phillips also notes that Ross switched to a definition of anomaly, i.e., any period when his govern would apply, that is clearly circular. *Id.* p. 119.

2136. According to Phillips, during the hearing, when faced with evidence in the form of the Naphtha contracts that higher prices for Naphtha on the West Coast could be sustained, Ross changed his rationale for his governor in a subtle but important way, introducing for the first time the theory that a governor was needed because the market for Naphtha on the West Coast is opaque. *Id.* at pp. 119-20. Phillips states that, prior to the hearing, Ross's governor was a yardstick of transportation costs, but now it had shifted to the theory that his governor was meant to model a transparent market, that is, one with a published price. *Id.* at pp. 120-21.

2137. It was inappropriate for Ross to adjust his calculations or present new theories at the hearing, exclaims Phillips. *Id.* at p. 121. While conceding that almost every witness did this in reaction to the significant amount of new evidence that was made available after all pre-filed testimony had been submitted, Phillips asserts that Ross did more, however, than merely adjust his calculations to take into account new evidence or respond to technical criticisms. *Id.* In Phillips's opinion, no other witness changed his proposal or the justification for his proposal so thoroughly as Ross. *Id.*

2138. Phillips states that, by the end of the hearing, Ross's proposal and the theory underlying it are almost completely unrecognizable when compared with what Ross had initially presented in Exhibit No. BPX-8. *Id.* It notes that the level of the governor is different, the justification of the need for the governor is different, and the explanation of what the governor represents is different. *Id.* That Ross was so willing to change his testimony when the facts became inconvenient to what he had previously proposed strongly suggests to Phillips that there is no fundamental principle underlying his governor proposal. *Id.* Instead, Phillips argues that the governor represents a preferred end-result in search of a theory on which to base it. *Id.*

2139. It is Phillips's position that the effect of Ross's governor would be to preclude the implementation of a West Coast Naphtha value for the Quality Bank. *Id.* Whether it is Tallett's or O'Brien's West Coast Naphtha value that is selected as the base West Coast Naphtha value, Phillips asserts that the governor applies so often that it really replaces the base valuation methodology. *Id.* at pp. 121-22. According to Phillips, Exhibit No. EMT-437 shows that the governor applied in 79 out of the 96 months (82%) between 1994 and 2001 when applied to Tallett's proposal, and 82 out of same 96 months (85%) when applied to O'Brien's proposal. *Id.* at p. 122. Therefore, Phillips points out that this means the actual West Coast value would apply less than 20% of the time. *Id.*

2140. Phillips maintains that Ross's governor is needed in order to simulate a transparent market price on the West Coast and that the Naphtha price in a transparent market will be lower than a price achieved under the West Coast Naphtha contracts is not justified. *Id.* at p. 124. It asserts that Ross is not qualified to give an opinion on economic principles, because he has no formal training and no experience as an economist. *Id.* (citing Exhibit No. BPX-2). Therefore, argues Phillips, Ross's economic testimony regarding opaque and transparent markets and the need for the governor to replicate a transparent market price should not be given much weight. *Id.*

2141. Baumol, by contrast, Phillips notes, is well-qualified to give economic testimony.[679] *Id.* It notes that Baumol contradicted Ross's contention that there must be a published price in order for there to be a market price, noting that most people in most markets have limited information. *Id.* at p. 125.

2142. Moreover, states Phillips, the Quality Bank simply looks to the actual market prices paid for products, not to what the price theoretically might be if conditions were different. *Id.* Phillips points out that no other cut has been valued with an adjustment to reflect a supposedly more competitive market. *Id.* Its position is that Ross's efforts to impose changes on the market value of Naphtha alone violate the *OXY* uniformity

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[679] Phillips notes that Baumol testified before Ross and was not able to specifically address Ross's new theory, which had not been presented in the pre-filed testimony and therefore had not been raised at the time of Baumol's testimony. Phillips Initial Brief at p. 124. However, states Phillips, Baumol indirectly did address certain contentions that were later made by Ross. *Id.*

requirement. *Id.*

2143. Furthermore, states Phillips, Ross testified that when there is no published price, contract prices might be above the actual market price or they might be below the actual market price. *Id.* at p. 126. It explains that Ross testified how actual contract prices might compare to those in a transparent, competitive market would depend upon the relative strength of the buyer and seller. *Id.* Further, notes Phillips, he testified that a seller with monopoly power can charge a high price, whereas a buyer with monopsony power can command a low price. *Id.* Phillips asserts that the only evidence in the record as to the relative bargaining positions of Naphtha buyers and sellers on the West Coast falls far short of showing either monopoly or monopsony power. *Id.* If it shows anything, it suggests to Phillips that the buyers might have greater leverage than the sellers, and that would lead to the Naphtha prices being below the purely competitive level – precisely the opposite of what is needed to support Ross's governor. *Id.*

2144. Finally, Phillips argues that Ross ignores the fact that there is a transparent published price for Naphtha on the Gulf Coast. *Id.* at p. 128. As a result, explains Phillips, the participants in the West Coast Naphtha market have all the information they need to know how the prices they are contracting for compare with the Gulf Coast price of Naphtha. *Id.*

2145. Not only is Ross's proposal unsupported as a matter of theory, Phillips asserts, there is also ample empirical data demonstrating that product prices on the West Coast are not constrained by Gulf Coast prices as Ross testified. *Id.* According to Phillips, this data demonstrates that prices between the Gulf Coast and the West Coast routinely diverge to a much greater extent than Ross's $1.49/barrel governor would suggest. *Id.*

2146. Phillips points out that Ross relies upon one contract as being particularly relevant to this proceeding because he claims that this contract has price cap provisions which are very similar to his governor and that the contract thus "validates the price cap concept for valuing West Coast Naphtha." *Id.* at p. 129 (quoting Exhibit No. BPX-67 at p. 15). It disagrees, and points out that of the over three hundred contracts produced in this proceeding, the contract relied upon by Ross is the only contract that has a price cap based on Gulf Coast prices. *Id.* (citing Exhibit No. BPX-67 at p. 18). While a single contract may not have much probative value, Phillips asserts, as hundreds of contracts do not have a price cap based on Gulf Coast prices, it strongly suggests that the West Coast market does not consider Gulf Coast Naphtha prices in establishing prices for West Coast Naphtha. *Id.* Moreover, explains Phillips, the product being sold under the contract is Full Range Naphtha. *Id.* This product will have a lower value than Quality Bank Naphtha, continues Phillips, which is a Heavy Naphtha, and its pricing terms are not probative of how Quality Bank Naphtha will be priced. *Id.*

2147. Furthermore, Phillips notes, this contract caps the price to be paid at the Gulf

Coast price of Naphtha plus \$2.96/barrel (7¢/gallon), even though the product being sold is Full Range Naphtha. *Id.* at p. 130. This, states Phillips, is almost exactly twice as high as Ross's \$1.49/barrel (3.5¢/gallon) governor that applies to the more valuable ANS Heavy Naphtha. *Id.* It points out that use of a price cap this high means that the purchaser under the contract could pay well over Ross's governed price of Gulf Coast Naphtha plus \$1.49/barrel for a much less valuable product. *Id.* Phillips asserts that the contract, therefore, is inconsistent with Ross's theory that a purchaser of Naphtha would purchase Heavy Naphtha from the Gulf Coast and ship it to the West Coast rather than pay a price that exceeded Gulf Coast prices by more than \$1.49/barrel. *Id.*

2148. Faced with the data showing West Coast minus Gulf Coast product price differentials well in excess of his governor, Phillips notes, Ross introduced evidence attempting to create a distinction between finished products and intermediate products. *Id.* at p. 134. It explains that Ross claimed that the market dynamics for finished products are different from the dynamics for intermediate products, and that, therefore, the governor for finished products should be \$1/barrel (2.5¢/gallon) greater than for intermediate products. *Id.* Ross presented Exhibit No. BPX-78, which, according to Phillips, purports to show how price differentials for finished products fit within one range, while price differentials for intermediate products fit into a lower range. *Id.* Exhibit No. BPX-78 also, continues Phillips, purports to show that his governed Naphtha values fit into the intermediate product band while the O'Brien and Tallett differentials fit into the finished product band. *Id.*

2149. Phillips suggests that there are several problems with this argument. *Id.* First, it asserts that, on its face, the data in Exhibit No. BPX-78 is inconsistent with Ross's governor. *Id.* Of the two intermediate products shown on the Exhibit, Phillips points out, the VGO price differential is above \$2/barrel, which is 50¢/barrel over the \$1.49/barrel intermediate product governor, while the price of LSR is over \$3/barrel less on the West Coast than on the Gulf Coast and clearly is subject to different market forces. *Id.* at pp. 134-35. Phillips also notes that all five of the finished product price differentials shown on the Exhibit exceed Ross's finished product governor of \$2.50/barrel (6¢/gallon). *Id.* at p. 135. Only one, states Phillips, Platts Waterborne Jet Fuel, is even close to the finished product shipping differential, and even this price differential slightly exceeds the finished product governor calculated by Ross.[680] *Id.* Thus, asserts Phillips, none of the price

[680] Phillips points out that Exhibit No. BPX-78 is drawn to the same scale as other Ross Exhibits that make it difficult to determine exactly where the points lie on the graph. Phillips Initial Brief at p. 135, n. 54. However, states Phillips, p. 5 of Exhibit No. PAI-176 shows price differentials for the same 1999-2001 time period represented by Exhibit No. BPX-78. *Id.* Exhibit No. PAI-176, according to Phillips, shows that the waterborne jet fuel price differential is 6.48¢/gallon for this time period which, it claims, is above the 6¢/gallon finished product price cap calculated by Ross. *Id.*

differentials shown in Exhibit No. PAI-78 are consistent with either Ross's finished product or intermediate product governor. *Id.*

2150. In addition, Phillips claims, Ross's intermediate/finished product distinction is based on price differentials averaged over a several year period. *Id.* In Phillips's view, his theory breaks down completely when product price differentials are examined on a shorter term basis. *Id.* For example, states Phillips, Exhibit No. PAI-202 shows fluctuations between product price differentials on an annual basis and clearly demonstrates that it simply is not possible to assert that there is any pattern whatsoever between finished and intermediate product differentials when those differentials are viewed on an annual basis. *Id.* at pp. 135-36. The relationship breaks down even further, continues Phillips, when prices are viewed on a monthly or shorter-term basis. *Id.* at p. 136 (citing Exhibit No. PAI-209 at p. 2).

2151. Furthermore, notes Phillips, Exhibit No. BPX-78 leaves out a number of finished and intermediate products that have reported prices on both the Gulf Coast and the West Coast. *Id.* These product price differentials, continues Phillips, as well as the ones shown on Exhibit No. BPX-78, are shown on Exhibit Nos. PAI-175 and PAI-176. *Id.* When all of the products are displayed in the same graphic format as Ross's Exhibit No. BPX-78, Phillips asserts, the patterns he purports to find disappear. *Id.* (citing Exhibit No. PAI-175). Turning then to Exhibit No. PAI-176, Phillips points out, page 1 shows differentials for 1992-2001, page 3 shows differentials for 1992-98, and page 5 for 1999-2001. *Id.* at pp. 136-37. In Phillips's opinion, these charts demonstrate that there is no pattern for the differentials that would show finished price differentials consistently higher than the intermediate product price differentials. *Id.* at p. 137. According to Phillips, the price differentials shown on Exhibit No. PAI-176 are consistently higher than the intermediate and finished product governors calculated by Ross. *Id.*

2152. Phillips states that Ross recognizes that actual price differentials for other products exceed his governor, even after taking into account the higher governor he assigns to finished products. *Id.* It asserts that this undercuts any claim that the governor is based on the cost of transportation between the two coasts, and notes that Ross attempts to explain away at least some of these differentials on the basis that there were abnormal or anomalous conditions for VGO, jet fuel, and conventional gasoline during 1999-2001. *Id.* (citing Exhibit No. BPX-67). Phillips suggests that "it is ironic" that Ross would present such an explanation. *Id.* It states, Ross's justification for imposing a governor in the first place is that it was necessary to address anomalies in the Naphtha marketplace during the 1999-2001 time frame – i.e., that Naphtha was moving in a way that was different from all other gasoline blendstocks and feedstocks. *Id.*

2153. Ross intended, Phillips claims, that the governor prevent the Naphtha price from going too high during these times because he thought imports or the threat of imports would have prevented the West Coast/Gulf Coast Naphtha differential from exceeding his governor. *Id.* at pp. 137-38. It notes that, now, Ross would have the Commission believe that price differentials for other products also exceeded the governor because of anomalies during the very same time period he asserts that the governor must be applied to Naphtha price differentials to prevent them from getting too high. *Id.* at p. 138. However, if West Coast market economics caused other product price differentials to move to high levels in the 1999-2001 time period, then Phillips suggests that it is reasonable to assume that Naphtha price differentials also rose in this time period. *Id.* At the very least, Phillips argues, it is not reasonable to assume that the threat of imports governed Naphtha values alone out of all products on the West Coast. *Id.*

2154. In any event, regardless of the validity of any of the theories underlying Ross's governor, Phillips asserts that it is clear that Ross's calculation of the governor is flawed and leaves out many elements that cause it to be too low. *Id.* Many of these flaws, in Phillips's view, are the same as the flaws in the transportation cost calculations of Culberson and Sanderson. *Id.* Phillips points out that all three transportation cost differential calculations assume that there are no barriers to entry on the West Coast. *Id.* According to Phillips, this assumption is at odds with the independent reports entered into the record detailing severe logistical problems in the California market that limit imports of gasoline and products used to make gasoline. *Id.* at pp. 138-39 (citing Exhibit Nos. EMT-385, EMT-489). It explains that these reports make the following points about barriers to entry: (1) tankage for clean products like gasoline and Naphtha is already constrained, and will be reduced by 10-15% over the next seven years, (2) it is unlikely that additional terminals can be constructed in the future and, in fact, existing terminals may be closed, (3) existing refinery tankage cycles on a frequent basis in the regular course of business and cannot be used for the receipt of imports, which require large tanks to be empty at the planned arrival date of the ship and then be drawn down slowly, (4) tank space is extremely difficult to find, leading to a reduction in the availability of spot tankage that could be used for imports of products, and (5) California is an insular market for petroleum products, separated from world markets not just by geographic distance, but also by product quality aspects, commercial barriers and infrastructure limitations. *Id.* at p. 139 (citing Exhibit Nos. EMT-385 at pp. 16, 51, 53; EMT-489 at p. 101).

2155. Phillips states that the Stillwater report concerning the California Strategic Fuels Reserve (Exhibit No. EMT-489) describes the impact of these barriers to entry on California prices in terms that are directly applicable here. *Id.* It states that the report notes that, as Ross, Culberson and Sanderson have hypothesized, "local prices should be at world market prices plus transport cost" and concludes, explains Phillips, that this is not the case for many California products. *Id.* (quoting Exhibit No. EMT-489 at p. 101). Phillips explains further that the report attributes this to a restraint on import options because of lack of terminal capacity and price volatility. *Id.* Similarly, notes Phillips, Exhibit No. EMT-385 reflects that the extreme price spikes observed in California that occurred over prolonged periods with no importer bringing in Naphtha are a clear indication of the barriers to entry in the California market. *Id.* at pp. 139-40.

2156. Ross, Sanderson and Culberson, Phillips contends, attempted to avoid the impact of these studies by asserting that they applied only to CARB gasoline or California Air Resources Board components, and not to Naphtha. *Id.* at p. 140. It asserts that this is not correct, and states that Exhibit No. EMT-385 specifically indicates that the gasoline blending components studied "include alkylate, Naphtha, reformate, raffinate, and natural gasoline" and that Exhibit No. EMT-489 discusses, "petroleum products" in general, not just CARB gasoline. *Id.* (quoting Exhibit Nos. EMT-385 at p. 24; EMT-489 at p. 101).

2157. Phillips maintains that logistics issues are a fact of life on the West Coast, particularly in California. *Id.* It argues that Ross's calculation of the governor, as well as Culberson's and Sanderson's import cost differential calculations, ignore these barriers to entry and therefore overstate the ability of the potential for imports to moderate West Coast prices. *Id.*

2158. Ross, as well as Culberson and Sanderson, according to Phillips, ignored the so-called "forward price risk," i.e., that the price differential between the Gulf Coast and the West Coast will decrease to a point where the import is uneconomic before the tanker transporting the Naphtha reaches the West Coast. *Id.* Phillips contends that this can be a significant deterrent to a trader considering whether to send a cargo to the West Coast to take advantage of a current price spike. *Id.* It explains that the estimates of the time it takes to transport Naphtha from the Caribbean were two to three weeks (Culberson) and 15 days (Ross). *Id.* at p. 141. Further, continues Phillips, this time potentially can be increased if there are delays getting through the Panama Canal, a not uncommon experience. *Id.* Phillips notes that all of the witnesses who calculated transportation price differentials agreed during the hearing that a price premium above the shipping cost differential would be required in order to compensate for the forward price risk. *Id.* None of them, notes Phillips, included such a premium in their calculations. *Id.* Accordingly, Phillips argues that all their estimates are low. *Id.*

2159. Phillips states that there is no evidence to support BP's assertion that the governor is needed to simulate a transparent market, which is based on a speculative and unsupported theory much like the theories advanced to support the continued use of Gulf Coast prices. Phillips Reply Brief at p. 76. Indeed, it asserts that the evidence in this record proves that West Coast Naphtha prices are not constrained by anything like the proposed governor. *Id.* Phillips points out that there is extensive price data available for markets that are "transparent" by BP's definition in that they have published prices on both coasts. *Id.* at p. 77. This data shows, according to Phillips, that prices on the West Coast in these "transparent" markets are routinely higher than Ross's governor would suggest.[681] *Id.* Clearly, it concludes, the evidence is inconsistent with the governor. *Id.*

[681] Phillips states that this remains true even if one accepts Ross's assertion that

2160. BP's assertion that the O'Brien proposal is like a shadow price is simply wrong, Phillips argues. *Id.* at pp. 77-78. It states that there is an important distinction that Ross admitted in his testimony, but which BP omitted from its brief -- that a true shadow price might overstate the actual value of a product because, as Ross testified, a "shadow price does not reflect a fixed cost." *Id.* at p. 78 (quoting Transcript at p. 9702). Phillips explains that this is because shadow prices represent the marginal value of a product, whereas fixed and capital costs represent sunk costs that have not effect on the incremental supply costs of products. *Id.* It notes that a refiner might be willing to pay up to the shadow price for a feedstock, because the shadow price covers all of the refiner's variable costs even should it not cover the refiner's total costs. *Id.*

2161. By contrast, Phillips notes, O'Brien's methodology includes all fixed and capital costs. *Id.* According to Phillips, Ross conceded that O'Brien's proposal is different from a shadow price because it "includes a capital recovery factor and fixed costs in [the] reformer costs." *Id.* (quoting Transcript at pp. 9703-04). It asserts that O'Brien's capital recovery factor of 20% and his fixed and capital recovery costs combined equal 5.7¢/gallon in 1996 dollars, a significant discount below what a shadow price valuation would be. *Id.* (citing Exhibit No. PAI-37). Therefore, Phillips maintains, BP errs in asserting that O'Brien's methodology reflects the maximum that a refiner would pay for Naphtha. *Id.* In fact, it notes that a refiner could pay up to 5.7¢/gallon more than O'Brien's value and still make a profit on the transaction. *Id.*

2162. According to Phillips, O'Brien's cost-based formula, which includes a return on capital, is consistent with cost-based pricing that the Commission has traditionally implemented. *Id.* at p. 79. It claims that such cost-based calculations which include a profit component are supposed to reflect the prices that would be paid in a competitive market. *Id.* (citing *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, at pp. 692-93 (1923)). Thus, far from reflecting the maximum price that a refiner would pay, Phillips asserts, O'Brien's methodology reflects the price that a refiner *should* pay in a competitive market under traditional regulatory theory in order to recover a reasonable return on its investment. *Id.* It suggests that this price does not need to be governed, and BP's efforts to limit O'Brien's calculated Naphtha value to a much lower level cannot be justified by BP's shadow price theory. *Id.*

2163. Phillips also notes that Ross testified that O'Brien's methodology is like a shadow price in that both are based on the demand side of the market and neither reflects the supply side. *Id.* It states that Ross apparently means that O'Brien does not recognize the

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there are different logistics patterns (and hence different governors) for finished products than for intermediate products. Phillips Reply Brief at p. 77, n.36. It asserts that West Coast prices routinely exceed the governor that Ross claims should be applicable. *Id.*

potential for imports from the Caribbean by using a governor based on Gulf Coast prices plus Ross's view of the cost of imports. *Id.* (citing Transcript at p. 9704). While conceding that Ross is correct that neither a shadow price nor O'Brien's methodology uses a governor, it asserts that this does not transform O'Brien's cost-based methodology into a shadow price. *Id.* Moreover, Phillips contends, the evidence makes clear that imports do not govern the Naphtha market as Ross suggests and there is no reason for O'Brien to take Ross's theory into account. *Id.*

2164. Furthermore, Phillips argues that none of the other Quality Bank cut values would meet Ross's supply side test either. *Id.* at p. 80. It explains that price differential data shows that almost every other Quality Bank cut has Gulf Coast/West Coast price differentials that exceed the Gulf Coast price plus the cost of a governor as calculated by Ross. *Id.* Noting that no governor has been imposed to limit those values, Phillips argues that there is no reason to impose such a governor solely on Naphtha. *Id.* This is especially true, it claims, since O'Brien's methodology already reflects the costs that would be reflected by a competitive market price. *Id.*

2165. According to Phillips, the Quality Bank has consistently used market prices to value the distillation cuts, and the artificial ceiling and floor in Ross's governor are the very antithesis of market values. *Id.* It points out that Ross's governor would preclude the use of the actual market values over 80% of the time. *Id.* (citing Exhibit No. EMT-437).

2166. Phillips theorizes that BP errs in claiming that there are gasoline price spikes which are unrelated to price increases in intermediate products, such as Naphtha, and that use of a gasoline-based Naphtha valuation methodology will result in calculated Naphtha price increases that overstate Naphtha values in a transparent market. *Id.* It contends that BP offers no evidence to support this theory and that evidence in the record makes clear that it is not correct. *Id.* According to Phillips, as is the case on the West Coast, Naphtha is one of several intermediate products on the Gulf Coast which can be blended to make gasoline. *Id.* at p. 81. Therefore, Phillips contends, BP's assertion that "gasoline prices often change due to forces that have nothing to do with naphtha" should apply with equal force on the Gulf Coast. *Id.* (quoting BP Initial Brief at pp. 36-37). Yet, explains Phillips, Exhibit No. EMT-394 shows that Gulf Coast Naphtha prices followed every single gasoline price spike on the Gulf Coast in the 1999-2001 time period when the Gulf Coast gasoline market also was quite volatile. *Id.* It states that Gulf Coast Naphtha prices have closely followed Gulf Coast gasoline prices since 1992, as shown both in Exhibit No. EMT-394 and in Tallett's correlation calculation of a 0.9673 R-squared between Gulf Coast Naphtha and gasoline prices. *Id.* (citing Exhibit No. EMT-11 at p. 18). As a result, Phillips contends, the available evidence about the relationship between Naphtha and gasoline prices during price spikes, on both the West Coast and the Gulf Coast, shows that Naphtha prices consistently follow gasoline price spikes. *Id.* at pp. 81-82.

2167. BP next argues, Phillips states, that because the 1993 VGO settlement methodology did not do a good job of matching the actual VGO prices, a governor is needed to prevent calculated Naphtha prices from rising to unjustified levels. *Id.* at p. 82. Phillips suggests, in reply, that the 1993 settlement value is not analogous to O'Brien's methodology, and points out that the 1993 settlement value was not a cost-based methodology as is O'Brien's Naphtha methodology. *Id.* Rather, Phillips notes, the 1993 settlement was a negotiated formula that ostensibly was based on "market values" negotiated among the settling parties for periods prior to 1993. *Id.* That the 1993 VGO settlement methodology has not done a good job tracking VGO prices speaks well of the Commission's decision to reject that methodology, but, Phillips suggests, it says nothing at all about whether O'Brien's completely different proposal is just and reasonable or needs to be governed as proposed by BP. *Id.*

2168. Petro Star, Phillips notes, supports the continued use of the Gulf Coast Naphtha price to value West Coast Naphtha. Phillips Initial Brief at p. 141. It explains that Dudley's proposal was submitted by Petro Star as an alternative in the event that the Commission determined that a West Coast Naphtha value should be developed. *Id.* Given that Petro Star sponsors Dudley's methodology, Phillips states, it is not surprising that his methodology reaches results very similar to the Gulf Coast price of Naphtha. *Id.* It explains that Dudley calculated that the average price of West Coast Naphtha for 1992-2001 under his methodology is 0.19¢/gallon below Gulf Coast Naphtha prices. *Id.* Dudley's proposal is severely flawed, argues Phillips, and should not be accepted by the Commission. *Id.*

2169. Dudley's methodology was doomed from the start, Phillips asserts, by the fact that Petro Star asked him "to determine whether [he] could devise a method for determining the value of West Coast Naphtha that does not rely on finished gasoline prices." *Id.* at p. 142 (quoting Exhibit No. PSI-5 at p. 2). It explains that the overwhelming use of Naphtha on the West Coast is to make gasoline, and states that, asking Dudley to develop a West Coast Naphtha price that does not rely on gasoline prices, is asking him to ignore the fundamental value of West Coast Naphtha. *Id.*

2170. Phillips also points out that developing a Naphtha price that ignores its value in making gasoline is inconsistent with Dudley's advice to his other clients in other representations. *Id.* It notes that Dudley testified that he has calculated the value of Naphtha for other clients and that in every instance, that value was based on the value of gasoline. *Id.* According to Phillips, precluding the use of gasoline required Dudley to develop a methodology that, to his knowledge, is not used by any refinery in valuing the products that it produces. *Id.* Certainly, claims Phillips, this method is not used by Petro Star in valuing its own Naphtha, as Boltz testified. *Id.*

2171. It is apparent, according to Phillips, why Petro Star would want Dudley to ignore gasoline prices in developing a West Coast Naphtha price -- West Coast gasoline prices historically have exceeded Gulf Coast gasoline prices, suggesting, it states, a higher value for Naphtha. *Id.* In order to develop a West Coast Naphtha value that is as low as the Gulf Coast price, Phillips explains, Dudley had to move to some other pricing basis. *Id.* at pp. 142-43. Phillips asserts that ignoring gasoline prices, however, required Dudley to ignore a fundamental reality in how Naphtha is valued. *Id.* at p. 143.

2172. According to Phillips, to develop a West Coast Naphtha value without resorting to gasoline prices, Dudley decided to base his value on the West Coast/Gulf Coast price differentials of LSR and VGO. *Id.* Phillips states that his proposal assigns Naphtha a West Coast/Gulf Coast price differential that is between the differentials of LSR and VGO, and then applies that differential to the Gulf Coast Naphtha price to determine the West Coast Naphtha value. *Id.* (citing Exhibit No. PAI-218).

2173. Phillips notes that the price of LSR was 5.4¢/gallon less on the West Coast than on the Gulf Coast for the time period 1992-2001, while the price of VGO was 1.02¢/gallon more on the West Coast than on the Gulf Coast for the same 1992-2001 period. *Id.* (citing Exhibit No. PAI-219). Because Dudley's formula puts the Naphtha West Coast/Gulf Coast price differential between the LSR (-5.4¢/gallon) and VGO (+1.02¢/gallon) price differentials, Phillips states, his calculated Naphtha West Coast/Gulf Coast price differential will be a very wide range, equivalent to $2.70/barrel. *Id.* Implicit in this formula, according to Phillips, is an assumption that the West Coast/Gulf Coast Naphtha price differential should be somewhere above the -5.4¢/gallon LSR price differential and somewhere below the +1.02¢/gallon VGO price differential.[682] *Id.*

2174. All experts, including Dudley, Phillips claims, agreed that the negative 5.4¢/gallon West Coast/Gulf Coast LSR differential results from the fact that LSR has a high Reid Vapor Pressure, which severely limits its value on the West Coast. *Id.* at pp. 143-44. Further, states Phillips, all experts, including Dudley, agreed that Naphtha has a low Reid Vapor Pressure and, therefore, it is unlikely to have such a low value on the West Coast relative to the Gulf Coast. *Id.* at p. 144. It therefore is reasonable, asserts Phillips, for Dudley to conclude that the West Coast/Gulf Coast price differential for Naphtha will be higher than that for LSR. *Id.*

2175. There is no agreement, notes Phillips, that the West Coast/Gulf Coast Naphtha differential will be lower than the VGO price differential, as Dudley's formula assumes. *Id.* Thus, Phillips suggests, there is no purely objective way to determine which product

[682] It must be noted that in its Initial Brief at p. 143, Phillips cites the VGO differential from Exhibit No. PAI-219 as 1.04¢/gallon in two places rather than the correct figure of 1.02¢/gallon.

will have a higher differential, but it asserts that the record evidence suggests that Naphtha should have a higher differential than VGO. *Id.* In any event, Phillips points out, Dudley testified that he has not studied and does not know whether VGO has a higher or lower West Coast/Gulf Coast price differential than Naphtha. *Id.* According to Phillips, this admission is fatal to his methodology, which assigns a lower price differential to Naphtha than VGO. *Id.* In Phillips's opinion, if Dudley does not know whether this is an accurate assumption, he cannot know whether his formula has any validity. *Id.*

2176. Although Dudley did not base his methodology on gasoline prices, Phillips notes, he testified that he chose LSR and VGO differentials because those two products are used in the production of gasoline. *Id.* As there are a number of other products that also are used in the production of gasoline, states Phillips, Dudley's arbitrary choice of LSR and VGO for his formula had a profound effect on his proposed Naphtha value. *Id.* Phillips cites Exhibit No. PAI-219, which, it suggests, shows West Coast/Gulf Coast price differentials for six products used to make gasoline, to illustrate this point. *Id.* at p. 145. As this Exhibit shows, explains Phillips, the differentials for these six products for the time period 1992-2001 range from a positive 9.81¢/gallon for isobutane to a negative 9.57¢/gallon for butane. *Id.* Dudley acknowledged that all of the products in Exhibit No. PAI-219 are gasoline components, yet, notes Phillips, he arbitrarily chose to place the Naphtha differential between LSR and VGO.[683] *Id.*

2177. Phillips points out that, had Dudley chosen to use different products in his formula, the outcome would have been materially affected. *Id.* For example, explains Phillips, LSR and Butane both have high Reid Vapor Pressure levels and therefore are valued lower on the West Coast than the Gulf Coast. *Id.* Since Naphtha does not have any Reid Vapor Pressure problems, Phillips suggests, it is unreasonable to use either of them in estimating a Naphtha price differential. *Id.* Had Dudley used a formula involving VGO and Isobutane price differentials, Phillips states, the result would be a much higher Naphtha price differential – somewhere between 1¢/gallon and 9.8¢/gallon. *Id.* While it does not advocate the use of these products or any other Naphtha valuation formula based on West Coast/Gulf Coast price differentials, Phillips asserts, the point is that Dudley has not presented any compelling reason to use the LSR and VGO differentials instead of any of the other differentials. *Id.* The fact that the potential outcome of his methodology depends so heavily on his unsupported choice of the product prices used demonstrates, in the opinion of Phillips, that the methodology is arbitrary and should not be adopted. *Id.* at pp. 145-46.

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[683] Phillips notes that while the boiling point of Naphtha falls between the boiling points of VGO and LSR, Dudley testified that there is no direct relationship between boiling point and relative market values on the Gulf Coast and West Coast. Phillips Initial Brief at p. 145, n.58.

2178. Once he decided to place the Naphtha price differential between the LSR and VGO price differentials, explains Phillips, Dudley had to decide exactly where to locate Naphtha between these two differentials. *Id.* at p. 146. Given that there is an almost 6.5¢/gallon spread between the LSR differential and the VGO differential, Phillips asserts, this decision, too, had a profound impact on the ultimate Naphtha value which results from Dudley's methodology. *Id.*

2179. In his rebuttal testimony, notes Phillips, Dudley argues that the formula is justified on the grounds that "[d]ifferences in the price of Naphtha between the Gulf and West Coasts are more likely to be similar to differences in the price of VGO of than LSR." *Id.* (quoting Exhibit No. PSI-11 at p. 5). This explanation, according to Phillips, does not support the use of a formula that weights the differentials precisely equal to the percentages of VGO and LSR contained in ANS crude.[684] *Id.*

2180. During the hearing, Phillips points out, Dudley changed rationales. *Id.* at p. 147. It explains that he attempted to justify his formula on the grounds that refineries need to balance their products to produce gasoline, and that, were the amount of VGO or LSR included in the ANS stream to change, "then that affects its ability to deal with the naphtha that comes into it." *Id.* (quoting Transcript at p. 10069). Phillips points out that Dudley never explained how this theory translates into a higher or lower West Coast/Gulf Coast Naphtha price differential; nor does he explain how the differentials relate precisely to the percentage of LSR and VGO in ANS. *Id.* It declares that this is because the formula employed by him has nothing to do with the West Coast/Gulf Coast price differential for Naphtha. *Id.* In Phillips’s opinion, this formula is just one more arbitrary aspect of Dudley's proposal. *Id.*

2181. It is not surprising, in Phillips’s view, that Dudley's proposal does so poorly when compared to the empirical data. *Id.* at p. 148. It states that this is because Dudley's proposal: (1) is not based on the value of the product into which Naphtha is made; (2) relies on the unsupported assumption that the West Coast/Gulf Coast Naphtha price differential is less than the VGO price differential; (3) is based on the arbitrary choice of VGO and LSR price differentials; and (4) is based on an arbitrary formula to locate the Naphtha differential between the LSR and VGO differentials. *Id.*

[684] Phillips points out that one effect of this approach is to make the value of Naphtha depend upon the operations of the refineries connected to TAPS. Phillips Initial Brief at p. 146, n.59. Thus, explains Phillips, the proportions of VGO and LSR in the stream passing the Petro Star Valdez Refinery depend upon what the Petro Star refinery takes out and puts back, and Dudley's Naphtha value would vary based on that dynamic rather than on the supply and demand in the West Coast product market. *Id.*

2182. Phillips states that Petro Star's argument in support of Dudley's proposal makes no sense. Phillips Reply Brief at p. 83 (citing Petro Star Initial Brief at pp. 11-15). It asserts that there is no reason to believe that use of a formula that takes an arbitrarily weighted average of one imperfect indication of the West Coast/Gulf Coast Naphtha price differential and another even worse indication of the Naphtha differential somehow would somehow come up with a reasonable approximation of the Naphtha differential. *Id.* at pp. 83-84. Phillips argues, the average of a bad indicator and an even worse indicator cannot possibly be an appropriate proxy for West Coast Naphtha values. *Id.* at p. 84. Further, it contends, this logic could never pass muster under the Circuit Court's *Exxon* decision, which requires that there be a rational relationship between a proxy price and the value of the cut represented by that proxy price. *Id.*

2183. According to Phillips, some alternative proposal could conceivably provide for a reasonable West Coast Naphtha value that would be acceptable to Phillips. Phillips Initial Brief at p. 149. However, it expresses some concern that none of these alternative proposals could satisfy the *OXY* uniformity requirement. *Id.* Phillips has an additional concern with respect to these new Naphtha methodologies that it does not have regarding the Exxon proposal: while there is an extensive record regarding the existing proposals advanced by the parties in their pre-filed testimony, there would be very little, if any, record regarding an alternative methodology, and certainly almost no opportunity for the parties to submit evidence demonstrating the shortcomings of such an alternative. *Id.* This lack of a record regarding an alternative proposal could undermine its validity on appeal, states Phillips, no matter how reasonable the results might turn out to be. *Id.*

2184. Phillips is not suggesting that the Commission must accept an existing proposal without alteration or could not adjust one of the existing proposals if the adjustment were supported by record evidence. *Id.* However, Phillips declares that there is a difference between adjusting a proposal based on sound record evidence and implementing a new proposal that was not tested on the record by the parties, which, it suggests, could lead to problems on appeal. *Id.*

2185. The ANS + $4.00 proposal, Phillips contends, is based on the floor in Ross's governor and Ross testified that this figure represents the cost basis for a supplier. *Id.* at p. 150. It explains that Ross is asserting that it would cost a refiner $4.00/barrel to produce Naphtha from ANS. *Id.* According to Phillips, such an approach is inconsistent with the approach taken for all other cuts, which are valued based not on the cost of producing the cut from ANS, but on the market value of the products made from the cut less the costs, if any, of processing the cut so that it can be sold at the market price. *Id.* As such, Phillips claims, the ANS + $4.00 approach violates the requirement in *OXY* that all cuts be valued on the same basis. *Id.*

2186. Moreover, Phillips explains, the support that Ross provided for his assertion that the ANS + $4.00 floor is cost-based has nothing to do with the costs of producing

Naphtha from ANS. *Id.* Instead, continues Phillips, Ross's support consisted of price differentials between Gulf Coast Naphtha and the price of West Texas Sour crude, as well as a more complex calculation based on Naphtha, VGO and ANS prices. *Id.* It points out that Ross also presented similar calculations based on Isthmus crude prices instead of West Texas Sour crude. *Id.* In Phillips's view, this comparison of crude and product prices is, if anything, a market-based test that does not provide a cost basis for the ANS + $4.00 floor that is consistent with the cost calculations. *Id.* As such, it asserts that the use of an ANS + $4.00 value would violate the *OXY* requirement of consistency, even were it acceptable to base the Naphtha value on the cost of refining ANS into Naphtha instead of the cost of processing Naphtha into a saleable product. *Id.*

2187. Furthermore, according to Phillips, there is a huge variation (anywhere from -79¢/barrel to +$13.68/barrel) in the monthly results shown in Exhibit Nos. BPX-138 and BPX-170. *Id.* at pp. 150-51. Therefore, Phillips's position is that use of a fixed $4.00/barrel to represent this wide variation of results violates the requirement in *Exxon* that the proxy price bear a rational relationship to the value the proxy is supposed to represent. *Id.* at p. 151.

2188. Phillips states that Williams supports the use of the price of ANS plus $4.00/barrel as an alternative to the use of the Gulf Coast Naphtha price, because it is similar to the Gulf Coast Naphtha price. Phillips Reply Brief at p. 84. It asserts that this is not a sufficient justification to support the proposal. *Id.* Phillips argues that there are considerable problems with the merits of that proposal, separate and apart from the fact that its stated goal is to replicate Gulf Coast Naphtha prices. *Id.* To begin, Phillips notes that the ANS plus $4.00 proposal does not follow the typical Quality Bank approach. *Id.* at pp. 84-85. It states that, rather than take the published product prices, minus any processing costs, it takes the price of crude, and adds the costs of processing the crude into the product. *Id.* at p. 85. According to Phillips, Williams attempts to avoid this distinction through the use of semantics, by using the term "feedstocks" to describe both crude and the products of refining crude. *Id.* Phillips concedes that it may be semantically accurate that crude oil and intermediate products both can be called "feedstocks," but suggests that there is a fundamental distinction between a "crude plus" approach (such as the price of ANS + $4.00) and a "product minus" approach (that takes a published product price and subtracts the costs of processing a Quality Bank cut into that product). *Id.* Because the Quality Bank follows a product minus approach for all other cuts, Phillips contends, use of a crude plus approach for Naphtha alone would violate the uniformity requirement of *OXY*. *Id.*

2189. One difference, Phillips states, between the product minus and crude plus approaches is that the crude plus approach eliminates all the profit allowed by the marketplace and is nothing more than the sum of the refiner's costs. *Id.* It claims that such an approach understates the value of the cut by eliminating the differential between the sum of the costs and the market price (i.e., the profit). *Id.* According to Phillips, the product minus approach properly accords the cut its full market value by starting from the product market value and subtracting only the cost of processing required to bring the cut up to the specifications of the product. *Id.*

2190. Phillips asserts that the difference in results between a crude plus and a product minus approach can be significant. *Id.* at p. 86. It notes that Exhibit No. PAI-3, which it describes as a schematic of the processing required to produce each of the Quality Bank cuts, shows that crude is processed the same way to produce Naphtha as it is to produce Light Distillate. *Id.* In each instance, they are produced from crude solely by being run through an atmospheric distillation tower, claims Phillips. *Id.* Thus, under a crude plus approach, Phillips explains, a refiner would incur the exact same cost, which Williams asserts without proof is ANS + $4.00, to process crude into the Naphtha and Light Distillate cuts. *Id.*

2191. The record shows, notes Phillips, that use of an ANS + $4.00 proxy price for Light Distillate would yield significantly different, and lower, values for Light Distillate than the jet fuel minus 0.5¢/gallon price used by the Quality Bank. *Id.* It points out that Exhibit No. PAI-176 shows that the average West Coast Waterborne Jet Fuel Price for 1994-2001 was 63.27¢/gallon. *Id.* (citing Exhibit No. PAI-176 at p. 22). According to Phillips, the average Light Distillate price under the approved Quality Bank methodology for 1994-2001 was, therefore, 62.77¢/gallon. *Id.* Further, Phillips states, the average ANS + $4.00/barrel price for the same time period was $23.16/barrel, which is 55.14¢/gallon. *Id.* (citing Exhibit No. EMT-494 at p. 4). It concludes that the difference in the value of Light Distillate using a crude plus and a product minus approach is thus over 7.5¢/gallon, which is material under anyone's definition. *Id.* Phillips contends that use of a crude plus approach for Naphtha and a product minus approach for every other cut therefore will result in inconsistent valuations, in violation of *OXY*. *Id.*

2192. There is another more general inconsistency with applying the crude plus approach to Naphtha but not to any other products, according to Phillips. *Id.* It explains that the use of a crude plus approach would lead to three general groupings of cuts based on the cost of initial processing of crude into that cut. *Id.* at pp. 86-87 (citing Exhibit No. PAI-3). Naphtha, Light Distillate and Heavy Distillate are processed in the atmospheric distillation tower, states Phillips, while the natural gas liquids are further processed in the light end fractionator and VGO and Resid are further processed in the vacuum distillation tower. *Id.* at p. 87. Viewed this way, Phillips maintains, there would be three groups of products that all received the same basic processing, and the products within each group would all have the same cost of processing when viewed on a crude plus basis.[685] *Id.*

[685] Phillips notes that, while it is true the Resid, Heavy Distillate, Light Distillate and Naphtha cuts undergo additional processing to be sold as finished products, that processing occurs after the distillation process, and thus is irrelevant to the crude plus approach, which stops calculating costs after the crude is distilled into the Quality Bank

Under the crude plus approach, it points out that all of the products in each group would receive the same price, but in the real marketplace they would each have significantly different product values. *Id.* For example, Phillips notes that Isobutane and Butane would be in the same processing cost group, but the average price difference between Isobutane and Butane on the West Coast from 1994-2001 was over 21¢/gallon. *Id.* (citing Exhibit No. PAI-176 at p. 10).

2193. Phillips asserts that the four factors delineated by Williams do not support the ANS+$4.00 proposal. *Id.* (citing Williams Initial Brief at p. 82). While Phillips agrees with Williams's first factor, that the published ANS price is a robust price with little risk of manipulation, it claims that that fact does not justify the proposal unless the value otherwise is consistent with the valuation of the other cuts and is reasonably related to the actual value of West Coast Naphtha. *Id.* at pp. 87-88. Phillips states that the ANS plus $4.00 proposal does not meet either of those criteria. *Id.* at p. 88. As for Williams's second factor, that the ANS + $4.00 proposal would be simple to implement and administer, while conceding that it also is true, Phillips contends that simplicity alone does not justify the use of a proposal which otherwise is not just and reasonable, as the Circuit Court held in both *OXY* and *Exxon*. *Id.*

2194. According to Phillips, Williams asserts its proposal "is consistent with the philosophy of using feedstock prices to value the intermediate, Quality Bank cuts whenever possible." *Id.* (quoting Williams Initial Brief at p. 82). In Phillips's view, this is where Williams's justification, based on its use of semantics to apply the term feedstock to both crude and intermediate products, truly falls apart. *Id.* Repeating its assertion that the ANS plus $4.00 proposal is a crude plus approach which is inconsistent with the product minus approach that applies to all other cuts, Phillips also claims that it is not the philosophy of the Quality Bank to value cuts based on the cost of producing them from crude oil. *Id.*

2195. Moreover, Phillips expresses amazement that Williams would assert that the proposal "is supported by the largest volume produced Naphtha contract . . . which utilized ANS crude oil plus $4.00 per barrel to value Naphtha." *Id.* (quoting Williams Initial Brief at p. 82). It claims that, as Williams well knows, that contract sets the price at the Gulf Coast Naphtha price plus $2.96/barrel, and employs ANS Plus $4.00 only as a floor below which the Naphtha price can never fall. *Id.* (citing Transcript at pp. 8142, 8433). Phillips maintains that because that particular contract used ANS + $4.00 as a floor does not justify setting the Naphtha market value exactly at that floor, and the contract Ross used certainly does not justify Williams's basic reason for supporting the ANS plus $4.00 proposal in the first place, which is that it reaches results that are similar to the use of the Gulf Coast price. *Id.* at pp. 88-89.

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cuts. Phillips Reply Brief at p. 87, n.37.

2196. During the trial, Phillips notes, witnesses were asked whether a West Coast Naphtha price could be developed by determining where the Gulf Coast Naphtha price fell between the Gulf Coast VGO and Gulf Coast conventional gasoline prices, and applying that same percentage to the West Coast VGO and conventional gasoline prices. Phillips Initial Brief at p. 152. According to Phillips, such an approach could lead to results that are reasonably close to the West Coast value of Naphtha, provided that the correct products are chosen for the analysis. *Id.* For example, explains Phillips, LSR and butane prices are depressed on the West Coast relative to the Gulf Coast due to their Reid Vapor Pressure content, and it therefore would be inappropriate to use these products in such a valuation methodology. *Id.* However, Phillips suggests that the Commission not adopt such an approach for two reasons. *Id.* First, while the concept was discussed with a number of witnesses, Phillips points out, no specific proposal was ever addressed on the record. *Id.* Therefore, according to Phillips, there is no record evidence examining the reasonableness of such a proposal, and this would likely lead to problems on appeal. *Id.* Second, Phillips claims, this proposal is very similar in concept to the Exxon proposal presented by Tallett which, according to it, looks at the relationship between Naphtha, gasoline and jet fuel prices on the Gulf Coast and applies that relationship to gasoline and jet fuel prices on the West Coast. *Id.* The major difference, according to Phillips, between the interpolation method suggested at trial and Tallett's proposal is that Tallett has applied a more well developed regression analysis that should allow his proposal to more accurately capture the existing relationship between these product prices. *Id.* at pp. 152-53. Furthermore, Phillips points out, Tallett's proposal was fully addressed by all parties at the hearing and there is more than enough evidence on the record regarding his proposal. *Id.* at p. 153. Accordingly, Phillips recommends that, if the Commission prefers an approach based on relationships between prices on the Gulf Coast, that they adopt Tallett's proposal rather than the interpolation method suggested at the trial. *Id.*

2197. Phillips states that, in a proposal closely related to the ANS + $4.00 proposal, Sanderson suggested that it would be possible to develop a value for Naphtha based on the cost of processing ANS crude into Naphtha. *Id.* It notes that Sanderson did not, however, provide any cost data from which such a value could be determined; instead suggesting that a proxy for these costs would be the difference between the price of Gulf Coast Naphtha and ANS. *Id.* In Phillips's view, the differential between ANS and Gulf Coast Naphtha prices leads back to a price equal to the Gulf Coast Naphtha price, as Sanderson conceded on the stand. *Id.*

2198. At trial, notes Phillips, Judge Wilson explored with Culberson and Sanderson the possibility that Naphtha should be valued somewhere between two imaginary lines that represent the price of ANS plus the cost of producing Naphtha and the price of gasoline minus the cost of its production from Naphtha. *Id.* at p. 154. Phillips states that both witnesses agreed with Judge Wilson that the value of Naphtha should be within this range. *Id.* While agreeing, in theory, that the value of Naphtha generally should fall somewhere between these two lines, Phillips claims that this will not always be the case because the reforming process results in more products than just reformate – most notably hydrogen. *Id.* As described above, continues Phillips, when the value of hydrogen and/or other products of reforming is high, the value of Naphtha can in fact exceed the price of gasoline. *Id.*

2199. Furthermore, even the hypothesis as a general principle, Phillips asserts, cannot be turned into a Naphtha valuation methodology. *Id.* It states that there is no record evidence that would allow a reasoned decision as to: (1) what the costs are of producing Naphtha from ANS; or (2) where in the range between the two imaginary lines the value of Naphtha might fall. *Id.* While Phillips may believe that a methodology that places a West Coast Naphtha value somewhere between these lines might represent an appropriate value, depending upon where that value is placed, it believes that it would be very difficult for such a value to be sustained on appeal based on the record in this proceeding. *Id.*

3. BP

2200. BP argues that fundamental differences in the Gulf Coast and West Coast Naphtha markets make the use of a West Coast price assessment more appropriate than a Gulf Coast price assessment for valuing the West Coast Naphtha component. BP Initial Brief at p. 28. It notes that Tallett, O'Brien, and Ross all agree that a West Coast value for Naphtha is appropriate, even if a reporting service does not publish an assessment for it. *Id.* Therefore, according to BP, it makes sense to value Naphtha on the West Coast according to its predominant use, which is as a feedstock to make reformate, a gasoline blendstock. *Id.*

2201. Because there is no reported price for Naphtha or reformate on the West Coast, BP explains, an alternate methodology for valuing West Coast Naphtha must be developed and that value must be rooted in West Coast market dynamics and bounded by a ceiling and floor to ensure that it remains in line with the way a transparent market would actually function. *Id.* at p. 29. BP asserts that the West Coast Naphtha value should begin with a methodology that is based on the reported price for West Coast gasoline, adjusted for the cost of transforming Naphtha into a gasoline component, on the same waterborne basis as the other distillation cuts for liquid products in the TAPS Quality Bank methodology. *Id.* It suggests that either O'Brien's or Tallett's gasoline-based formula can serve as a starting point for its valuation. *Id.* However, continues BP, valuing Naphtha solely on a gasoline-based calculation has the inherent flaw that it may not reproduce values which would result if there were a transparent market for Naphtha on the West Coast. *Id.* Thus, according to BP, valuing West Coast Naphtha solely on the basis of either the O'Brien or the Tallett approach would interject an error into the calculation, considering the significant West Coast gasoline price spikes in recent years. *Id.* at pp. 29-30.

2202. Exxon does recognize, according to BP, that "[f]ar more than a mere cost adjustment to an existing market price is … required" to properly value the West Coast Naphtha cut. BP Reply Brief at p. 30 (quoting Exxon Initial Brief at p. 270). Nonetheless, BP maintains, Exxon and Phillips each fail to ensure that their proposed gasoline-based formula produces values comparable to the other Quality Bank prices formed in transparent markets. *Id.*

2203. BP notes that Ross has demonstrated that price anomalies have resulted in significantly greater increases in the price for gasoline than can be attributed to an increase in the value of Naphtha and the other significant gasoline feedstocks including, most importantly, VGO. BP Initial Brief at p. 30. If an adjustment is not made to account for this condition, BP suggests, the value of Naphtha will be significantly overstated. *Id.* BP argues that a viable Naphtha-valuation methodology must protect against these potential distortions. *Id.*

2204. Exxon and Phillips, BP acknowledges, have criticized the governor on the grounds that it is a result in search of a theory based on the fact that it has been modified several times since it was originally proposed. BP Reply Brief at p. 43. It asserts that this criticism is not valid. *Id.* Instead, BP notes, details of the proposal were changed only when it became apparent they were needed to meet the goal of representing Naphtha values on a consistent basis with other Quality Bank cuts. *Id.* at pp. 43-44.

2205. In order to simulate the supply-and-demand functions present in a transparent market, BP states, the gasoline-based valuation calculation must include a governor. BP Initial Brief at p. 30. As Ross explained, notes BP, once the gasoline-based calculation is performed, one must adjust the value resulting for Naphtha from a gasoline-minus calculation to cap the price at a level at which Naphtha from other markets otherwise could be imported into the West Coast. *Id.* According to BP, this provides protection against overvaluing Naphtha on the West Coast, as the cap simulates the higher end of the market price that would result in a transparent market where importers and exporters enter into transactions based on publicly available prices. *Id.*

2206. In addition, BP agrees with Ross’s view that the governor should also have a floor to prevent under-valuation of Naphtha.[686] *Id.* at pp. 30-31. It explains that Ross's governor provides a floor – the price of ANS crude oil plus $4.00/barrel – to ensure that the Naphtha price never falls below a price that is representative of the cost of local supply. *Id.* at p. 31. The key, notes BP, to proper valuation using a gasoline-minus

[686] BP points out that Ross used the terms floor and ceiling as a shorthand for the local supply component and imported supply component of the governor, respectively. BP Initial Brief at p. 31, n.8. If the floor exceeds the ceiling, the floor applies. *Id.*

formula is to constrain it with a floor and ceiling to ensure that the formula only represents simulated transactions that either would occur, or could occur, in a transparent market. *Id.* According to BP, a governor prevents the Naphtha value from fluctuating wildly because of gasoline price spikes and seeks to create a price similar to what would exist in a transparent market. *Id.* In BP's view, subjecting either the Tallett or O'Brien base Naphtha formula to the Ross governor provides an essential check to prevent over-valuation or under-valuation of West Coast Naphtha by simulating prices that would occur in a transparent market. *Id.*

2207. BP compares the gasoline-based formulæ without a governor to the "shadow prices" used by oil traders in making purchasing decisions.[687] *Id.* The true market value, according to BP, will be different than the shadow price because it will be influenced not only by the demand for the product but also by the availability of supply in the market. *Id.* at p. 32.

2208. Ross suggested, according to BP, that the O'Brien and Tallett gasoline-minus formulæ display some aspects of shadow prices, although, it suggests, they are not true shadow prices. *Id.* BP explains that the O'Brien and Tallett formulæ only consider the demand side of the West Coast market for Naphtha and fail to capture the supply side components such as import opportunities and a local refinery's ability to affect the Naphtha supply. *Id.* For that reason, BP asserts, the gasoline-minus formulæ will predict prices at the maximum that refiners can afford to pay for a product, an inherent flaw in a formula that is intended to simulate a price. *Id.* By contrast, BP states, proponents of using Gulf Coast prices to value West Coast Naphtha focus solely on the supply function when they assert that it costs the same to manufacture Naphtha on the West Coast as on the Gulf Coast. BP Reply Brief at p. 29. BP asserts, both methodologies are incomplete because, without the Ross governor, they do not balance the supply and demand functions to correctly simulate a transparent market. *Id.* According to BP, the Ross governor fixes this aspect of the O'Brien or Tallett formulæ by representing the supply component. BP Initial Brief at p. 32. As a ceiling, explains BP, it limits the price from going beyond the market value in a transparent market by providing a cap at the level that imports would start flooding the market and thereby lowering prices; as a floor, continues BP, it provides a baseline below which the price should not fall as the local suppliers have the ability to influence the Naphtha price with their local supplies. *Id.* at pp. 32-33. Without the Ross governor, it asserts, either the O'Brien or Tallett formula will tend to over-value Naphtha, like an unchecked shadow price. *Id.* at p. 33.

[687] BP notes that shadow prices, which are generated by linear programs, are "the maximum that a refiner should pay in a market," but don't represent an actual market price at which transactions would occur in a transparent market. BP Initial Brief at p. 31 (quoting Transcript at p. 9703).

2209. BP explains that the Ross governor is designed to represent prices which one would see in a transparent market. *Id.* Without a published price, states BP, the Quality Bank must attempt to assess a price under circumstances that do not currently exist. *Id.* According to it, this forces the Quality Bank to make estimates that simulate where the supply and demand curve would cross on the West Coast if the market were competitive with transparent pricing, in keeping with the characteristics of the markets for the other Quality Bank products. *Id.* BP suggests that the Ross governor is based on the realities of the West Coast gasoline market and its relationship to gasoline feedstocks. *Id.* That includes, in the view of BP, limiting the value ascribed to Naphtha based on Ross's conclusion that the price of Naphtha on the West Coast could never exceed the price of (1) Naphtha imported to the Gulf Coast added to (2) the differential cost of transporting Gulf Coast Naphtha to the West Coast market. *Id.* at pp. 33-34. If the price of Naphtha on the West Coast were to exceed the price of imported Naphtha diverted from delivery to the Gulf Coast, BP claims, the West Coast market would react and would cause Naphtha to be imported into the West Coast. *Id.* at p. 34. Thus, notes BP, the potential for importation of Naphtha into the West Coast place a price ceiling on the value of West Coast Naphtha. *Id.*

2210. The proponents of the Tallett methodology, BP contends, claim that the Gulf Coast relationship between Naphtha, gasoline, and jet fuel can be transported to the West Coast in order to predict West Coast Naphtha values. BP Reply Brief at p. 30. The proponents, according to BP, assert that the Gulf Coast and West Coast markets are sufficiently similar because Naphtha is processed into reformate on both coasts and the relationships between the products are structurally identical. *Id.*

2211. Exxon, in defending Tallett's regression formula, BP notes, claims that the Gulf and West Coast markets are similar enough so that the relationship between the prices of Naphtha, gasoline and jet fuel on the Gulf Coast can be transferred and used to value Naphtha on the West Coast based on the price of gasoline and jet fuel. *Id.* BP asserts that Exxon fails to address the marked differences in the Gulf Coast and the West Coast markets. *Id.* For example, it explains that (1) operating margins on the West Coast are higher than on the Gulf Coast, (2) the West Coast is subject to strict CARB restrictions which make it more expensive to process gasoline, (3) the supply and demand dynamics are different on the Gulf Coast than on the West Coast, and (4) the Gulf Coast has a petrochemical market for Naphtha that does not exist on the West Coast. *Id.* at pp. 30-31. It maintains that these differences, along with general flaws in using a gasoline-based formula, make transferring an unadjusted relationship on the Gulf Coast to the West Coast inappropriate. *Id.* at p. 31.

2212. The O'Brien formula, BP argues, cannot be used without application of a governor either, as it also would result in overvaluation. *Id.* It explains that, after 1999, anomalies detailed in the Stillwater report, Exhibit No. EMT-385, caused gasoline prices to rise sharply relative to crude oil on the West Coast. *Id.* While gasoline prices continued to rise, BP maintains, nothing suggests that the cost to transform crude oil to Naphtha changed, nor did the cost to transform Naphtha to gasoline, confirming that the value of Naphtha on the West Coast has not increased along with gasoline prices. *Id.* (citing Exhibit No. BPX-27 at pp. 11-12). As a consequence, it is BP's view that the sum of the production costs no longer had much explanatory value in calculating gasoline prices. *Id.*

2213. BP notes that O'Brien tries to develop an intermediate product price (the West Coast Naphtha value) by subtracting the processing costs from the finished product price (the price of gasoline). *Id.* It points out that such an approach freezes a cost differential between Naphtha and gasoline under the mistaken assumption that all of the difference between the ordinary gasoline price and the elevated gasoline price would flow through to Naphtha. *Id.* at pp. 31-32. Unadjusted, BP argues, the O'Brien formula would overvalue Naphtha, failing to account for the gasoline pricing anomalies that uncoupled Naphtha prices from gasoline prices. *Id.* at p. 32. Thus, BP concludes, the O'Brien formula fails, just as the Tallett formula fails, by not producing prices representative of the prices that would result in a transparent market – unless an appropriate governor is applied. *Id.*

2214. According to BP, a price ceiling is required to avoid overvaluing Naphtha. BP Initial Brief at p. 34. It maintains that Exxon and Phillips err in suggesting that their proposed methodologies properly capture the relationship between Naphtha and gasoline production on the West Coast and produce a just and reasonable results. BP Reply Brief at p. 32.

2215. Without a governor, explains BP, the Tallett and O'Brien gasoline-based Naphtha formulæ track all gasoline price spikes and improperly attribute the entire margin in gasoline, a finished product, to Naphtha, an intermediate product. BP Initial Brief at p. 34. As intermediate products have margins associated with their production and sale that differ from the margins associated with finished products, BP states, attributing finished product margins to Naphtha is inappropriate and would result in Naphtha's overvaluation. *Id.*

2216. BP argues that the basic flaw of the ungoverned gasoline-based formulæ is compounded when a methodology transfers Gulf Coast relationships to the West Coast and assumes no margin changes. BP Reply Brief at p. 32. According to it, refining data confirms that the profitability for finished products is higher on the West Coast than the Gulf Coast. *Id.* For example, it points out that cash operating margins have been consistently higher on the West Coast than the Gulf Coast by a margin of $2.87/barrel – more than 6¢/gallon – over a seven-year period from 1995-2001. *Id.* at pp. 32-33 (citing Exhibit No. WAP-8 at p. 5). Also BP notes, Tallett recognizes that refining margins on the West Coast have been higher than margins on the Gulf Coast. *Id.* at p. 33. Further, it states that the report to the California Attorney General that Pulliam co-authored (Exhibit No. WAP-199) explains that the higher gasoline prices flow through to the benefit of the refinery on the West Coast and not to the intermediate product. *Id.* Consequently, BP maintains, attributing finished product margins to Naphtha is inappropriate and results in overvaluation. *Id.* It states that this flaw is exacerbated when no effort is made to strip out the higher margins on the West Coast from flowing through to the formula-generated Naphtha values. *Id.* For example, BP claims that basing the value of Naphtha only on gasoline would wrongly attribute the full value earned by the gasoline to the Naphtha cut, even when the gasoline price is responding to shortages that have nothing to do with Naphtha supplies.[688] BP Initial Brief at p. 24. According to BP, this would severely overstate the actual value of Naphtha at certain times. *Id.* Therefore, in BP's view, a governor needs to be applied in order to fairly represent how a transparent market price would respond. *Id.*

2217. Exxon acknowledges, according to BP, that disruptions for VGO occurred on the West Coast that would cause VGO to depart from gasoline values.[689] BP Reply Brief at p. 35. However, BP points out, Exxon asserts that factors in the West Coast market, such as the introduction of CARB gasoline, do not prevent the price of Naphtha from moving in lockstep with gasoline. *Id.* at p. 34. BP asserts that, however, there is ample record evidence that intermediate product values – including Naphtha values – have become disassociated from gasoline values on the West Coast. *Id.* Exhibit No. BPX-37, continues BP, detailed disruptions in the West Coast refining industry that impacted gasoline prices, but had no effect on intermediate feedstock prices during the 1999-2001 period. BP Initial Brief at p. 35. For example, explains BP, a series of problems with cat crackers and Cokers affected the value of gasoline but did not necessarily affect the value of intermediate feedstocks. *Id.* In periods after the cat cracker incidents, such as March-April 1999, June-July 1999, and August-September 2001, BP notes, gasoline prices tended to rise, while VGO prices did not rise in parallel, because the demand for VGO as a cat cracker feedstock was reduced. *Id.*

2218. In periods after the Coker incidents, such as June-August 2001, gasoline and VGO prices rose together, comments BP, because the supply of Coker VGO had been reduced. *Id.* In both cases, however, the supply of cat gasoline was reduced, states BP, so the demand for reformate that could be blended within the restrictive West Coast gasoline specifications was reduced. *Id.* Further, continues BP, lower reformate demand meant lower Naphtha demand and lower Naphtha values. *Id.* Thus, refinery disruptions

[688] According to BP, Exhibit No. BPX-12 showed situations where there have been gasoline price spikes that are unaccompanied by price spikes of components that are used to make gasoline. BP Initial Brief at p. 35.

[689] Exhibit No. EMT-443, notes BP, plotted West Coast conventional unleaded gasoline versus West Coast VGO and showed that there has been a disconnect between the spikes in the gasoline price and the movement of the VGO price on at least four occasions from 1999 through 2001. BP Initial Brief at p. 35.

occurred throughout 1999-2001 which caused gasoline prices to spike, but, states BP, would not have caused Naphtha values simultaneously to spike. *Id.* BP concludes that, while gasoline prices were spiking, thereby reducing demand for reformate, Naphtha prices in a transparent market would have fallen. *Id.* at pp. 35-36.

2219. Exhibit No. BPX-37, according to BP, shows some examples of situations where disruptions or other market dynamics can reduce the supply, and drive up the price, of gasoline in the West Coast while the price of the intermediate feedstocks would not see a corresponding increase (and indeed, may move in the opposite direction). *Id.* at p. 36. The reason that the gasoline price spikes should not have flowed through to the intermediate feedstocks is that, in BP's view, if refineries are not functioning at their full capability, the demand for intermediate feedstocks decreases as the amount of gasoline supplied to the West Coast market decreases. *Id.* It acknowledges that the decreased gasoline supply would lead to an increase in the price of gasoline on the West Coast. *Id.* A gasoline price spike in this situation should not, asserts BP, flow through to the value of intermediate feedstocks, which are in lesser demand than they were before the refinery disruptions. *Id.* It states that the O'Brien and Tallett gasoline-based Naphtha valuation approaches would unjustly credit the value of West Coast Naphtha with those gasoline-only price spikes. *Id.* According to BP, this is unjustified and the Ross governor is required in order to correct this unjust result. *Id.*

2220. BP notes that, although essentially all Naphtha is dedicated to gasoline, Naphtha's primary derivative, reformate, accounts for only about one fourth of the gasoline pool. *Id.* Because of Naphtha's limited role in the gasoline pool, explains BP, gasoline prices often change due to forces that have nothing to do with it. *Id.* at pp. 36-37. Further, notes BP, West Coast gasoline prices have become increasingly erratic relative to gasoline prices in other markets since 1998. *Id.* at p. 37. It states that those gasoline price increases would not have affected intermediate products, such as VGO, whose primary use, like Naphtha's, is in gasoline manufacturing. *Id.* This erratic price behavior of West Coast gasoline occurs due to increasing demand on the West Coast for gasoline, claims BP, while stringent quality specifications and restrictive permitting of new refinery process plants are limiting supply on the West Coast. *Id.* Consequently, it states, West Coast finished product markets are increasingly dependent on imports and the markets can be very volatile as prices move into, and out of, import parity. *Id.* BP asserts, however, that these volatile price swings often are not associated with changes in intermediate feedstock values, such as Naphtha. *Id.*

2221. Disruptions and other market dynamics in the West Coast refining industry will continue to impact gasoline prices, according to BP, with no (or non-corresponding) effect on intermediate feedstock prices. *Id.* Consequently, states BP, formulæ, such as Tallett's and O'Brien's, without a governor that did not constrain the impact of these gasoline price spikes would have overvalued Naphtha during the 1999-2001 period. *Id.* It is BP's position that Naphtha values should not get the benefit of gasoline price spikes unrelated to gasoline component feedstock values. *Id.* Additionally, notes BP, any formula that attributes the entire margin of gasoline, a finished product, to Naphtha, an intermediate product, will overvalue it. *Id.*

2222. BP points out that the Tallett and O'Brien gasoline-based formulæ for West Coast Naphtha are not the first gasoline-based formulæ proposed in the Quality Bank proceedings. *Id.* at p. 38. A comparison of the 1993 settlement's proposed VGO formula to actual prices for VGO is instructive, states BP, to understanding the problems with an ungoverned gasoline-based West Coast Naphtha formula. *Id.* It claims that Exhibit No. BPX-166 demonstrates that the 1993 formula did not track the values that OPIS ascribed to that market over time. *Id.* In fact, explains BP, it shows a marked difference between the differential between the calculated price and the OPIS price between the 1994-1998 period and the 1999-2001 period. *Id.* BP notes that, during the 1994-1998 period, before the gasoline price fluctuations, the formula performed relatively well with an average differential from the reported price of $1.26/barrel. *Id.* at pp. 38-39. The 1999-2001 period was far worse, BP points out, with an average differential of $3.33/barrel. *Id.* at p. 39. The OPIS-reported VGO price did not, according to BP, track the gasoline-based 1993 settlement formula price for VGO. *Id.* Moreover, according to BP, the formula settlement price for VGO was consistently high, which would have resulted in a considerable overvaluation of VGO. *Id.* Thus, BP concludes, a gasoline-based formula can depart from prices that would be seen in a transparent market. BP Reply Brief at p. 36. It maintains that the risk that an ungoverned gasoline-based formula will depart from prices present in a transparent market increases when the finished product upon which the formula is based enters an anomalous pricing period. *Id.*

2223. In a similar manner, BP argues, the values produced by a VGO regression formula analogous to Tallett's Naphtha regression formula further illustrate the dangers inherent in relying on an ungoverned gasoline-based formula. *Id.* It explains that the analogous VGO regression formula resulted in values that were significantly higher than the actual West Coast VGO prices. *Id.* For the 1994-2001 period, BP notes, the analogous VGO regression formula would have overvalued VGO on the West Coast by $2.736/barrel. *Id.* In 2001, they continue, the regression formula would have overvalued VGO by over $4.00/barrel. *Id.* In BP's view, these examples cast further doubt on the ability to use ungoverned gasoline-based formula. *Id.*

2224. Further, BP notes, the O'Brien formula can produce a Naphtha price that would occasionally exceed the price of gasoline. *Id.* It asserts that this "nonsensical" result illustrates that, without a governor, a gasoline-based formula can result in values that are well above prices that would result in a transparent market. *Id.* According to BP, the O'Brien formula produces Naphtha prices that would have exceeded the corresponding gasoline prices for over an eight-month period spanning 2000 and 2001. *Id.* It points out that Phillips now claims that the value of Naphtha could exceed the value of gasoline under circumstances where the price of products made from Naphtha besides reformate skyrocket. *Id.* BP notes that, before it was known that O'Brien's own formula resulted in values for Naphtha that could exceed the price of gasoline, O'Brien criticized Stancil's Naphtha valuation formula for the fact that it could result in a Naphtha price that exceeded the price of gasoline. *Id.* at p. 37. The Ross governor, BP contends, would stop that kind of error from occurring. *Id.*

2225. BP explains that, according to Exxon, the Tallett formula allegedly includes an attenuating factor of approximately 30% jet fuel, touted as protection against gasoline price spikes. *Id.*; BP Initial Brief at p. 39. In reply, BP asserts that including jet fuel in the flawed formula does not check against price spikes in gasoline if (1) jet fuel has corresponding price spikes or (2) the price spikes in gasoline bias the total result. BP Reply Brief at p. 37. BP notes that the 1993 settlement also included what could be called an attenuating factor, 30% distillate; yet, during the 1999-2001 period, the formula price for VGO never would have fallen below the OPIS reported price. BP Initial Brief at p. 39.

2226. Record evidence, according to BP, indicates that the Tallett formula spiked along with gasoline prices from 1999-2001. BP Reply Brief at p. 37 (citing Exhibit Nos. EMT-395, EMT-433). Moreover, it notes that Exhibit No. EMT-417 reflects that the Tallett formula's generated values were not markedly different whether or not jet fuel was included as a component of the formula. *Id.* BP explains that the Naphtha values, when including jet fuel, were less than half a cent per gallon lower on average from 1999-2001. In some months, it claims, inclusion of jet fuel actually resulted in higher values. *Id.* at pp. 37-38 (citing Exhibit No. EMT-417 at p. 2). Thus, BP contends, the evidence suggests that the inclusion of jet fuel is not restraining the formula values from spiking along with gasoline when gasoline prices spike due to factors that would not have affected its intermediate components, like Naphtha. *Id.* at p. 38. Further, BP argues, it is difficult to predict whether the Tallett formula's inclusion of jet fuel would provide any protection against gasoline price spikes, when a similar inclusion of distillate in the 1993 VGO methodology would have failed to attenuate gasoline price spikes included in a gasoline-based formula to ensure appropriate valuation of VGO. BP Initial Brief at p. 39.

2227. Because the attenuation factor may not properly protect against price spikes, BP asserts, an appropriate question would be whether the Ross governor would provide the missing price spike protection. *Id.* It asserts that Ross's analysis showed that the governed approach would have performed better than the ungoverned settlement approach when compared to the actual reported West Coast VGO prices. *Id.* at p. 40 (citing Exhibit No. BPX-169 (a revision of Exhibit No. BPX-167)). BP asserts that Exhibit No. BPX-169 shows that the differential between the OPIS-reported price and the governed approach during the 1999-2001 period is closer than the differential between the OPIS reported price and the ungoverned approach. *Id.* In fact, notes BP, the ungoverned approach would have been 3.3¢/gallon too high for the 1999-2001 time period while the governed approach would have been only 0.72¢/gallon above the actual

VGO value during the same period. *Id.*

2228. Over the entire period, explains BP, the settlement minus the OPIS line would have been $2.04/barrel and the governed price minus the OPIS line would have been $1.15/barrel. *Id.* (citing Transcript at p. 9774). So, over the entire period, concludes BP, the governed, 1993 settlement price for VGO would have performed better than the ungoverned, 1993 settlement price for VGO when compared with the OPIS reported prices for West Coast VGO. *Id.*

2229. BP notes that the opponents of the Ross governor claim that it does not function properly in non-anomalous periods because it would have been active in 1994-1998 before the large gasoline price spikes in 1999-2001. BP Reply Brief at p. 46. These criticisms, according to BP, are based on the misunderstanding that the governor has only a single purpose – to eradicate effects of pricing anomalies. *Id.* Further, BP asserts, during a period without severe gasoline price spikes – such as the West Coast market in the 1990s before 1999 – the governor does no harm. BP Initial Brief at p. 41. Prior to 1999, explains BP, the governor was not essential due to a lack of noticeable gasoline price spikes. *Id.* In BP's view, however, having the governor in place to protect against the potential occurrence of price spikes would have been perfectly appropriate and certainly would have caused no negative impact on valuation. *Id.* It points out that using a governor is essential for periods that resemble the 1999-2001 period, but serves as insurance during periods that resemble the 1994-1998 period. *Id.*

2230. Suggestions that Ross indicated that it would have been inappropriate to apply the governor from 1994-1998 are, according to BP, mistaken. BP Reply Brief at p. 46. It states that Ross agreed that in the 1994-1998 period he would not have recommended a governor because he would not have seen anomalies that signaled the need, but he never departed from his belief that it would still be appropriate to apply the governor in periods that did not appear troublesome on their face. *Id.*

2231. According to BP, strong evidence in the record supports the view that a governor, when properly applied to a gasoline-based formula, more closely reproduces the prices which would be paid for Naphtha in a transparent market. BP Initial Brief at p. 43. It is BP's position that Ross's thesis, that the price of Naphtha would never exceed the price of Naphtha imports, is amply supported. *Id.* First, states BP, there is a continuous flow of Naphtha moving from Caribbean refineries in Venezuela, Trinidad, Aruba, and Curacao to the Gulf Coast. *Id.* BP explains that, as the quality of Naphtha from Venezuelan crude oil, which is widely used in Caribbean refineries, is suitable for reformers, the same Naphtha that is designated for use in petrochemical plants on the Gulf Coast is equally usable as reformer feedstock on the West Coast. *Id.* Second, asserts BP, only two to three import cargoes of Naphtha annually would be required to impact the Naphtha market price. *Id.* BP explains that this is because of the relatively small volume of Naphtha traded compared to the large volume used internally by refiners. *Id.* Third, states BP, there is sufficient port capacity on the West Coast to handle two or three imported cargoes per year. *Id.* Fourth, if the economics supported West Coast imports, then, according to BP, they would occur because traders in a transparent market have information available on their desktops when they are looking for opportunities to trade. *Id.* As a final, but not, states BP, the last example, there are substantial quantities of other gasoline feedstocks imported into the West Coast indicating that where arbitrage opportunities are present and identifiable, they will be exploited and regulate prices. *Id.* at pp. 43-44.

2232. Consequently, in a transparent market, BP argues that West Coast Naphtha prices should never exceed the cost of Naphtha imports for any extended period of time. *Id.* at p. 44. Therefore, it is BP's position that the attacks on the Ross governor are unfounded and unsupported by record evidence. *Id.*

2233. BP asserts that opponents of the Ross governor imply that the governor has changed due to "methodological soul searching" rather than as a logical progression to bring the formula to its most accurate representation of Naphtha prices in a transparent market. BP Reply Brief at p. 44. It argues that this implication is misguided. *Id.* According to BP, although some witnesses have ignored methodological flaws that needed correction, the record of this case is full of refinements and corrections. *Id.* For example, BP notes, O'Brien provided an alternative to his original proposal that includes a benzene saturation unit as a cost component of Naphtha production on the West Coast, and Tallett recognized that his formula may need to be updated if Naphtha market conditions change. *Id.* BP maintains that modifications to a formula do not indicate problems with the formula's underlying economic principles. *Id.* They contend that the modifications made by Ross serve to better ensure that the formula meets its underlying premise. *Id.*

2234. The governor, BP asserts, establishes the alternative cost for a refiner to import Naphtha into the West Coast, which acts as the ceiling component of the governor. BP Initial Brief at p. 44. It explains that the original formula established this imported value by calculating, on a monthly basis, the differential transportation costs to the West Coast and adding these to the value of Gulf Coast Naphtha. *Id.* Because there are no consistent, direct shipments of Naphtha to the West Coast, continues BP, the transportation cost has been calculated using the differential of the costs incurred in shipping Naphtha from a common location, Venezuela's Paraguana Refining Complex, to Houston on the Gulf Coast and Los Angeles on the West Coast. *Id.*

2235. Criticism of Ross, according to BP, for failing to use a Platts published shipping differential fails because: (1) the alternative use of the Platts shipping differential yields an insignificant difference; and (2) the use of the Platts shipping differential was non-viable in the 1994-1997 period. *Id.* at pp. 44-45. A comparison of the differential between the West Coast and Gulf Coast tanker rates demonstrates that, in BP's view, between 1994 through 1997, the Platts shipping differential data was unsound for at least two reasons. *Id.* at p. 45. First, notes BP, the differential between the Gulf Coast and West Coast rates was erratic; second, continues BP, the data during the time period was sporadic. *Id.* Consequently, BP claims that the Platts shipping differential from Venezuela to West Coast is inappropriate. *Id.*

2236. According to BP, the Platts shipping differential is not so substantially different from the shipping differential actually used by Ross as to make a significant impact on his governor nor would it have undercut the support for using his governor. *Id.* It points out that a comparison of the Ross governor using a methodology consistent with that presented in Exhibit No. BPX-72 with a governor derived using the Platts West Coast tanker rate for clean products[690] demonstrates the reasonableness of the Ross governor's transportation differential, the primary component of the ceiling. *Id.* (citing Exhibit No. BPX-148). From 1998 through 2001, when the data for Platts became more consistent and reliable, BP notes, the average difference between the Ross governor's original transportation differential, included in Exhibit No. BPX-72, and the differential using the Platts differential is only -4¢/barrel.[691] *Id.* at pp. 45-46 (citing Exhibit No. BPX-148 at p. 2).

2237. Nonetheless, BP declares, should the Commission decide that it would rather use a rate for the differential that varies over time, since 1997, "the relationship between the West Coast rates and Gulf Coast rates appears to have stabilized, and the Platts Caribbean to West Coast rate would appear on the face of it to have become more reliable." *Id.* (quoting Transcript at p. 9554). There are more data points reported from 1997 forward, BP points out, further supporting the viability of this reported price during the period beginning in 1997 forward. *Id.* Because the Platts rate is published weekly, BP states, it could be used if the Commission prefers to have the rate vary over time. *Id.* Moreover, continues BP, this Platts Caribbean to West Coast shipping rate is similar to other rates used in the Quality Bank. *Id.* Thus, rather than undercutting the Ross governor, BP claims, the analysis of the Platts shipping differential from Venezuela to the West Coast provides further support for the Ross calculations, thereby providing an alternative technique to vary the calculation over time if the Commission so desired. *Id.*

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[690] BP notes that, because Naphtha is a clean product, that rate was the appropriate rate to consider. BP Initial Brief at p. 45, n.10.

[691] BP explains that Platts is the only reporting service identified that publishes a price for this shipping differential; H.P. Drewry, another company that looks at shipping rates, does not. BP Initial Brief at p. 46. Thus, BP claims that the only source that provides such data indicates that the Ross governor's estimate of the shipping differential is completely reasonable and fails to cast any doubt that the importation costs are correctly calculated. *Id.*

2238. BP states that opponents of the Ross governor also criticize it by implying that it was inappropriate for Ross to use a rule of thumb for determining shipping costs through the Panama Canal. *Id.* at pp. 46-47. It claims that an examination of the criticism, however, reveals that what the opponents are actually challenging is whether Ross adequately validated his rule of thumb. *Id.* at p. 47. The critics in turn challenge the transportation rate included in Exhibit No. BPX-72, notes BP, as the Panama Canal charge is a component of the overall governor ceiling calculation. *Id.* In BP's view, the evidence does not support these challenges. *Id.*

2239. According to BP, Exhibit No. BPX-149 demonstrates the appropriateness of the Ross estimate of the Panama Canal charge, which is based on the charge published by Worldscale, a recognized and authoritative source of shipping information. *Id.* Using the Boyd Steamship Quick Reference Guide to Panama Canal Costs, continues BP, Ross compared his calculation to the charges that would apply under the Boyd's Quick Reference Guide approach. *Id.* The result, states BP, is that the difference between the two calculations is slight, with no meaningful impact on the ceiling component of the governor or on the value of Naphtha. *Id.*

2240. Although the Boyd's Quick Reference Guide provides support for Ross's Panama Canal charge, BP maintains, it remains appropriate to base the Panama Canal charge, included within the ceiling component of the governor, on the Worldscale. *Id.* BP notes that Ross explained that he had not had sufficient time to conduct due diligence on the Boyd's guide, saying he could not depend on Boyd's to continue to publish the required Panama Canal charges. *Id.* Consequently, based on industry knowledge, discussions with knowledgeable industry participants, and the support developed by use of the Boyd's Quick Reference Guide, BP asserts that the Ross governor's use of Panama Canal charges is appropriate. *Id.* at pp. 47-48.

2241. BP states that, as originally proposed, the Ross governor does not vary over time, but instead, is fixed at $1.488/barrel. *Id.* at p. 48. In Exhibit No. BPX-171 (which updates Exhibit No. BPX-151), notes BP, Ross provided an alternative approach to the governor that will vary over time as costs and prices change. *Id.* The formula contained in Exhibit No. BPX-171 is comparable to the one in Exhibit No. BPX-72, explains BP, but allows for a monthly calculation. *Id.* According to BP, the only difference is the use of a variable transportation differential. *Id.* Conceptually, states BP, the governor included in Exhibit No. BPX-171 is consistent with governor in Exhibit No. BPX-72. *Id.* The variable transportation differential captures changes in the Platts West Coast and Gulf Coast transportation rates on a monthly basis, notes BP, and captures the annual change in the Panama Canal charge. *Id.* at pp. 48-49. Thus, if the Commission determines that it is more appropriate to use a transportation differential that would float in time according to specific changes in cost components of transportation in the West and Gulf coasts, BP explains, Exhibit No. BPX-171 provides that option. *Id.* at p. 49.

2242. Rejecting criticism of Ross's choice of Venezuela as the starting point for the hypothetical Naphtha shipments to the West Coast for the purpose of calculating the transportation cost, BP states, Ross used the Caribbean price as the basis for his calculations because the Caribbean is likely to be the marginal source of supply to the West Coast. *Id.* It points out that, from time to time, there may be cargoes available from Ecuador or Alaska that might be less expensive, but states that "as these cargoes are inconsistent they could artificially suppress the price of naphtha." *Id.* Moreover, because of the Jones Act, BP states, cargoes can be shipped from the Caribbean less expensively than they can from the Gulf Coast. *Id.* Thus, BP concludes, the most likely source for Naphtha imports are cargoes redirected to the West Coast from the Caribbean. *Id.*

2243. Further, explains BP, Venezuela's Paraguana refinery is the largest refining center in the Caribbean, and therefore can be considered a surrogate for all possible shipment origins in the Caribbean. *Id.* Finally, maintains BP, had the Ross governor used another Caribbean starting point, the costs would have been nearly identical. *Id.*

2244. In BP's view, another misplaced concern raised at the Quality Bank hearing is whether barriers to entry on the West Coast would prevent Naphtha imports from entering the market and being able to restrain prices. *Id.* at p. 50. It notes that Exxon contends that the evidence does not support the premise that imports will check Naphtha prices and claims that there is no reliable evidence that Naphtha is imported to the West Coast sufficient to support the Ross governor. BP Reply Brief at p. 39. BP acknowledges that the Ross governor critics also claim that barriers to entry including tankage and terminal constraints, risks associated with lead time, lack of market liquidity making hedging risky, and costs to change crude slates to accommodate imports would prevent sufficient import quantities from checking West Coast Naphtha prices under the Ross governor theory. *Id.*

2245. In BP's view, this concern is misplaced and incorrect for a number of reasons: (1) the quantities of Naphtha required to move prices in the Naphtha market are not substantial in comparison to the quantities of imports that enter the West Coast each and every year; (2) were it economically attractive, the West Coast participants would find room within existing infrastructure for a few Naphtha imports; (3) even the danger of imports entering the market can restrain price increases in a transparent market; and (4) with the transparency provided by publicly available prices, the price of Naphtha would be held in check by the knowledge that raising prices beyond a certain level would invite imports, as arbitrage opportunities became economically attractive. BP Initial Brief at p. 50.

2246. BP points out that many of the arguments that barriers to entry would prevent Naphtha imports from entering the market were based on the Stillwater report, Exhibit No. EMT-385. *Id.* It argues that the Stillwater report did not conclude that barriers to entry exist in the West Coast which would keep Naphtha from being imported. *Id.*

Instead, notes BP, the report stated that clean products are being imported at a rate of approximately 250,000 barrels/day. *Id.* The Stillwater report, continues BP, did not indicate whether Naphtha imports could enter the market. *Id.* Further BP states, although the Stillwater report highlighted current and anticipated constraints on imports of products into the West Coast, Ross concluded, "there's a lot coming in, and my experience is that these things are generally not insurmountable problems." *Id.* at pp. 50-51 (quoting Transcript at p. 9617). While the constraints discussed in the Stillwater report may pose a challenge to supply managers, BP claims, managers can handle that challenge and can work increasingly well with constrained facilities when necessary to capture financially attractive opportunities. *Id.* at p. 51.

2247. According to BP, record evidence reflects that clean product moves from the Caribbean to the West Coast, specifically VGO[692] and jet fuel.[693] *Id.* (citing Transcript at pp. 9584-86). Further, it points out, evidence in the record shows there were eight importers of VGO and nineteen importers of jet fuel.[694] *Id.* (citing Transcript at p. 9591). Moreover, explains BP, Exhibit Nos. BPX-79, BPX-80, and BPX-147 reflect that gasoline and jet fuel imports continue to enter the West Coast. *Id.* Consequently, according to BP, Ross concluded, were there transparent price signals in the West Coast Naphtha market, Caribbean Naphtha imports would similarly flow into that market, just as they already do for gasoline, VGO, and jet fuel. *Id.* (citing Transcript at p. 9591). Logically, BP asserts, Naphtha could move from the Caribbean to the West Coast if it were economically attractive. *Id.* (citing Transcript at pp. 9583-84). Thus, BP concludes, because any barriers to entry have not prevented imports of VGO or jet fuel from entering the West Coast, there is no rational basis to conclude that they would prevent Naphtha imports. *Id.*

2248. In addition, there are already shipments of Naphtha that come into the West Coast from the Caribbean, notes BP, as demonstrated in Tallett's compilation of contracts, which was supplemented to include contract information about the source of origin and appears at Exhibit No. BPX-153. *Id.* at pp. 51-52. There were seventeen cargoes that have made it through the California port system between 1999-2001. *Id.* at p. 52. Thus, states BP, Naphtha imports are already entering the market. *Id.* If transparent prices were available, asserts BP, they would likely come in greater quantities, and they would be transacted at prices that more accurately reflect prices at equilibrium rather than prices that result from bilateral negotiations. *Id.* Although in a transparent market these Naphtha imports would have to compete with other imported blendstocks for space, BP

[692] BP cites Exhibit No. EMT-444. BP Initial Brief at p. 51.

[693] BP cites Exhibit No. EMT-450. BP Initial Brief at p. 51.

[694] BP cites Exhibit No. BPX-152. BP Initial Brief at p. 51.

maintains the market could accommodate them if they were needed. *Id.*

2249. Furthermore, BP states, there is no need to import a large quantity of Naphtha to have a significant impact on the West Coast market for traded Naphtha because that total quantity traded is quite small. *Id.* Exhibit Nos. BPX-154 and BPX-158 made this point, explains BP, showing that the market for Naphtha reflected in the contract analyses by Pulliam and Tallett is a very small percentage of the overall Naphtha volumes consumed on the West Coast on a given day. *Id.* As the total traded volume amounts to roughly 5,300 barrels/day under the Pulliam contract analysis and 8,700 barrels/day under the Tallett contract analysis, BP claims, imports that amounted to approximately 2,100 barrels/day, representing three additional cargoes, would have a significant impact on the traded Naphtha value. *Id.* (citing Exhibit Nos. BPX-158 at p. 2, BPX-154 at p. 2). BP points out that these 2,100 barrels/day would constitute roughly 40% of the traded Naphtha in Pulliam's contract analysis and roughly 25% of the traded Naphtha in Tallett's contract analysis. *Id.* That amount, which BP argues can be handled by existing infrastructure, it claims, would have a large impact on the traded Naphtha price on the West Coast. *Id.* at pp. 52-53.

2250. BP states that this theory is supported by Ross's industry experience. *Id.* at p. 53. It asserts that small changes in percentages of crude production can have significant impacts on the price of crude. *Id.* For example, explains BP, Venezuela was alleged to have exceeded its proper production of 3.5 million barrels/day in 1998 by roughly 770,000 barrels/day and it was claimed that this influenced prices. *Id.* (citing Exhibit No. BPX-156). According to BP, the estimated world production at the time was roughly 73 million barrels/day. *Id.* (citing Exhibit No. BPX-155). Thus, notes BP, a change of 770,000 barrels/day in comparison to the total market of 73 million barrels/day was significant enough to cause concern about impacts on crude oil prices. *Id.* It points out that Exhibit No. BPX-156 illustrated the significant impact on prices from these minor changes in total production for crude oil, substantially below the percentage change that would occur in the Naphtha market were the hypothetical equivalent of three cargoes of Naphtha to enter the West Coast. *Id.* Thus, states BP, small volume changes in the traded market for Naphtha, volumes that clearly could and would enter the market if the Naphtha market became transparent, would have significant price limiting effects on naphtha. *Id.*

2251. Finally, BP argues, imports need not actually enter the market to limit prices. *Id.* It suggests that basic economics supports this argument. *Id.* Should imported Naphtha become available in a visible and transparent way and should it be cheaper than the Naphtha that was available locally, BP insists, refiners would buy imported Naphtha rather than local Naphtha. *Id.* Further, states BP, should the existing suppliers not lower their prices, then companies would stop buying locally and would import instead. *Id.* This, according to BP, would have the effect of lowering local prices, which would, in turn, push out the imported supplies. *Id.* at pp. 53-54. Thus, concludes BP, the possibility of imports would serve to discipline the local suppliers because, if the local suppliers tried to raise their prices, "then they risk attracting imported supplies again, so the presence of imports or the threat of imports would apply some discipline to their pricing on the local market, whether or not those imports came in." *Id.* at p. 54 (citing Transcript at p. 9982). BP states that this straightforward analysis depends on the existence of a transparent market. *Id.* With an opaque market, explains BP, neither suppliers nor buyers can see the opportunity. *Id.*

2252. BP asserts that criticism that the Ross governor's ceiling does not account for a risk premium to attract cargoes from the Gulf Coast to the West Coast is unfounded and that it is appropriate that the governor does not included a risk premium. *Id.* In a transparent market, which the governor attempts to represent, BP explains, there would be no significant risk premium. *Id.* It notes that Ross explained:

> In a transparent market, companies importing or accessing naphtha would have a price series that they can analyze and use to predict future prices. They would have the ability to do quantitative analysis. They would be able to come up with mechanisms to mitigate their risk through the transparency of the market.

Id. (citing Transcript at p. 9668). Conversely, BP asserts, the price risk is a much greater concern in an opaque market than it is in a transparent market. *Id.* Consequently, as the Ross governor is attempting to simulate a transparent market and not an opaque market, BP maintains, accounting for a risk premium would be inappropriate. *Id.* at pp. 54-55. In addition, BP states, there is no objective way to measure a risk premium. *Id.* at p. 55. It points out that individual businesses have their own risk tolerance and attempting to identify a risk premium appropriate for all the different Naphtha suppliers which could provide imports would require guesswork. *Id.*

2253. Ross considered the criticism that the governor should not apply instantaneously, BP states, and determined, for at least three compelling reasons, that the governor should not have a time lag, but should be applied instantaneously. *Id.* First, notes BP, the single West Coast contract that Ross considers persuasive and which has a governor concept does not have use a time lag. *Id.* Second, it points out, Ross testified that

> the floor helps correct for sudden dips in the Gulf Coast price which may not be reflected instantly to the West Coast price. So if there's a sudden dip in the Gulf Coast price, the ceiling would dip on the West Coast, but the floor is there to protect the cost structure on the West Coast to reflect the fact that that wouldn't happen in reality. So I feel that the floor and the ceiling compliment each other to produce an equitable answer and deal at least in part with the issue of time lag and risk.

Id. (quoting Transcript at p. 9784). Third, BP reiterates, it is not necessary that there actually be imports for prices to be checked in a transparent market. *Id.* Thus, it argues, the effect of a lower available price would be instantaneous in a transparent market with published prices, because local suppliers would be aware of prices that would attract imports and cut into their market share. *Id.* at pp. 55-56. BP claims that the imports would arrive if the local suppliers did not check their prices sufficiently and quickly enough, but the effect of the imports on local prices would already have been felt. *Id.* at p. 56.

2254. Another criticism of the Ross governor noted by BP is the absence of a premium specifically to account for transit complications that may result in traversing the Panama Canal. *Id.* It explains that Ross considered this issue and determined that there was no need for such a risk premium even if it could be calculated. *Id.* In 1999-2000, BP claims, passage required 31 hours, but in 2001-2002 it required only 26 hours. *Id.* (citing Exhibit No. BPX-160). Further, states BP, the Panama Canal is undergoing a modernization program and, therefore, problems with the Panama Canal cited by proponents of a transit risk premium predate the recent improvement to the canal's efficiency. *Id.* BP's position is that the concerns that transit through the Panama Canal will meet with serious delays are unfounded and inapplicable to a formula operating in the modern time period with the Panama Canal constantly increasing its efficiency. *Id.*

2255. Additionally, BP explains, critics of the Ross governor claimed the finished and intermediate products do not exhibit discernible patterns in terms of their West Coast-to-Gulf Coast pricing differentials. *Id.* According to BP, they use this claim to attack Ross's theory that intermediate products and finished products behave differently in terms of pricing and logistic patterns. *Id.* at pp. 56-57. For example, continues BP, Exhibit Nos. PAI-175 and PAI-176 attempt to show that the prices for various products in the finished or intermediate categories do not follow the same pattern of pricing for other finished or intermediate products. *Id.* at p. 57. Further, states BP, the Ross critics emphasized MTBE as illustrating that the product differentials are not following a discernable pattern according to intermediate and finished product classifications. *Id.* BP explains that the critics argued that pricing patterns for MTBE fall more in line with finished products, although MTBE is a feedstock. *Id.*

2256. In BP's view, these criticisms are misplaced. *Id.* It maintains that MTBE is not an intermediate feedstock and has entirely different logistics that account for its product differential between the West and Gulf coasts being more in line with finished products. *Id.* According to BP, Ross explained that MTBE is properly classified as a "fine chemical" and not as a feedstock despite its use in producing gasoline. *Id.* It needs no further processing than Naphtha and VGO require, BP claims, and is directly blended into gasoline. *Id.* Moreover, notes BP, its logistics patterns are more in line with finished products, as illustrated in Exhibit No. BPX-162. *Id.* BP states that the gas liquids do not have the same logistics patterns as the liquid products because they do not ship regularly to the West Coast; it is thus meaningless, it continues, to compare them with the other liquid finished and intermediate products in terms of their differentials between the West and Gulf coasts. *Id.* (citing Exhibit No. BPX-162). When one considers the product differentials between the West and Gulf coasts on a proper basis (as BP asserts Exhibit No. BPX-162 does), BP claims, it becomes clear that finished products (including MTBE) and intermediate products have distinct logistics, devaluing the criticism of the Ross governor based on MTBE 's following finished product patterns rather than intermediate product shipping patterns. *Id.* at pp. 57-58.

2257. In addition, BP points out, the West Coast import infrastructure will get a reprieve from current MTBE imports when, by 2004, it is phased out of gasoline production. BP Reply Brief at p. 40. The phase-out of MTBE, BP claims, will free up import infrastructure for other clean products imports. *Id.* Because MTBE 's primary replacement will be ethanol, which, unlike MTBE, is not exclusively imported by marine, but also by rail car and truck, some additional infrastructure could be used for Naphtha imports were opportunities present and discernible in a transparent market. *Id.*

2258. Nonetheless, BP states, opponents of the Ross governor claim that even a finished product shipping differential still fails to explain why jet fuel, VGO, and conventional gasoline had periods where prices remained above the import price. *Id.* at p. 42. It states that they fail to consider three factors: (1) jet fuel is below the finished product import price the majority of the time and only remained above the import price for short periods of time when the jet fuel market was extremely heated;[695] (2) the conventional gasoline market in the West Coast is unique in that it must compete for components used in its production that are also needed for CARB gasoline; and (3) as imports cannot alleviate the CARB gasoline demand surges, CARB gasoline demand surges can force component prices upward not only for CARB gasoline, but also for conventional gasoline which forces the price of both above import parity for more extended periods of time.[696] *Id.*

2259. BP states that the 20¢/barrel adjustment to the transportation cost in Exhibit No. BPX-72 is supportable, despite what critics of the governor maintain. BP Initial Brief at p. 58. It explains that the 20¢ is added to the transportation cost derived using Gulf Coast freight rates in order to estimate the higher cost of chartering vessels to the less frequented West Coast market and accounts for a host of factors, including backhaul and inventory costs. *Id.* BP points out that the 20¢ was based on Ross's industry experience

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[695] BP cites Exhibit No. BPX-67 at pp. 23-24 in support. BP Reply Brief at p. 42.

[696] BP cites Exhibit No. BPX-67 at pp. 24-25 in support. BP Reply Brief at p. 42. It further claims that there were only a few such incidents involving VGO which, it claims, were caused by several short lived incidents involving Cokers which reduced the VGO supply. *Id.* (citing Exhibit No. BPX-37).

and confirmed by a reliable contact in Venezuela. *Id.* (citing Transcript at p. 7966). Moreover, BP claims that it is unlikely that the 20¢ is inadequate, resulting in too low of a governor and undervaluing Naphtha. *Id.* It points out that Ross uses a 10% interest rate calculating the inventory cost component of the 20¢. *Id.* This interest rate is high in the current interest market, states BP, providing further support that the governor calculation under Exhibit No. BPX-72 would not result in undervalued Naphtha and provides an appropriate cap through its transportation cost.[697] *Id.* Finally, BP notes, any concern that this 20¢ differential is subjective should be assuaged by Exhibit No. BPX-171, which uses Platts rates for shipments to the West Coast along with providing for a formula that would float according to transportation costs component changes such as world freight rates. *Id.* at pp. 58-59.

2260. Responding to critics who state that the Ross governor's floor is not supportable as a cost base for suppliers of Naphtha with two arguments, first, BP states, Ross compared the differential between Gulf Coast Naphtha and West Texas Sour, a grade of Gulf Coast crude analogous to ANS. *Id.* at p. 59. Second, continues BP, he calculated the Naphtha-to-VGO differential on the Gulf Coast and combined that with the VGO-to-ANS differential on the West Coast to come up with what the Naphtha-to-ANS differential would have been on the West Coast if the same relationship had applied between VGO and Naphtha as on the Gulf Coast. *Id.* The results of these calculations are consistent with Ross's floor, according to BP, the price of ANS crude plus $4.00/barrel, and indicates that the floor is a reasonable means to represent what the supply side of the Naphtha market would be on the West Coast in a transparent market. *Id.*

2261. Both validations of the ANS + $4.00 floor are contained in Exhibit No. BPX-138, according to BP. *Id.* In addition, in Exhibit No. BPX-170, states BP, Ross performed a validation analogous to the differential between Gulf Coast Naphtha and West Texas Sour, using Isthmus crude, to illustrate that the same validation holds true for a crude that is made into Naphtha on the Gulf Coast. *Id.* at pp. 59-60. The result in Exhibit No. BPX-170 is, according to BP, comparable to the result in Exhibit No. BPX-138. *Id.* at p. 60.

2262. BP asserts that all three of these calculations (Exhibit Nos. BPX-138, BPX-170) support the ANS + $4.00 floor as a reasonable baseline for the supply side of naphtha. *Id.* It points out that the differentials shown in Exhibit No. BPX-138 range from $3.24/$4.06/barrel (1994-2001/1999-2001) to $3.57/$5.21/barrel (1994-2001/1999-

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[697] BP points out that, in Exhibit BPX-171, the alternative governor, the interest rate is defined as the Commission monthly interest rate and will vary over time. BP Initial Brief at p. 58, n.11.

2001).[698] *Id.* These four numbers, BP claims, bracket the $4.00 figure. *Id.* Its position is that the validations plainly support the determination that the ANS + $4.00 figure is a reasonable number to use for the Naphtha price baseline in a transparent market. *Id.* at p. 61. BP explains that the ceiling and floor concept is meant to simulate a transparent market, where potential imports act as the ceiling and local manufacture acts as the floor. *Id.* (citing Transcript at pp. 7927-28).

2263. Acknowledging that critics question the appropriateness of the Ross governor because it allows the ANS + $4.00 floor to set the West Coast price when the Gulf Coast Naphtha price plus the transportation differential is lower than the floor, BP explains, the implication is that if Ross truly believes that the price of West Coast Naphtha should never exceed the cost of imports, the floor should never trump the cost of imports. *Id.* According to BP, this criticism is inconsequential. *Id.* First, explains BP, in any situation where the price of Gulf Coast Naphtha became low in relation to the crude oil of comparable quality to ANS on the Gulf Coast, inducing lower prices on the West Coast, the situation could not be sustained and thus would only last a short time. *Id.* Second, continues BP, the lower Gulf Coast Naphtha price would stimulate higher demand, and the price would bounce back up again in short order to crude parity, i.e., a value equal to, or greater than, crude ANS + $4.00. *Id.* at pp. 61-62. It asserts that it would be unfair to allow a temporary drop in Gulf Coast Naphtha prices to immediately affect the governor's simulation of a transparent market. *Id.* at p. 62. In that situation, BP argues, it is more equitable to allow the floor to set the price for what it believes would be a very short period of time. *Id.* To do otherwise, argues BP, would allow unsustainable dips in Gulf Coast Naphtha value to improperly depress West Coast Naphtha values. *Id.*

2264. BP asserts that further support for the ANS + $4.00 floor is found in a contract produced in this proceeding. *Id.* This contract had a governor mechanism that is more complicated than the version Ross uses, but, notes BP, its floor was explicitly listed as ANS + $4.00. *Id.* Ross then tested the floor to determine if the ANS + $4.00 baseline was reasonable, as discussed above, and, states BP, every validation calculation supported his reasonableness conclusion. *Id.* BP concedes that this is not proof for the validity of the ANS + $4.00 floor; however, they assert that it is support of the reasonableness of Ross's methods. *Id.*

2265. Conceding that the Ross governor's ceiling or floor as applied to the gasoline-based formula proposing by Tallett or the one proposed by O'Brien control roughly 80% of the time over the time period from 1994-2001, BP states that, while critics of the Ross governor emphasized that the governor would have controlled, rather than the base

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[698] BP notes that the comparable validation using Isthmus instead of West Texas Sour provides similar results. BP Initial Brief at p. 60, n.12 (citing Exhibit BPX-170 at p. 3).

formula, more often during the 1994-1998 period, neither it nor Ross considers this problematic. *Id.* at p. 63 (citing Exhibit Nos. EMT-436 and EMT-437). According to BP, the frequency with which the Ross governor might control the Naphtha price on the West Coast fails to undercut the value of the governor; rather it emphasizes what BP sees as the inherent flaws in a gasoline-based formula. *Id.* It argues that the ungoverned gasoline-minus formulæ incorporate finished product margins and inappropriately attribute them to intermediate products. *Id.* Further, continues BP, the base formulæ fail to capture much of what would be going on in a transparent market. *Id.* In any period, BP claims that the base formulæ fail to provide an accurate representation of what the price of Naphtha would be in a transparent market. *Id.* BP's position is that the governor addresses those flaws. *Id.*

2266. BP states that the Ross governor opponents claim it is inconsistent with the way other Quality Bank cuts are valued. BP Reply Brief at p. 67. In addition, BP notes, the opponents claim that the Ross governor does not represent actual market conditions, but sets the Naphtha price regardless of what transpires in the West Coast Naphtha market. *Id.* It suggests that these arguments are baseless and that the Ross governor ensures that the price of Naphtha on the West Coast does not depart from values comparable to those for the other Quality Bank cuts formed in transparent markets. *Id.*

2267. The Ross governor does not set values, BP asserts, but attempts to constrain Naphtha values to those that would be found in a transparent market. *Id.* If the governor results in values that are not represented currently in the Naphtha transactions on the West Coast, BP declares, that it is because those contract values depart from values that would be present in a transparent market. *Id.* It claims that the governor's opponents fail to acknowledge the absence of a West Coast Naphtha market comparable to the markets for the other Quality Bank cuts. *Id.* at pp. 67-68. Consequently, BP maintains, the actual contracts which the governor opponents assert the Naphtha values should emulate are an inappropriate basis for setting the West Coast Naphtha value. *Id.* at p. 68.

2268. BP contends that the Ross governor opponents fail to acknowledge that it is their methodologies, not the Ross governor, which depart from the consistency standards required by the Circuit Court's *OXY* and *Exxon* decisions. *Id.* In this regard, BP notes, the Ross governor's opponents claim that their methodologies accurately represent market prices consistent with the Circuit Court's requirements. *Id.* BP insists that the Tallett and O'Brien methodologies are not market prices as their proponents believe. *Id.* Its position is that none of the formulæ represent true market prices. *Id.*

2269. Ross's governor, BP states, is designed to correct for flaws associated with each of the gasoline-based formulæ that Exxon's, Phillips's and Alaska's witnesses propose. BP Initial Brief at p. 64. It maintains that the use of a Gulf Coast reference price for valuing West Coast Naphtha no longer is appropriate. *Id.*

2270. According to BP, Exxon, Phillips, and Alaska make circular arguments justifying their proposals. BP Reply Brief at p. 68. Their logic is flawed, it claims, because they do not focus on the true goal which, in BP's view, is to find a method for valuing Naphtha that simulates a transparent market. *Id.* at p. 69. BP argues that, because of the fundamental differences between the Gulf Coast and West Coast markets, any analysis that uses Gulf Coast data in a formula meant to be used on the West Coast produces meaningless results. *Id.* at pp. 69-70. According to it, a formula that works on the Gulf Coast may not accurately predict values on the West Coast. *Id.* at p. 70.

2271. Exxon, BP asserts, challenged the idea that its formula will inflate the Naphtha value on the West Coast by failing to account for differences in the Gulf and West Coast markets. *Id.* BP further notes that Exxon claims there are no structural differences that prevent the use of its Gulf Coast derived formula on the West Coast, and suggests that this argument must be rejected as inconsistent with the testimony Exxon has given on why it is inappropriate to continue to use the Gulf Coast price for Naphtha to value West Coast Naphtha. *Id.* at pp. 70-71. Exxon, BP contends, cannot argue so tenaciously that differences in the markets make the Gulf Coast price for Naphtha unreliable and then dismiss fears that differences in the two coasts undermine the ability to rely on a formula that bases its calculations on transporting Gulf Coast dynamics to the West Coast. *Id.* at p. 71. Moreover, it asserts, Phillips also cannot argue consistently that the ability to predict Gulf Coast values validates a West Coast formula. *Id.* Consequently, BP suggests, a determination that Gulf Coast values plugged into either the O'Brien or Tallett formula match the Gulf Coast Naphtha prices provides no meaningful information about their ability to predict West Coast Naphtha prices formed under completely different market conditions. *Id.*

2272. BP believes that ANS + $4.00 is an appropriate floor, as used in the Ross governor, but does not believe that it is an appropriate method for valuing West Coast Naphtha on a stand-alone basis. BP Initial Brief at p. 64. It asserts that, because the Ross floor and ceiling were designed to work together, they will more accurately produce values that match prices that would be present in a transparent market for Naphtha on the West Coast when used in tandem. BP Reply Brief at p. 74. BP claims that use of the ANS + $4.00 formula only represents a single supply function and produces results inconsistent with those of a transparent market. *Id.*

2273. Furthermore, BP states that Exxon's bracketing proposal raised during the course of the hearing is not an appropriate method for valuing Naphtha on the West Coast. BP Initial Brief at p. 64. It points out that the relationship between the products selected may not be the same on both coasts. BP Reply Brief at p. 75. Fundamental differences exist in the Gulf Coast and West Coast markets which make this type of analysis inappropriate, BP declares. *Id.* Furthermore, it explains that there can be changes in one product or feedstock that are not related to the other products or feedstocks. *Id.* For that reason, BP states, the use of any bracketing formula will inappropriately attribute changes in other products to the value of Naphtha on the West Coast even when they are unrelated to the value of Naphtha. *Id.* Finally, BP points out, using the Exxon "bracket" formula gives over 80% weighting to the West Coast gasoline price that is corrupted by price spike anomalies in recent years that have nothing to do with the value of naphtha. *Id.*

2274. Also, BP states, it is not surprising, given that Exxon made this proposal, that the bracketing formula is very similar to the Tallett proposal. *Id.* It maintains that both the proposed Exxon bracketing technique and the Tallett formula are based on the faulty assumption that relationships that exist on the Gulf Coast can be transferred intact to the West Coast. *Id.* Theoretically, BP suggests, the Ross governor could correct the bracketing formula's deficiencies in the same manner that it corrects the deficiencies in the Tallett and O'Brien generated values. *Id.* at pp. 75-76. Thus, BP states, if the Commission determined that it wants to use the bracketing formula as the starting point for determining a West Coast Naphtha value, this value could then be subjected to the Ross governor to ensure that it produces values that would be found in a transparent market and comparable to the values used to value the other Quality Bank cuts. *Id.* at p. 76.

4. Petro Star

2275. Petro Star supports continued use of Gulf Coast pricing. Petro Star Initial Brief at p. 9. If, and only if, the Commission decides that the current methodology should be discontinued, then Petro Star supports Dudley’s proposal as the best alternative available. *Id.* It suggests that Dudley’s proposal contains fewer and less severe defects than either Tallett’s or O’Brien’s proposal. Petro Star Reply Brief at p. 14.

2276. Dudley’s methodology, Petro Star explains, follows three basic steps: (1) it determines the price differentials between the Gulf Coast and the West Coast for VGO and LSR; (2) it determines the relative contributions of VGO and LSR to the ANS crude oil common stream; and (3) it applies the volume weighted LSR and VGO price differentials to the reported Gulf Coast Naphtha price to determine an imputed West Coast Naphtha price to be used by the Quality Bank.[699] Petro Star Initial Brief at p. 9.

2277. In Petro Star’s view, Dudley’s approach has two major strengths: (1) it uses current Gulf Coast Naphtha prices as a starting point; and (2) it avoids reliance on the West Coast finished gasoline market. *Id.* at p. 9-10. While suggesting that there is no perfect way to measure the market value of West Coast Naphtha when there is no such market, Petro Star, however, claims that the virtues of Dudley’s proposal exceed those of

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[699] If a new Gulf Coast Naphtha reference price is selected by the Commission (or the parties), Petro Star states, it would serve as the input to Dudley’s methodology. Petro Star Initial Brief at p. 9, n.8.

the other proposed methodologies. *Id.* at p. 10.

2278. According to Petro Star, the purported need for a new methodology to value West Coast Naphtha arises from the belief that there are significant differences between the West Coast and the Gulf Coast Naphtha markets. Petro Star Reply Brief at p. 15. It states that Dudley explained that, if the Commission decides that a departure from Gulf Coast Naphtha pricing is necessary because the West Coast and Gulf Coast Naphtha markets are different, his methodology seeks to directly answer the question: How different are the markets? Petro Star Initial Brief at p. 10. According to Petro Star, Dudley's methodology uses data already available from the Quality Bank to quantify how differently the West and Gulf Coast markets value crude oil cuts that can be processed into, or used directly as, gasoline blendstocks. *Id.* It explains that VGO, LSR, and Naphtha itself are the only materials that meet Dudley's criteria, and that his methodology uses all of the available Quality Bank data pertaining to these three cuts. *Id.* Petro Star notes that undisputed LSR and VGO Quality Bank reference prices are available for both the Gulf and West Coasts,[700] and an increasing selection of Naphtha prices are available from the Gulf Coast. *Id.*

2279. Like Naphtha, explains Petro Star, LSR and VGO are intermediate products derived from crude oil, are refined on both coasts, and are used to manufacture gasoline blendstocks. *Id.* at p. 11. According to Petro Star, these fundamental similarities mean that the West Coast value of Naphtha will have the same general relationship to the Gulf Coast value that West Coast LSR and VGO values have to their Gulf Coast Values. *Id.* It states that several factors cause this relationship to be imperfect, but claims that the assumptions involved in the Dudley methodology are fewer, more straightforward, and more likely to be valid than those embodied in either Tallett's or O'Brien's proposed methodologies. *Id.*

2280. Petro Star states that the fundamental assumption that Dudley makes is that West Coast and Gulf Coast prices of Naphtha, LSR, and VGO will behave similarly, but not identically, over time. *Id.* It argues that, as either VGO or LSR differentials are very unlikely to exactly duplicate Naphtha differentials, or each other, both should be used. *Id.* Under Dudley's approach, notes Petro Star, the VGO differential provides a good approximation of the Naphtha differential, and the LSR differential provides additional relevant data. *Id.*

[700] According to Petro Star, all parties agree that the Gulf Coast reference price for VGO should be replaced by the West Coast price. Petro Star Initial Brief at p. 10, n.9. Moreover, Petro Star points out that the parties have stipulated that the West Coast VGO price should have the same effective date as any new West Coast Naphtha value adopted by the Commission. *Id.*

2281. Basic to Dudley's proposal, explains Petro Star, is that LSR and VGO are supplied from similar sources and end up in similar products on both Coasts. *Id.* Petro Star points out that, of the nine Quality Bank cuts, only LSR and VGO share these fundamental similarities to Naphtha. *Id.* at p. 11-12. It lists Dudley's explanation for why he excluded the remaining non-Resid Quality Bank cuts:[701]

- Propane is not included because it is irrelevant to gasoline blending economics.

- Isobutane is not included because it typically comprises less than 1% of ANS crude oil. It is provided almost exclusively from sources outside the refinery.[702]

- Normal Butane is not included because it is also supplied principally by gas plants and is not a major constituent of gasoline pools.

- Light Distillate is not included because it is made directly into jet fuel and plays no part in gasoline manufacture.

- Heavy Distillate is not included because it is made directly into finished products and plays no part in the gasoline manufacture.

Id. at p. 12.

2282. Petro Star also notes that Dudley explained that he would not agree with including two proposed non-Quality Bank candidates for his methodology, MTBE and low sulfur VGO, because MTBE was a manufactured component traded in merchant markets, and low sulfur VGO already was represented by the Quality Bank VGO cut. *Id.* In short, asserts Petro Star, VGO and LSR are the only realistic indicators for Naphtha. *Id.*

2283. Generally, explains Petro Star, Quality Bank cuts other than LSR and VGO also are used in gasoline blending (normal butane) or as feedstocks (Isobutane, to alkylation units), but they differ from LSR, Naphtha, and VGO in that they are present in crude oil in very small quantities and typically are purchased by refineries rather than refined from crude oil. Petro Star Reply Brief at pp. 15-16. It states that Dudley's approach tweaks the current methodology by departing as little as possible from the well-established Gulf Coast price, but it departs enough to address concerns that West Coast markets for

[701] Petro Star notes that no party has asserted that Dudley should have included Resid in his methodology, and counsel did not question him about Resid. Petro Star Initial Brief at p. 12, n.10.

[702] In addition, according to Petro Star, Isobutane is in very tight supply on the West Coast. Petro Star Initial Brief at p. 12, n.11.

intermediate products are different from Gulf Coast markets. *Id.* at p. 16.

2284. On both the Gulf and West Coasts, according to Petro Star, VGO and Naphtha have similar uses. Petro Star Initial Brief at p. 12. It explains that Naphtha is used primarily as feed for catalytic reformers which produce reformate, a gasoline blendstock, as their primary products. *Id.* at p. 12-13. Further, states Petro Star, VGO is used primarily as feed to cat crackers which produce FCC gasoline and alkylate precursors which end up in gasoline as well as Heavy Distillates. *Id.* at p. 13. Petro Star asserts that the extensive conflicting evidence on the issue of whether and to what extent VGO is processed differently on the Gulf and West Coasts does not undermine Dudley's proposed methodology. *Id.* At most, according to Petro Star, this evidence demonstrates that VGO undergoes more extensive processing on the West Coast than on the Gulf Coast, particularly in connection with the manufacture of CARB gasoline. *Id.* This fact, according to Petro Star, presumably would tend to lower VGO's value to West Coast refiners, except that CARB gasoline is a very high priced product, and that fact presumably would raise its value to West Coast refiners. *Id.* Nevertheless, Petro Star argues that these issues concerning VGO processing do not detract from the premise that VGO use generally is similar on the two Coasts, and that, as a general matter, it is reasonable that the VGO differential can be used to help predict the Naphtha differential. *Id.*

2285. LSR has a relatively high Reid Vapor Pressure and consequently, points out Petro Star, the quantities of LSR that can be blended into summer gasoline on the West Coast is constrained. *Id.* It consistently has been priced lower on the West Coast than the Gulf Coast, Petro Star claims, and this fact appears to be attributable primarily to vapor pressure, although petrochemical demand for LSR on the Gulf Coast (which is virtually nonexistent on the West Coast) may contribute as well.[703] *Id.* at pp. 13-14. Petrochemical demand is relevant, states Petro Star, because Naphtha is used by the Gulf Coast petrochemical industry as feed for catalytic reformers used to produce aromatics, but there is no corresponding demand on the West Coast. *Id.* at p. 14. Similarly, continues Petro Star, at least in the production of CARB gasoline, both Naphtha and LSR can provide feed to C_5/C_6 isomerization units and be processed into higher octane material that can be used in the gasoline pool. *Id.*

2286. In light of the above factors, Petro Star argues, LSR differentials are almost certainly more different from Naphtha differentials than are VGO differentials. *Id.* Nevertheless, it suggests, the relationship between LSR and Naphtha is similar in many ways on the Gulf and West Coasts, and LSR provides valuable additional data relevant to

[703] In addition, notes Petro Star, in blending CARB gasoline, the ability to blend more Normal Butane and LSR in the winter season allows more heavy components to be blended as well. *Id.* at p. 14, n.12.

probable Naphtha differentials. *Id.* at pp. 14-15.

2287. Petro Star notes that Dudley's methodology does not give equal weight to the VGO and LSR differentials when the Naphtha differentials are calculated. *Id.* at p. 15. Rather, according to Petro Star, they are weighted according to their relative percentages in ANS crude at Valdez. *Id.* It explains that Dudley rejected a 50/50 weighting because, the LSR differential is likely to be more different from the Naphtha differential than is the VGO differential. *Id.* Dudley's weighting, states Petro Star, directly reflects the relative contributions of VGO and LSR to the TAPS stream. *Id.* It notes that Dudley's method favors VGO over LSR by approximately 4:1 and is nearly a constant.[704] *Id.* The heavier weighting afforded VGO reflects the ratio of VGO and LSR that can be derived from ANS crude oil, and is a virtue, according to Petro Star, because of VGO's position as the "strongest indicator of gasoline economics." *Id.*

2288. Petro Star notes that Dudley readily acknowledged that the detailed economics of LSR and VGO and Naphtha are different, and that LSR and VGO usage have different economics on the Gulf and West Coast. Petro Star Reply Brief at p. 17. They are not sufficient, in Petro Star's view, to reject Dudley's proposal or to select either Tallett's or O'Brien's instead. *Id.* Rather, explains Petro Star, there are differences in the precise economics governing the three cuts which are the foundation of Dudley's proposal. *Id.* These differences do not, according to Petro Star, detract from Dudley's basic starting point that LSR, Naphtha, and VGO are all used as feedstocks in process units that produce gasoline blendstocks on both coasts. *Id.* It points out that Dudley is, after all, trying to estimate how different Naphtha prices would be based on the differentials between LSR and VGO prices. *Id.* Moreover, states Petro Star, the differences in use between coasts are differences of degree. *Id.*

2289. According to Petro Star, the West Coast/Gulf Coast differentials for LSR comprise one set of data that can be used to estimate what the Naphtha differential is likely to be. *Id.* The differentials for VGO comprise another set of data, continues Petro Star, and provide another estimate. *Id.* Because they are different, Petro Star states, it is necessary to average the two estimates in order to bring both sets of data to bear on the question.

[704] Petro Star acknowledges that month-by-month adjustment of the weighting factor is unlikely to make Dudley's methodology more accurate and believes that this weighting factor could be adjusted at longer intervals. *Id.* at p. 15, n.13. It notes that Exxon also complains that, because the weighting factor would be calculated at Valdez (i.e., downstream of the Williams and the Petro Star refineries), the refineries could "influence the amount of VGO and LSR in the steam and thereby impact the Quality Bank value of Naphtha on the West Coast." Petro Star Reply Brief at p. 20, n.8 (quoting Exxon Initial Brief at p. 315). However, states Petro Star, the composition of ANS crude at Valdez reflects the concentrations of LSR and VGO as the crude is sold in the market. *Id.*

Id. at pp. 17-18. It argues that more data are better. *Id.* at p. 18. For the same reason, asserts Petro Star, Exxon's argument that LSR and VGO prices don't correlate as well on the West Coast as on the Gulf Coast is not persuasive. *Id.* at n.7. Petro Star claims that Dudley didn't contend that the relationship among VGO, Naphtha, and LSR values was the same on both coasts. *Id.* According to Petro Star, his proposal instead rests on the assumption that differences in LSR and VGO prices between the coasts are the best indicators of what differences in Naphtha prices are likely to be. *Id.*

2290. Petro Star maintains that to require that LSR and VGO economics be precisely identical on the West and Gulf Coasts would set an impossible standard for Dudley's methodology, while allowing Tallett to assume that the relationships among Naphtha, gasoline, and jet fuel are identical on the two coasts despite demonstrably different markets, or O'Brien to assume (in the face of the contrary evidence) that the use of Naphtha in the manufacture of his "three component blend" is representative of the use of Naphtha generally on the West Coast. *Id.* at p. 18. Petro Star's position is that, while Dudley's methodology is not perfect, it is better than the alternatives proposed by Tallett or O'Brien. *Id.*

2291. Exxon's complaint that Dudley used LSR and VGO despite the fact that their prices are below Naphtha's is, Petro Star claims, irrelevant. *Id.* It points out that Dudley's proposal relies on the weighted average inter-coast differentials of LSR and VGO prices, and does not depend on the relationship among the absolute prices of the cuts. *Id.* In Petro Star's view, the fact that LSR, Naphtha, and VGO prices can vary independently also does not detract from the logic that underlies Dudley's approach. *Id.* at p. 19. Under his proposal, explains Petro Star, the LSR differential is one piece of evidence and the VGO differential is another. *Id.* By averaging them, states Petro Star, the proposal lessens the impact that will occur if one or the other cut is influenced by factors that do not affect intermediate gasoline feedstocks generally. *Id.*

2292. In Petro Star's view, Phillips errs in arguing that Dudley's proposal relies on an unsupported assumption that the West Coast/Gulf Coast Naphtha differential is less than the VGO differential. *Id.* According to it, Dudley made no such assumption. *Id.* As a matter of arithmetic, Petro Star points out that, because his methodology averages the LSR and VGO differentials to calculate the Naphtha differential, the Naphtha differential will fall between the other two. *Id.* Therefore, continues Petro Star, if LSR differentials are lower than the VGO differentials, calculated Naphtha differentials will be lower than VGO differentials because that's what the data indicate, not because Dudley assumed they would. *Id.* Petro Star asserts, Naphtha differentials are very likely to fall between LSR and VGO differentials. *Id.* It explains that this is because LSR is impacted by Reid Vapor Pressure and other constraints that decrease its value on the West Coast relative to the Gulf Coast, while VGO's importance to CARB gasoline manufacture have made it become more valuable on the West Coast than the Gulf Coast. *Id.* Consequently, states Petro Star, Sanderson's opinion is that the Naphtha differential is very likely to fall between the LSR and VGO differentials. *Id.* at pp. 19-20.

2293. Exxon argues that Dudley's approach should have been able to predict price relationships among Normal Butane and Isobutane, LSR, and VGO, notes Petro Star. *Id.* at p. 20. In fact, asserts Petro Star, the failure of Dudley's proposal to pass Exxon's test simply reflects the fact that the logic he used in selecting cuts did not extend to the butanes. *Id.* Petro Star points out that the butanes are typically purchased from gas plants rather than refined from crude oil, and isobutane in particular is both very high valued and in very short supply on the West Coast. *Id.* It explains that Dudley's proposal is designed to value Naphtha by considering the available data from two cuts that are, like Naphtha, produced from crude oil and used by refiners in gasoline manufacture. *Id.* at p. 21.

2294. Moreover, Petro Star notes, Dudley's critics assert that his proposal is weak because it does not incorporate finished gasoline prices. *Id.* Far from ignoring the products from which 90% or more of West Coast Naphtha derives its value, Petro Star argues, Dudley sought out cuts for his methodology that are similar to Naphtha in their character as feedstocks to process units that produce gasoline components. *Id.* It acknowledges that Dudley does indeed avoid reliance on West Coast gasoline finished product prices, but it maintains that this is a strength, not a weakness, of his proposal. *Id.*

2295. Petro Star argues that Tallett's and O'Brien's methodologies both depend entirely on assumed relationships between finished gasoline prices and West Coast Naphtha values. *Id.* at pp. 21-22. It explains that, as discussed below, Tallett's methodology assumes that the relationship between Naphtha and finished gasoline prices is the same on the West Coast as on the Gulf Coast. *Id.* at p. 22. Similarly, states Petro Star, O'Brien's methodology assumes that his formula precisely captures the gasoline-Naphtha relationship. *Id.* However, it notes, West Coast gasoline markets are more concentrated than Gulf Coast markets and higher gasoline prices and profits flow through to the refineries. *Id.* Moreover, continues Petro Star, West Coast Naphtha typically is refined and used internally by the refiners that produce it. *Id.* Therefore, Petro Star's view is that Tallett's and O'Brien's assumptions are precarious. *Id.* It argues that Dudley's proposal avoids this problem by the simple expedient of looking to other intermediate products with similar uses to determine what the value of West Coast Naphtha is likely to be. *Id.*

2296. For Petro Star, the core question is whether the Naphtha valuation methodology should cause the Naphtha valuation to skyrocket whenever West Coast finished gasoline prices do. Petro Star Initial Brief at pp. 15-16. The Phillips and Exxon sponsored methodologies appear to differ in approach but, according to Petro Star, share one crucial characteristic: they both result in West Coast Naphtha valuations that would closely track West Coast finished gasoline prices no matter how wildly those prices fluctuate. *Id.* at p. 16. Petro Star claims that Tallett's proposal does this because his methodology relies on the relatively steady relationship between Gulf Coast gasoline and jet fuel prices and

Naphtha prices to determine West Coast relationships that are similarly close, and that O'Brien's proposal largely tracks gasoline prices wherever they go. *Id.* While Ross's governor would mitigate these methodologies, Petro Star explains, it nevertheless would still allow consistent overvaluation during periods in which the governor is not in effect. *Id.*

2297. Tallett calculates a regression formula that expresses the relationship of Gulf Coast Naphtha prices to Gulf Coast waterborne conventional unleaded regular gasoline and Gulf Coast waterborne jet fuel prices, explains Petro Star. *Id.* at pp. 16-17. While Petro Star agrees that the logic that underlies this formula is straightforward, Petro Star declares that it is not compelling. *Id.* at p. 17. It points out that the methodology assumes that the relationships are the same on both coasts, and that it, therefore, is appropriate to use the same formula on both coasts. *Id.* However, Petro Star claims that Tallett testified that, if the relationships among the three variables were to change over a period of time, then the regression formula would change. *Id.* By the same token, continues Petro Star, if the relationships among the three variables are different on the West Coast than on the Gulf Coast, Tallett's Gulf Coast formula would not accurately describe the West Coast. *Id.* Further, Petro Star notes, Tallett admitted that the relationship between jet fuel and unleaded regular gasoline was not the same on the West Coast as on the Gulf Coast and that the discrepancy had increased after the introduction of CARB gasoline in 1996. *Id.*

2298. In fact, asserts Petro Star, the evidence suggests that it would be highly unlikely for the same relationship to apply on both coasts. Petro Star Reply Brief at p. 24. According to Petro Star, the factors that Exxon enumerates have only the most general or tangential connections to the supply and demand factors that influence price. *Id.* Indeed, Petro Star asserts that, although he carefully explained his methodology in terms of a portion of the refinery flow diagram, which is similar on the two coasts, Tallett selected inputs for his methodology (finished gasoline and jet fuel prices) that strongly diverge because of very different market conditions. *Id.* Thus, explains Petro Star, gasoline manufacture is the predominant use of Naphtha on both coasts, but the two coasts have very different gasoline markets and the same is true for jet fuel. *Id.* Similarly, Petro Star states, refiners can change their Naphtha/Light Distillate cut points on both coasts to vary the amounts of Naphtha that they make into gasoline or jet fuel, but they base their decisions to do so on the different gasoline and jet fuel market conditions on the two coasts. *Id.*

2299. Petro Star declares that the close correlation on the Gulf Coast between gasoline and jet fuel prices on the one hand and Naphtha prices on the other does not provide any evidence that the same correlation exists on the West Coast. *Id.* at p. 25. At most, according to Petro Star, this factor might support an inference that Naphtha values on the West Coast might be correlated with gasoline and jet fuel prices. *Id.* In Petro Star's view, the profound differences in the gasoline markets on the two coasts, and the lesser differences in the jet fuel markets, however, indicate that, even if such a correlation exists on the West Coast, it almost certainly is different from the correlation observed on the Gulf Coast. *Id.*

2300. According to Petro Star, Tallett offers two principal arguments in support of his methodology: (1) the general process relationships among jet fuel, unleaded regular gasoline, and Naphtha are similar on the West and Gulf Coasts; and (2) that O'Brien's analysis is also consistent with the methodology. Petro Star Initial Brief at p. 18. Petro Star asserts that the first of these arguments rests on Tallett's key assumption that if the process is similar, the economics are similar. *Id.* The key economics to be considered are, according to Petro Star, the relative prices of Naphtha, unleaded regular gasoline, and jet fuel. *Id.* By focusing too narrowly on the similarities within the Naphtha portion of the refining process, Petro Star claims, Tallett neglects the very important questions of how these commodities are obtained and where and how they are sold. *Id.* According to it, the answers to these latter questions frequently are different for the Gulf and West Coast. *Id.* These differences make it unlikely, in Petro Star's view, that simply because West Coast process can be similar to Gulf Coast process, West Coast economics are similar to Gulf Coast economics. *Id.*

2301. On cross-examination, notes Petro Star, Sanderson testified to the many differences between the West Coast and Gulf Coast gasoline markets, such as different supply and demand, and different, and increasingly more stringent, environmental regulations. *Id.* at p. 19. It states that West Coast environmental regulations may make it more difficult to build or expand refineries, and West Coast refineries can't easily expand to meet increasing demand. *Id.* According to Petro Star, the combination of restricted refining capacity, inadequate logistics infrastructure, and commercial barriers have made the California gasoline market increasingly unstable, so that even small supply disruptions cause major price upswings. *Id.*

2302. In contrast, Petro Star points out that, on the Gulf Coast, there is a larger refining base, sometimes different processing configurations, and sometimes a greater ability than on the West Coast to absorb refinery upsets when they occur. *Id.* Under normal circumstances, it states, the Gulf Coast gasoline market is less volatile than the West Coast. *Id.* Finally, Petro Star notes, the Gulf Coast supplies large markets in the Midwest and Northeast. *Id.*

2303. Petro Star states that Tallett's methodology assumes that none of these factors will cause a different relationship to exist between Naphtha and unleaded regular gasoline on the West Coast than exists on the Gulf Coast. *Id.* at pp. 19-20. Instead, explains Petro Star, Tallett assumes that the relationship on the West Coast will be the same as on the Gulf Coast. *Id.* at p. 20.

2304. It would, in fact, Petro Star argues, be an astounding coincidence if, despite all these differences, the relationships among Naphtha, unleaded regular gasoline, and jet fuel prices were the same. *Id.* It states that Tallett relies principally on the similarities between his results and O'Brien's to support his methodology. *Id.* Nevertheless, points out Petro Star, he acknowledged in his prepared testimony that a refiner with enough Naphtha in its crude supply is not going to purchase any Naphtha, and that only when a refiner is short of Naphtha would he expect it to pay prices approximating the cost of processing deducted from gasoline and jet fuel prices. *Id.*

2305. Petro Star states that Tallett's methodology relies on a regression formula calculated using ten years's data from the Gulf Coast. *Id.* It explains that, even were it assumed that the regression formula would apply on the West Coast, the formula would be used to calculate current values based on the historical relationship among unleaded regular gasoline, Naphtha and jet fuel prices. *Id.* This would, notes Petro Star, put West Coast Naphtha valuation on a different footing than all of the other Quality Bank cuts, which rely on current pricing. *Id.* Nor, according to Petro Star, do those reference prices that contain fixed processing cost adjustments, like that for Light Distillate, provide any support for Tallett's approach. *Id.* at pp. 20-21. Petro Star explains that the Light Distillate processing cost adjustment was calculated for 1996 but is adjusted using Nelson Farrar indices each year. *Id.* at p. 21. Further, states Petro Star, it is true that a new processing cost is not calculated from scratch each year, but current Nelson Farrar indices are used, so that the end result for any given year is an estimate of what the cost is in that year, not during the average of the past ten years. *Id.*

2306. This discordance between Naphtha valuation and the valuations of other cuts could be especially difficult for the refiners, declares Petro Star. *Id.* It explains that refiners continuously make optimization decisions that include whether or not fuels can be sold at a profit, and that it does not help refiners that Naphtha prices will average out over time. *Id.* If the current Quality Bank valuation is unduly high because it reflects historical data, Petro Star asserts, this may make some sales unprofitable and cause the refiner to cut back production. *Id.* The refiner will not necessarily be able to make up those lost profits when the valuation in turn becomes unduly low, Petro Star points out, because market conditions may have changed or the refinery may already be operating at its full capacity. *Id.*

2307. Finally, Petro Star claims, periodically updating the regression formula would ameliorate, but not solve, this problem. *Id.* In 2007, Petro Star states it would definitely be preferable to base valuations on 1997 through 2006 data than on 1992 through 2001 data, but 2007 data would be better still. *Id.*

2308. Petro Star points out that Exxon's argument that O'Brien's methodology validates Tallett's necessarily rests entirely on the validity of O'Brien's analysis. Petro Star Reply Brief at p. 26. It concurs with Williams and Unocal/OXY that O'Brien's methodology is fatally flawed, and asserts that this alone is enough to reject it as validation of Tallett's methodology. *Id.* It states that Tallett's methodology, like O'Brien's, erroneously attributes to Naphtha a great part of the profits to be made by making gasoline on the West Coast. *Id.* Because Tallett's and O'Brien's methodologies share this fundamental shortcoming, Petro Star notes that it is no surprise that they generate Naphtha values that roughly correspond. *Id.*

2309. Exxon argues, according to Petro Star, that Exhibit No. PAI-147, which demonstrates that O'Brien's methodology may be able to predict Gulf Coast Naphtha prices, also confirms that Tallett's approach is sound. *Id.* at p. 27. In fact, argues Petro Star, Exhibit No. PAI-147 conclusively demonstrates that both Tallett's and O'Brien's proposals are fatally flawed, because they reflect the Gulf Coast relationship between gasoline prices and Naphtha values. *Id.* Because under both proposals Naphtha values are very strongly linked to gasoline values, if the proposals accurately describe the Gulf Coast relationship, Petro Star asserts, they cannot describe the West Coast relationship unless conditions on the two coasts are the same. *Id.* Petro Star maintains that they are not. *Id.*

2310. O'Brien proposes, according to Petro Star, to value West Coast Naphtha by: (1) calculating the product yield when Naphtha is processed through a catalytic reformer; (2) determining the value of that product yield; (3) determining the processing costs involved; and (4) subtracting those processing costs from the value of the product yield. Petro Star Initial Brief at p. 22. To perform these calculations, Petro Star explains, he assumes a three component blend, in which the only constituents used in making unleaded regular gasoline are reformate, LSR, and Normal Butane. *Id.*

2311. Petro Star points out that, to approve O'Brien's methodology, it would be necessary to accept (1) his conclusions that the "Three Component Blend" is legal gasoline that can be sold on the West Coast, and (2) the implicit assumption that the economics of processing Naphtha into a "Three Component Blend" fairly represent the economics of processing Naphtha on the West Coast. *Id.* Given the many assumptions that go into the model itself, Petro Star considers it highly unlikely that these conditions could be met. *Id.*

2312. Ross's proposed governor, Petro Star submits, is a common sense approach that would improve the gasoline-based methodologies proposed by Tallett and O'Brien, although it would not completely control overvaluations under either the Tallett or the O'Brien methodology. *Id.* at p. 23. Petro Star explains that, under Ross's ceiling proposal, if there was a transparent Naphtha market on the West Coast, and if refiners needed Naphtha, they would import Naphtha if it were cheaper to import it than to buy Naphtha locally. *Id.*

2313. Petro Star suggests that the concept of the floor to be more problematic. *Id.* It explains that the $4.00 figure is derived from a large volume Naphtha term contract with carefully negotiated pricing provisions and validated by Ross's analysis of crude oil and intermediate product differentials on the Gulf and West coasts. *Id.* According to Petro Star, Ross concluded that the $4.00 average represents the value local suppliers would expect to get for their Naphtha and is, therefore, appropriate to use as a floor for valuing Naphtha. *Id.*

2314. As a refiner, Petro Star states it would like to have its product prices subject to a floor. *Id.* It asserts that it is by no means certain that a Naphtha refiner on the West Coast can find a buyer at a good price. *Id.* In other words, explains Petro Star, even though the $4.00 floor fairly represents the price the refiner might expect, market conditions might preclude it from actually getting that price. *Id.* at p. 23-24. Based on its own experience, Petro Star argues, it has more confidence that imports will hold prices down than production costs will hold prices up. *Id.* at p. 24.

2315. Although ANS + $4.00 is problematic when used as a floor in the Ross methodology, Petro Star states, ANS + $4.00 holds promise as a stand-alone Naphtha valuation method. *Id.* It explains that the term is derived from a sophisticated Naphtha contract and represents the cost (including margin) of refining crude oil into Naphtha. *Id.* Because the lowest cost source of Naphtha to a refiner typically will be to produce it from crude oil itself, and because almost all of the Naphtha used on the West Coast is produced from crude oil by the end-user, Petro states that this measure would be much more representative of the great majority of West Coast Naphtha. *Id.*

2316. Petro Star does not favor valuing West Coast Naphtha by interpolating a value from other prices. *Id.* It agrees with Dudley's explanation of why VGO and LSR are appropriate Quality Bank cuts and why other Quality Bank cuts, as well as non-Quality Bank cuts like MTBE, are not. *Id.* Choosing different products for a similar methodology would be difficult, states Petro Star *Id.* It points out that selecting products by price rather than by functional relationship would make results depend very much on which products were chosen, and such selection would be problematic if the prices of the products chosen turned out to be volatile. *Id.* at pp. 24-25. Moreover, to the extent that finished products were selected, Petro Star asserts, the methodology could commit the error of assuming without support that differentials between finished product prices and intermediate product prices are the same on the West Coast as on the Gulf Coast. *Id.* at p. 25.

2317. According to Petro Star, Exxon suggests that it would be a viable methodology to extrapolate the price relationships of crude oil, finished gasoline, and Naphtha on the Gulf Coast to calculate West Coast Naphtha values based on West Coast crude oil and finished gasoline prices. Petro Star Reply Brief at p. 27. Petro Star notes that Exxon asserts that this approach confirms that Exxon's valuation method is reasonable. *Id.* It states that, in fact, this approach shares the fundamental flaw of Tallett's proposal: it assumes that the relatively low profits that gasoline refiners on the Gulf Coast are able to achieve are mirrored on the West Coast, and that, therefore, West Coast Naphtha values should be relatively close to finished gasoline prices. *Id.* at pp. 27-28. Petro Star asserts that this approach would value Naphtha too highly either on its own merits or as a means of validating Tallett's approach. *Id.* at p. 28.

5. Unocal/OXY

2318. Unocal/OXY submit that the current Naphtha value is just and reasonable and should not be changed. Unocal/OXY Initial Brief at p. 37. Should the Commission disagree, however, Unocal/OXY recognizes that it must adopt a methodology to replace the use of Gulf Coast prices to value West Coast Naphtha. *Id.* They explains that three replacement methodologies were proposed, and a fourth methodology, the Ross governor, was proposed as an add-on to whatever methodology the Commission adopts. *Id.* In addition, continue Unocal/OXY, some hybrids were suggested in the course of the proceedings. *Id.* Among the proposed replacement methodologies submitted at the hearings, they claim, two would produce a value for West Coast Naphtha that is far above its actual value, and it is Unocal/OXY's position that they should be rejected without further consideration. *Id.* at pp. 37-38. Three deserve further consideration, state Unocal/OXY. *Id.* at p. 38.

2319. According to Unocal/OXY, Dudley presented a straight forward proposal that would use price differentials between the West and Gulf Coasts for LSR and VGO (which are Quality Bank cuts with published prices, and which are used as feedstocks for process units that make gasoline blendstocks) to adjust the Gulf Coast Naphtha market price for use on the West Coast. *Id.* (citing Exhibit Nos. PSI-5 through PSI-8 and PSI-11). They explain that each of the two separate differentials is then weighted according to the relative amount of that product in the TAPS common stream, the weighted differentials are then combined, and the Gulf Coast Naphtha price is then adjusted by that amount to determine the West Coast Naphtha value. *Id.*

2320. The Dudley proposal, according to Unocal/OXY, works well because it recognizes that LSR, Naphtha, and VGO are all intermediate feedstock products used to make gasoline. *Id.* Further, they continue, the proposal is consistent with Sanderson's testimony that the West Coast value of Naphtha would lie between the West Coast values of VGO and LSR. *Id.* at pp. 38-39. Additionally, they suggest, it is consistent with Culberson's similar conclusion and his observation that West Coast Naphtha may have a lower value than Gulf Coast Naphtha. *Id.* at p. 39. Unocal/OXY state that it relies on the fact that the Gulf Coast and West Coast markets for intermediate products, unlike the markets for finished products, are similar, and that there are no excess margins assigned to the West Coast intermediate products, no evidence of non-competitive conditions in the intermediate product market, and no excessive volatility or spiking prices for these products. *Id.* Furthermore, Unocal/OXY explain, the record evidence shows there is an active trade in VGO, and there are published prices on both Coasts for VGO and LSR. *Id.* Unocal/OXY suggest that because the method is simple, easy to comprehend, and easy to administer they would recommend its adoption were the Commission to determine that the existing methodology is no longer just and reasonable. *Id.*

2321. According to Unocal/OXY, the Ross governor is a proposal which caps the West Coast price of Naphtha at the cost of importing Venezuelan Naphtha to the West Coast. *Id.* They note that the cost of shipping from the Caribbean to the West Coast has been addressed by Ross, Culberson and Sanderson. *Id.* Unocal/OXY point out that Ross proposes a shipping rate of $1.49/barrel, added to the Gulf Coast Naphtha price, as a governor. *Id.*

2322. The proposal has merit, according to Unocal/OXY, and should be considered. *Id.* They assert that they do not oppose the governor if a decision is made to adopt a West Coast based methodology; and in fact support it if the Commission decides to approve either the O'Brien or Tallett methods. Unocal/OXY Reply Brief at p. 85. However, Unocal/OXY assert, the governor may be set too high. Unocal/OXY Initial Brief at p. 39. They explain that the governor is based on the presumption that the West Coast value of Naphtha should not exceed the cost of imports. *Id.* However, note Unocal/OXY, the cost of imports is likely less than $1.49 above the Gulf Coast price. *Id.* at pp. 39-40. Unocal/OXY point out that not all witnesses were in agreement as to the shipping costs to import Naphtha. *Id.* at p. 40. Further, Unocal/OXY suggest, a more basic issue is whether the origin should be a Pacific origin that does not require a Panama Canal transit, or a Venezuelan or Mexican origin that does. *Id.* As Mexico is now the largest supplier of Naphtha to the Gulf Coast, Unocal/OXY state, the possibility of shipping from Mexico's Pacific port to the West Coast should be investigated to avoid including Panama Canal charges. *Id.* Ecuador's Pacific port is another possibility worthy of consideration, they claim, as Ecuador is now a significant source for VGO imports. *Id.*

2323. Unocal/OXY explains that O'Brien proposes a methodology based on a model gasoline produced by blending reformate, LSR and butane. *Id.* (citing Exhibit Nos. PAI-33, PAI-34, and PAI-35). They assert that there are several problems with this approach, that it is fatally flawed, and should be rejected. *Id.*; Unocal/OXY Reply Brief at p. 79. First, Unocal/OXY state, the three component blend will not meet air quality regulations prevailing on the West Coast and, therefore, it cannot be used in California, the Seattle area, Phoenix, or Las Vegas. Unocal/OXY Initial Brief at pp. 40-41. Unocal/OXY note that even the addition by O'Brien of a benzene saturation unit does not solve this problem. Unocal/OXY Reply Brief at p. 80. Further, they point out, Exhibit No. PAI-237, used by Phillips to support its assertion that O'Brien's three component blend will meet air standards, is outdated, so that all the questioning of Culberson on this Exhibit is irrelevant. *Id.* at pp. 81-82. Instead, they state, the correct information and the correct results for the benzene saturation model is found in Exhibit No. UNO-57. *Id.* at p. 82.

2324. Culberson's testimony that the O'Brien blend produces an unusable gasoline, Unocal/OXY assert, is not undercut by the questions as to the specifications for conventional gasoline as opposed to CARB or reformulated gasoline. *Id.* They note that CARB specifications apply throughout California, and reformulated gasoline specifications apply in the other areas catalogued by Culberson, and state that regular unleaded conventional gasoline cannot be sold in these areas, which comprise virtually all of the populated areas of the West Coast. *Id.* Accordingly, Unocal/OXY suggest, it is disingenuous for Phillips to suggest that the O'Brien blend is a usable grade of gasoline. *Id.* In addition, Unocal/OXY argue, the three component blend is not used by as many refineries as Phillips states. *Id.* They state that O'Brien has provided only one example of a refinery producing such a blend, U.S. Oil & Refining in Tacoma, and the available evidence on this refinery indicates that it does not produce such a three component blend. *Id.*

2325. Second, Unocal/OXY claim, the O'Brien model grossly overstates West Coast Naphtha values. Unocal/OXY Initial Brief at p. 41. Despite the fact that O'Brien himself stated that a predicted Naphtha value should not exceed the price of gasoline, otherwise the refiner would not bother to use the Naphtha to make gasoline, Unocal/OXY point out, O'Brien's model does exactly that. *Id.* They explain that O'Brien's model produces Naphtha values that exceed gasoline prices over an eight month period. *Id.* Third, continue Unocal/OXY, the method would produce Naphtha values significantly higher than the cost of imports from Venezuela even though the absence of such imports indicates that these values have never been attained by West Coast Naphtha. *Id.* Fourth, state Unocal/OXY, the O'Brien model attributes all of the gasoline margin to Naphtha, an entirely unrealistic assumption. *Id.* Fifth, Unocal/OXY point out, the O'Brien method is inconsistent with the cost model sponsored by O'Brien for the Resid valuation. *Id.* Finally, conclude Unocal/OXY, even in comparing the O'Brien predicted values to the West Coast contracts, its Naphtha values are higher than the contract averages for all periods, except for the anomalous 1999-2001 period. *Id.* Accordingly, Unocal/OXY posit that the O'Brien method is unjust and unreasonable and should be rejected. *Id.*

2326. Tallett's proposal is a least squares regression formula that relies on the relationship between the prices of unleaded regular gasoline, jet fuel and Naphtha on the Gulf Coast, according to Unocal/OXY. *Id.* at pp. 41-42 (citing Exhibit Nos. EMT-11 at pp. 17-20, EMT-17, EMT-18). They argue that Tallett's method also is fundamentally flawed and assert that there is no reason to assume that the Gulf Coast relationship between Naphtha and gasoline/jet fuel can be translated to the West Coast and used to derive a West Coast Naphtha price. *Id.* at p. 42. Unocal/OXY note that the relationship relied on is between an intermediate product (Naphtha) and finished products (gasoline and jet fuel), and the evidence discussed above demonstrates that finished products on the West Coast have much higher margins than do finished products on the Gulf Coast. *Id.* Accordingly, Unocal/OXY's position is that a relationship between finished and intermediate products cannot be transferred from one coast to the other without distorting values. *Id.*

2327. The proof of this fact, according to Unocal/OXY, is in the tests of the Tallett method done by Ross (Exhibit Nos. BPX-27, BPX-39), O'Brien (Exhibit No. PAI-52 at pp. 3-4), and Sanderson (Exhibit Nos. WAP-20, WAP-39). *Id.* at pp. 42-43. Unocal/OXY explain that these test showed that Tallett's regression method overvalued West Coast Naphtha by at least $1.56/barrel (Ross and Sanderson) and as much as $8.03/barrel (O'Brien). *Id.* These tests demonstrate conclusively, in the view of Unocal/OXY, that the Tallett method would overvalue West Coast Naphtha, and it is therefore not just and reasonable. *Id.* at p. 43.

2328. Unocal/OXY state that one other methodology suggested at the hearings is worthy of consideration. Unocal/OXY Initial Brief at p. 43. They note that Ross proposed to modify his governor by adding a floor set at the price of ANS + $4.00. *Id.* (citing Exhibit No. at BPX-67 at p. 8). Unocal/OXY explain that there is evidentiary support of the concept for this method in Sanderson's testimony respecting the derivation of Naphtha value from the cost of crude oil. *Id.*

2329. In reply, Unocal/OXY state that Ross's interpolation of a West Coast Naphtha price, as reflected in Exhibit No. BPX-138, would be an acceptable alternative. Unocal/OXY Reply Brief at p. 85. They explain that it involves taking the differential between Naphtha and VGO on the Gulf Coast and adding that to the VGO/crude oil differential on the West Coast. *Id.* The resulting differential is then added to a West Coast crude oil price, such as ANS, to calculate a West Coast Naphtha price, according to them. *Id.* at pp. 85-86. Ross did not sponsor this as a recommended methodology, but rather used it to check the ANS + $4.00 approach. *Id.* at p. 86.

6. Williams

2330. Williams submits that continued use of the Platts Gulf Coast Heavy Naphtha (waterborne) price is just and reasonable and that that price should continue to be used to value the West Coast Naphtha component of the Quality Bank. Williams Initial Brief at p. 54. However, it states that, if it is determined that the West Coast Naphtha component must be valued on a West Coast basis, then the only other West Coast Naphtha pricing methodology that has the essential characteristics (objective basis using a published price) of the Gulf Coast Naphtha price is ANS + $4.00 in that it, on average, is closer to the same value as Platts Gulf Coast Heavy Naphtha (waterborne) price quote. *Id.* Because it is essentially the same value as the Platts Gulf Coast Heavy Naphtha (waterborne) price and because the Platts Gulf Coast Heavy Naphtha (waterborne) price has been shown to be just and reasonable and continues to be just and reasonable, Williams contends that the ANS + $4.00 value is also just and reasonable. *Id.*

2331. None of the other proposals, Williams contends, meet the objective price standard that is preferred for valuing a component of the Quality Bank, although it states that Dudley's proposal comes close. *Id.* at pp. 54-55. Moreover, Williams claims, the two proposals that rely on West Coast gasoline prices as part and parcel of the method, those of O'Brien and Tallett, are fundamentally flawed because the basis of their proposals is to attribute all or most of the higher West Coast gasoline margins to Naphtha[705] in order to drive the value of Naphtha up as high as possible to the benefit of the proponents of their methods. *Id.* at p. 55. It asserts that this results in those two proposals being unjust and unreasonable, and argues that, although Ross's governor attempts to flatten the effects of West Coast gasoline run-ups and, therefore, reduces the amount of West Coast gasoline margin attributable to West Coast Naphtha, because his proposal is tied to O'Brien's and Tallett's proposals and thus West Cost gasoline, it suffers the same fate. *Id.*

2332. Williams states that Phillips and Alaska support the proposal developed by O'Brien which is based on the cost of processing Naphtha into conventional gasoline and which uses the published price of Seattle gasoline. Williams Initial Brief at pp. 55-56. In his zeal to raise the West Coast Naphtha value as much as possible, Williams argues, O'Brien inserted various fatal flaws into his proposal. *Id.* at p. 56. The O'Brien proposal, according to Williams, uses a finished product, gasoline, to try to estimate the value of the West Coast Naphtha component of the Quality Bank. *Id.* It asserts that this is inconsistent with the methods used to value other components even though it concedes that other Quality Bank components, such as Light Distillate and Heavy Distillate, use a finished product to derive the Light Distillate and Heavy Distillate intermediate feedstock values for Quality Bank purposes when there is no reported intermediate feedstock price. *Id.* Williams notes that the finished products which the other Quality Bank cuts use are almost exclusively made from the intermediate feedstock for which they are being used to value and do not require the blending of components manufactured from other Quality Bank cuts like gasoline does. *Id.* at pp. 56-57. For instance, it states that the West Coast Low Sulfur No. 2 Fuel Oil (Diesel) product used in the valuing of the Quality Bank Heavy Distillate component can be and often is made solely from the Heavy Distillate intermediate feedstock. *Id.* at p. 57. Williams claims that such is not the case with the use of gasoline. *Id.* It explains that it is made from multiple Quality Bank components: Isobutane, Normal Butane, LSR, Naphtha, VGO and Resid. *Id.* Thus, asserts Williams, were Naphtha valued using a formula based on gasoline, it would be different than the other Quality Bank cuts and different from the method proposed for Resid. *Id.* at pp. 57-58. Williams notes that Sanderson explained, "[t]his error is particularly acute in the valuation of West Coast naphtha because of the higher refinery margins on the West Coast." *Id.* at p. 58. (quoting Exhibit No. WAP-8 at p. 23).

2333. Phillips's statement that O'Brien's proposal is validated because it accurately predicts Gulf Coast Naphtha values and its argument that the Gulf Coast and West Coast markets are separate cannot both be true, claims Williams. Williams Reply Brief at p. pp.

[705] Williams states that Exhibit No. WAP-221 graphically illustrates this point. Williams Initial Brief at p. 55, n.46.

62-63. It states that, when all the other Gulf Coast prices are substituted into O'Brien's formula, as shown in Exhibit No. WAP-132 at p. 1, the calculated Gulf Coast Naphtha value averages 2.1¢/gallon below the actual Gulf Coast Naphtha value. *Id.* at p. 64. Instead of being a good job, this simply illustrates, in Williams's view, how poorly O'Brien's formula works on the Gulf Coast and how dramatically the Naphtha value calculated by the formula varies with the gasoline price. *Id.* It states that the formula's failure to predict the Gulf Coast Naphtha price, if anything, indicates the Gulf Coast Naphtha price is elevated by the presence of the petrochemical demand for it. *Id.*

2334. Williams argues that O'Brien's proposal suffers from the same fatal flaw that all gasoline and finished product-based formulæ suffer from – it inappropriately attributes the margin or profit refiners receive for their investments and market power in producing their most valuable refined product, gasoline, to the Naphtha feedstock. Williams Initial Brief at p. 58. They note that Sanderson elaborated on this point in his pre-filed answering testimony:

> A West Coast naphtha value calculated this way is unjust and unreasonable because it fails to take into account the contribution made by the processing of other intermediate feedstocks blended into gasoline and arbitrarily assigns all of the profitability associated with the investments in the other gasoline producing process facilities to the naphtha feedstock rather than to the refiner who produces gasoline from a variety of feedstocks rather than simply the reformer, naphtha hydrotreater, saturate gas plant and associated offsites.

Id. (quoting Exhibit No. WAP-8 at p. 15).[706]

2335. Ross, Willaims claims, voiced a similar concern: "In particular, O'Brien's methodology takes values that are peculiar to and isolated to the finished product price for gasoline and passes those through to the value of Naphtha, which is an intermediate product. In my view, that distorts the value of Naphtha on the West Coast." *Id.* at pp. 58-59 (quoting Exhibit No. BPX-27 at p. 3). It explains that Ross further characterized this distortion in the Naphtha value as "overstat[ing] (sometimes significantly) the actual value of Naphtha on the West Coast." *Id.* at p. 59 (quoting Exhibit No. BPX-27 at p. 3).

2336. Thus, Williams argues, the use of gasoline in O'Brien's proposal also distorts any comparison of his Naphtha result with the Gulf Coast published Naphtha price. *Id.* It asserts that the testimony in this proceeding was clear that gasoline prices on the West Coast are higher than on the Gulf Coast. *Id.* More importantly, states Williams,

[706] Williams also refers to Transcript at pp. 10687-88, 11086-88. Williams Initial Brief at p. 58.

refiners's margins on gasoline are higher on the West Coast than the Gulf Coast. *Id.* It notes that O'Brien agrees, stating that he previously testified via an affidavit that

> [t]he fact is that gasoline price differences between the two regions [Gulf Coast and West Coast] are more reflective of gasoline market fundamentals as opposed to any implicit differences in the value of naphtha. The refinery profit margin on gasoline has traditionally been higher on the West Coast than on the Gulf Coast because of the stronger gasoline market on the West Coast.

Williams Reply Brief at p. 65-66 (quoting and citing Exhibit No. WAP-8 at p. 8; emphasis in original omitted).[707]

2337. Williams explains that Pulliam testified that, in 1999, higher gasoline profits flowed through to the refinery. Williams Initial Brief at p. 59. Thus, it contends that attributing these higher margins to Naphtha on the West Coast unreasonably inflates the value of Naphtha calculated using formulæ that rely totally or principally on the West Coast finished product prices, and maintains that this inflation is further exacerbated by the fact that CARB gasoline, which makes up 73% of the West Coast gasoline market, further increases the prices of West Coast gasoline since non-CARB gasoline tends to follow CARB gasoline prices. *Id.*

2338. In Williams's view, the flaws and skewing in O'Brien's proposal are easily illustrated by reviewing the coefficients in the formula, which are set out in Exhibit No. PAI-39, particularly "A = (1.0710) x Seattle Regular Unleaded (SRUL) conventional gasoline price." *Id.* at p. 60. It points out that O'Brien confirmed the fact that, for every $1.00/barrel change in the price of gasoline, O'Brien's Naphtha value increases by $1.07/barrel. *Id.* Thus, Williams explains, O'Brien's Naphtha value moves in lock-step with the finished gasoline price with a 7% premium added on top. *Id.* Williams concludes that this clearly shows that no matter what the refiner's margin is on gasoline, O'Brien is attributing all of that margin to his calculated West Coast Naphtha value. *Id.*

2339. An important part of O'Brien's calculation and distorted result, Williams contends, is the value he attributes to hydrogen. *Id.* It states that his approach is inconsistent, with the inconsistency designed to increase the resulting value of Naphtha, and it points out that within coefficient B of his formula, the hydrogen value is composed of two pieces, both of which are related to the price of natural gas. *Id.* at pp. 60-61. In other words, Williams points out, O'Brien allows the natural gas price in the formula to float with the market price of natural gas. *Id.* at p. 61. It states that this is inconsistent with the valuation in his Resid calculations, because, there, he fixed it at a standard

[707] Williams also refers to WAP-13 at p. 4. Williams Reply Brief at p. 66.

$1.75/standard cubic foot, with the only adjustment to that figure being the Nelson-Farrar escalation. *Id.* Williams notes that O'Brien admitted that he could have used the same approach with his Naphtha calculation, but did not. *Id.* It asserts that Sanderson demonstrated why in Exhibit No. WAP-215, which shows that O'Brien's Naphtha value would not have exceeded the Seattle regular unleaded price a total of nine months if the hydrogen value had been fixed, and point out that, by letting the value of the hydrogen float with the price of natural gas, O'Brien has built in another feature that results in a Naphtha value so high that it can skyrocket to as much as 15¢/gallon higher than the finished gasoline product, in this case, Seattle unleaded regular gasoline. *Id.* Williams maintains, this underscores the skewed result arising from the inconsistent approach O'Brien used to value hydrogen in his Naphtha valuation compared to his Resid approach. *Id.* at pp. 61-62.

2340. Moreover, it claims that a further inconsistency exists in O'Brien's choice of pricing the hydrogen. *Id.* at p. 62. Williams notes that, rather than use a natural gas price in the Seattle area which would be consistent with his use of a Seattle gasoline price, O'Brien elected to use a potentially much more highly volatile Southern California natural gas price. *Id.* It states that Exhibit No. WAP-211 shows that the Seattle area natural gas price was considerably lower than the Southern California natural gas price O'Brien used during last months of 2000 and the first half of 2001, and that Exhibit No. WAP-210 confirms that the price run-up in Southern California was limited to that area and was not a widespread escalation of natural gas prices across the country. Williams Reply Brief at p. 69.

2341. Williams takes exception to Phillips explanation that O'Brien's assumption concerning hydrogen was based on his view that it is one of the products, and not one of the costs, in the Naphtha reforming process. Williams Reply Brief at p. 67. Further, according to Williams, it does not agree with O'Brien's decision not to reflect the cost savings he mentioned from making hydrogen via the reformer process. *Id.* Thus, it asserts, O'Brien's inconsistent choice of natural gas pricing for his Naphtha value calculation formula is but one more area where he has inserted the potential to skew the value Naphtha in Phillips's financial interest.[708] Williams Initial Brief at p. 62.

2342. The "unreasonableness" of O'Brien's approach, formula, and result, according to Williams, is underscored further by the prolonged period of eight consecutive months during which his calculated value of Naphtha would have exceeded the finished gasoline product price. *Id.* Williams argues that a refiner would not continue to make gasoline using Naphtha if the value was higher for nine months, rather, as O'Brien stated, the refiner would sell the Naphtha instead. *Id.* at p. 63. Williams concludes that to allow

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[708] Williams states that Exhibit No. WAP-215 supports this view. Williams Reply Brief at p. 68, n.35.

such a formula to be used to value Naphtha on the West Coast would result in an unjust and unreasonable result. *Id.*

2343. O'Brien concurs, Williams notes, that it would make no sense for Naphtha to be valued higher than gasoline for such a period of time when he testified concerning Stancil's proposed methodology. *Id.* Even though O'Brien tried to qualify his pre-filed testimony, it claims, on cross-examination he admitted that the Naphtha price should not exceed gasoline prices for nine months. *Id.* Thus, according to Williams, O'Brien's proposal results in an unjust and unreasonable result for the very same reason as Stancil's previous proposal. *Id.* at pp. 63-64.

2344. In reply, Williams states, the evidence cited by Phillips of instances where Gulf Coast Naphtha prices exceeded gasoline prices for only three separate months does not alter the fact that O'Brien's formula results in an unrealistic and unreasonable Naphtha value. Williams Reply Brief at pp. 70-71. The reason O'Brien's formula is wrong is not because of isolated excursions above the gasoline price, but rather due to the prolonged continuous estimated valuation of West Coast Naphtha above gasoline, claims Williams. *Id.* at p. 71.

2345. According to Williams, it strenuously objects to Phillips suggestion that the Quality Bank Administrator be permitted to suggest a different natural gas price if the Commission is concerned about manipulation. *Id.* at p. 74. It suggests that, in this regard, Phillips's proposal is disingenuous, and note that, under that proposal, the Quality Bank Administrator could not act until the Commission had concluded that a manipulation had occurred, which takes time and occurs long after the actual manipulation takes place. *Id.*

2346. Williams also points out that, under that proposal, Phillips and Exxon would benefit because the Quality Bank Administrator's recommendation could only be prospective. *Id.* at pp. 74-75. It notes that the Commission order responding to the 2000-2001 run up in California natural gas prices was not released until 2003, as cited in Phillips's own brief. *Id.* at p. 75 (citing *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange*, 102 FERC ¶ 61,317 at P 56-63 (2003.

2347. O'Brien's Naphtha calculation, Williams states, and thus Phillips's entire proposal, also hinges on the validity of the three-component blend he chose to use. Williams Initial Brief at p. 64. It explains that O'Brien's premise is that a conventional regular unleaded gasoline can be blended from LSR, Normal Butane, and reformate, and that the value can be calculated because there are published prices for all the components. *Id.* Williams asserts, however, that this three-component blend gasoline is an unrealistic blend to produce Seattle conventional unleaded regular gasoline. *Id.*

2348. According to Williams, O'Brien's "three-component blend of gasoline is inconsistent with the gasoline produced by the coking refinery configuration proposed by all parties as the basis for valuing the resid cut as it does not include gasoline components produced from the VGO cut and the resid cut." *Id.* (quoting Exhibit No. WAP-8 at p. 17). It states that the assumption that the three-component blend can be priced as conventional unleaded gasoline produced by a complex refinery with a Coker, catalytic cracker, and alkylation unit on the West Coast without taking into account the costs or capital recovery contribution of these feedstocks and process facilities defies logic and ignores the evidence that the three-component blend cannot be sold as conforming conventional gasoline by the complex refineries he uses as a basis for his valuation. *Id.* at pp. 64-65. Williams notes that this is not the type of refinery that O'Brien pointed to when forced to identify a refinery that he alleged produces a three-component blend of gasoline that he actually used for his cost calculations. *Id.* at p. 65.

2349. In his pre-filed testimony, Williams notes, Sanderson compared the exhaust toxic emissions from O'Brien's three-component blend with those of the "anti-dumping statutory baseline" or simply the "statutory baseline" set forth in 40 C.F.R. § 80.91 (c)(5)(2004). Williams Reply Brief at p. 76. It explains that the three-component blend does not comply with the EPA standards for the "statutory baseline" and asserts that it is reasonable for the Commission to expect a proposal to value West Coast Naphtha in the Quality Bank to produce gasoline no worse than the national average statutory baseline established by the EPA. *Id.* Williams points out that this baseline applies to all refineries that do not have their own established baselines and to all gasoline produced in excess of any refinery established baseline. *Id.*

2350. Contrary to the claims of Phillips, Williams argues, O'Brien's three-component blend is not even in compliance with all of the refineries he picked. *Id.* at p. 77. It notes that the EPA anti-dumping requirements are a necessary requirement to market conventional gasoline in the U.S. *Id.* Furthermore, Williams assets that the three-component blend meets this condition only were the Commission to accept the position taken by Phillips regarding the cherry-picking of benzene and aromatics levels of reformate outlined by Phillips in its Initial Brief. *Id.* (citing Phillips Initial Brief at pp. 103-11).

2351. Williams states, O'Brien pointed to the U.S. Oil & Refining in Tacoma, Washington in support. Williams Initial Brief at p. 65. However, it notes that, as first shown in Exhibit No. WAP-136, using benzene and aromatics for LSR, which O'Brien agreed represented ANS, and using PIMS aromatics and benzene for Naphtha, U.S. Oil & Refining would fail its EPA exhaust toxics standards. *Id.* It states that, because O'Brien went on to say he believed that indicates a problem with the numbers for benzene and aromatics, Exhibit No. WAP-140 was introduced using benzene and aromatic levels for ANS taken from Exhibit No. WAP-139. *Id.* According to Williams, the result was the same: the U.S. Oil & Refining Tacoma refinery would fail its annual exhaust toxics standard. *Id.* In addition, it states that, because it has an isomerization unit, it would not make the same three-component blend as O'Brien uses. *Id.* Williams claims that, using the ANS benzene and aromatic levels, the same failure to comply with its exhaust toxics limits results for the Kern Oil refinery in the Bakersfield, California area. *Id.* at p. 66.

2352. Phillips attempted, Williams explains, to use the reformate, benzene and aromatics values provided by the Phillips Ferndale refinery to show that O'Brien's blend would meet EPA standards. Williams Reply Brief at p. 77. However, it notes, O'Brien admits that the refinery only runs 75% ANS rather than 100% ANS, and that Phillips rejects the other record evidence provided from independent sources that indicates that the benzene and aromatics levels in reformate are indeed much higher than the values proposed by Phillips from the refinery. *Id.* at pp. 77-78. Moreover, Williams notes that the PIMS model, which O'Brien uses to calculate the reformer yields in his proposal, suggests that the benzene and aromatics levels are much higher than that produced at the Phillips Ferndale refinery – 5.5 vol % benzene and 61.3 vol % aromatics. *Id.* at p. 78. It explains that use of the benzene and aromatics levels from the PIMS model would correspond to annual average exhaust benzene levels of 210.8 mg/mile, making it fail to comply with all of the refinery individual baselines and the statutory baseline. *Id.*

2353. Additional evidence, according to Williams, was provided by the technology licensing firm UOP for a complex refinery processing 100% ANS crude from an NPRA article titled: "Benzene Reduction Alternatives" which indicates the reformate produced from a complex refinery processing 100% ANS crude oil is 4.0 vol % benzene and 63.7 vol % aromatics. *Id.* at pp. 78-79. It notes that Phillips argues that this data is not applicable because O'Brien was not using hydrocracked or Coker Naphtha. *Id.* at p. 79. Williams asserts that, if O'Brien's three-component blend is indeed produced by a complex refinery as he testified, then his reformate feed must contain Coker Naphtha and hydrocracked Naphtha like the reformate characterized by UOP and have comparable benzene and aromatics levels to those in Exhibit No. WAP-139. *Id.* Again, using the benzene and aromatics levels from the UOP article, Williams claims, O'Brien's three-component blend would fail to comply with the statutory baseline and individual refinery baseline standards selected by Phillips. *Id.* at pp. 79-80.

2354. Williams explains that O'Brien did look at the cost of adding a benzene saturation unit to his cost calculation, stating that it would cost about $4,600,000 in capital costs and thereby reduce his Naphtha value by approximately 1.3¢/gallon. Williams Initial Brief at p. 66. However, it notes, O'Brien also testified that he did not think that the benzene saturation unit was necessary. *Id.* In addition, Williams points out, U.S. Oil & Refinery does not have a benzene saturation unit. *Id.* It states that the refinery has an isomerization unit, as O'Brien acknowledged at the hearing, and explains that it is clear that O'Brien did not try to cost out such a unit because he did not include one in his cost estimate. *Id.* Williams notes that Exhibit No. WAP-138 shows that an isomerization unit using the Gary & Handwerk cost curve for a 2,300 barrel/day isomerization unit (the size of the isomerization unit at U.S. Oil & Refining as confirmed by O'Brien) would cost $13.1 million in Year 2001 dollars. *Id.* at pp. 66-67. Thus, Williams claims, it is not surprised that O'Brien did not include an isomerization unit in his costs to make his three-component blend of gasoline as the added cost would have significantly lowered his calculated value of Naphtha on the West Coast. *Id.* at p. 67.

2355. Williams concludes that the net result of O'Brien's being unable to prove that any refiner makes the three-component blend of gasoline which he uses, much less sells it legally on the West Coast, means that, at best, his three-component blend is simply another unfinished gasoline blendstock that does not have any reported published price and that cannot be reliably valued. *Id.* It suggests that this also invalidates O'Brien's entire proposal because his costs are not reflective of a gasoline made on the West Coast and the additional complex and expensive process units needed to make legal gasoline. *Id.*

2356. O'Brien's calculated high Naphtha value, Williams argues, also flies in the face of the evidence indicating that there, allegedly, is idle reforming capacity on the West Coast. *Id.* (citing Exhibit Nos. WAP-135, WAP-47, WAP-48, WAP-226). Williams contends this means that the demand for Naphtha on the West Coast is not high. *Id.*

2357. Williams also asserts that, were West Coast Naphtha valued as high as O'Brien calculates it to be, there should be a flood of imports of Naphtha into the West Coast. *Id.* It notes that "O'Brien's proposed West Coast naphtha price exceeds the price at which West Coast refiners could economically import naphtha supplies from Venezuela, a large-volume supplier of reforming-grade naphtha to the Gulf Coast market by an average of 5.8 cents per gallon despite the availability of excess reforming capacity in California." *Id.* at pp. 67-68 (quoting Exhibit No. WAP-8 at p. 16). Williams asserts that Sanderson came to the same conclusion, and states that there has been no such flood of Naphtha imports into the West Coast. *Id.* at p. 68.

2358. Because O'Brien's processing-based proposal is so subjective, Williams claims, Tallett rejected such an approach, including Stancil's approach, at the outset. *Id.* It states that Tallett also expressed concern that such a methodology could be subject to manipulation. *Id.* Williams notes that, instead of a processing based proposal, Tallett devised a regression-based equation between gasoline and jet fuel, two high priced Gulf Coast finished products, and Full Range Naphtha to estimate the value of the West Coast component of the Quality Bank. *Id.* at pp. 69-70. It states that the Tallett proposal simply takes the Gulf Coast Naphtha price, which Exxon states is unjust and unreasonable to use, and adds approximately a 7¢/gallon premium to it, derived from the full additional margins that refiners earn on producing West Coast gasoline and jet fuel. Williams Reply Brief at p. 83. Despite choosing a different approach from O'Brien, Williams asserts, the result is the same. Williams Initial Brief at p. 70.

2359. Williams argues that the important price relationship between the finished products and feedstock prices on each coast is their price differential or margin rather than whether these products are related to or track each other. *Id.* If Tallett had analyzed margins, Williams states, he would have realized it was improper to transfer the Gulf Coast price relationship between gasoline and jet fuel and Naphtha to the West Coast. *Id.* Instead, it notes, Tallett emphasizes products tracking each other on each coast. *Id.* It asserts that this "sleight-of-hand" results in a proposal which over-values Naphtha on the West Coast. *Id.*

2360. The use of a regression-based formula to transfer the narrow Gulf Coast price relationship to the West Coast results in an inappropriate, implicit assumption that refining margins (i.e., feedstock to product spreads) are the same on the West Coast as they are on the Gulf Coast, posits Williams. *Id.* It states that that is not true, as Sanderson demonstrated in his pre-filed answering testimony where he explained that margins are higher on the West Coast for the conversion of feedstocks into finished products. *Id.* For instance, Williams claims, relying on Muse, Stancil & Company data, "[t]he comparative refining margin data confirms that the refinery cash operating margins have been consistently higher on the West Coast than the Gulf Coast, averaging $2.87 per barrel or 6.8 cents per gallon higher over the seven-year period the refinery margin data was available." *Id.* at pp. 70-71 (quoting Exhibit No. WAP-8 at p. 5).

2361. Williams notes that Sanderson compared "crack spreads"[709] between similar refined product and feedstock prices, because that indicates the price differentials available for refining operations or margins before costs on the two coasts. *Id.* at p. 71. It states that, in his analysis, Sanderson uses "[a] 3-2-1 crackspread between a basket of conventional gasoline and low sulfur No. 2 fuel prices minus crude oil prices. . . because it is sometimes used to approximate the margin before costs for a complex refinery like the hypothetical Quality Bank refinery."[710] *Id.* (quoting Exhibit No. WAP-8 at p. 6). According to Williams, the difference between the Gulf Coast and the West Coast is that this crack spread averages 6.7¢/gallon or $2.81/barrel higher on the West Coast than the Gulf Coast over the seven-year period 1994 through 2001. *Id.* It states that the higher crack spreads are the cause of the higher finished product prices on the West Coast. *Id.*

2362. According to Williams, the averages of the two different methods employed by

[709] Williams notes that "[a] crack spread is the difference between a refined product price or group of refined product prices sometimes referred to as a 'basket' of prices and a feedstock price." Williams Initial Brief at p. 71, n.55.

[710] Williams notes that the discussion of this 3-2-1 crack spread is in Exhibit No. WAP-8 at pp. 6-7. Williams Initial Brief at p. 71, n.56.

Sanderson are virtually identical 6.8¢/gallon and 6.7¢/gallon, respectively. *Id.* Thus, it claims, the conclusion indicated by the Muse Stancil refinery data that refinery profitability on the West Coast has been higher than on the Gulf Coast is supported by the higher West Coast crack spreads. *Id.* Tallett, Williams indicates, shared this view. *Id.* at p. 72.

2363. Williams states that the record reflects that, during the period 1994-2001, virtually the entire amount by which Tallett's calculated West Coast Naphtha prices exceeds the Gulf Coast Naphtha price used in the Quality Bank is due to the difference in refining margins or profitability that Sanderson calculated. *Id.* It notes that the Muse Stancil refining margin is $2.87/barrel or 6.8¢/gallon higher on the West Coast over the period 1995-2001, and that Tallett's calculated Naphtha price exceeds the Gulf Coast Naphtha price by $2.92/barrel or 7.0¢/gallon over the 1994-2001 period, almost of which represents the difference between the Gulf Coast refiners's margin and the higher West Coast refiners's margin. *Id.* Williams points out that, when that amount is subtracted from Tallett's calculated West Coast Naphtha price, the difference is a "miniscule" 5¢/barrel or a "mere" 0.2¢/gallon, meaning that, when adjusted to put the two coasts on an equivalent basis, the two Naphtha prices are almost identical. *Id.* at pp. 72-73. Thus, Williams asserts, Tallett's own calculation, properly adjusted, shows that the Gulf Coast and West Coast Naphtha prices are the same. *Id.* at p. 73. Therefore, Williams submits, the Gulf Coast Naphtha price is a reasonable proxy for the West Coast Naphtha component of the Quality Bank. *Id.*

2364. Tallett's use of the Gulf Coast relationship between gasoline/jet fuel and Naphtha, according to Williams, cannot possibly be valid because the market characteristics or nature (supply, demand and, therefore, price) of the Gulf Coast and West Coast gasoline market changed during the period he developed his equation. *Id.* at p. 74. It notes that Tallett agreed that, if a major change occurred in one of the markets, he would have to change his regression equation, and noted that Tallett viewed this as a benefit of his approach. *Id.*

2365. The advent of CARB Phase II gasoline in California, Williams claims, imposed a significant and irreversible change on the West Coast (conventional and CARB) gasoline and jet fuel markets that did not occur on the Gulf Coast. *Id.* It maintains that this major market change resulting from the CARB gasoline specifications requires that the coefficients in Tallett's regression-based formula change in 1996, but it claims that he did not change them. *Id.* According to Williams, the reason why this change was not made was because it did not impact the Gulf Coast market, which is the basis for Tallett's formula. Williams Reply Brief at p. 86.

2366. Williams states that another way that the value of Naphtha on the West Coast has been negatively impacted since the introduction of CARB requirements is in the narrowing of the distillation cut range. Williams Reply Brief at p. 93. It states that the record evidence, and the testimony of witnesses Sanderson, Sarna and Tallett, document that the CARB gasoline and specifications have forced West Coast refiners producing CARB gasoline to narrow the distillation range of reforming Naphtha from those similar to the Quality Bank cut points (175°F to 350°F) to a narrower cut range estimated by the witnesses to be approximately 208°F to 330°F. *Id.* at pp 93-94. Williams explains that this has eliminated the volumes of Naphtha boiling from 175°F to 208°F and the volumes boiling from 330°F to 350°F from refineries producing CARB gasoline. *Id.* at p. 94.

2367. Assuming a linear boiling point curve for the Naphtha distillation, Williams asserts that the volume of reforming Naphtha used in CARB gasoline (208°F to 330°F) would be approximately 70% of the Quality Bank cut or a 30% reduction in the volume processed compared to the Quality Bank cut range of 175°F to 350°F.[711] *Id.* Thus, it points out, the predominant West Coast Naphtha cut is different than the Gulf Coast Naphtha cut which Tallett took as the basis for his regression formula, yet he made no adjustment in his formula to reflect this. *Id.* at pp. 94-95. Williams asserts that this is because there is no way he could formulate a regression formula to reflect this difference; so he simply ignored it, rendering his formula worthless. *Id.* at p. 95.

2368. It is obvious, Williams claims, that the narrowing of the Naphtha cut points used for CARB gasoline changes the value of Naphtha on the West Coast compared to the Quality Bank Naphtha cut, and it asserts that Sanderson shared this view at the hearing. *Id.* at pp. 95-96. It explains that the reduction in the value of West Coast reforming Naphtha can be calculated based on the disposition of the 175°F to 208°F cut to LSR and the 330°F to 350°F cut to jet fuel, and that this shows that CARB gasoline's effect on the West Coast Naphtha cut is to reduce its value by 1.3¢/gallon for the period 1996 through 2001. *Id.* at p. 96.

2369. Williams states that the Gulf Coast Naphtha market is an import market which requires the price of Naphtha to be sufficiently elevated to attract supplies from other supply centers such as the Caribbean and Europe. Williams Initial Brief at p. 75. It explains that the petrochemical markets significantly influence Gulf Coast Naphtha demand and, therefore, prices. *Id.* Thus, Williams suggests, the Gulf Coast Naphtha

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[711] Williams notes that the percentage of the 175°F to 350°F Quality Bank Naphtha cut comprised of the narrower 208°F to 330°F cut used in CARB gasoline is calculated assuming as linear boiling point curve as follows:

$$\text{208°F - 330°F Naphtha Cut as a Percent of the Quality Bank Naphtha cut} = \frac{(330 - 208)}{(350 - 175)} = \frac{122}{175} = 70\%$$

Williams Reply Brief at p. 94, n.61.

market is a demand market because there is not enough Naphtha to supply or market without imports. *Id.* In contrast, it asserts that the West Coast Naphtha market is a self-sufficient market with little demand for Naphtha beyond that produced from crude oil and no commercially significant petrochemical market. *Id.* Williams further suggests, Naphtha demand is not even strong enough on the West Coast to fill existing reforming capacity there, despite the often critical shortage of gasoline on the West Coast. *Id.*; Williams Reply Brief at p. 89.

2370. A report published by the American Petroleum Institute (API) and National Petroleum Refiners Association (NPRA) containing a survey of the utilization rates of U.S. operating refineries, according to Williams, shows that, for the survey period of May 1 through August 31, 1996, after the introduction of CARB Phase II gasoline, the reformer utilization rates in California were 66.3%. Williams Reply Brief at p. 89. It notes that the 66.3% utilization figure for California reformers is much lower than that for reformers in other states on the West Coast (PADD V excluding California) of 92.3% and the Gulf Coast region (PADD III) of 86.4%. *Id.* In addition, Williams points out, the Solomon Survey information on reformer utilization for the West Coast clearly shows reformers have operated well below their maximum achievable stream-day utilization rates of 90 to 95%, averaging 76.3%, in the Solomon Surveys published in 1994, 1996, 1998 and 2000. *Id.*

2371. Not only have reformer utilization rates been low on the West Coast, Williams asserts, refiners also have reduced reforming capacity over the 1994 to 2001 period as well, again showing that the demand for Naphtha to reform into gasoline has decreased on the West Coast. *Id.* at pp. 89-90. Williams contends that Sanderson unquestionably established this decrease in reformer utilization at the hearing. *Id.* at pp. 90-91. In light of the huge price run up in gasoline prices during the 1999-2001 period and the imports of gasoline but not Naphtha, during this period,[712] Williams argues, there is no explanation for the decrease of the equivalent of two reformers during this period other than that the demand for straight run naphtha, i.e., the Naphtha that is being valued for Quality Bank purposes, has decreased, and therefore, so has its value on the West Coast. *Id.* at p. 91.

2372. As further evidence that reformer capacity has been reduced on the West Coast (PADD V), Williams cites Exhibit No. EMT-667, which is an excerpt from a Purvin & Gertz table of PADD V process capacity changes from 1992 to 2002 and indicates that total reforming capacity in PADD V, including both Semi-Regenerative and Continuous Reformers, declined by 39,000 barrels/calendar day from 598,000 barrels/calendar day to

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[712] Williams cites Exhibit No. WAP-44, showing imports of gasoline and gasoline components compared to the nominal imports of Naphtha during the 1999-2001 period. Williams Reply Brief at p. 91, n.55.

559,000 barrels/calendar day[713] or 6.5% during the period at issue in this proceeding.[714] *Id.* at pp. 91-92. According to Williams, not only does Exhibit No. EMT-667 indicate that actual reforming capacity has declined in PADD V over the 1992 through 2002 period, but Purvin & Gertz also forecasts that no additional reforming capacity will be needed in PADD V through 2015, while additional capacity will be required for other gasoline-producing process units: 42,000 barrels/calendar day more cat cracking capacity will be needed for processing VGO; 27,000 barrels/calendar day more alkylation capacity will be needed for processing VGO and isobutane; 173,000 barrels/calendar day more isomerization capacity will be needed for processing LSR; and 64,000 barrels/calendar day more hydrocracking capacity will be needed for processing VGO and light cycle oil by 2015. *Id.* at p. 92.

2373. The Gulf Coast market for gasoline and jet fuel is also radically different than the West Coast market, Williams maintains. Williams Initial Brief at p. 75. On the Gulf Coast, it notes, supplies of gasoline and jet fuel are produced and shipped to other U.S. locations through both pipeline and waterborne trade. *Id.* It contends that this means that prices for gasoline and jet fuel on the Gulf Coast must necessarily be below that of the destination markets it serves, including the West Coast. *Id.* The West Coast, according to Williams, is an import market for gasoline and jet fuel. *Id.* Since 1998, it notes, the West Coast has been a regular and increasing importer of jet fuel. *Id.* In 2000, Williams explains, imports of jet fuel on the West Coast were approximately 20% of the total jet fuel supplied to PADD V. *Id.* (citing Exhibit No. WAP-191 at p. 2). It argues that the West Coast gasoline market is priced to attract imports of gasoline and gasoline components on a routine basis with occasional periods of notably high prices related to the difficulty refiners from outside California have in producing CARB gasoline. *Id.* at p. 76. Even in that case, states Williams, there are still no significant Naphtha imports. *Id.*

2374. Williams states that Tallett's attempt to use the Gulf Coast regression-based equation to value West Coast Naphtha was shown to be flawed by using his own feedstock-to-product correlation for Gulf Coast VGO as a predictor of West Coast VGO prices. *Id.* It suggests that the result was that his own correlation over-predicted the price of West Coast VGO by 4.4¢/gallon during the period 1994-2001. *Id.* Even if the VGO prices used are changed to reflect a different level of sulfur in the VGO, Williams notes, the result is the same –Tallett's regression equation overstates the actual West Coast

[713] Williams explains that barrels/calendar day refers to the annual operating capacity of a process unit, taking into account the capacity lost due to maintenance activities. Williams Reply Brief at p. 91, n.56.

[714] Williams claims that Exxon, erroneously, introduced Exhibit No. EMT-667 for the proposition that "Sanderson's claim about low utilization levels for West Coast reforming capacity was directly contradicted by a report prepared by [his] own firm." Williams Reply Brief at p. 92, n.57 (quoting Exxon Initial Brief at pp. 233-34).

VGO price. *Id.*

2375. According to Williams, Ross recognizes that the proposals for valuing West Coast Naphtha overstate the actual West Coast Naphtha value because he proposes his governor to correct for situations when the West Coast price of gasoline is high. *Id.* Thus, Williams asserts, Ross acknowledges that any proposal for valuing West Coast Naphtha using a West Coast gasoline-based formula is problematic, so much so that, without a governor to account for gasoline price anomalies, Ross testified, O'Brien's and Tallett's proposals are unsound and should be rejected.[715] *Id.* at pp. 77-78. Williams states that one of Ross's reasons for not relying on ungoverned gasoline prices as a basis for valuing West Coast Naphtha is significant and confirms Sanderson's testimony concerning O'Brien's and Tallett's proposals, to wit: "the results of the formulae proposed by Mr. Tallett and Mr. O'Brien whose formulae grossly inflate the value of Naphtha." *Id.* at p. 78 (quoting Exhibit No. BPX-67 at p. 38).

2376. Thus, Williams argues, the difference between Ross and Sanderson is that Ross suggests that it is preferable to try to devise a way to value West Coast Naphtha on a West Coast basis, hence his advancing the "governor" proposal. *Id.* It notes that Sanderson, by contrast, starts from a "more logical" basis; rather than start with "unjust and unreasonable" proposals to value West Coast Naphtha and try to "cobble-up" an untried and untested fix such as a "governor," a more sound approach is simply to continue using the tried and tested Gulf Coast Heavy Naphtha (waterborne) price quote. *Id.* at pp. 78-79. Williams questions the appropriateness of using convoluted formulæ and governors when Ross has conceded that the advent of the Platts Gulf Coast Heavy Naphtha price and its approximately one-cent increase in the Gulf Coast price used to value West Coast Naphtha lessened his concerns with using a Gulf Coast price. *Id.* at p. 79. Because Ross advocated a preference for a West Coast price basis, if feasible, Williams argues, it would be too much to have expected him to concede that his concerns were completely gone. *Id.* However, it contends that Ross, earlier, did state that it was fair to characterize his testimony as indicating that he would prefer to continue to use the Gulf Coast Naphtha price if the only alternative was one of the ungoverned Tallett or O'Brien approaches. *Id.*

2377. Williams argues that, as Sanderson testified, Dudley's approach has merit because he takes into account feedstock relationships and uses VGO and LSR to value West Coast Naphtha. *Id.* at pp. 79-80. It suggests that Dudley's proposal is based on a good fundamental understanding of the economics of petroleum refining on the West Coast and Gulf Coast, because he avoids the mistake made by Tallett and O'Brien of overvaluing Naphtha by starting with a West Coast gasoline price. *Id.* at p. 80. Dudley

[715] Williams points out that Sanderson expressed the same concerns. Williams Initial Brief at p. 78, n.61.

"correctly" recognizes that, according to Williams, using comparable intermediate feedstock prices such as LSR and VGO, is a more valid basis for valuing Naphtha, another feedstock, than using gasoline, a finished product. *Id.* It maintains that it also is apparent that LSR and Naphtha are produced as co-products due to the wide variety of distillation cut points used in the industry. *Id.* Furthermore, Williams contends that, because Dudley's percentages are based on the supply percentages of LSR and VGO in ANS, there is some logic to his approach. *Id.*

2378. Williams's position is not that Dudley's proposal is the one to pick to replace continued use of Platts Gulf Coast Heavy Naphtha (waterborne) price, rather it claims that its position is that the greatest value of Dudley's proposal is that it demonstrates the validity of the Gulf Coast Naphtha value being used as the proxy for the West Coast value of Naphtha over the long-term. *Id.* In the event that neither Platts Gulf Coast Heavy Naphtha (waterborne) price nor its feedstock price equivalent on the West Coast, ANS + $4.00, are to be continued, it states that Dudley's proposal is the next logical choice because it is the only other proposal that attempts to value West Coast Naphtha on an intermediate feedstock basis rather than on a West Coast finished gasoline basis. *Id.* at pp. 80-81.

2379. Should the Commission decide that a West Coast price basis for valuing West Coast Naphtha is a necessity, Williams argues, the only appropriate objective and simple methodology would be to value West Coast Naphtha at the West Coast published ANS crude oil price plus $4.00/barrel. *Id.* at p. 81. It states that using ANS + $4.00 has many merits that are parallel with using the Gulf Coast Heavy Naphtha price quote: (a) it would be based on a published robust, West Coast feedstock price with little risk of manipulation by any one of the Parties to this proceeding; (b) it would be simple to implement and administer; and (c) it is consistent with the philosophy of using feedstock prices to value the intermediate Quality Bank cuts whenever possible. *Id.* at p. 82.

2380. Williams asserts that the record evidence indicates ANS + $4.00/barrel is consistent with the current Quality Bank value for West Coast Naphtha using Platts Gulf Coast Heavy Naphtha (cargo) price quotation until the Commission rules. *Id.* It explains that Sanderson testified that the Gulf Coast Naphtha averaged about $3.60 above ANS from 1994-2002, making that a benchmark. *Id.*

2381. Williams does not recommend the proposed methodology discussed during the course of the Naphtha hearing which performs an "interpolation" between various product prices on the Gulf Coast to impute a Naphtha price on the West Coast be adopted. *Id.* at p. 84. It notes that Sanderson discussed the methodology and identified several problems with the concept. *Id.* The major problem, it posits, stemmed from the choice of Light Distillate and LSR. *Id.* Williams notes that Sanderson described the problem encountered as follows:

> And the problem we ran into was naphtha, because of its price relationships can be higher priced than light distillate, and occasionally, not very often but a couple of times in the period we looked at, it was priced below LSR, so these percentages fluctuated pretty wildly. So you had fairly big variations month to month. Then if you go to the West Coast, the differential – and I don't have the numbers here, but we could provide those – the differential between light distillate and LSR is much wider on the West Coast because jet fuel prices and light distillate prices are somewhat higher and LSR prices are somewhat lower. You have a broader differential. When you apply the percentages from the Gulf Coast ratio to the West Coast, you get a very wildly swinging naphtha price, which I thought was not particularly attractive, and we can show you the results of that. So that concerned me as not being very stable.

Id. (quoting Transcript at pp. 11086-87).

2382. According to Williams, the Exxon interpolation proposal should be dismissed as the "disingenuous" proposal it is. Williams Reply Brief at p. 101. In fact, it asserts that the only valid aspect of the Exxon proposal is that, through this proposal, Exxon concedes that crude oil prices on the two coasts have equalized. *Id.* This proposal, like Tallett's regression analysis, incorrectly assumes that processing margins between feedstocks and finished products (in this case unleaded gasoline and crude oil) are identical (the same interpolation percentage) on the Gulf Coast and West Coast, according to Williams. *Id.* at p. 104. Sanderson testified, it states, that his major problem with Tallett's proposal is that Tallett is using finished products rather than intermediate products. *Id.* at pp. 104-05. In fact, Williams claims, Sanderson went on to testify that the similarity in crude oil prices on the two coasts supports use of the Gulf Coast heavy naphtha value on the West Coast. *Id.* at p. 106-07.

2383. Further, Williams explains, Sanderson considered the possibility of starting with a finished product and LSR. Williams Initial Brief at p. 85. However, it notes, using a finished product has some of the same problems that Sanderson noted in other proposals, primarily that part of the refining margin from the selected product to Naphtha would be inappropriately attributed to the value of Naphtha. *Id.* Thus, Williams states, no satisfactory result was ever achieved using various Quality Bank prices. *Id.*

F. APPLICABILITY OF PLATTS HEAVY NAPHTHA PRICE

1. TAPS Carriers

2384. According to the TAPS Carriers, two decisions of the Quality Bank Administrator regarding Naphtha valuation are at issue: (1) the February 2003 change to the Gulf Coast reference price for Naphtha; and (2) the June 18, 2003 averaging proposal. TAPS

Carriers Reply Brief at p. 2. According to them, the Quality Bank Administrator is an independent neutral expert who attempts to resolve the issues in accordance with his best professional judgment, and the Commission should give due weight to his expertise, neutrality, and "broad authority" to manage the Quality Bank in evaluating criticisms of his decisions by parties with a financial interests in the impact of these decisions. *Id.*

2385. On February 11, 2003, note the TAPS Carriers, the Quality Bank Administrator determined that it was necessary to change the Gulf Coast reference price used to value the Naphtha component. TAPS Carriers Initial Brief at p. 14. They note that both Toof and Sanderson agreed with the Quality Bank Administrator's decision to use the Heavy Naphtha price assessment rather than the Full Range Naphtha price assessment. *Id.* at p. 15.

2386. The TAPS Carriers assert that no evidence was submitted challenging the decision of the Quality Bank Administrator to use Platts Gulf Coast waterborne price assessment for Heavy Naphtha to value the Naphtha component on both the Gulf Coast and the West Coast. TAPS Carriers Reply Brief at p. 2. Nonetheless, state the TAPS Carriers, two parties submitted criticisms of the Quality Bank Administrator's decisions: Unocal/OXY and Petro Star. *Id.* at p. 3. According to the TAPS Carriers, Unocal/OXY oppose the use of the Heavy Naphtha price assessment because: (1) the old Naphtha quote is still available and no implementation problems were presented; (2) the Gulf Coast price overvalues West Coast Naphtha; and (3) the changes have the effect of freezing the prior month's value in place until the issue is resolved. *Id.* at pp. 3-4. They point out that this ignores the fact that the Commission directed the Quality Bank Administrator to use Platts Gulf Coast Naphtha price to value the Quality Bank Naphtha component, and that when Platts began publishing a second assessment for Naphtha in February, 2003, the Quality Bank Administrator had to make a decision as to which price to use. *Id.* at p. 3. Further, the TAPS Carriers state, because the publication of a second Naphtha price assessment was unanticipated and the prior orders of the Commission did not provide guidance to follow, the Quality Bank Administrator used the authority contained in Item III.J. of the Tariff to choose the price that best reflected the value of Quality Bank Naphtha in the Gulf Coast market. *Id.*

2387. By criticizing the Quality Bank Administrator's action for allegedly overvaluing West Coast Naphtha, the TAPS Carriers state, Unocal/OXY are implying that the lower of the two available prices should have been chosen to avoid overvaluing Naphtha. *Id.* at pp. 3-4. They maintain that the Quality Bank Administrator lacks the authority to make that determination. *Id.* at p. 4. Instead, explain the TAPS Carriers, the Quality Bank Administrator was required to pick the price that best matched the specifications of the Quality Bank Naphtha component, and there is no dispute, according to the TAPS Carriers, that he did so. *Id.*

2388. Finally, the TAPS Carriers point out, Unocal/OXY's concern over the freezing in place of the prior month's value would be accurate only if the Quality Bank Administrator had acted under Item III.G.5.b., the provision dealing with a change in the basis for a price assessment. *Id.* In this case, they note, the new price assessment was effective when proposed by the Quality Bank Administrator until changed prospectively by order of the Commission. *Id.*

2389. Petro Star, according to the TAPS Carriers, argues that the Quality Bank Administrator exceeded his authority by acting under Item III.J. *Id.* at p. 5. The TAPS Carriers state that Petro Star does not consider that the publication of the new price by Platts can create an unanticipated implementation issue when the previously used price is still being published. *Id.* They declare that Petro Star is incorrect, and assert that it was clearly unanticipated that Platts would begin to publish two prices and that, even though the Commission had previously approved use of a Gulf Coast Naphtha price, the Quality Bank Administrator clearly had to pick one of the two. *Id.* Further, note the TAPS Carriers, the choice had to be made based on the Quality Bank Administrator's best understanding of the intent of the Commission. *Id.* at pp. 5-6. The TAPS Carriers argue that, by picking Platts Heavy Naphtha assessment, the Quality Bank Administrator fulfilled his obligations, because the Heavy Naphtha specifications more closely match the specifications of Quality Bank Naphtha. *Id.* at p. 6. In the TAPS Carriers's view, the arguments of Petro Star and Unocal/OXY that the Quality Bank Administrator should not have done so would effectively read Item III.J. out of the Tariff. *Id.*

2390. At the June hearing, according to the TAPS Carriers, the principal issue of controversy among the parties was whether Platts Heavy Naphtha assessments should be adjusted by adding 1.5¢/gallon to reflect the higher N+A content of the Naphtha component of ANS. TAPS Carriers Initial Brief at p. 15. They point out that the Quality Bank Administrator did not believe he had authority to make such a change. *Id.* Further, state the TAPS Carriers, the Quality Bank Administrator took no position on whether the Commission should or should not add 1.5¢/gallon to the published Heavy Naphtha price assessment. *Id.*

2391. The TAPS Carriers state that Platts announced on February 5, 2003, that it would begin publishing an assessment for waterborne Heavy Naphtha on the Gulf Coast, with the new price effective February 3, 2003. *Id.* According to them, the Quality Bank Administrator decided to use Platts new Heavy Naphtha price assessment for purposes of the Quality Bank effective March 1, 2003. *Id.* The TAPS Carriers assert that it was not necessary for the Quality Bank Administrator to give serious consideration to postponing use of the Heavy Naphtha price assessment because of Platts's experience in getting prices for Heavy Naphtha transactions on the Gulf Coast and its confidence in its assessments. *Id.* at pp. 15-16. Thus, in the TAPS Carriers's view, it was clearly reasonable for the Administrator to choose March 1, 2003, as the effective date of the change to the Gulf Coast Heavy Naphtha price. *Id.* at p. 16.

2392. The Quality Bank Administrator's June 18, 2003, Notice raises two issues, in the views of the TAPS Carriers, under Item III.G.5.b. of the TAPS Quality Bank Methodology Tariff: (1) was the basis for the Heavy Naphtha price assessment "radically altered" after May 1, 2003; and, if so, (2) is the replacement product price proposed by the Quality Bank Administrator appropriate? TAPS Carriers Supplemental Brief at p. 9. If the answers to those questions are "yes," then the TAPS Carriers assert that the Quality Bank Administrator's proposal should be adopted effective August 17, 2003, to value the Naphtha component (1) on the Gulf Coast and (2) on the West Coast for any period for which a Gulf Coast price assessment is used, either permanently or on an interim basis, to value the Naphtha component on the West Coast. *Id.* at pp. 9-10.

2393. The TAPS Carriers state that parties have offered two criticisms of the Quality Bank Administrator's June 18, 2003, proposal. TAPS Carriers Reply Brief at p. 8. First, they argue that the Heavy Naphtha price assessment has not been "radically altered," and, second, they argue that the Quality Bank Administrator's proposed replacement price is not "appropriate." *Id.* The TAPS Carriers's position is that the Commission should reject the criticisms of the Quality Bank Administrator proposed replacement product price to value the Naphtha component, because they are not consistent with existing Quality Bank methodology or with the parties's pending proposals. *Id.*

2394. It is beyond dispute, state the TAPS Carriers, that the basis for the Heavy Naphtha quotation has been altered. TAPS Carriers Supplemental Brief at p. 10. Prior to May 1, they explain, Platts Heavy Naphtha price assessment was an overall assessment of the waterborne market, which included both cargo and barge transactions. *Id.* This is clear, note the TAPS Carriers, from all three memoranda of conversations with Sharp, an employee of Platts. *Id.* (citing Exhibit Nos. TC-20 through 22). For example, the TAPS Carriers note, in the September 15, 2003, conference call in which representatives of other parties participated in addition to the Quality Bank Administrator, Sharp stated that earlier Heavy Naphtha assessments were a general market assessment, neither solely cargo nor solely barge. *Id.* Indeed, Sharp "stated that during the initial three months of the assessment, he sometimes used barge transactions for the high for the day and cargo transactions for the low." *Id.* (quoting Exhibit No. TC-22 at pp. 1-2). In contrast, assert the TAPS Carriers, it is uncontested that after May 1, despite the fact that the name did not change, the "Heavy Naphtha" price assessment covered only transactions in cargo lots and the "Heavy Naphtha Barge" price assessment covered only transactions in barges. *Id.* at pp. 10-11.

2395. In arguing that there has been no radical alteration of the basis for the Heavy Naphtha price assessment, the TAPS Carriers state, Williams relies on conclusory statements by Sharp that, prior to May 1, the Heavy Naphtha price assessment was "primarily a cargo number" and "consistent with the current cargo assessment." TAPS Carriers Reply Brief at p. 9. When Toof sought clarification from Sharp, it appeared that the principal basis for Sharp's opinion was that he saw little quantitative difference between the Heavy Naphtha price assessment before and after May 1. *Id.* The TAPS Carriers assert that in deciding whether the basis for a price assessment has been "radically altered," the Quality Bank Administrator should not consider the financial impact of the change in the basis for the price assessment. *Id.*

2396. The TAPS Carriers argue that Toof's further questions clarified Sharp's position and made it clear that the basis for the Heavy Naphtha price assessment had in fact been radically altered. *Id.* They note that, prior to May 1, 2003, Platts Heavy Naphtha price assessment reported a range of prices that covered the entire waterborne market for Heavy Naphtha on the Gulf Coast, with barge transactions on the high end and cargo transactions on the low end. *Id.* at pp. 9-10. Further, the TAPS Carriers point out, the Quality Bank methodology uses the average of the daily highs and lows reported by Platts. *Id.* at p. 10. Therefore, they state, the Quality Bank Administrator's proposal to average the Heavy Naphtha assessment (now purely a cargo assessment) and the Heavy Naphtha Barge assessment is a reasonable attempt to approximate the results of the Heavy Naphtha price assessment prior to May 1, 2003. *Id.* Indeed, assert the TAPS Carriers, it is the best available approximation, given the information available. *Id.*

2397. Because it is beyond dispute that the basis for the Heavy Naphtha price assessment was "altered" after May 1, 2003, the TAPS Carriers state, it is difficult to see how an argument that it was not "radically altered" can be successful. TAPS Carriers Supplemental Brief at p. 11. In effect, according to the TAPS Carriers, Platts bifurcated the prior Heavy Naphtha price assessment into two price assessments, each assessing a portion of the market that had been taken into account in the prior Heavy Naphtha assessment. *Id.* Since Platts used the term "Heavy Naphtha" to report prices in different markets before and after May 1 (all waterborne transactions versus only cargo transactions), the TAPS Carriers assert, the change in the basis for those prices is properly characterized as "radically altered." *Id.*

2398. In the two instances in which bifurcation of an existing price assessment has occurred in the past, the TAPS Carrier state, the Quality Bank Administrator also concluded that "the specifications or other basis for the remaining quotation(s)" have been "radically altered" and proposed a replacement product price. *Id.* In both cases, noted the TAPS Carriers, the Commission accepted, subject to the outcome of the pending litigation, the Quality Bank Administrator's conclusion that the bifurcation constituted a radical alteration in the basis for the price quotation and the Quality Bank Administrator's recommended replacement product price. *Id.* at pp. 11-12. For example, note the TAPS Carriers, a similar situation arose with respect to the gas oil component: On December 1, 1997 OPIS announced, through the OPIS overnight fax service, that beginning, January 1, 1998, it would cease to report a single price range for High Sulfur VGO on the Gulf Coast and instead would report separate price ranges for barge and cargo. *Id.* at p. 12. According to the TAPS Carriers, the Quality Bank Administrator concluded that, in that case, the basis for one of the remaining price quotations had been radically altered. *Id.* He, therefore, proposed an appropriate replacement product price, which, state the TAPS Carriers, was accepted by the Commission subject to the outcome of the pending litigation. *Id.* (citing *Trans Alaska Pipeline System*, 83 FERC ¶ 61,083 (1998)).

2399. Similarly, continue the TAPS Carriers, in September 1996 the Quality Bank Administrator concluded that the basis for the quotation used to value the LSR component on the Gulf Coast had been radically altered. *Id.* The TAPS Carriers explain that the Tariff had specified that the LSR component would be valued on the Gulf Coast using Platts Mont Belvieu, Texas, spot quote for natural gasoline. *Id.* Platts began reporting two natural gasoline quotes at Mont Belvieu – Natural Warren and Natural Non-Warren. *Id.* According to the TAPS Carriers, the Commission accepted the Quality Bank Administrator's proposed replacement product price subject to the outcome of the pending litigation. *Id.*

2400. The TAPS Carriers note that Sharp tended to downplay the significance of the change in the Heavy Naphtha assessment. *Id.* at p. 13. Thus, according to the TAPS Carriers, he stated that the difference between the old and the new (0.5¢/gallon) is insignificant. *Id.* Sharp, apparently, based that opinion, state the TAPS Carriers, on what he believed to be the quantitative difference in the size of the old and new Heavy Naphtha price assessments. *Id.* They assert, however, that the financial impact of a change in the basis for a price assessment should not be the ground upon which the Quality Bank Administrator decides whether the basis for a price assessment has been "radically altered." *Id.*

2401. In the first place, argue the TAPS Carriers, the Tariff gives no basis for suggesting that the Quality Bank Administrator should consider the financial impact on one or more shippers when making his decisions under Item III.G.5.b. *Id.* Moreover, they continue, there can be no assurance that the difference between the price of Heavy Naphtha in the Gulf Coast cargo market and the price of Heavy Naphtha in the overall Gulf Coast waterborne market (cargo plus barge transactions) will continue to be half a cent per gallon. *Id.* The TAPS Carriers point out that markets change over time in unpredictable ways in response to changes that cannot be anticipated. *Id.* It would be unreasonable, they assert, to adopt a rule that, in effect, requires the Quality Bank Administrator to predict future price behavior when determining whether the basis for a price quotation has been "radically altered." *Id.* According to them, the fact that prices are being quoted from a different market should be sufficient for the Quality Bank Administrator to conclude that the basis for those price quotations has been "radically altered." *Id.*

2402. Even were the Tariffs interpreted to require the Quality Bank Administrator to undertake a quantitative analysis when deciding whether the basis for a price quotation had been radically altered, they argue, he would be required to conclude that such a radical alteration had occurred with respect to the Heavy Naphtha price assessment. *Id.*

at p. 14. The TAPS Carriers explain that Sharp estimated that the difference in the Heavy Naphtha price assessment before and after May 1 was approximately a 0.5¢/gallon or 21¢/barrel. *Id.* In their opinion, the only comparable benchmark of economic significance in the Quality Bank Methodology Tariff is in Item III.F.3.c.(ii). *Id.* The TAPS Carriers note that one of the tests in the Item for whether the Quality Bank Administrator must investigate the validity of a monthly sample of a stream is whether the volume change in the specific component has resulted in a significant change in the stream's relative value when compared to the prior month's relative value using the prior month's prices. *Id.* If, state the TAPS Carriers, the change results in a price movement of more than ± 15¢/barrel, then the sample's validity must be investigated. *Id.* Thus, according to the TAPS Carriers, a variation in value of 15¢/barrel is apparently considered significant for purposes of the Quality Bank. *Id.* Should quantitative factors be considered, the TAPS Carriers suggest that Sharp's estimate of a 21¢/barrel difference in the value of a barrel of Heavy Naphtha should not be ignored. *Id.*

2403. The TAPS Carriers state that Unocal/OXY's argument, that the basis for the Heavy Naphtha price assessment has not been radically altered because the previous Heavy Naphtha cargo quote has not been discontinued, is not valid either. TAPS Carriers Reply Brief at p. 10. They assert that focusing on the name of the price assessment rather than its content is elevating form over substance. *Id.* It is uncontested, according to the TAPS Carriers, that, prior to May 1, 2003, the price assessment labeled "Hvy Naphtha" reported transactions in both the cargo and barge markets; after May 1, the name did not change, but only cargo transactions were reported under that name. *Id.* In fact, note the TAPS Carriers, the Heavy Naphtha assessment, as it had existed prior to May 1 (an assessment of both cargo and barge transactions), ceased to be reported by Platts on May 1. *Id.* Two new assessments – one for cargo transactions and one for barge transactions – took its place. *Id.* The TAPS Carriers state that the fact that Platts chose to use the name "Hvy Naphtha" to describe the price assessment for cargo transactions does not change the fact that the basis on which it reported price assessments for waterborne Heavy Naphtha had been radically altered. *Id.* at pp. 10-11.

2404. Once the Quality Bank Administrator determined, the TAPS Carriers continue, that the basis for the Heavy Naphtha price assessment had been "radically altered," he was required to "notify the [Commission] . . . and all shippers of this fact and propose an appropriate replacement product price, with explanation and justification." TAPS Carriers Supplemental Brief at p. 14 (quoting Exhibit No. TC-3 at p. 7). They note that Sharp pointed out that transactions for Heavy and Full Range Naphtha, for both barge and cargo lots, exist, although he did indicate that barge transactions may predominate. *Id.* at p. 15. Further, state the TAPS Carriers, Sharp was not able to provide a detailed report of the transactions, although transactions for barge and cargo lots are representative of the market for Heavy Naphtha on the Gulf Coast. *Id.*

2405. According to the TAPS Carriers, it would be arbitrary to choose as the replacement price the assessments for only one of the two markets. *Id.* They claim that there is no logical reason or factual basis for choosing the price assessments for either cargo transactions or barge transactions as representative of the entire market for Heavy Naphtha on the U.S. Gulf Coast. *Id.* A simple average of the prices in both markets will come much closer, in the opinion of the TAPS Carriers, to capturing the value of Heavy Naphtha on the Gulf Coast. *Id.*

2406. When making his recommendation in the June 18, 2003, Notice, the TAPS Carriers state, the Quality Bank Administrator pointed out that there was only a superficial similarity to the bifurcation of High Sulfur VGO prices into barge and cargo transactions by OPIS in 1998. *Id.* at p. 17. In this case, the TAPS Carriers assert, in contrast to that situation, "both the barge and cargo markets appear to be active, and neither appears to be more representative of the Gulf Coast market for Heavy Naphtha." *Id.* (quoting Exhibit No. TC-19 at p. 5). Thus, conclude the TAPS Carriers, there is no reasonable basis for ignoring a major and representative portion of the Gulf Coast market for Heavy Naphtha. *Id.*

2407. The TAPS Carriers assert that, contrary to the views of some of the parties, the use of an average of two prices to value a component is an integral and consistent part of the Quality Bank methodology. TAPS Carriers Reply Brief at p. 11. For example, state the TAPS Carriers, for each reference price the Quality Bank averages the high and low price for each day and then averages the daily averages to obtain a monthly price for each component on the Gulf Coast and the West Coast. *Id.* at pp. 11-12. In addition, note the TAPS Carriers, a location factor is then used to calculate a weighted average of the Gulf Coast and West Coast prices for each component. *Id.* at p. 12. The TAPS Carriers note that the location factor is based on averaging shipment data obtained from the Maritime Administration over a six-month period to determine the percentage of ANS being transported to the Gulf Coast and the West Coast. *Id.* Further, continue the TAPS Carriers, the gravity differential used for the Valdez quality bank is calculated from the averages of the gravity differentials for several companies and then weighted using a location factor to arrive at the overall differential. *Id.* Finally, conclude the TAPS Carriers, the Nelson Farrar Index used to adjust the size of the deductions in the pricing basis for the Light Distillate, Heavy Distillate and Resid components is developed by calculating annual averages of the monthly refinery operating inflation factors. *Id.*

2408. It is true, the TAPS Carriers concede, as some of the opposing parties point out, that prior to the Commission's accepting the Quality Bank Administrator's recommendation with respect to the valuation of the Naphtha component, none of the Quality Bank components was valued by using an average of two reference price assessments in the same region (Gulf Coast or West Coast). *Id.* at pp. 12-13. However, they point out that no decision of the Commission has ever adopted that as a policy. *Id.* at p. 13. Moreover, continue the TAPS Carriers, although Naphtha is currently the only component that is valued using an average of two reported price assessments, all parties support the adoption of a method for valuing the Resid component that will use a weighted average of nine reported price assessments. *Id.* In addition, explain the TAPS Carriers, several of the parties's proposals for valuing the Naphtha component on the West Coast are based on the weighted average of reported prices. *Id.* Thus, in arguing that it is inconsistent with the Quality Bank convention to use a simple average of two price assessments, the TAPS Carriers assert that opponents of the Quality Bank Administrator's proposal are themselves inconsistent with their own proposals to the Commission. *Id.*

2409. Finally, state the TAPS Carriers, Williams and Unocal/OXY argue that approval of the use of an average of two prices would open the door for a continuing series of changes for a component's valuation. *Id.* According to them, this ignores the fact that the Quality Bank Administrator is charged with proposing a replacement price only in the narrow circumstances presented by Item III.G.5.b. – when the basis for an existing price is radically altered. *Id.* The TAPS Carriers point out that the Quality Bank Administrator has no authority to propose a replacement product price (whether an average of two price assessments or a single price assessment) in the many cases in which the Commission has approved the use of a single price assessment to value a component and the basis for that price assessment has not been radically altered. *Id.* at pp. 13-14. Moreover, note the TAPS Carriers, on only one occasion in the ten years that the current methodology has been in effect did the Quality Bank Administrator propose the use of an average of two prices. *Id.* at p. 14. Thus, assert the TAPS Carriers, the great risk of complication that Williams and Unocal/OXY purport to fear is purely imaginary. *Id.*

2410. The TAPS Carriers state that some parties believe that using Platts Heavy Naphtha Barge price assessments is inconsistent with a Quality Bank convention of using only cargo transactions or transactions in the largest parcels available. *Id.* Explain the TAPS Carriers, the Commission has never approved any such "convention," and the price assessments currently being used by the Quality Bank do not support the existence of any such convention. *Id.* For example, they state, the gas oil component is valued on both the Gulf Coast and West Coast using a price assessment for barge High Sulfur VGO. *Id.* Further, note the TAPS Carriers, all parties have agreed that the gas oil component on the West Coast should be valued using the OPIS West Coast High Sulfur VGO price assessment, which includes both barge and cargo transactions. *Id.* In addition, they state, the Resid component is valued on the West Coast using a pipeline price assessment despite the fact that there are West Coast waterborne, i.e., cargo price assessments for heavy (No. 6) fuel oil. *Id.* at p. 15. All parties also agree, according to the TAPS Carriers, that the best base price to use to value the Heavy Distillate component on the West Coast is the pipeline price assessment for Low Sulfur Diesel (formerly Low Sulfur No. 2) despite the fact that there is also a price assessment for waterborne Low Sulfur gasoil on the West Coast, which is essentially the same product. *Id.*

2411. Thus, the TAPS Carriers argue, the convention to which some parties refer simply does not exist. *Id.* In their opinion, the goal should not be to comply with a non-existent convention, but to choose a price assessment (whether a single price assessment or an average) that best represents the market price of the product in question. *Id.*

2412. Some parties, state the TAPS Carriers, suggest that the Quality Bank Administrator's recommendation to average the Heavy Naphtha and Heavy Naphtha Barge price assessments is inconsistent with his prior recommendation with respect to the gas oil component on the Gulf Coast. *Id.* According to them, this is not correct. *Id.* In both the gas oil and LSR situations, the price assessments were bifurcated, explain the TAPS Carriers, and the Quality Bank Administrator concluded that as a result of such a bifurcation "the specifications or other basis for the remaining quotation(s)" had been "radically altered," and the Commission accepted that recommendation. *Id.* at pp. 15-16.

2413. The TAPS Carriers argue that Petro Star expressly conceded the correctness of the Quality Bank Administrator's decision that bifurcation of the prior High Sulfur VGO price assessment constituted a radical alteration of the basis for the price assessment and, therefore, implicitly concedes that the Quality Bank Administrator's decision with respect to the Heavy Naphtha price quotation was also correct. *Id.* at p. 16. In the case of both the High Sulfur VGO price assessment and the Heavy Naphtha price assessment, according to the TAPS Carriers, the reporting service decided to quote separate price assessments for "barge" and "cargo." *Id.* Thus, in both cases, claim the TAPS Carriers, the basis for the preexisting price quotation was radically altered and the Quality Bank Administrator was required to act. *Id.*

2414. Some parties also suggest, according to the TAPS Carriers, that the Quality Bank Administrator was inconsistent in recommending, as the replacement product price, an average of the two new prices following bifurcation rather than recommending only one of them, as he did in the two prior cases. *Id.* In fact, assert the TAPS Carriers, the Quality Bank Administrator has been completely consistent. *Id.* In each of the two prior cases, explain the TAPS Carriers, he considered recommending an average of the two new prices following bifurcation, but rejected that option because it was clear that one of the two new markets being assessed was much more liquid than the other and that price assessments of that market would be more representative of the value of the product at issue. *Id.* at pp. 16-17. In contrast, the TAPS Carriers argue, in this case both markets are active and neither appears to more representative of the Gulf Coast market for Heavy Naphtha. *Id.* at p. 17. Moreover, state the TAPS Carrier, the fact that prior to May 1 the Heavy Naphtha assessment reported "cargo [transactions] typically on the low end and barge transactions on the high end," suggests that an average of the cargo and barge transactions would be the most accurate representation of the market value of Heavy Naphtha on the Gulf Coast. *Id.*

2415. In the view of the TAPS Carriers, there is no basis for any of the allegations of sloppy work that Williams leveled against the Quality Administrator. *Id.* The TAPS

Carriers state that Williams never specifies what additional investigation it believes the Quality Bank Administrator should have undertaken. *Id.* Nor, according to the TAPS Carriers, does it specify what data it considers "necessary," or whether such data are in fact available. *Id.* Moreover, continue the TAPS Carriers, Williams identifies no factual inaccuracies in the Quality Bank Administrator's explanation of the reasons for his recommendation. *Id.* Because Williams waived a hearing on the issues raised by the Quality Bank Administrator's recommendation, the TAPS Carriers point out that he had no opportunity to respond to these allegations. *Id.*

2416. The TAPS Carriers assert that there is certainly no reason to believe that Williams's investigation was more thorough than the investigation undertaken by the Quality Bank Administrator. *Id.* For example, note the TAPS Carriers, as late as August 26, 2003, on the basis of its investigation, Williams apparently believed that prior to May 1, 2003, the Heavy Naphtha price assessment was solely a cargo price, a claim that it abandoned after further conversations with Sharp. *Id.* at pp. 17-18. Moreover, continue the TAPS Carriers, at the time of the final conversation with Sharp, Williams's representative was apparently under the impression, on the basis of his prior investigation, that there was great significance to the code number assigned to the Heavy Naphtha price assessment, a theory that Sharp firmly rejected. *Id.* at p. 18.

2417. In any event, according to the TAPS Carriers, the criticisms of the Quality Bank Administrator's investigation, in addition to being baseless and unfair, are simply irrelevant. *Id.* When Williams requested that there be further conversations with Sharp, the TAPS Carriers point out that the Quality Bank Administrator readily agreed; in the last of those conversations Williams's representative participated and was allowed to ask any questions he wished. *Id.* Following those conversations, note the TAPS Carriers, Williams stipulated that a hearing would not be necessary to resolve the issues raised by the Quality Bank Administrator's June 18, 2003, Notice and that the Commission could resolve those issues based on the record in this proceeding, including the Quality Bank Administrator's notes of the conversations with Sharp. *Id.* Thus, the TAPS Carriers argue, Williams simply has no basis to complain that all facts relevant to a decision on the Quality Bank Administrator's recommendation have not been fully developed. *Id.*

2418. Should the Commission adopt a new methodology for valuing the Naphtha component on the West Coast, the TAPS Carriers state that the Quality Bank Administrator's proposal for valuing the Naphtha component on the Gulf Coast will have effect only as an interim pricing methodology (if the Exxon proposal to adopt a new West Coast methodology retroactively is accepted) or for a relatively brief period until a new methodology is adopted for valuing Naphtha on the West Coast (if one of the proposals for prospective adoption of a West Coast methodology is accepted). TAPS Carriers Supplemental Brief at p. 17.

2419. The TAPS Carriers note that the Commission accepted the Quality Bank

Administrator's proposed replacement product price to be effective August 17, 2003. *Id.* at pp. 17-18 (citing *Trans Alaska Pipeline System*, 104 FERC ¶ 61,201 at P 9 (2003)). The choice of that date, according to the TAPS Carriers, is consistent with the scheme laid out in the TAPS Quality Bank Methodology Tariff. *Id.* at p. 18. Item III.G.5.b. of the Tariff states that if the Commission "take[s] no action within 60 days of the filing, the replacement product price proposed by the Quality Bank Administrator will become effective as of the sixtieth day." *Id.* (quoting Item III.G.5.b.; *see also* Exhibit No. TC-3 at p. 7).

2420. There is no reason, declare the TAPS Carriers, to change the August 17, 2003, effective date. *Id.* They maintain that should be the effective date of the Quality Bank Administrator's proposal for valuing the Naphtha component on the Gulf Coast as well as the effective date of the Quality Bank Administrator's proposal for valuing the Naphtha component on the West Coast, subject to whether the Commission decides to adopt a new methodology for valuing Naphtha on the West Coast and the effective date they choose for any such new methodology. *Id.*

2. Unocal/OXY

2421. On February 27, 2003, explains Unocal/OXY, pursuant to Item IIIG.5.b. of the TAPS Quality Bank Methodology Tariff, the Quality Bank Administrator filed a "Notice Regarding Proposed Replacement Product Price To Value Naphtha Component on the U.S. Gulf Coast and U.S. West Coast" with the Commission. Unocal/OXY Initial Brief at p. 43. According to them, issues raised by the filing include whether the Quality Bank Administrator should continue to use Platts "Naphtha" price assessment, or whether he should use a new "Heavy Naphtha" assessment, whether, if the "Heavy Naphtha" assessment is used, it should be further modified to include an "N+A" adjustment, and what the effective date of any change should be. *Id.* at p. 44.

2422. Unocal/OXY explain that the Quality Bank Administrator proposed to change the reference price for Gulf Coast Naphtha that currently is used to value both the Quality Bank Naphtha cuts. *Id.* Rather than use the Platts reported price for Full Range Gulf Coast Naphtha as the value for both Gulf and West Coast Naphtha, Unocal/OXY state, the Quality Bank Administrator proposes to use a Platts Gulf Coast price for Heavy Naphtha effective March l, 2003, on the grounds that Heavy Naphtha is closer in quality to the Quality Bank Naphtha cut. *Id.* (citing Exhibit No. PAI-222 at p. 2).

2423. The Quality Bank Administrator, Unocal/OXY claim, acted under the authority of Section III.J of the TAPS Quality Bank Tariff, which states that, in case of an unanticipated issue, the Administrator is authorized to act in accordance with its best understanding of the intent of the Commission. *Id.* at pp. 44-45. According to them, all matters touching upon the Quality Bank methodology and its implementation are contentious, and no TAPS shipper is entirely neutral on even minor matters. *Id.* at p. 45.

Further, state Unocal/OXY, matters concerning Naphtha, the cut at issue with the March 1, 2003, change, are at the forefront of the ongoing disputes. *Id.* Under these circumstances, Unocal/OXY advocate that a conservative reading of Section III.J is warranted. *Id.*

2424. Unocal/OXY oppose the change to the "Heavy Naphtha" price quote for three reasons. *Id.* First, because the old Naphtha quote is still available, Unocal/OXY asserts, no implementation problems are presented by the advent of the new Heavy Naphtha quote. *Id.* They explain that nothing occurred to prevent or frustrate the continued use of the old price so the Quality Bank Administrator did not actually face a problem that required resolution at this time. *Id.* Instead, note Unocal/OXY, the Administrator could have continued use of the old price and thereby left any interested party who preferred the use of the new price the option of initiating a change by filing a complaint with the Commission. *Id.*

2425. Second, Unocal/OXY state, virtually all Quality Bank Naphtha is presently landed on the West Coast, and the Gulf Coast price is used to value the West Coast Naphtha. *Id.* They assert that the record indicates that the Gulf Coast price overvalues West Coast Naphtha. *Id.* Unocal/OXY explain that the overvaluation is caused by the presence of petrochemical demand on the Gulf Coast, but not on the West Coast, and stringent CARB gasoline regulations on the West Coast, but not on the Gulf Coast. *Id.* at pp. 45-46. According to Unocal/OXY, these two facts depress the value of West Coast Naphtha relative to the Gulf Coast price. *Id.* at p. 46. Consequently, Unocal/OXY's position is that the Gulf Coast price should not be adjusted in any manner that would increase the current valuation of West Coast Naphtha. *Id.*

2426. Third, Unocal/OXY note that pricing changes initiated by the Quality Bank Administrator have the effect of freezing in place the prior month's value until the issues raised by the Quality Bank Administrator initiative are resolved by the Commission. *Id.* They maintain that the Quality Bank Administrator should be discouraged from making changes that have this effect unless they cannot be avoided. *Id.*

2427. Unocal/OXY note that a memorandum from the Quality Bank Administrator recording a telephone conversation with Platts states that Platts adjusts prices reported to it to N+A 40, "using a value of .15 cents per % per gallon up to an N+A of 50." *Id.* (citing Exhibit No. PAI-222 at p. 8). In their comments on the Quality Bank Administrator's notice, continue Unocal/OXY, Exxon and Phillips have proposed that the Quality Bank Administrator adjust Quality Bank Naphtha in a similar manner. *Id.* Unocal/OXY point out that the Exxon and Phillips proposal would further increase the price of West Coast Naphtha. *Id.*

2428. According to Unocal/OXY, Sorenson, a refinery engineer with the Phillips's Los Angeles refinery, testified that such an adjustment would be warranted because high N+A

Naphtha is in great demand on the West Coast and the higher N+A that characterizes Quality Bank Naphtha would command a price premium. *Id.* Unocal/OXY contend that Sanderson opposes any N+A adjustment because: (1) an N+A adjustment would afford the Naphtha cut inconsistent treatment as other prices used for Quality Bank cuts are not adjusted for quality parameters; (2) the presence of tight air quality restrictions on aromatics penalizes the production of benzene, and high N+A Naphtha produces benzene; and (3) the market does not normally price adjust for N+A. *Id.* at p. 47. Further, Unocal/OXY note, Sarna, a chemical engineer, testified that high N+A is undesirable because it produces toxic emissions in gasoline, which California Air Resources Board regulations are designed to limit. *Id.*

2429. The record demonstrates, Unocal/OXY assert, that high N+A Naphtha has been devalued by the advent of California Air Resources Board regulations in California. *Id.* They claim that Sorenson's approach to N+A can be explained by the very substantial capital improvements undertaken at his refinery to deal with excess benzene. *Id.* Accordingly, Unocal/OXY argue, from a technical standpoint, adjusting the TAPS Naphtha value upward to account for higher N+A would not be warranted because its high N+A content decreases its value. *Id.* at pp. 47-48. Also, from a legal and procedural standpoint, according to Unocal/OXY, the N+A issue opens up the issue of intra-cut quality that the parties deferred by stipulation. *Id.* at p. 48.

2430. Unocal/OXY note that one of the offsetting cut quality adjustments addressed in testimony that was deferred was an N+A adjustment for Naphtha. *Id.* This and other potential adjustments were raised in order to illustrate that the particular quality adjustments pursued by Exxon were selectively raised to benefit Exxon, assert Unocal/OXY, and they claim that numerous other adjustments were possible. *Id.* In Unocal/OXY's view, the N+A adjustment proposed is simply a back door attempt to get a quality adjustments that was deferred at the front door. *Id.* Unocal/OXY's position is that in order to maintain consistency in the way different cuts are treated, the proposed N+A adjustment must be rejected.[716] *Id.*

2431. Unocal/OXY's position is that any resolution as to the applicability of the Heavy Naphtha price should be implemented as of March 1, 2003, the date that the Quality Bank Administrator made his change effective. *Id.* Further, they assert, any change ordered with respect to an N+A adjustment should be implemented prospectively from the date of decision. *Id.*

2432. To the extent that refunds are ordered back to March 1, 2003, according to Unocal/OXY, the only thing that can be refunded is the amount of any increase over the previously effective rate that the Commission determines to be unjust and unreasonable.

[716] On reply, Unocal/OXY state that they also adopt the arguments on this point set out in Williams's Initial Brief. Unocal/OXY Reply Brief at p. 86.

Unocal/OXY Reply Brief at pp. 86-87. They assert that there is no authority under Section 15(6) of the Interstate Commerce Act (49 U.S.C. App. § 15(7)(1988)), to order shippers to pay any such refunds. *Id.* Unocal/OXY state that any refund order can be issued to the TAPS Carriers and can only order the refund of amounts collected since the suspension order was issued that are ultimately determined to be excessive. *Id.* That means, according to Unocal/OXY, that the only parties eligible for refunds under Section 15(7) are parties who paid into the Quality Bank, and they are entitled to refunds only of increased assessments they paid subsequent to March 1, 2003. *Id.* Unocal/OXY maintain that there is no authority under Section 15(7) to order a recalculation of Quality Bank debits and credits beyond the limited scope of refunds described above. *Id.*

2433. In the June 18, 2003, Notice, Unocal/OXY explain, the Quality Bank Administrator cited the provision of Section IIIG.5.b that permits him to select a new product price if the "specifications or other basis for the remaining quotation(s) is radically altered." Unocal/OXY Supplemental Brief at p. 2 (citing Exhibit No. TC-19 at p. 3). Further, note Unocal/OXY, the Quality Bank Administrator claimed that Platts quoting of a new price series for “Heavy Naphtha Barge” was a radical alteration. *Id.* at pp. 2-3. Finally, state Unocal/OXY, the Quality Bank Administrator explained that both ship cargo prices, for volumes up to 250,000 barrels, and barge cargo prices, typically 50,000 barrels, were included in the Heavy Naphtha quote prior to May 1, 2003, and that after May 1, the Heavy Naphtha quote was used solely for cargo quotes and the separate Heavy Naphtha Barge quote solely for barge volumes. *Id.* at p. 3.

2434. In Unocal/OXY’s view, the Quality Bank Administrator's averaging proposal is an unnecessary and unwarranted complication to the pricing of the Naphtha cut. *Id.* First, they state, nothing has happened that requires the Quality Bank Administrator to make a change of any kind. *Id.* Unocal/OXY point out that the previously existing price has not been discontinued, and it is not clear that it has been radically altered. *Id.* The previous Heavy Naphtha quote experienced a slight change, but according to Unocal/OXY, certainly not a significant enough change to require that action be taken by the Quality Bank Administrator. *Id.* Second, continue Unocal/OXY, the proposal would treat the Naphtha cut in a manner that is inconsistent with the treatment of other Quality Bank cuts, as averaging of posted prices for different quotes is not done for any of the other cuts. *Id.* Accordingly, Unocal/OXY’s position is that the proposal set forth in the Notice should be rejected, and the Quality Bank Administrator should be required to continue using the “Naphtha” or “Heavy Naphtha” assessment alone, without averaging the “Barge” quote. *Id.*

2435. Prior to March 1, 2003, explain Unocal/OXY, the TAPS Quality Bank used a single price assessment of Platts published as “Naphtha” to value both the Gulf Coast and West Coast portions of the Naphtha cut, which encompasses the boiling range of 175°F to 350°F. *Id.* at pp. 3-4 (citing Exhibit No. TC-3 at p. 11). As a result, continue Unocal/OXY, the Quality Bank Administrator changed the reference price to “Heavy

Naphtha," a new price published in addition to general "Naphtha." *Id.* at p. 4 (citing Exhibit No. PAI-222 at p. 2). They note that the Commission accepted the change and allowed it to take effect subject to refund. *Id.* Thus, state Unocal/OXY, the proposal of June 18, 2003, is the second change in the Naphtha cut reference price by the Quality Bank Administrator in less than four months. *Id.*

2436. The pricing change now proposed is discretionary, in Unocal/OXY's view, and not required by factual changes. *Id.* at p. 5. According to them, the effect of the first change, which substituted the Platts Waterborne Heavy Naphtha price quote for the Full Range Waterborne Naphtha quote, was to increase the value of the Waterborne Naphtha cut by approximately 1¢/gallon. *Id.* (citing Exhibit No. TC-18, Exhibit Nos. EMT-642, WAP-265). The effect of the second change, according to Unocal/OXY, is to add another increase of 0.5¢/gallon. *Id.* (citing Exhibit No. TC-19 at p. 6).

2437. While the magnitude of the difference between barge and cargo price quotes is not large, Unocal/OXY assert, accepting the Notice would impact the parties to this case unequally. *Id.* They explain that parties whose Naphtha cuts are proportionally larger than that in the common stream will benefit, while those whose cuts are smaller will be harmed. *Id.* Unocal/OXY note that they, Petro Star, and Williams are among the parties who will be harmed by allowing the proposed change to take effect, whereas Exxon and Phillips will be benefited. *Id.* at pp. 5-6. Under such circumstances, Unocal/OXY argue, the Quality Bank Administrator should initiate action to change a reference price only when compelled to do so, and the Commission should provide instructions to the Quality Bank Administrator precluding the imposition of entirely discretionary changes that impact shippers non-uniformly. *Id.* at p. 6.

2438. Because they claim that the currently proposed change is discretionary, Unocal/OXY's position is that it should not be approved. *Id.* They argue that the Quality Bank Administrator's proposal is based on an erroneous interpretation of the Tariff. *Id.* Unocal/OXY points out that the language at issue states: "If . . . *the specifications or other basis for the remaining quotation(s) is radically altered*, the Quality Bank Administrator shall notify the [Commission] and all shippers of this fact and propose an appropriate replacement product price, with explanation and justification." *Id.* (quoting Exhibit No. TC-3 at p. 7, Section lII.G.5.b) (emphasis added by Unocal/OXY). Interpreting the italicized phrase in the context in which it appears, Unocal/OXY assert, it is clear that the change in the Heavy Naphtha price referenced by the Quality Bank Administrator was not a radical alteration. *Id.* According to them, accepted maxims of tariff construction, which are summarized in *Trans Alaska Pipeline System*, 57 FERC 63,010 at p. 65,041 (1991), require such a conclusion. *Id.* They note that in *Penn Central Co. v. General Mills, Inc.*, 439 F.2d 1338, at pp. 1340-1341 (8th Cir. 1971) the Circuit Court stated that "a tariff is no different from any contract," and "its true application must sometimes be determined by the factual situation upon which it is sought to be impressed." *Id.*

2439. Further, state Unocal/OXY, tariffs are to be interpreted "strictly against the carrier," and are to be given a reasonable construction "to avoid unfair, unusual, absurd or improbable results." *Id.* at pp. 6-7 (quoting *Penn Central*, 439 F.2d at p. 1341). In interpreting a tariff, Unocal/OXY assert, its terms must be taken in the sense in which they are generally used and accepted, and it must be construed in accordance with the meaning of the words used. *Id.* at p. 7. Unocal/OXY also point out that a tariff is not an abstraction, and the factors and purposes of the terminology must be considered to avoid making adjudication "an exercise in semantics." *Id.* (quoting *United States v. Western Pacific R. Co.*, 352 U.S. 59, at p. 67 (1956)).

2440. Applying these "maxims of tariff construction," Unocal/OXY argue, the language of the highlighted phrase in the Tariff should be construed in the context provided by the phrase preceding it, with due consideration given to the Platts reporting practices. *Id.* In other words, Unocal/OXY claim, the phrase "radically altered" follows, and is used in association with, the phrase "no longer quoted," therefore, it should take a narrowly circumscribed meaning, limited to a change that would be substantial enough to preclude the continued use of the reference price, just as when a price is no longer quoted. *Id.* Accordingly, because the previous Heavy Naphtha price is still published, Unocal/OXY assert, there would be a "radical alteration" only if the values reflected in that price were changed so substantially that the price could no longer be used. *Id.*

2441. Unocal/OXY's position is that the Quality Bank Administrator's showing does not meet this test. *Id.* They note that the Quality Bank Administrator explains that, according to Platts, the Heavy Naphtha assessment prior to May 1, 2003, included both barge and cargo transactions, and that after May 1, 2003, "Platts has now elected to report the barge and cargo transactions separately." *Id.* (quoting Exhibit No. TC-19 at pp. 3-4). Thus, explains Unocal/OXY, the "Heavy Naphtha" assessment is now, according to the Quality Bank Administrator, limited to cargo transactions.[717] *Id.* at pp. 7-8. They state that there is only a one cent difference between cargo and barge assessments, and the remedy proposed by the Quality Bank Administrator (averaging of barge and cargo) would reduce that difference to one half of one cent. *Id.* at p. 8. Furthermore, Unocal/OXY point out that the Quality Bank Administrator has conceded that there are

[717] Unocal/OXY note that they have recommended the continued use of "Naphtha" in lieu of "Heavy Naphtha." Unocal/OXY Supplemental Brief at p. 8, n.3. They explain that what is said here about Heavy Naphtha applies equally to Naphtha. *Id.* As shown on Exhibit TC-19 at 6, explain Unocal/OXY, the Naphtha assessment also has an associated Naphtha Barge assessment. *Id.* Like Heavy Naphtha, Full Range Naphtha has a "Naphtha" price limited to cargo transactions, and a "Naphtha Barge" price limited to barge transactions. *Id.* Thus, should the Commission determine to continue the Naphtha reference price, Unocal/OXY's position is that it should use the cargo price and not the Naphtha Barge assessment. *Id.*

transactions for the sale of Heavy Naphtha in both barge and cargo lots on the Gulf Coast. *Id.* Accordingly, Unocal/OXY argue, there is no showing that the continued Heavy Naphtha assessment has been radically altered, or that it no longer is a viable reference price due to its being based on too few transactions. *Id.*

2442. Lending support to this conclusion, in Unocal/OXY's view, is the evidence that the previously assessed Heavy Naphtha price was already heavily weighted toward cargo transactions, and that the initiation of a parallel barge quote, therefore, did not change the prior Heavy Naphtha assessment to any significant degree. *Id.* at pp. 8-9 (citing Exhibit No. TC-22). Further, Unocal/OXY indicate, the record reflects that, in the earlier Heavy Naphtha assessment, barge transactions were taken into account, and that Sharp stated "there definitely had been a change" in this price after May 1, 2003. *Id.* at p. 9 (quoting Exhibit No. TC-22 at p. 2). Unocal/OXY also assert that evidence related to other cuts shows that the change from barge to cargo pricing is not radical. *Id.* (citing Exhibit Nos. UNO-59, UNO-62; Transcript at pp. 11533-35, 11976-79). While the difference between the Exhibits is not perceptible, Unocal/OXY point out, Exhibit No. UNO-59 carries a table that shows the difference caused by switching from barge to cargo, a difference that ranges from 0 to 0.85¢/gallon.[718] *Id.* Similarly, explain Unocal/OXY, Exhibit No. TC-19 indicates that the differences between the barge and cargo Platts quotes for Heavy Naphtha prices are of the same magnitude. *Id.* Given that the pricing change for the different quotes is not large, that the practice of quoting both barge and cargo prices is not unusual, and that the previous Heavy Naphtha cargo quote has not been discontinued, Unocal/OXY's position is that adding a barge quote for Heavy Naphtha is not a radical change. *Id.* at pp. 9-10. The change proposed by the Quality Bank Administrator should, therefore, be rejected, in the view of Unocal/OXY, and he should be instructed to continue the previous reference price without the proposed change. *Id.* at p. 10.

2443. Unocal/OXY assert that the proposal set forth in the Notice would afford inconsistent treatment to the Naphtha cut. *Id.* They point out that the averaging of different price quotes is not used for any other cut, notwithstanding that there are multiple price postings similar to those published for Naphtha for several other cuts. *Id.* For example, explain Unocal/OXY, VGO has prices assessed for both barge and cargo on the

[718] More specifically, of the 25 data points shown in Exhibit UNO-59 at p. 2, nine show that the change made no difference, 13 showed that the difference between Gulf Coast and West Coast narrowed because the OPIS Gulf Coast High Sulfur VGO cargo assessment was lower by between .082¢/gallon and 1.034¢/gallon than the previous assessment, and on only two occasions did the Gulf Coast High Sulfur VGO assessment increase, once by .155¢/gallon and once by .855¢/gallon. Unocal/OXY appears to wish to ignore the instances where the replacement reference price caused the value of Gulf Coast VGO to go down relative to its value on the West Coast, perhaps because they do not wish to call attention to the fact that the difference is not as imperceptible as they argue.

Gulf Coast. *Id.* However, the barge and cargo prices for VGO are not averaged; instead, note Unocal/OXY, the barge assessment is used. *Id.* (citing Exhibit No. TC-3 at p. 12). They explain that the current price used for VGO was approved by the Commission in 1998. *Id.* (citing *Trans Alaska Pipeline System*, 82 FERC ¶ 61,343 (1998)). In the notice that preceded that order, state Unocal/OXY, the Quality Bank Administrator also claimed that the addition of a barge price quote, in this case by OPIS instead of Platts, was a radical alteration. *Id.* (citing Exhibit No. TC-23 at p. 4). Unocal/OXY point out, in the case of VGO, the Quality Bank Administrator proposed using only the barge quote because there were only a few, isolated cargo transactions in VGO. *Id.* Thus, note Unocal/OXY, as distinguished from the facts of the Heavy Naphtha situation, the Quality Bank Administrator concluded that the price change was radical because it rendered the previously used price for VGO unreliable, while the new VGO Barge price "would probably be more representative of the High Sulfur VGO market value on the Gulf Coast." *Id.* at pp. 10-11 (citing Exhibit No. TC-23 at p. 4).

2444. The issue of using an average for the VGO price, Unocal/OXY point out, was considered and rejected because there was no data on which to base a weighting of the two prices, and "[t]here is no reason to believe that a simple arithmetic average would accurately reflect the market price." *Id.* at p. 11 (citing Exhibit No. TC-23 at p. 5). In contrast, when it came to Heavy Naphtha, Unocal/OXY note, the same facts applied, but the Quality Bank Administrator reached a different result. *Id.* (citing Exhibit No. TC-19 at p. 4).

2445. In addition to VGO and Naphtha, Unocal/OXY state, there are multiple prices quoted for other cuts, yet the Quality Bank Administrator has not suggested that averaging should be used for the other reference prices. *Id.* They explain that this is true for the Heavy Distillate, Resid, and LSR cuts. *Id.* at pp. 11-12 (citing Exhibit Nos. TC-3, TC-19, WAP-262). Therefore, Unocal/OXY argue, averaging the Heavy Naphtha assessments is inconsistent with the pricing used for these other cuts. *Id.* at p. 12.

2446. Also, Unocal/OXY note, the convention used in the Quality Bank has been to choose the largest available quantities for valuing each cut. *Id.* (citing Exhibit No. BPX-1 at p. 16). They explain that the Heavy Naphtha assessment is the largest quantity for Naphtha, as it is based on cargo lots of up to 250,000 barrels, whereas barge lots are considerably smaller, typically 50,000 barrels. *Id.* (citing Exhibit No. TC-19 at p. 3). In Unocal/OXY's view, averaging the barge and cargo prices breaches this principal and affords inconsistent treatment to the Naphtha cut. *Id.*

2447. It is the position of Unocal/OXY that the Gulf Coast Naphtha price should continue to be used to value the West Coast cut. *Id.* In Unocal/OXY's view, their argument regarding the inappropriateness of averaging barge and cargo quotes applies equally to the West Coast. *Id.* It is their position that the Full Range Naphtha price should be used, as it has in the past, to value both the Gulf Coast and West Coast cuts, and that the barge assessment should not be used. *Id.* In addition, should the Commission approve the switch to the Heavy Naphtha price, Unocal/OXY state, that price should be used without any consideration of the Heavy Naphtha Barge price. *Id.*

2448. Unocal/OXY note that the Commission's order accepting the Quality Bank Administrator's proposal made the proposed change effective August 17, 2003, subject to refund. *Id.* at p. 13. Because the proposal is subject to refund, Unocal/OXY explain that the new averaging proposal took effect on August 17, 2003, and remains in effect until changed by the Commission in the final order resolving this case. *Id.* Hence, according to Unocal/OXY, the effective date for the change, if approved by the Commission, is August 17, 2003. *Id.*

2449. Under section 15(7) of the ICA, 49 U.S.C. App. §15(7)(1988), Unocal/OXY assert, the Commission can grant refunds for that part of a carrier-initiated rate that constitutes an increase over the previously effective rate. *Id.* (citing *OXY*, 64 F.3d at pp. 698-99; *Buckeye Pipe Line Co*., 13 FERC ¶ 61,267 at p. 61,595 (1980)). Accordingly, should the Commission not approve the proposal to average the barge and cargo quotes, Unocal/OXY argue, shippers who paid higher Quality Bank assessments as a result of the change that took effect on August 17, 2003, will be entitled to a refund for the increased amount they paid. *Id.*

3. Petro Star

2450. Petro Star believes that use of the Platts Gulf Coast Heavy Naphtha price is suitable to value Gulf Coast Naphtha, although it suggests that the TAPS Quality Bank Administrator exceeded his authority by unilaterally changing to the new quotation. Petro Star Initial Brief at p. 25. It further states that use of the new quotation would be appropriate for use in Dudley’s methodology, which Petro Star has proposed as the best alternative should the Commission determine that Gulf Coast pricing no longer should be used for West Coast Naphtha. *Id.* However, it would be unfair, Petro Star submits, to impose an N+A adjustment on the Gulf Coast, and even more unfair to impose one on the West Coast for the reasons asserted by Williams and Unocal/OXY. *Id.* Moreover, Petro Star asserts, any change to the Naphtha valuation is subject to the Joint Stipulation that the effective date for any new Naphtha price should be the same as the effective date for using the West Coast VGO reference price. *Id.* at p. 26.

2451. According to Petro Star, the specifications for Platts Gulf Coast Heavy Naphtha assessment appear to better match the 175°F – 350°F boiling range of Quality Bank Naphtha. *Id.* However, Petro Star does not agree that it was proper for the Quality Bank Administrator to unilaterally determine to put the new reference price into effect. *Id.* It notes that, in his February 27, 2003, filing, the Quality Bank Administrator explained that he perceived that the Platts announcement of the new Heavy Naphtha quotation created an “unanticipated implementation issue,” that he had concluded that “it is more consistent" with the intent of the Commission to use the new quotation rather than the one that had been approved by the Commissions, and that he had determined to make the new quotation effective on March 1, 2003, two days later. *Id.*

2452. There was no evidence, according to Petro Star, that the Full Range Naphtha quotation already in use had changed. *Id.* It notes that the Quality Bank Administrator's telephone conversation with Sharp indicated that it had not, and asserts that the new Heavy Naphtha quotation was an additional quotation that the Quality Bank Administrator believed was more appropriate than the one in use. *Id.*

2453. According to Petro Star, the Quality Bank Administrator took action under Tariff Item III.j, which authorizes him to resolve unanticipated issues concerning implementation of a methodology. *Id.* at pp. 26-27. Petro Star does not agree that mere publication of a new quotation can create an unanticipated implementation issue. *Id.* at p. 27. When the language in Item III.j was drafted, Petro Star states, there had never been a distillation methodology used by the TAPS Quality Banks, all the "facilities and technical and contractual arrangements required to implement the Assay Methodology" had to be put in place, and temporary Quality Bank debits and credits needed to be calculated and then replaced when the new methodology was implemented. *Id.* (quoting *Trans Alaska Pipeline System*, 65 FERC at p. 62,286). Moreover, continues Petro Star, other well-known distillation methodologies had been agreed to rather than imposed, so there was no history to indicate that implementing a distillation methodology would be easy. *Id.* Petro Star asserts that, instead, there was ample reason to be concerned that a truly unanticipated issue could arise that would prevent the new methodology from being implemented unless the Quality Bank Administrator had discretion to deal with it. *Id.* It argues that didn't happen here. *Id.* According to Petro Star, the existing Naphtha reference price continued on unchanged. *Id.* Had the Quality Bank Administrator not acted unilaterally, claims Petro Star, the Quality Bank would have continued to function precisely as it had before. *Id.*

2454. Petro Star recommends that any change in the West Coast Naphtha price (including any change that is accomplished by alteration of the Gulf Coast Naphtha price) should have an effective date consistent with the parties's Joint Stipulation that any new valuations for West Coast Naphtha and West Coast VGO have the same effective date. *Id.* at pp. 27-28. All parties have agreed on the appropriateness of using the OPIS West Coast high sulfur VGO price to value West Coast VGO on the West Coast since the first round of testimony. *Id.* at p. 28. Consequently, Petro Star asserts that it would be unfair to allow the Quality Bank Administrator's action to accelerate the Naphtha timetable relative to the VGO timetable and thereby avoid the parties's Stipulation. *Id.* Petro Star states that the parties's Stipulation thus should control if, and to the extent that, any new Naphtha price is adopted to value West Coast Naphtha. *Id.*

2455. In addition, contrary to the arguments presented by Exxon and Phillips (joined by

Alaska), Petro Star believes that any N+A adjustment to Naphtha prices, if made at all, only can be made prospectively from the date of the final Commission decision. Petro Star Reply Brief at p. 28. It states that both Exxon and Phillips argue that a March 1, 2003, effective date would be consistent with *OXY*, but, according to Petro Star, they appear to base their position on the Commission's acceptance of the TAPS Carriers's tariff filings effective March 1, 2003, subject to refund, in which the TAPS Carriers proposed to apply the newly-reported Platts Gulf Coast Heavy Naphtha price in the valuation of Naphtha in the Quality Bank. *Id.* at pp. 28-29. Petro Star asserts, however, that Exxon and Phillips cannot evade the fact that the N+A adjustment was not requested by the Carriers in their tariff filings as accepted and suspended by the Commission in *BP Pipelines (Alaska) Inc. Id.* at p. 29. Rather, explains Petro Star, Phillips and Exxon requested the N+A adjustment in their protests to the Carriers's tariff filings. *Id.* Therefore, argues Petro Star, Exxon's and Phillips's position is inconsistent with the requirement in Section 15(7) of the Interstate Commerce Act which authorizes the Commission "to require the interested carrier or carriers . . . to refund, with interest . . . such portion of such increased rates or charges as by its decision shall be found not justified." *Id.* at pp. 29-30 (quoting 49 U.S.C. App. § 15(7)(1988)). Thus, explains Petro Star, the statute provides for refunds only in the case of rate changes filed by carriers. *Id.* at p. 30.

2456. When carriers initiate a rate change, Petro Star states, it triggers the Commission's Section 15(7) suspension power; it does not trigger a free-for-all. *Id.* Petro Star notes that the Circuit Court in *OXY* explained by saying that:

> In their 1989 filing, the TAPS Carriers proposed increases in the Quality Bank adjustments; they did *not* propose a change in the gravity methodology. Thus while it was entirely proper for the Commission to consider the proposed adjustments under the provisions of section 15(7) and, if warranted, to order refunds, the gravity methodology could not be subject to those proceedings because it remained the established method of calculating Quality Bank credits and debits.

Id. (quoting 64 F.3d at pp. 699-700) (emphasis in original). In the 1989 proceedings that led to *OXY*, explains Petro Star, the Carriers filed a tariff change increasing the gravity differential. *Id.* Notes Petro Star, OXY and Phillips challenged the new gravity filings and, in addition, sought relief from the Carriers's acceptance of natural gas liquids in the petroleum shipped through TAPS. *Id.* In the instant proceeding, continues Petro Star, the Carriers filed proposed changes to the reference price to be used for Gulf Coast Naphtha, and Exxon and Phillips (although they didn't challenge the proposed changes) sought to institute a wholly new N+A adjustment. *Id.* Thus, according to Petro Star, Exxon's and Phillips's position here is analogous to Conoco's and OXY's request in 1989 for relief from the Carriers's acceptance of natural gas liquids, not Conoco's and OXY's challenge to the Carriers's proposed increase in the gravity adjustment. *Id.*

2457. As a result, Petro Star states, in the *OXY* proceedings, refunds would have been limited to overpayments made because of the increased gravity differential. *Id.* at p. 31. It states that the resulting net payments would have been within the bounds set by the gravity differential in effect before the change and the changed differential. *Id.* Petro Star's position is that this should be the case here. *Id.* It notes that the Commission did not accept the N+A adjustment effective March 1, 2003, nor did it accept it subject to refund. *Id.* Petro Star asserts that refunds back to the March 1, 2003 suspension date should be within the bounds established by the prior Naphtha valuation, Gulf Coast Naphtha, and the change filed by the TAPS Carriers, Gulf Coast Heavy Naphtha. *Id.* It is Petro Star's position that Exxon's and Phillips's N+A position would require refunds well outside these bounds without any justification at all. *Id.* In addition, states Petro Star, retroactive application of the N+A adjustment, if adopted, would be inequitable to refiners for the reasons outlined in Issue 5 of the Eight Parties's Briefs on this issue. *Id.*

2458. On June 18, 2003, states Petro Star, the Quality Bank Administrator filed a notice with the Commission in which he proposed a replacement product price to value the Naphtha component on both the Gulf Coast and the West Coast. Petro Star Supplemental Brief at p. 2. After considering comments, notes Petro Star, the Commission accepted the proposed replacement product price, effective August 17, 2003, subject to the outcome in the pending Quality Bank proceedings. *Id.* Petro Star supports the arguments made by Williams on the proposed replacement product price to value Naphtha. *Id.* In addition, for the following reasons, Petro Star opposes the Quality Bank Administrator's proposal to value Gulf Coast Naphtha, and by extension West Coast Naphtha, as the arithmetic average of the average monthly price for Gulf Coast Waterborne "Heavy Naphtha" and Gulf Coast Waterborne "Heavy Naphtha Barge" as reported by Platts. *Id.* at p. 2-3. Petro Star does not agree that the Quality Bank Administrator has demonstrated there has been a "radical alteration" in the Platts Gulf Coast Heavy Naphtha assessment. *Id.* at p. 3. It states that, according to conversations with Sharp, it appears that the prior "Heavy Naphtha" quote did encompass data pertaining to both cargos and barge lots, but was weighted toward cargos, and that the current "Heavy Naphtha" quote covers only cargos, with barge lots now having their own new quote. *Id.* (citing Exhibit TC-22 at pp. 1-2). Moreover, in Petro Star's view, it appears highly questionable whether the change justifies the solution proposed by the Quality Bank Administrator. *Id.*

2459. Petro Star points out that a situation arose in 1998 with regard to the VGO cut that, "superficially," was similar. *Id.* A comparison to that situation is useful here, states Petro Star, because, at that time, the Quality Bank Administrator provided guidance as to the quality of data that would be needed to justify using an average of two quotes. *Id.* It explains that, while the tariff provided for use of the OPIS U.S. Gulf Coast spot quote for High Sulfur VGO, there was no doubt that the High Sulfur VGO was discontinued when OPIS announced that it would quote separate price changes for barge and cargo High Sulfur VGO. *Id.* at pp. 3-4. Petro Star concedes that, in that case, the Quality Bank

Administrator had to act. *Id.* at p. 4. Because there were significant periods of time when no cargo transactions took place, Petro Star explains, the Quality Bank Administrator decided that the OPIS barge spot quote would best represent the High Sulfur VGO market on the Gulf Coast. *Id.* In reaching that conclusion, Petro Star states, the Quality Bank Administrator considered and rejected the use of both a weighted and a simple average of the two new quotations, because there was not enough data to support a weighted average and an arithmetic average was not considered representative of the market price. *Id.* Thus, in 1998, it explains, the Quality Bank Administrator apparently preferred to use a weighted over an arithmetic average, but the necessary data were not available. *Id.*

2460. Nothing in the Notice which the Quality Bank Administrator filed with the Commission, declares Petro Star, or in the telephone conversation logs submitted as Exhibits TC-20 through TC-22, indicates that, with regard to averaging, the situation is any different today than it was in 1998. *Id.* at p. 5. It points out that, according to Sharp, the unadorned Heavy Naphtha quote previously weighted cargo more heavily and could be correctly described as primarily a cargo assessment. *Id.* (citing Exhibit Nos. TC-21, TC-22 at p. 1). Further, notes Petro Star, Sharp reported having sometimes used barge quotes for the high prices for a day and cargo for the low prices. *Id.*

2461. It is difficult, Petro Star submits, to see how arithmetically averaging the new "Heavy Naphtha Barge" quote with the "Heavy Naphtha" quote is consistent with the descriptions of the Heavy Naphtha quote previously being weighted towards cargo lots. *Id.* According to Petro Star, barge lots – with their higher prices – would have a greater impact than they did before. *Id.* Further, Petro Star contends, the weighted average approach is no more promising: Even though barge transactions may slightly predominate, it maintains, on average, they involve only about 20% of the volume that cargo transactions do, and Sharp was unable to provide any detailed breakdown of the transactions. *Id.* (citing Exhibit TC-20 at p. 1).

2462. Petro Star contends that, like the Quality Bank Administrator's decision to use the Heavy Naphtha quotation, the decision to average the "Heavy Naphtha" and "Heavy Naphtha Barge" quotations is not required or authorized by the Tariffs. *Id.* at pp. 5-6. Here, explains Petro Star, although the publication of the "Heavy Naphtha Barge" quotation affected the "Heavy Naphtha" quotation by removing the relatively minor influence of barge lot data, it did not radically alter the "Heavy Naphtha" quotation. *Id.* at p. 6.

4. BP

2463. BP notes, it agrees that Platts Heavy Naphtha's specifications are more in line with the specifications for Quality Bank Naphtha. BP Initial Brief at p. 65. Moreover, BP points out, all of the parties have agreed that the Platts Heavy Naphtha price should be used. *Id.* Consequently, it is BP's position that the Platts Heavy Naphtha price is the appropriate price to use for valuing Gulf Coast Naphtha. *Id.*

2464. Exxon and Phillips, BP contends, each argue that Platts Heavy Naphtha assessment should be adjusted upwards by 1.5¢/gallon (based on a 0.15¢ adjustment for each increase in N+A above 40 to a maximum of 50 N+A) to take into account the difference between the N+A content of Platts Heavy Naphtha and the N+A content of naphtha contained in ANS crude. *Id.* (citing Transcript at pp. 13339-40). Using assays in the record, BP explains, the Quality Bank Administrator has stated that the N+A content of ANS is roughly 55 and there has not been a material change in its N+A content since 1993. *Id.* at pp. 65-66 (citing Exhibit No. PAI-222 at p. 7).

2465. BP points out that, whereas Platts in its Naphtha assessment clearly delineates a 40 N+A content, the Platts Heavy Naphtha assessment is silent on its N+A content. *Id.* at p. 66. Without clear proof of the N+A content of the Platts Heavy Naphtha quote, BP argues, assumptions regarding its N+A content and adjustments to the Naphtha price based on those assumptions are inappropriate. *Id.*

2466. It further argues that, because the Quality Bank has used an unadjusted Platts Naphtha assessment to value the ANS Naphtha cut for ten years, it would be inappropriate to now make an N+A adjustment. *Id.* at p. 67. According to BP, there is nothing different about the use of the Platts Heavy Naphtha assessment that leads to the conclusion that an N+A adjustment is needed in the Quality Bank in order to value the naphtha cut. *Id.* Moreover, BP points out that there also has been no material change in the N+A content of ANS Naphtha over time. *Id.* Consequently, it is BP's position that no justification exists for making an N+A adjustment for Naphtha in these proceedings, assuming the current specification, Platts Heavy Naphtha, contains the same N+A as the past specification, Platts Naphtha. *Id.*

2467. BP asserts that an N+A adjustment is unnecessary to ensure that the Quality Bank values Naphtha appropriately nor does it assist in valuing each Quality Bank component at a market price. *Id.* It disagrees with Exxon and Phillips that the N+A adjustment is needed in order to meet the Circuit Court's requirement that the Commission "must accurately value all cuts – not merely some or most of them – or it must overvalue or undervalue all cuts to approximately the same degree." *Id.* (citing *OXY*, 64 F.3d at p. 693); *see also* BP Reply Brief at p. 77. Instead, according to BP, the logic of *OXY* cuts squarely against it. BP Initial Brief at p. 68.

2468. The Circuit Court, BP claims, established a relative standard in its *OXY* decision. *Id.* In order to comply with the Circuit Court's decision, BP states, the Commission must look to the valuation of all of the Quality Bank cuts to determine if they are being overvalued or undervalued to approximately the same degree. *Id.* It maintains that the N+A adjustment that Exxon and Phillips recommend would treat Naphtha differently than any other cut, and asserts that making an adjustment would not lead to consistency in valuation; in BP's view, it would lead to inconsistency. *Id.*

2469. BP explains that the proposed N+A adjustment adds an additional level of analysis to only the Naphtha cut. *Id.* At present, notes BP, there is only one type of adjustment made to reference prices – those cost-based adjustments that are needed to bring finished product reference prices back to the intermediate products that they are intended to value. *Id.* For example, continues BP, the Light Distillate cut is valued using the price of jet fuel, a finished product, minus the cost that would be associated with processing ANS light distillate, an intermediate product, to final product status. *Id.* (citing *Exxon,* 182 F.3d at p. 35).

2470. Similarly, according to BP, the proposed Heavy Distillate cut reference price deductions are designed to account for costs that would be necessary to process the intermediate ANS Heavy Distillate into the quality of finished product that can be sold on the West Coast and Gulf Coast. *Id.* Other than these processing adjustments, however, BP claims, no other adjustments are made to the price assessments used to value the various Quality Bank cuts.[719] *Id.* at pp. 68-69. BP concludes that the proposed N+A adjustment to Naphtha in no way compares to the necessary processing cost deductions associated with the Light Distillate or Heavy Distillate cuts. *Id.* at p. 69.

2471. BP notes that the proposed N+A adjustment would make an adjustment to an intermediate product reference price – Platts Heavy Naphtha – to value a comparable intermediate product. *Id.* It asserts that that kind of adjustment is not made today to any reference price that is used in the Quality Bank, and notes that Exxon and Phillips each suggested that this change is justified because the industry recognizes that there are value differences among Naphthas with varying N+A contents. *Id.* (citing Transcript at pp. 13213, 13340). BP argues that that argument ignores the basic teaching of the Circuit Court's *OXY* decision – that all cuts have to be valued on a consistent basis. *Id.* In a later decision, according to BP, the Circuit Court reinforced the importance of looking at the valuation of the Quality Bank cuts as a whole rather than on an isolated basis. *Id.* In *Exxon*, BP notes that the Circuit Court rejected Exxon's attempt to suggest that the Commission had violated the *OXY* decision by failing to account for quality differences in the distillate cuts of the streams coming from the different ANS oil fields. *Id.* (citing *Exxon*, 182 F.3d at p. 38). BP points out that the Circuit Court reinforced the importance of focusing on the consistent, relative valuation of the Quality Bank cuts:

[719] BP explains that the Eight Parties's proposed logistics adjustment to the Heavy Distillate cut is different in character than the proposed N+A adjustment, because it does not attempt to value Heavy Distillate according to its individual chemical characteristics, but simply attempts to place Heavy Distillate at a consistent location, waterborne, where the other cuts are valued. BP Initial Brief at p. 69, n.13.

> In *OXY*, we recalled that the goal of the Quality Bank is "to assign accurate *relative* values" to the diverse streams delivered to the pipeline. We vacated in part the last order because the methodology approved therein had favored one class of cuts above others. We remanded in order that [the Commission] might provide a methodology with a reasoned relative uniformity, knowing that absolute precision at any level of the cuts was unachievable. That is, we did not remand because the old method was inaccurate, but because it was unfairly nonuniform.

Id. at pp. 69-70 (quoting *Exxon*, 182 F.3d at p. 38)(emphasis in original, citation omitted).

2472. Were an N+A adjustment made to Naphtha, BP suggests, it would inject another level of analysis and administrative complication into the Quality Bank. *Id.* It points out that those parties who claim that this is not true (for example Phillips) have failed to consider that other intermediate products whose reference prices are used to value Quality Bank cuts also can have variations in value depending on changes in specifications associated with the particular cut. *Id.*; BP Reply Brief at p. 78. To apply the type of approach to other cuts that Exxon and Phillips seek to apply to Naphtha, BP asserts, the Commission would need to examine whether there are differences between the specifications for the reference prices used and the ANS quality for each of the Quality Bank cuts. BP Initial Brief at p. 70. For example, there are other adjustments that could be made to LSR, Naphtha, Light Distillate, Heavy Distillate, VGO, and Resid that would, in BP's opinion, add an entirely new level of complexity to the proceedings. *Id.* at pp. 70-71. Moreover, maintains BP, these other adjustments would need to be considered or the Quality Bank would depart from the consistency in valuation required by *OXY* and *Exxon*. *Id.* at p. 71.

2473. BP disagrees with Phillips's arguments that there is no evidence that Platts makes similar adjustments to other Quality Bank cuts and thus no need to be concerned that an N+A adjustment to Naphtha would require a similar analysis for the other cuts. BP Reply Brief at p. 79. First, BP notes, the only evidence allowed on this point was a listing of other cuts that may need adjustment. *Id.* It asserts that, even standing alone, that list indicates that, were an N+A adjustment made, review of almost all of the remaining cuts will be required to see if similar adjustments should be made. *Id.* Second, as the N+A proposed adjustment occurred mid-hearing, BP explains, a full analysis of the other cuts regarding potential adjustments like an N+A adjustment has not been performed. *Id.* Third, BP points out, the parties opposing the N+A adjustment are not seeking any other adjustments, they simply note that, were an N+A adjustment made, others will need to be considered. *Id.* BP agrees and suggests that if the proposed N+A adjustment was made, it would encourage the parties to seek other adjustments that would be economically advantageous which would lead to prolonged litigation to resolve all the multitude of adjustments that could be made to the other Quality Bank cuts. *Id.*

Finally, even assuming there is no record evidence indicating that other cuts may require similar adjustments, BP contends, it does not mean that such evidence does not exist. *Id*.

2474. Further, BP notes that Platts does not now publish, and never has published, an N+A adjustment. BP Initial Brief at p. 71. It points out that the Quality Bank Administrator's notice, Exhibit No. PAI-222, does not suggest that Platts makes it a practice to survey the market periodically to determine if the N+A adjustment is appropriate or remains appropriate over time; nor is there any suggestion that this is a cost-based adjustment. *Id.* at pp. 71-72. Further, explains BP, Platts does not recommend that its customers apply this, or any other, N+A adjustment when using any Platts Naphtha assessment. *Id.* at p. 72.

2475. The only evidence provided that Platts makes this adjustment, maintains BP, comes from conversations the Quality Bank Administrator, Mitchell, had with Sharp in which Mitchell learned that Sharp makes this adjustment as a rule of thumb. *Id.* BP notes that if Sharp was replaced Mitchell did not know whether his replacement would make the same N+A adjustment. *Id.*

2476. BP asserts that this information is entirely different from the kind of price quotation information that is used to value any of the Quality Bank cuts. *Id.* It states that there is no conclusive proof that Platts includes an N+A adjustment each time a Naphtha price assessment is made, and argues that the record contains only a references to one man's rule of thumb that is not part of the official specifications for Platts. *Id.* BP maintains that this is not the kind of evidence that underlies the other cuts's valuations and is too speculative to justify a departure from past practice by making a new N+A adjustment to the price of Naphtha. *Id.* Accordingly, it is BP's position that it is not appropriate to use this information to make an adjustment to the reference price used to value naphtha. *Id.*

2477. In its reply brief, BP notes, proponents of the N+A adjustment claim that N+A adds value on the West Coast in the same manner that they claim it does on the Gulf Coast and that the N+A adjustment may be needed as a correction. BP Reply Brief at p. 81. BP argues that the proponents of a potential West Coast N+A adjustment fail to recognize that making such an adjustment would be inappropriate on the West Coast for the same reasons it would be inappropriate on the Gulf Coast. *Id.* at pp. 81-82; BP Initial Brief at p. 72.

2478. BP notes that Phillips argues that the N+A adjustment should be made retroactive to March 1, 2003, and that the overall methodologies should be retroactive to March 1, 2003. BP Reply Brief at p. 82. It asserts that both a new Naphtha methodology and any N+A adjustment should be applied only prospectively for the reasons explained regarding Issue Nos. 5 and 9 in the Eight Parties's Initial Brief. BP Initial Brief at p. 73; BP Reply Brief at p. 82. In BP's view, making the Naphtha value retroactive to March 1, 2003, would deviate from the effective date for VGO. BP Reply Brief at p. 82. It notes that the parties have stipulated that the Naphtha and VGO valuations should be effective as of the same date and that it would be inappropriate to have their effective dates differ. *Id.*

2479. On June 18, 2003, BP acknowledges, the TAPS Quality Bank Administrator filed a Notice explaining that there had been a change in the way that Platts provides assessments for its Heavy Naphtha quotations on the Gulf Coast. BP Supplemental Brief at p. 1. Previously, noted BP, Platts had a single assessment for Heavy Naphtha that it called "Heavy Naphtha," which the Quality Bank has used to value naphtha since March 1, 2003, subject to the outcome of the hearing. *Id.* (citing *BP Pipelines (Alaska) Inc.*, 102 FERC ¶ 61,345 at P 13). Now, states BP, Platts has added a second Heavy Naphtha assessment that it calls "Heavy Naphtha Barge."[720] *Id.*

2480. BP claims that, notwithstanding that Platts continues to quote the Heavy Naphtha price that the Quality Bank previously used to value Naphtha, the Quality Bank Administrator has proposed a new Naphtha valuation approach that uses both the Heavy Naphtha and Heavy Naphtha Barge quotations, to wit: taking the average of the Heavy Naphtha and Heavy Naphtha Barge prices each month and using that average as the price for valuing Naphtha on the Gulf Coast and on the West Coast, pending the ultimate resolution of the valuation of West Coast Naphtha. *Id.* at p. 2 (citing Exhibit No. TC-19 at p. 4). It notes that Exxon, Phillips and the TAPS Carriers agree with the use of the averaging proposal, and Williams and Unocal/OXY do not agree. BP Reply Brief at p. 83. BP's position is that the proposed averaging approach is inconsistent with the approach used to value other Quality Bank components in two ways, and therefore, should be rejected. BP Supplemental Brief at p. 2.

2481. First, BP asserts that no other cut in the Quality Bank is valued using the average of more than one reported price. *Id.* If there is a price that can be used to value a Quality Bank component, explains BP, a single price is used. *Id.* It reiterates that choosing to introduce an averaging approach to the valuation of one Quality Bank component, and

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[720] BP claims that there has been no change in the specifications of the Heavy Naphtha product. BP Supplemental Brief at p. 1, n.3. Based on the information available at this time, notes BP, it appears that the specifications of the Heavy Naphtha and Heavy Naphtha Barge products are the same. *Id.* Previously, explains BP, the Heavy Naphtha price was based on both waterborne and barge deliveries, although the evidence does not identify the exact influence that each had on the overall price. *Id.* (citing Exhibit Nos. TC-19 at pp. 3-4, TC-20 at p. 1, TC-21 at p. 1, TC-22 at pp. 1-2). BP states that the change separates the price reported for each. *Id.* According to BP, the Quality Bank Administrator has stated that the Heavy Naphtha assessment reports on the cargo deliveries and the Heavy Naphtha Barge assessment reports on the barge deliveries. *Id.* (citing Exhibit No. TC-19 at pp. 3-4).

not to any other, introduces an unnecessary inconsistency into the Quality Bank. *Id.* Further, BP maintains, it would result in one more issue for the Commission to consider whenever there is a change to a reported price. *Id.*

2482. Second, BP argues, the Platts Heavy Naphtha price is now an assessment of the price of the largest cargoes available, while the Heavy Naphtha Barge price assesses smaller-sized shipments. *Id.* The Quality Bank methodology previously has chosen the largest available quantities for valuing each cut, explains BP, which minimizes possible marketing margins that might be added to prices at lower levels of aggregation. *Id.* BP sees no reason to act differently here. *Id.*

2483. BP's position is that, as Platts continues to publish the Heavy Naphtha price, it sees no reason for a change. *Id.* at pp. 2-3. According to it, the Heavy Naphtha price is consistent with other published prices used in the Quality Bank and the averaged price proposed by the Quality Bank Administrator is not. *Id.* at p. 3.

2484. Supporters of the averaging proposal claim, BP states, that the Quality Bank Administrator was justified in using the averaging proposal, because creation of the new Heavy Naphtha Barge assessment constitutes a radical change. BP Reply Brief at p. 83-84. In its reply brief, BP asserts that this support for the averaging proposal is misplaced. *Id.* at p. 84. Although the Quality Bank Administrator reports that there has been a change in the way Platts does its Heavy Naphtha assessment, BP asserts, the Heavy Naphtha reference price that the Quality Bank Administrator previously had supported as appropriate to value Naphtha continues to be reported and Sharp himself characterized the change as insignificant. *Id.*; BP Supplemental Brief at p. 3. BP alleges that none of the parties challenges the view that the Platts Heavy Naphtha assessment as previously done remains a viable price.[721] BP Reply Brief at p. 84. While the basis is somewhat different now because it reports only cargoes, BP states, the change does not impact the viability or appropriateness of the use of the assessment and is not the type of radical change that should cause a change in the Quality Bank procedure. *Id.*; BP Supplemental Brief at p. 3.

2485. BP asserts that an approach that results from the averaging of two different reference prices is inconsistent with the valuation approach used for other components, and, therefore, is unacceptable. *Id.* As the Circuit Court repeatedly has made clear, argues BP, consistency is an important factor in fashioning the prices used for the various Quality Bank cuts. *Id.* Most recently, for example, BP states the Circuit Court expressed

[721] This claim is somewhat confusing as it is clear that Platts no longer is publishing a Heavy Naphtha assessment as it previously did and is in conflict with BP's recognition that this assessment now only relates to cargoes and not cargo and barge transactions.

the importance of consistency in the TAPS Quality Bank methodology in *Exxon*, explaining that "[a]lthough we recognized that we could not require [the Commission] to achieve a perfect method of valuing petroleum streams . . . we nonetheless held that [the Commission] must be consistent in its methodological choices." *Id.* at pp. 4-5 (quoting *Exxon*, 182 F.3d at p. 35).

2486. Additionally, BP asserts, there is no reason to introduce additional, unnecessary complexity to the Quality Bank when there is a viable reported price. *Id.* at p. 5. BP states that moving away from the use of a single reported price would introduce a potential new issue each time there is a reference price change. *Id.* Adding that complication will impair the consistency of the methodology, BP claims and, in its view, increase the likelihood that issues will be raised in the future related to this and other reference prices, as shippers consider whether the adoption of similarly "averaged" prices may also work to their advantage for other cuts. *Id.*

2487. BP asserts that Exxon recognizes that the averaging proposal is not consistent with how the other Quality Bank cuts are valued. BP Reply Brief at p. 85. It states that Exxon tries to skirt the issue by claiming that this is not important and arguing that the average best represents the market value and that to find otherwise would impose an unduly rigid consistency standard. *Id.* In reply, BP asserts, there is no evidence in the record that indicates that the averaging proposal would be a better representation of the price of Naphtha on the Gulf Coast than using the Heavy Naphtha price alone. *Id.* at p. 86. Second, it states that these arguments fail to justify a departure from the Quality Bank valuation consistency requirements as espoused repeatedly by the Circuit Court. *Id.* Clearly, a minor change in the price assessment for Heavy Naphtha is not a change that would justify departing from the consistency standards emphasized by the Court. *Id.*

2488. BP acknowledges that the Quality Bank Administrator noted that, in an earlier proceeding, the Commission decided to use the barge assessment for Gulf Coast VGO when a cargo assessment also existed. BP Supplemental Brief at p. 6 (citing Exhibit No. TC-19 at pp. 4-5; Exhibit No. TC-23). It states that the situation presented there was different than the one that faces the Commission here. *Id.* In that case, according to BP, the Quality Bank Administrator was told by OPIS that "cargo transactions were infrequent and that barge transactions were more representative of High Sulfur VGO market value." *Id.* (quoting Exhibit No. TC-19 at pp. 4-5).

2489. At that time, BP supported the Quality Bank Administrator's decision to use the reported price, which the Quality Bank Administrator stated was the only accurate and viable measure of the market. BP Supplemental Brief at pp. 6-7. (citing Exhibit No. EMT-257 at p. 7). Here, however, BP claims, there is a choice between two robust, useable price quotations. *Id.* at p. 7. BP argues that the Quality Bank should look to the quotation that will be the truest, and most consistent, measure of the value of Naphtha with the lowest possible marketing margins that would impact the overall value of the product. *Id.* BP's position is that use of the Heavy Naphtha assessment, which focuses on cargoes of Heavy Naphtha, meets that goal. *Id.*

2490. Should the Commission determine that the averaging proposal is appropriate for the valuation of Gulf Coast Naphtha, BP states, the new pricing methodology should become effective on a date consistent with the date on which the claimed change occurred, that is, August 17, 2003. *Id.* It explains that this is because that is the date on which the Commission placed the Quality Bank Administrator's averaging proposal into effect, subject to refund. *Id.* at pp. 7-8 (citing *Trans Alaska Pipeline System,* 104 FERC ¶ 61,201 at P 9).

2491. BP maintains that, should a change be found necessary, this effective date issue becomes largely indistinguishable from the Heavy Distillate effective date issue. *Id.* at p. 8. In each case, explains BP, the Commission will have determined that there was a need to change the valuation of a Quality Bank component based on a change in the reference price used to value the relevant Quality Bank cut. *Id.* In the case of Heavy Distillate, all parties agreed and stipulated to an effective date that corresponds to the date that the reference price change took effect. *Id.* (citing Exxon Initial Brief at p. 151; Eight Parties Initial Brief at p. 133). Should the Commission determine that a change to the Gulf Coast Naphtha reference price is needed, BP states, the implementation of this new Gulf Coast Naphtha reference price should be accomplished in a manner comparable to the implementation of the new Heavy Distillate reference price. *Id.*

5. Williams

2492. Williams notes that Sanderson testified at the hearing that the Platts Gulf Coast Heavy Naphtha (waterborne) price is a suitable price to be used for the Quality Bank Gulf Coast Naphtha component, and it is also a suitable proxy for the Quality Bank West Coast Naphtha component. Williams Initial Brief at p. 85. Further, it asserts that the consistency of the Platts Gulf Coast Heavy Naphtha price is an additional reason for its suitability for Quality Bank purposes. *Id.* at p. 86.

2493. On reply, Williams asserts that it agrees with Unocal/OXY's reasons for opposing use of the Platts Gulf Coast Heavy Naphtha price. Williams Reply Brief at pp. 107-08. It states, while it would agree to using the higher priced assessment, because the increase in value of approximately 1¢/gallon should dispel all issues concerning whether use of the Gulf Coast Naphtha price assessment undervalues the West Coast Naphtha component, the record is clear that it does not. *Id.* at p. 108.

2494. Williams argues that there is no basis for making an N+A adjustment to the Gulf Coast or West Coast Naphtha component for several reasons. Williams Initial Brief at p. 86. First, it states that it would create inconsistency in valuation among the cuts because no other Quality Bank component price is adjusted for a particular quality characterization. *Id.* Second, it contends that the N+A adjustment Platts makes on the Gulf Coast is not a hard and fast formula. *Id.* Third, it maintains that the high levels of benzene, benzene precursors and heavy aromatics make ANS Naphtha less desirable for manufacturing finished gasoline with restriction on benzene content, particularly by the environmentally restricted CARB gasoline on the West Coast. *Id.* Williams notes that the first two reasons apply equally on both coasts, while the latter is more applicable on the West Coast. Williams Reply Brief at p. 109.

2495. Sanderson, Williams argues, testified that, should the Commission approve an N+A adjustment for the Naphtha cut, then, in his opinion, credible arguments could be made for secondary quality adjustments to all the liquid cuts, such as LSR, Naphtha, Light Distillate, Heavy Distillate, VGO and Resid in the Quality Bank and potentially endless litigation. Williams Initial Brief at p. 87. Williams believes that the formulæ proposed in the ExxonMobil Settlement Agreement in 1997 provide the basis for this result. *Id.* It notes that the Settlement contained complicated equations for measuring various quality characteristics of certain cuts, including Naphtha and LSR. *Id.*

2496. The premise, according to Williams, cited by Mitchell from his discussion with Sharp that Platts makes a uniform and consistent N+A adjustment is incorrect based on Sanderson's detailed discussions with Sharp, and thus are not a foundation for an N+A adjustment. *Id.* at p. 88. It notes that Mitchell's own testimony indicated some ambiguity as to whether this adjustment was always made. *Id.* Specifically, Williams claims that Mitchell testified that Platts makes an N+A adjustment, but failed to ask Sharp a number of key questions, such as whether Platts makes this N+A adjustment on every Naphtha price indication at which it looks. *Id.* It notes that Mitchell did state that an N+A adjustment was the only one Sharp indicated ever was made. *Id.* at p. 89.

2497. On the other hand, Williams states, Sanderson specifically asked Sharp questions regarding Platts's practice related to the N+A adjustment during the week before the N+A hearing. *Id.* It points out that Sharp stated, at that time, that the N+A adjustment was not a hard and fast rule, but only an industry rule of thumb, and that he also said that he considers specifications, other than N+A, in making his price assessments, if he can get the information from his industry contacts. *Id.* pp. 89-90. When asked about the range of any N+A adjustment by Platts, Williams indicates, Sharp consistently indicated to Sanderson that the N+A adjustment made by Platts is in the range of 35 to 48. *Id.* at p. 90. It notes that his answer was consistent with the first conversation Sanderson had with Sharp. *Id.*

2498. Furthermore, if the Platts N+A adjustment was an adjustment that was consistently applied by Platts, Williams argues, there would be an objective mention of it in the Platts Guide to Specifications, but there is not. *Id.* In fact, unlike its Full Range Naphtha assessment, Williams states that, for the Heavy Naphtha quote, Platts does not even mention, much less document, that the base N+A level for Heavy Naphtha is 40. *Id.*

The bottom line, according to Williams, is that the Quality Bank Administrator chose not to make any N+A adjustment. *Id.* Further, Williams claims that it appears that the Quality Bank Administrator believes he lacks the authority under the tariff to do so without a Commission order. *Id.* at p. 90-91.

2499. Williams contends that the parties proposing an N+A adjustment for the ANS Heavy Naphtha have ignored the very specific problems with processing ANS Naphtha, its high levels of benzene and benzene precursors. *Id.* at p. 92. It argues that repeated generic technical arguments have been made, or industry "rules-of-thumb" cited, for an N+A adjustment for the Quality Bank Naphtha without regard to the high levels of benzene and benzene precursors in ANS Heavy Naphtha. *Id.* Williams notes that Sanderson clearly described the problem with assigning an N+A adjustment based upon an industry rule-of-thumb to ANS Naphtha with high levels of benzene and benzene precursors on the West Coast. *Id.* According to it, Sanderson's view is that refiners would choose the Naphtha with low or no benzene and benzene precursors, because the yield of aromatics would go up. *Id.* Sarna, Williams adds, likewise described the problems N+A can present for making CARB gasoline as one where there can be excess benzene stemming from an excess of the C_{10} aromatic. *Id.* at p. 93. Thus, Williams contends that refiners try to operate with low levels of benzene in their reformulated gasoline formulations, because taking out the benzene gives a better return on their investment. *Id.*

2500. The record, Williams states, reflects that ANS Heavy Naphtha contains high levels of benzene and benzene precursors compared to other crudes is overwhelming based upon Sarna's testimony and industry articles. *Id.* It states that this is documented by UOP, a well-known technology licensor, in a 1991 technical article titled: "Benzene Reduction Alternatives," which states that it chose a refinery processing ANS crude as a worst case scenario for analyzing benzene reduction strategies. *Id.* at pp. 93-94. Williams notes that Sarna testified that ANS has substantially higher levels of benzene than other commonly processed West Coast crude oils. *Id.* at p. 94.

2501. Except for the change from Platts Gulf Coast Full Range Naphtha price quote that had been used to Platts Gulf Coast Heavy Naphtha (waterborne) price quote that was effective March 3, 2003, by action of the TAPS Carriers through the Quality Bank Administrator, Williams argues, any N+A adjustment can be effective only from the date, if ever, it is adopted by the Commission. *Id.* at pp. 94-95. Williams notes that it was not a change recommended by the TAPS Carriers, and the Quality Bank Administrator chose not to include such an adjustment. *Id.* at p. 95. Therefore, it is Williams's position that it only can have prospective application. *Id.*

2502. In Williams's view, the effect of the Quality Bank Administrator's averaging proposal is to increase the value of the Naphtha component of the Quality Bank. Williams Supplemental Brief at p. 2. It states that, because the Quality Bank

Administrator's notice was simply a recommendation, Section III.G.5.b. of the Tariff provides for shippers to comment on the Quality Bank Administrator's recommendation, and point out that Exxon and Phillips, the two principal advocates of skewed higher West Coast Naphtha price proposals, supported the Quality Bank Administrator's recommendation. *Id.* at pp. 2-3. Williams notes that BP, Petro Star, Unocal/OXY, and Williams opposed the Quality Bank Administrator's proposal. *Id.* at p. 3. Its position is that there is no justification for accepting the Quality Bank Administrator's recommendation on either the Gulf Coast or the West Coast. *Id.*

2503. Williams asserts that there is no valid reason for averaging the two Platts price quotes. *Id.* In fact, it contends, there are compelling reasons why the Quality Bank Administrator's recommendation should be rejected. *Id.* First, it states, Platts's adding the new Gulf Coast Heavy Naphtha Barge price quote does not constitute a "radical alteration" of the pre-existing price quote used to value the Naphtha Component. *Id.* Second, Williams submits, the Quality Bank Administrator's recommendation is inconsistent with the valuation of the other Quality Bank cuts. *Id.* Third, it notes that the Quality Bank Administrator's recommendation introduces a valuation that does not reflect Platts's assessment of the Gulf Coast Naphtha market. *Id.* Fourth, it explains that the Quality Bank Administrator's recommendation is premature at best, because it was not based on any independent analysis of the Gulf Coast naphtha market. *Id.*

2504. The Quality Bank Administrator's rationale for proposing yet another increase in the valuation of the Naphtha component of the TAPS Quality Bank, according to Williams, is that the introduction of the new Platts Heavy Naphtha barge quote constituted a "radical alteration in the basis for reporting one of the products used to calculate the TAPS Quality Bank adjustments." *Id.* (quoting Exhibit No. TC-19 at p. 1). It notes that the Quality Bank Administrator states that the situation seems to be covered by Section III.G.5.b. of the Tariff. *Id.* at pp. 3-4.

2505. Williams explains that the Quality Bank Administrator's notes regarding his conversations with Sharp indicate that the existing Heavy Naphtha price quote is an assessment of cargo transactions. Subsequently, it notes that, in a further conversation, Sharp confirmed that the Heavy Naphtha price quote from the outset "was intended to reflect a cargo basis and that the old number weighted barge a lot less and therefore was considered primarily a cargo number." *Id.* at p. 4 (quoting Exhibit No. TC-22 at p. 1). More significantly, according to Williams, Sharp confirmed that "he considered the old naphtha quote basis to be consistent with the current cargo assessment." *Id.*

2506. Williams asserts that a key premise of the distillation methodology is to use a single intermediate feedstock price quoted by an independent price reporting service without modification whenever possible. *Id.* It states that the averaging proposal introduces an internal inconsistency into the Quality Bank methodology which is neither necessary nor reasonable. *Id.*

2507. No other Quality Bank component, Williams argues, is valued by averaging price quotations for different classes of sale for the same commodity. *Id.* Therefore, Williams states, introducing a Quality Bank component valuation using an average of available price quotations for a commodity of different classes of sale would set a dangerous precedent which opens the door for perpetual attempts to change a component's valuation by advocating averaging two or more published price quotes for the same product. *Id.* On the Gulf Coast, it points out, price quotations for more than one class of sale exist for Light Distillate (waterborne and pipeline jet fuel), Heavy Distillate (waterborne and pipeline diesel fuel) and VGO (cargo and barge high sulfur VGO). *Id.* at pp. 5-6. Similarly, it notes that, on the West Coast, price quotations for more than one class of sale exist for Light Distillate (waterborne and pipeline jet fuel)[722] and Heavy Distillate (waterborne and pipeline diesel fuel.)[723] *Id.* at p. 6.

2508. Williams contends that averaging the Gulf Coast Heavy Naphtha (cargo) and Heavy Naphtha Barge price quotes would also contravene the Quality Bank pricing convention of using waterborne prices when available. *Id.* It notes that, in supporting the Eight Parties's inclusion of a logistics adjustment to convert the Platts Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil [Diesel] price to a waterborne basis, Ross testified that the convention has been to choose the largest available parcels to value each cut, because this minimizes the marketing margins. *Id.* at pp. 6-7. Further, it notes that Ross stated that waterborne cargoes are larger and more representative of the value of the streams at the refinery. *Id.* at p. 7.

2509. The Quality Bank Administrator's averaging recommendation, according to Williams, is even inconsistent with his recommendation in 1998 concerning what pricing should be used to value the Gulf Coast High Sulfur VGO price for the Gulf Coast Quality Bank VGO component, a pricing which also has served as the valuation for the West Coast Quality Bank VGO component. *Id.* On December 1, 1997, Williams notes, OPIS announced that, effective January 1, 1998, it was going to cease publishing its existing

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[722] In support, Williams cites Exhibit No. TC-19 at p. 6. Williams Supplemental Brief at p. 6.

[723] Williams notes that there are separate quotes for West Coast pipeline LS No. 2 in both Los Angeles and San Francisco, Northwest for Portland and Seattle, plus West Coast Waterborne Gasoil 0.05%. Williams Supplemental Brief at p. 6, n.5 (citing Exhibit No. TC-19 at p. 6). Thus, Williams asserts, for any proposal that attempts to draw a comparison or establish a Naphtha value comparing an alleged relationship between products such as gasoline and/or jet fuel, were Naphtha price quotes averaged on the Gulf Coast, then other product prices used in the comparison arguably would need to be compared on a product price averaged basis. *Id.* at p. 6, n.6.

single high sulfur price quote and start publishing separate price quotes for barge and cargo lots. *Id.* At that time, explains Williams, the Quality Bank Administrator referred to a "radical alteration" under Item III.G.5.b. of the Tariff and issued a notice similar to the averaging proposal under consideration here. *Id.* at pp. 7-8. However, it notes that, unlike the instant case, with respect to VGO, the Quality Bank Administrator did not recommend averaging; rather, he recommended that a single price, the Gulf Coast barge price quote, be used in lieu of the cargo price quote because "[t]his assessment appears to be the most representative indicator of High Sulfur VGO market value and therefore seems to be the best single price to reflect the market for High Sulfur VGO on the Gulf Coast." *Id.* at p. 8 (quoting Exhibit No. TC-23 at ¶ 7).

2510. In addition, Williams argues, the reason for the two VGO price quotes is completely the opposite of why Platts added a barge quote for Naphtha. *Id.* With respect to VGO, Williams notes, the Quality Bank Administrator explained that OPIS split the High Sulfur VGO price into two price quotes because there were only occasional cargo transactions and it was concerned that these transactions would distort the price range reported for a particular day. *Id.* With respect to the Platts Heavy Naphtha price quote, Williams maintains, there is no problem with volumes of cargo transactions. *Id.* It states that Sharp told the Quality Bank Administrator that "there are numerous transactions for both full range and heavy naphtha in both barge and cargo lots, although for heavy naphtha, barge transactions may slightly predominate." *Id.* (citing Exhibit No. TC-20 at p. 1). The initial Heavy Naphtha price quote, Williams continues, was not exclusively a cargo assessment, even though it was weighted toward cargo. *Id.* at pp. 8-9. It states that the reason for Platts adding the new barge quote was because "Sharp's customer feedback had encouraged a minimization of barge quotes since it was used for cargo contract pricing and therefore he considered the old heavy naphtha quote basis to be consistent with the current cargo assessment." *Id.* at p. 9 (Exhibit No. TC-22 at p. 1).

2511. Williams asserts that the Quality Bank Administrator's recommendation to use the arithmetic average of Platt's Gulf Coast Heavy Naphtha Cargo and Barge quotations by definition assigns an equal numerical weighting of 50% to both the cargo and barge quotations. *Id.* It states that this proposed equal weighting is contrary to Platts's weighting of the Heavy Naphtha price quote being used to value the Gulf Coast and thus West Coast Quality Bank Naphtha component before Platts introduced the Heavy Naphtha Barge quotation. *Id.* Williams believes that it is this equal weighting which represents a "radical alteration" should the phrase be applicable in this proceeding. *Id.*

2512. From a review of the three sets of notes that the Quality Bank Administrator compiled of the conversations with Sharp, Williams claims that, prior to May 1, 2003, Platts waterborne Naphtha quotes on the Gulf Coast for both Full Range and Heavy Naphtha did not equally weight cargo and barge quotations. *Id.* It asserts that Sharp's repeated statements to the Quality Bank Administrator, and in the joint conversation with Mitchell, Toof and Jones, made it clear that the single price quote was predominantly a cargo assessment. *Id.* at pp. 9-10 (quoting Exhibit Nos. TC-21, TC-22). Consequently, Williams concludes, there is no factual basis upon which to support the Quality Bank Administrator's proposed equal weighting of the two price quotes. *Id.* at p. 10. Moreover, it argues that, to do so, without any factual basis, totally contravenes the Quality Bank Administrator's rejection of averaging the two High Sulfur VGO prices in 1998 due to the lack of data. *Id.* at pp. 10-11 (quoting Exhibit No. TC-23 at ¶ 8). Williams contends that the same lack of volumetric data for weighting purposes exists with respect to the two Heavy Naphtha price quotes. *Id.* at p. 11. Yet, inexplicably to Williams, in this instance, the Quality Bank Administrator recommends that an arithmetic average be used. *Id.*

2513. In his reports, as well as in his recommendation filed with the Commission, Williams believes, the Quality Bank Administrator failed to provide any quantification whatsoever with respect to the robustness of the Gulf Coast waterborne trade by cargo and barge lots. *Id.* It states that all he provided was the statement that Sharp "said that there are numerous transactions for both full range and heavy naphtha in both barge and cargo lots, although for heavy naphtha, barge transactions may slightly predominate." *Id.* (quoting Exhibit No. TC-20 at p. 1). Williams asserts that the fact that the number of barge transactions may "slightly predominate" tells us absolutely nothing about the relative volumes of naphtha trade between barge and cargo transactions.[724] *Id.*

2514. Williams notes that the Commission, in its Order Accepting Replacement Product Price and Consolidating Issues with Hearing Procedures, issued August 13, 2003, accepted the Quality Bank Administrator's recommended replacement price effective August 17, 2003, "subject to refund and the outcome of the proceeding." *Id.* at p. 13. Therefore, Williams argues, the earliest date that this averaging of prices would be effective is August 17, 2003. *Id.* However, Williams contends that to allow August 17, 2003, to be the effective date should the ultimate decision be to adopt the averaging concepts sets a bad precedent especially when, in a similar type of situation in 1998, Mitchell expressly stated that the he could not recommend averaging of the barge and cargo prices because he did not have sufficient data. *Id.*

[724] Williams notes that Platts has indicated that typical sizes for barges are 50,000 barrels and cargoes are up to 250,000 barrels, so the volume of each barge transaction can be as little as 20% of each cargo transaction. Williams Supplemental Brief at p. 12, n.10. Were the number of barge and cargo transactions equal and because the volume of barge sales could be as little as 20% of the cargo Naphtha trade, Williams asserts, on this basis, this would indicate that the price weighting would be 80% cargo and 20% barge. *Id.* In Williams's view, this weighting certainly does not support that the initial, single Platts Gulf Coast Heavy Naphtha price quote was radically altered by the advent of a separate Gulf Coast Heavy Naphtha Barge price quote resulting in barge prices no longer being used in the Gulf Coast Heavy Naphtha (cargo) price quote. *Id.*

2515. Moreover, in Williams's view, the Quality Bank Administrator appears to be substituting his judgment for the Commission's in deciding what action to take. *Id.* at p. 14. It argues that the Commission has never stated or authorized use of more than a single product price quote. *Id.* Therefore, Williams states, the effective date should not be before a decision is made by the Commission on how to value a Quality Bank component. *Id.*

6. Phillips

2516. Phillips notes that the February 27, 2003, filing by the TAPS Carriers, which was entered into the record as Exhibit No. PAI-222, raised a number of additional issues, the first of which is whether the Platts Heavy Naphtha price is more suitable than the Platts Naphtha price for use in valuing ANS Naphtha. Phillips Initial Brief at p. 155. It claims that Mitchell testified that the Heavy Naphtha price was intended to apply to a reforming grade Naphtha that is similar in quality to Quality Bank Naphtha, while the Platts Naphtha price quote relates to a Full Range Naphtha that also includes the Quality Bank LSR cut. *Id.* Further, it states that all the witnesses, including Mitchell, agreed that the specifications for Platts Heavy Naphtha best fit the qualities of the Quality Bank Naphtha cut. Phillips Reply Brief at p. 89.

2517. It is Phillips's position that use of the Platts Gulf Coast Heavy Naphtha price on the Gulf Coast instead of the Platts Gulf Coast Naphtha price is supported by the record and is just and reasonable, subject to the imposition of an N+A adjustment. Phillips Initial Brief at p. 156. At the hearing, notes Phillips, no party entered any evidence to suggest that the Heavy Naphtha price is not more appropriate for use in the Quality Bank than the Naphtha price. *Id.*

2518. Nonetheless, Phillips notes that Unocal/OXY take the position in their brief that it is not appropriate to use the Heavy Naphtha price to value Quality Bank Naphtha. Phillips Reply Brief at p. 90. It states that they do so notwithstanding the unanimous agreement among the witnesses, including their own expert Culberson, as to the suitability of the Heavy Naphtha price. *Id.*

2519. Unocal/OXY assert, Phillips maintains, that, because of the existence of the petrochemical industry on the Gulf Coast, the existing Gulf Coast price overvalues West Coast Naphtha and, as a result, "the Gulf Coast price should not be adjusted in any manner that would increase the current valuation of West Coast naphtha." *Id.* (quoting Unocal/OXY Initial Brief at p. 46). That Unocal/OXY would take such a position highlights the extent to which they will take results-oriented positions, according to Phillips, without regard to the merits of the position or the evidence in the record. *Id.* It asserts that, not only is Unocal/OXY's position inconsistent with the testimony of their own expert, but it is inconsistent with their position that the Gulf Coast Naphtha price should be used to value West Coast Naphtha. *Id.* Phillips points out that Unocal/OXY cannot argue, on the one hand, that the Commission should not apply the best available published Gulf Coast price because the differences between the Gulf Coast and West Coast markets are too great, and, on the other hand, argue that the considerable differences between the Gulf Coast and West Coast markets should be ignored because the Gulf Coast price represents the best available price. *Id.*

2520. In addition, Phillips points out that Unocal/OXY and Petro Star assert that the TAPS Carriers lacked the authority under their Tariff to implement the change, even if the Heavy Naphtha price better reflects Quality Bank Naphtha. *Id.* at p. 91. It disagrees with this argument for two reasons. *Id.* First, Phillips states that Unocal/OXY and Petro Star argue that the publication of a new Heavy Naphtha price cannot be considered an unanticipated issue. *Id.* According to Phillips, that argument is untenable. *Id.* It explains that the Commission ordered the use of the Gulf Coast Naphtha price in 1993 because, under the approach it was following at that time, that Naphtha price most closely reflected Quality Bank Naphtha. *Id.* In the view of Phillips, the Commission could not have anticipated, in 1993, that a new Gulf Coast Naphtha price would be published ten years later that better reflected the quality of Quality Bank Naphtha. *Id.* at pp. 91-92. It states that, if the Commission knew that a more appropriate price would be published, it is clear that the Commission would have ordered that it be used. *Id.* at p. 92. Therefore, Phillips asserts, the Quality Bank Administrator's action appears to be the appropriate action to have taken under the Quality Bank Tariff's provisions. *Id.*

2521. Also, Phillips argues that it does not matter whether or not Section III.J of the Quality Bank Tariff expressly authorizes the change to the Heavy Naphtha price. *Id.* Under the Interstate Commerce Act, Phillips asserts, the TAPS Carriers clearly are authorized to unilaterally make revisions to their Tariffs, subject to review by the Commission to ensure that the revisions are just and reasonable. *Id.* (citing 49 U.S.C. App. § 15(7)(1988)). Thus, it concludes, the Commission has no authority to prevent the TAPS Carriers from making the change, which clearly is just and reasonable, regardless of whether or not it was authorized by the existing Quality Bank Tariff. *Id.*

2522. Phillips notes that Platts assesses Naphtha based on a standard N+A content of 40%. Phillips Initial Brief at p. 156. When Platts sees an actual transaction for the sale of Naphtha with a higher N+A content, Phillips explains, Platts adjusts the price of that transaction downward by 0.15¢/gallon per 1% of N+A above 40, up to a maximum adjustment of 1.5¢/gallon for Naphtha with an N+A of 50 or higher. *Id.* For example, continues Phillips, if Platts knew of a transaction where Naphtha with an N+A of 55 was sold for 91.5¢/gallon, Platts would reduce that price by 1.5¢/gallon to 90¢/gallon for reporting purposes in order to put the sale on its standard 40 N+A basis. *Id.* at pp. 156-57.

2523. It is uncontested, according to Phillips, that ANS Naphtha has a high N+A. *Id.* at

p. 157. Phillips points out that page 7 of the TAPS Carriers's February 27, 2003, filing summarizes the N+A data from the assays that were entered into the record in this proceeding. *Id.* (citing Exhibit No. PAI-222 at p. 7). It notes that this Exhibit shows that ANS Naphtha N+A content has varied from 55.3% to 58.3% and that all of these percentages are well above the 50 N+A maximum threshold that Platts uses in evaluating Naphtha transactions. *Id.*

2524. Phillips also states that the Quality Bank Administrator testified that he did not read the Quality Bank Tariff as giving him the authority to unilaterally implement an N+A adjustment. *Id.* It notes that he did not take any position as to whether the Commission should order that such an adjustment be made. *Id.*

2525. An N+A adjustment of 1.5¢/gallon, according to Phillips, should be applied to the published Platts Heavy Naphtha price in valuing Gulf Coast Naphtha for the simple reason that Platts actually applies such an adjustment in assessing Naphtha contracts. *Id.* at p. 158. In Phillips's view, both the memo that is attached at page 8 of Exhibit No. PAI-222 and Mitchell's testimony make clear that the published Platts price is based on a Naphtha with a 40 N+A, and that Platts adjusts the price of reported transactions for Naphtha with a higher N+A to put it on a 40 N+A basis. *Id.* Because Mitchell is a neutral third party with no interest in whether any N+A adjustment should be implemented, Phillips states there is no reason to doubt his testimony on this issue. *Id.* This means, continues Phillips, that when Platts publishes a Gulf Coast Heavy Naphtha price of 90¢/gallon, that price applies to Naphtha with an N+A of 40, and that Platts would value ANS Naphtha on the Gulf Coast at 91.5¢/gallon. *Id.* If the Quality Bank were to use the unadjusted 90¢/gallon price reported by Platts, Phillips points out, the Quality Bank would be valuing the ANS Naphtha at a value lower than would be assigned to it by Platts. *Id.* Use of a 1.5¢/gallon N+A adjustment on the Gulf Coast, asserts Phillips, is, therefore, necessary to give ANS Naphtha the value that Platts would assign to ANS Naphtha on the Gulf Coast. *Id.* Further, Phillips notes, Sanderson agreed with this view at trial and this result is in keeping with the requirement that the Quality Bank assign published prices to cuts when those prices are available. *Id.* at pp. 158-59.

2526. Furthermore, Phillips states, it is undisputed that Platts is correct that higher N+A has a higher value on the Gulf Coast. *Id.* at p. 159. It notes that Culberson, who opposes the use of an N+A adjustment on the West Coast, testified that an N+A adjustment would be appropriate on the Gulf Coast. *Id.* In addition, continues Phillips, Sanderson agreed that an N+A adjustment "might be appropriate on the Gulf Coast but not the West Coast" based on the value of N+A on the Gulf Coast, although Sanderson also asserted that use of an N+A adjustment for the Gulf Coast would be inconsistent with the rest of the Quality Bank. *Id.* (quoting Transcript at pp. 13570-72).

2527. According to Phillips, Sanderson elaborated on his view that use of an N+A adjustment on the Gulf Coast was inconsistent by noting that, were such an N+A adjustment implemented, then similar adjustments would be appropriate for other cuts, including the LSR, Naphtha, Light Distillate, Heavy Distillate, VGO and Resid cuts. *Id.* at pp. 159-60. According to Phillips, this argument is a red herring. *Id.* at p. 160. It points out that the proposed N+A adjustment is not based on the judgment of Phillips or any other party to this proceeding that an adjustment should be made to the Platts reported price, rather, explains Phillips, the proposed adjustment is based on the testimony of the Quality Bank Administrator that Platts makes this adjustment in developing its Gulf Coast Heavy Naphtha price. *Id.* Therefore, states Phillips, applying it is simply locating ANS Naphtha at the correct level on the scale published by Platts. *Id.* Further, notes Phillips, the only quality that Platts takes into account in developing its published price is the N+A content. *Id.* Thus, concludes Phillips, providing for an N+A adjustment would not open the door for further adjustments to the Naphtha price used for the Quality Bank. *Id.*

2528. Because the N+A adjustment is made solely on the basis that it reflects the actual Platts price, Phillips asserts that adoption of this adjustment is not inconsistent with the rest of the Quality Bank and does not open the floodgates for other changes. *Id.* There is no evidence, according to Phillips, that Platts makes a similar adjustment in reporting its Heavy Naphtha price or the price for any other product. *Id.*

2529. Phillips states that a second argument raised against the use of an N+A adjustment for the Gulf Coast is that Platts does not state in its posted prices or in its other published materials that it assumes a 40 N+A for its Heavy Naphtha quote or otherwise that it is employing the N+A adjustment in its valuation and, therefore, the adjustment should not be made by the Quality Bank. *Id.* at p. 161. Whatever force this argument may have as a general proposition, Phillips asserts, it does not apply here, where there is undisputed record evidence that Platts in fact does adjust the prices of the transactions that it reviews for N+A content. *Id.* Phillips points out that Mitchell, who has absolutely no interest in the outcome of this issue, reported at trial that he confirmed that Platts does use the N+A adjustment. *Id.* Because it has been established on the record that Platts does make this adjustment, Phillips's position is that the record also establishes that use of the Heavy Naphtha price without adjustment would undervalue the Platts ANS Naphtha assessment. *Id.*

2530. Sanderson made a related argument, Phillips claims, when he testified that Platts does not make the adjustment in every case, but rather applies it as a rule of thumb for the industry. *Id.* Phillips explains that this testimony provides corroboration of Mitchell's testimony that Platts does make an N+A adjustment, and the corroboration is stronger, in Phillips's view, because it comes from someone who opposes use of the adjustment. *Id.* It points out that, unlike Mitchell, Sanderson had every incentive to cast his conversation with Sharp in such a light as to undermine the need for an adjustment. *Id.* Nonetheless, notes Phillips, Sanderson did concede that the adjustment is applied as a rule of thumb. *Id.* Therefore, in Phillips's view Sanderson's testimony does not undercut the proposition that Platts typically would value ANS Naphtha at a price higher than the published Gulf Coast Naphtha price. *Id.*

2531. Culberson and Sanderson err in suggesting, Phillips argues, that N+A does not have value on the West Coast. *Id.* at pp. 164-65. According to Phillips, the Commission does not need to reach that question. *Id.* at p. 165. Should the Commission determine that the Gulf Coast Naphtha price should be used to value West Coast Naphtha notwithstanding the differences in the two markets, then Phillips asserts that the Commission must apply the same price to each market. *Id.* It declares that the Commission cannot ignore differences in the two markets in requiring the imposition of the Gulf Coast price to the West Coast, but conversely implement an N+A adjustment on the Gulf Coast and not on the West Coast because of differences in the two markets. *Id.* Moreover, Sorenson who, unlike any of the other witnesses who testified on the West Coast Naphtha issue, actually is employed by a West Coast refinery that processes Naphtha, testified as to the value of N+A on the West Coast.[725] *Id.*

2532. Sorenson, Phillips claims, explained that N+A has value to a refiner in reforming Naphtha, because, the higher the N+A of the Naphtha, the more valuable reformate it will yield. *Id.* It explains that a higher N+A in the Naphtha allows the same octane to be produced at a lower cost than if the Naphtha had a lower N+A. *Id.* at p. 166. Phillips points out that Sorenson explained how Exhibit No. PAI-254 demonstrates this yield effect of having a higher N+A by showing that increasing the N+A of Naphtha from 40 to 55 would increase the reformate yield by 5% when reformed to a 95 octane. *Id.* According to Phillips, this is a significant benefit to a refinery. *Id.*

2533. Phillips states that the witnesses asserting that N+A does not have value on the West Coast do not disagree with Sorenson's testimony that higher N+A improves reforming yields. *Id.* According to Phillips, Culberson defined good Naphtha as Naphtha with an N+A "somewhere in the 50 range" because of "how it would perform in a reformer." *Id.* (quoting Transcript at p. 11330). Further, notes Phillips, Sanderson also agreed that higher N+A has the yield impact described by Sorenson. *Id.* Finally, states Phillips, Sarna, Williams's other witness, similarly agreed that higher N+A will give a higher yield of reformate from a Naphtha. *Id.*

2534. Rather than dispute the beneficial impacts of N+A, Phillips explains, Sanderson and Sarna argued that the California Air Resources Board specifications, with strict limits on benzene in gasoline, have created a benzene penalty offsetting any benefit that might

[725] Phillips explains that Sorenson's job is to evaluate the economics of the various feedstocks used by Phillips's Los Angeles refinery, and thus he is uniquely qualified to testify as to the value of N+A in Naphtha on the West Coast. Phillips Initial Brief at p. 165.

be obtained from the higher yields. *Id.* Further, notes Phillips, Sarna also presented Exhibit No. WAP-275 showing that unfavorable N+A comes out of the reformer as benzene. *Id.* Using the Phillips refinery as an example, Phillips continues, Sorenson explained that these concerns are not valid because his refinery found, regardless of the crude slate, that equipment is needed to address the California Air Resources Board benzene specifications. *Id.* at p. 167. As a result, Phillips explains, the refinery made extensive investments in benzene processing equipment in 1994 to allow it to process any Naphtha regardless of its benzene content. *Id.* Therefore, concludes Phillips, the refinery has "the capability to handle both benzene and aromatics without that being a limitation to it." *Id.* (quoting Transcript at p. 13255).

2535. Phillips concedes, however, that Sorenson has less knowledge about other refineries in California. *Id.* Yet, states Phillips, he observed that all ANS refined in California has to meet the California Air Resources Board specifications, which indicates to him that those refineries that process ANS had made similar investments in benzene handling equipment. *Id.* Because the production of ANS has declined since the California Air Resources Board specifications went into effect in 1996, Phillips asserts, California refiners should be able to continue handling the benzene in ANS, even under the California Air Resources Board III specifications. *Id.*

2536. According to Phillips, Sorenson's testimony about the other California refiners is supported by Exhibit Nos. PAI-259 through PAI-262. *Id.* It explains that these Exhibits contain surveys, based on Oil & Gas Journal data, of benzene handling capacity on the West Coast as of January 1, 1998 (Exhibit No. PAI-259), and January 1, 2003 (Exhibit No. PAI-261), as well as backup for these surveys. *Id.* Phillips states that the surveys show that all but two California refineries had benzene handling equipment in both 1998 and 2003, and that the two refineries without such equipment do not process ANS. *Id.*

2537. Furthermore, Phillips states, Sorenson presented a study in Exhibit Nos. PAI-255 and PAI-256 that showed the impact on a California refinery of reforming Naphtha with a higher N+A. *Id.* at p. 168. It explains that the study used different scenarios, some of which involved solely conventional gasoline production and some of which involved combined CARB and conventional gasoline production. *Id.* In this study, notes Phillips, Sorenson looked at both the impact of substituting 1000 barrels of 55 N+A Naphtha for 1000 barrels of 40 N+A Naphtha and of decreasing the amount of N+A in the ANS being refined. *Id.* Additionally, continues Phillips, the refinery had benzene reduction equipment included, so Sorenson's study considered the impacts of this equipment on Naphtha value. *Id.* (citing Transcript at pp. 13226-235).

2538. Phillips asserts that the bottom line result of the study is that refinery economics were more favorable when running Naphtha with a higher N+A under all cases. *Id.* According to Phillips, this is true even though the refinery is operating to meet the CARB II specifications which are in effect in California. *Id.* Phillips claims that, while

Sorenson did not claim that his study showed the exact value of N+A in California, it does, however, illustrate that a higher N+A has value to a refinery in California operating under California Air Resources Board specifications. *Id.*

2539. In Phillips's view, Sarna's testimony challenging Sorenson's study was tainted by at least three serious deficiencies: (1) Sarna misrepresented Sorenson's work; (2) Sarna failed to recognize that certain costs are constant across all scenarios; and (3) Sarna himself was extremely evasive during his testimony. *Id.* at p. 169. It asserts that Sarna misrepresented Sorenson's work. *Id.* For example, explains Phillips, Sarna criticized Sorenson for not using the correct cost curves in his reformer calculations. *Id.* According to Phillips, he testified that Sorenson should have used cost curves for 150 psig and not 300 psig. *Id.* Phillips maintains that Sarna should have realized that Sorenson did in fact assume a 150 psig reformer in his work. *Id.*

2540. Second, states Phillips, Sarna's criticisms of Sorenson that certain costs were not accounted for failed to recognize that these costs remained constant across all scenarios and thus would not affect Sorenson's calculation of the differences between the scenarios. *Id.* For example, notes Phillips, Sarna criticized Sorenson for not including the capital cost of a benzene saturation unit in his calculations, even though Sorenson explained "that fixed cost [of a benzene saturation unit] would have been identical in each case," and "when you subtracted the one case from the other, the net effect would be zero." *Id.* (quoting Transcript at pp. 13330-31). Finally, Phillips notes that Sarna's testimony was extremely evasive to the point where the court questioned the utility of having him testify at all. *Id.*

2541. Phillips notes that Williams alleges that the high benzene content in Naphthas, such as ANS Naphtha, that have a high N+A content cause problems. Phillips Reply Brief at p. 94. In reply, it asserts that Williams completely ignores the testimony of Sorenson that a refiner with benzene reduction equipment does not discount the value of Naphtha with high benzene levels, because the benzene reduction equipment addresses the problems that high benzene content causes. *Id.* Phillips states that this failure to even acknowledge, much less address, the primary reason why benzene content is not a problem on the West Coast is a fatal flaw that requires Williams's arguments to be dismissed. *Id.*

2542. Unocal/OXY acknowledge Sorenson's testimony, states Phillips, but it argues that Sorenson ignores the substantial capital costs of the benzene reduction equipment that refiners have installed. *Id.* Phillips states that Unocal/OXY's argument that the need for this expensive equipment has caused the value of higher N+A to have decreased misses the point of Sorenson's testimony. *Id.* at pp. 94-95. It concedes that it is true that the benzene reduction equipment installed on the West Coast has a significant capital cost. *Id.* at p. 95. However, Phillips explains that most California refiners have already installed the necessary equipment and incurred the cost.[726] *Id.* As a result, Phillips continues, when these refiners are comparing a purchase of ANS Naphtha with an N+A of 55 and a purchase of Naphtha with an N+A of 40, they will not have to incur any additional cost to process the ANS Naphtha. *Id.* Phillips maintain it would be foolish of them to pay the same price for Naphtha with an N+A of 40 as for ANS Naphtha when the ANS Naphtha will yield more gasoline without incurring any more costs. *Id.* In Phillips's view, to do so would be to deprive themselves of the benefits of the benzene reduction equipment that they have already installed. *Id.*

2543. It is clear from the Commission order consolidating the TAPS Carriers's February 27, 2003, filing into this hearing, according to Phillips, that the effective date of the Commission's decision regarding that filing is to be March 1, 2003. Phillips Initial Brief at p. 170 (citing *BP Pipelines (Alaska) Inc.,* 102 FERC ¶ 62,345 at P 13).[727]

2544. In Phillips's view, the authority of the Commission to order retroactive application of its decision on this issue also is clear. *Id.* Phillips points out that Section 15(7) of the Interstate Commerce Act provides that the Commission can, when a new rate such as the one at issue here is filed, set the rate for hearing subject to refund. *Id.* Further, states Phillips, the Circuit Court held, in *OXY,* that Section 15(7) would authorize a retroactive application of a change in rates initiated by the TAPS Carriers. *Id.* at pp. 170-71 (citing *OXY*, 64 F.3d at pp. 698-99).

2545. Phillips states that the effective date of the TAPS Carriers's filing is important to this proceeding. *Id.* at p. 171. Before that filing, explains Phillips, the West Coast Naphtha price was being reviewed as a consequence of complaints filed by Exxon and Tesoro. *Id.* For the reasons set forth in the Eight Parties's Joint Brief (which Phillips joined) on Issue No. 5, Phillips notes, it is clear that the Commission could not implement a change in the Naphtha value retroactively in response to those complaints. *Id.*

[726] Phillips states that the benzene reduction equipment was generally installed as part of the modifications that were made when the California Air Resources Board regulations came into effect in 1996. Phillips Reply Brief at p. 95, n.39. It notes that Sorenson testified those regulations made such investments necessary as a practical matter regardless of the crude processed by the refinery. *Id.*

[727] Phillips does not assert that the TAPS Carriers are obligated to make refunds from their own funds, because they redistribute the Quality Bank payments that they receive to other shippers. Phillips Initial Brief at p. 170, n.62. Rather, according to Phillips, the TAPS Carriers should be obligated to recalculate Quality Bank payments and receipts and implement a retroactive redistribution of those payments and receipts. *Id.*

2546. The TAPS Carriers filing, according to Phillips, changes the dynamic of the Commission's review of the West Coast Naphtha price. *Id.* It explains that the Commission did not limit the investigation of the February 27 filing simply to the issue of whether it is more appropriate to use the published Gulf Coast Heavy Naphtha price than the published Gulf Coast Naphtha price. *Id.* Instead, notes Phillips, the Commission found that the protests raised the broader issue of "the value of, and appropriate Quality Bank pricing basis for the Quality Bank Naphtha cut on the West Coast." *Id.* (quoting *BP Pipelines (Alaska), Inc.*, 102 FERC ¶ 62,345 at P 11). Because the Commission held that the issue of the appropriate West Coast Naphtha value is raised by the TAPS Carriers filing, it is Phillips's position that the March 1, 2003, effective date for the TAPS Carriers's filing also is the effective date for any holding by the Commission that a West Coast based Naphtha value is required. *Id.* at pp. 171-72. For example, explains Phillips, if the Commission concludes, based on the record, that O'Brien's proposed Naphtha value should be implemented, the effective date of that change should be the March 1, 2003, date specified in the Commission's Order. *Id.* at p. 172.

2547. Phillips explains that the Circuit Court held, in *OXY,* that Section 15(7) of the Interstate Commerce Act does not permit retroactive treatment of a change in methodologies when the TAPS Carriers filing was made in accordance with an approved existing methodology. *Id.* (citing *OXY,* 64 F.3d at pp. 699-700). In that case, Phillips explains, the Circuit Court held that Section 15(7) did not authorize the Commission to retroactively apply a change from the previously approved gravity methodology to a distillation methodology as a consequence of the TAPS Carriers doing nothing more than making the semiannual filing that was required by the gravity methodology, updating the amount to be paid per degree of API gravity. *Id.* (citing *OXY,* 64 F.3d at pp. 699-700).

2548. The Circuit Court in *OXY,* according to Phillips, put great importance on the issue of notice to shippers as to whether retroactive implementation of a change will be required. *Id.* First, explained Phillips, the court noted that "Section 15(7) procedures do not undermine the rule against retroactive ratemaking because all parties are placed on notice that the agency has the authority to order a refund of any part of the increase that it finds to be unjustified." *Id.* (quoting *OXY*, 64 F.3d at p. 699). Phillips explains further that the Circuit Court then relied heavily on the fact that the Commission, in setting the justness and reasonableness of the gravity methodology for hearing, had stated that any change in the methodology would be prospective only. *Id.* (citing *OXY,* 64 F.3d at p. 700; *Trans Alaska Pipeline System*, 49 FERC ¶ 61,349 at pp. 62,264-65 (1989); *Trans Alaska Pipeline System*, 51 FERC ¶ 61,062 at p. 61,137 (1990)). Indeed, the Commission could not have been any clearer on this point, maintains Phillips, holding that "because the TAPS owners have not proposed to change the existing methodology, any change in methodology should be effected prospectively." *Id.* (quoting *Trans Alaska Pipeline System*, 49 FERC at pp. 62,264-65).

2549. Here, by contrast, states Phillips, the Commission has given notice that any change in the value of Naphtha filed by the TAPS Carriers, whether on the Gulf Coast or the West Coast, will be made retroactive to March 1, 2003, as the language quoted above demonstrates. *Id.* at p. 175. Certainly, maintains Phillips, there is nothing in this proceeding remotely like the language in the Commission's 1989 and 1990 Orders that led the Circuit Court to hold that the distillation methodology could not be implemented retroactively. *Id.*

2550. Phillips notes that Williams argues that any imposition of an N+A adjustment to the Heavy Naphtha price can only be made prospective from the date it is adopted by the Commission. Phillips Reply Brief at p. 98. It asserts that Williams does not provide any citation to cases or statutes to support this position and that the sum total of Williams's argument on this point is as follows: “It [the N+A adjustment] was not a change recommended by the TAPS Carriers; indeed . . . the [Quality Bank Administrator] chose not to include such an adjustment. Therefore, it can have only prospective application.” *Id.* (quoting Williams Initial Brief at p. 95). Phillips argues that Williams’s argument is directly at odds with the controlling statutes regarding changes in rates, and claims that Section 15(7) of the Interstate Commerce Act makes clear that the Commission can require the TAPS Carriers to refund any amount of its "rates or charges as by its decision shall be found not justified." *Id.*

2551. Williams's argument, Phillips suggests, would gut the very reason for allowing a rate to go into effect subject to refund in the first place: to allow the Commission to adjust a proposed rate after hearing in order to implement the just and reasonable rate determined in the hearing retroactively to the effective date of the proposed rate. *Id.* at p. 99. By definition, it states, the just and reasonable rate determined by the Commission at the hearing may be different from what the TAPS Carriers proposed. *Id.* Should the Commission not implement any changes to what was proposed by the TAPS Carriers retroactively, it notes, the Commission could never order any refunds. *Id.* Phillips argues that this would render the Commission’s statutory refund authority a nullity. *Id.*

2552. According to Phillips, BP’s argument that any N+A adjustment can be made only prospectively is, like Williams’s argument, without any merit. *Id.* It notes that BP urges this result "for the reasons explained regarding Issue Nos. 5 and 9 in the Eight Parties' Initial Brief." *Id.* (quoting BP Initial Brief at p. 73). Phillips contends that Issue 5 deals with the question of whether the Commission should, as a matter of equity, implement changes made to the Resid, Heavy Distillate, and Light Distillate issues remanded by the *OXY* Court retroactive to December 1, 1993. *Id.* It maintains that there were no rate changes filed by the TAPS Carriers that were made effective on that date, and the Commission issued no orders making the collection of rates from 1993 forward subject to refund, and argues that the equitable issues involved in Issue 5 are completely distinct from the question of whether the Naphtha value should be made retroactive to March 1, 2003, as a consequence of the TAPS Carriers's Heavy Naphtha filing and the Commission’s order providing that the change was to be implemented subject to refund.

Id. at pp. 99-100.

2553. Phillips notes that Petro Star cites to the Stipulation that the parties reached with respect to the effective date for Issue No. 4, VGO, which provides as follows: "The Parties disagree as to the effective date of the new West Coast VGO value. However, the Parties agree that if a different West Coast Naphtha valuation methodology is adopted in this proceeding, it and the new West Coast VGO value should have the same effective date." *Id.* at pp. 100-01 (quoting Joint Stipulation at p. 4). It suggests that Petro Star argues that it would be unfair to allow the TAPS Carriers's Heavy Naphtha filing, which was made several months after the stipulation, to cause the Naphtha and VGO prices to have a different effective date. *Id.* at p. 101. Phillips states that Petro Star argues that any effective date that the Commission adopts for Naphtha should also apply to VGO. *Id.*

2554. According to Phillips, Petro Star's argument should not be accepted. *Id.* It claims that the TAPS Carriers's Heavy Naphtha filing impacted the stipulation on the VGO effective date as a matter of law in a way that prevents the stipulation from being applied to the Heavy Naphtha filing. *Id.* Prior to that filing, when the stipulation was entered into, Phillips explains, the only way that new Naphtha and VGO prices could be made to have retroactive effect was as a consequence of Exxon's claim for reparations under Section 16 of the Interstate Commerce Act. *Id.* In agreeing to the Stipulation, Phillips maintains, the parties were agreeing that, whatever merits the reparations claim had with respect to Naphtha, the same factors applied to VGO. *Id.* Phillips claims that the parties's position is that either reparations were appropriate for both, or they were appropriate for neither. *Id.*

2555. The Heavy Naphtha filing, Phillips argues, changed the equivalency between the legal standard applicable to the effective date for the two cuts. *Id.* It argues that, under the controlling statute, the Heavy Naphtha filing involved a change in rates under Section 15(7) of the Interstate Commerce Act which triggers a refund obligation back to March 1, 2003. *Id.* Further, it notes that the TAPS Carriers did not file any similar change in the VGO cut valuation. *Id.* As a result, Phillips asserts, the only way that the VGO valuation can, as a matter of law, be made retroactive is under Exxon's reparations claim and under a different statutory provision. *Id.* Phillips states that the record does not support a finding that reparations for VGO are required as of March 1, 2003 – indeed, it suggests, the record does not support any award of reparations for either VGO or Naphtha. *Id.* at pp. 101-02.

2556. The proposed new Naphtha price is appropriate for the Gulf Coast, provided that an N+A adjustment also is implemented, according to Phillips. Phillips Supplemental Brief at p. 7. It requests that this new price, as adjusted, be made effect August 17, 2003. *Id.*

2557. Phillips explains that, on June 18, 2003, the Quality Bank Administrator made a filing proposing a second substitute price for the Heavy Naphtha price that previously had been used. Phillips Supplemental Brief at p. 3. The proposed new price, according to Phillips, is the average of the cargo price and the barge price. *Id.* It notes that the Quality Bank Administrator stated that there are substantial cargo and barge transactions, and that both the cargo and barge prices therefore are representative of the Gulf Coast Heavy Naphtha value. *Id.* at pp. 3-4. Furthermore, continues Phillips, the Quality Bank Administrator stated that there is no data available that would allow the use of a volume weighted average of the cargo and barge prices. *Id.* at p. 4.

2558. It is Phillips's position that the proposed new price should be adopted for Gulf Coast Naphtha. *Id.* Phillips agrees with the Quality Bank Administrator's finding that there are significant barge and cargo Naphtha transactions conducted on the Gulf Coast, and nothing in the record supports a conclusion that one type of transaction is more representative of the Gulf Coast Heavy Naphtha market than the other. *Id.* In the absence of any data that would allow the calculation of a volume weighted average, Phillips further concurs with the Quality Bank Administrator's proposed arithmetic average of the two prices as reasonable. *Id.*

2559. Furthermore, states Phillips, the record indicates that the proposed average of the cargo and barge prices most likely is representative of the single Heavy Naphtha category whose prices Platts quoted before May 1. *Id.* This is because, notes Phillips, Sharp stated that the Heavy Naphtha prices that were published from March through April of 2003 typically included prices for cargo sized lots on the low end of the reported price and prices for barge sized lots on the high end. *Id.* This means, according to Phillips, that the calculation of the mid-point of the high and the low prices performed by the Quality Bank Administrator before May 1, 2003, in essence, represented the average of Gulf Coast cargo prices - which were reported by Platts as the low Heavy Naphtha price - and barge prices - which were reported by Platts as the high Heavy Naphtha price. *Id.* The Quality Bank Administrator's proposal to use the average of the barge price and the cargo price thus, in Phillips's view, approximates the way that the Quality Bank Administrator calculated the Heavy Naphtha price before the split in reported prices commenced. *Id.* at pp. 4-5.

2560. While Phillips supports the proposed averaging of the barge and cargo prices for use on the Gulf Coast, Phillips does believe that the Quality Bank Administrator's filing is deficient in one respect. *Id.* at p. 5. It notes that filing does not include an N+A adjustment. *Id.* Such an adjustment is required, asserts Phillips, for the reasons previously discussed. *Id.*

2561. Phillips agrees with the TAPS Carriers and Exxon that the decision by Platts to split the Heavy Naphtha price into Heavy Naphtha (Cargo) and Heavy Naphtha Barge prices constitutes a radical alteration of the previously published Heavy Naphtha price, in accordance with the Quality Bank Tariff. Phillips Reply Brief at p. 102 (Citing TAPS Carriers Supplemental Brief at pp. 10-14; Exxon Supplemental Brief at pp. 5-7). Ultimately, however, they assert that it does not matter whether there has been a radical alteration of the Gulf Coast Heavy Naphtha price or not. *Id.*

2562. As an initial matter, Phillips notes that the TAPS Carriers have the authority under the controlling statute to propose changes to their Tariff regardless of whether the changes are authorized by the existing Quality Bank Tariff. *Id.* It claims that the standard imposed by the controlling statutes is whether the change is just and reasonable, and, if a proposed change is just and reasonable, then it must be permitted. *Id.* at pp. 102-03. Furthermore, Phillips asserts that the Commission previously set for hearing, here, the justness and reasonableness of the TAPS Carriers's February 2003 filing that proposed the use of the Platts Heavy Naphtha price for the Quality Bank. *Id.* at p. 103. In the context of reviewing that filing, it argues that it is entirely appropriate for the Commission to consider intervening events since the time the TAPS Carriers's filing was made in February – indeed the Commission is required under the statutes to determine the just and reasonable rate to be charged in the future by the TAPS Carriers, and the fact that there now are both cargo and barge prices published for Heavy Naphtha certainly must be considered by the Commission in evaluating the TAPS Carriers's proposal that the Heavy Naphtha price should be used. *Id.* As a result, Phillips's position is that the Commission must consider the impact of the publication of separate Heavy Naphtha cargo and barge prices in the context of the TAPS Carriers's February 2003 Heavy Naphtha filing regardless of whether the TAPS Carriers's averaging proposal is justified under the Quality Bank Tariff. *Id.*

2563. Phillips notes that Unocal/OXY assert that the impact of the Quality Bank Administrator's averaging proposal is "to increase the value of the Waterborne Naphtha cut by approximately one cent per gallon." *Id.* at p. 104 (quoting Unocal/OXY Supplemental Brief at p. 5). It states that Williams similarly suggests that the proposal represents an increase in Naphtha value prices, arguing that it represents a "skewed higher West Coast naphtha price" proposal. *Id.* (quoting Williams Supplemental Brief at p. 2). This characterization of the impact of the Quality Bank Administrator's proposal, Phillips argues, is highly misleading. *Id.* It claims that the record makes clear that before May 1, 2003, the Platts Heavy Naphtha price quotes included both cargo and barge prices and asserts that the Quality Bank Administrator's averaging proposal does not represent an attempt to increase Naphtha values above what they were prior to the May 1, 2003, change by Platts in its reporting, but instead is an effort to maintain the use of a Quality Bank price that continues to be based on both cargo and barge prices. *Id.*

2564. Contrary to Williams's assertion, Phillips maintains that it is the opponents of the Quality Bank Administrator's proposal who are attempting to skew the Quality Bank Naphtha value to be lower than it was before. *Id.* It suggests that the record reflects that the cargo prices that they propose to use tend to be lower than the barge prices. *Id.*

Therefore, Phillips states that use of the cargo price alone will result in a lower Naphtha value than would have been the case before May 1, 2003, when Platts Heavy Naphtha price quote included both cargo and barge transactions. *Id.* at pp. 104-05.

2565. Phillips claims that the Quality Bank Administrator's averaging proposal represents an effort to keep the Quality Bank Naphtha value at the same level that it would have been had Platts not divided the Heavy Naphtha price into cargo and barge price quotes. *Id.* at p. 105. It contends that this is a reasonable goal that does not favor either those who want a higher Naphtha price or those who want a lower Naphtha price, and states that the assertions of Unocal/OXY and Williams that the proposal favors parties who want higher Naphtha prices are incorrect and should be rejected. *Id.*

2566. Williams also attacks, Phillips states, the proposal to weight cargo and barge prices equally in calculating an average of the Heavy Naphtha and Heavy Naphtha Barge prices. *Id.* It asserts that Williams is wrong to argue that there is no factual basis for the averaging proposal. *Id.* Rather, Phillips claims, Sharp made clear that there are numerous barge and cargo transactions and, further, while he was not able to give a precise breakdown of the transactions, he said the "barge transactions may slightly predominate." *Id.* (quoting Exhibit No. TC-20 at p. 1). According to Phillips, it thus appears there is a rough equivalence between the two types of transactions, even if the barge transactions slightly predominate. *Id.* While it would be preferable to have more detailed data on how much of each type of Naphtha is sold, Phillips argues, Sharp's description of the market provides an adequate factual support for the reasonableness of using a simple average in the absence of more detailed data. *Id.* at p. 106. It asserts that it is certainly more reasonable to use a simple average than to use only the cargo price, which represents the low end of the price range for Gulf Coast Naphtha without any allowance whatsoever for barge transactions. *Id.*

2567. Williams's argument that the weighting proposal is inconsistent with the decision not to weight cargo and barge prices for Gulf Coast VGO prices, according to Phillips, should be rejected. *Id.* It argues that Exhibit No. TC-23 makes clear that "[t]here are often periods of several weeks or more in which there are no actual [VGO] cargo transactions." *Id.* (quoting Exhibit No. TC-23 at p. 3). Under those circumstances, where there are substantially more barge transactions than the often non-existent cargo transactions, it contends, the record would not have supported using a simple average of cargo and barge prices. *Id.* at pp. 106-07. Here, it notes that, by contrast, the record supports the conclusion that there is a rough equivalency between cargo and barge transactions, and that a simple average of the two prices represents the most reasonable approach. *Id.* at p. 107.

2568. In its order setting the Quality Bank Administrator's June 18, 2003, filing for hearing, Phillips notes, the Commission made the replacement price effective August 17, 2003, subject to refund. *Id.* at p. 6 (citing *Trans Alaska Pipeline System*, 104 FERC at P

9). Given this explicit holding in the Commission's order, Phillips argues, the effective date for the new averaged Gulf Coast Naphtha price should be August 17, 2003. *Id.* To the extent that the Commission applies the new Gulf Coast Naphtha price to West Coast Naphtha, however, Phillips's position is that the West Coast Naphtha price should have the same effective date as the Gulf Coast Naphtha price, i.e., August 17, 2003. *Id.* Should the Commission adopt a West Coast-based Naphtha value, however, Phillips asserts, the value should have an effective date of March 1, 2003. *Id.*

2569. The N+A adjustment to the new Naphtha price should also apply as of the August 17, 2003, effective date established by the Commission, according to Phillips. *Id.* To the extent that a Gulf Coast Naphtha price is applied to West Coast Naphtha, then Phillips states, there also should be an N+A adjustment to the West Coast effective August 17, 2003. *Id.* On reply, Phillips attempted to clarify its position by stating that it now believes that there should also be an N+A adjustment to the Heavy Naphtha price effective March 1, 2003, which is the effective date of the Heavy Naphtha price established by the Commission. Phillips Reply Brief at p. 108.

7. Exxon

2570. In response to the February 3, 2003, Platts decision to begin publishing a new waterborne Heavy Naphtha price on the Gulf Coast in addition to the Full Range Gulf Coast Naphtha price, explains Exxon, the Quality Bank Administrator determined that the properties of the ANS Naphtha cut used by the TAPS Quality Bank are far closer to the Platts Heavy Naphtha specifications than they are to the Platts Full Range Naphtha specifications. Exxon Initial Brief at pp. 323-24. More specifically, states Exxon, the Quality Bank Administrator pointed out that the 175°F initial boiling point of the Quality Bank Naphtha cut is much closer to the initial boiling point of the Platts Heavy Naphtha price assessment (180°F) than to the initial boiling point of the Platts Full Range Naphtha price assessment (130°F). *Id.* at p. 324. Similarly, continues Exxon, the average 53°API gravity of the Quality Bank Naphtha cut is much closer to the API gravity of the Platts Heavy Naphtha price assessment (52-53°API) than to the API gravity of the Platts Full Range Naphtha price assessment (56-60°API). *Id.*

2571. Based on the fact that the properties of Quality Bank Naphtha cut are much closer to the Platts Heavy Naphtha specifications than to Platts Full Range Naphtha specifications, notes Exxon, the Quality Bank Administrator concluded that the Platts Heavy Naphtha price should be used to value the Quality Bank Naphtha cut rather than the Platts Full Range Naphtha price. *Id.* at pp. 324-25. Accordingly, on February 27, 2003, states Exxon, the Quality Bank Administrator filed tariff revisions with the Commission notifying the Commission and all parties that effective March 1, 2003, the Quality Bank would use the Heavy Naphtha price published by Platts to value all Quality Bank Naphtha. *Id.* at p. 325. By order dated March 28, 2003, continues Exxon, those Tariff revisions were accepted by the Commission effective March 1, 2003, subject to refund, and the issues raised by those tariff revisions were consolidated with this proceeding. *Id.* (citing *BP Pipelines (Alaska) Inc.,* 102 FERC ¶ 61,345).

2572. Exxon asserts that the decision by the Quality Bank Administrator to use Platts Heavy Naphtha price to value the Quality Bank Naphtha cut as of March 1, 2003, on the Gulf Coast (and the West Coast until such time as the Commission establishes a new methodology for valuing West Coast Naphtha) is strongly supported by the evidence and was not opposed at the hearing by any party. *Id.* at pp. 325-26. It is undisputed, according to Exxon, that the properties on which the Platts Heavy Naphtha assessment is based, including the initial boiling point and API gravity, more closely resemble ANS Quality Bank Naphtha than do the properties of the Platts Full Range Naphtha price. *Id.* at p. 326. Further, continues Exxon, the average differential between the Heavy Naphtha and Full Range Naphtha prices reported by Platts since February 2003 of approximately 1¢/gallon is approximately the same differential one would expect to find given that, on the basis of the Quality Bank cut points, the Platts Full Range Naphtha is approximately 5/6ths Quality Bank Naphtha and 1/6th Quality Bank LSR. *Id.*

2573. Unocal/OXY and Petro Star, Exxon claims, now raise a procedural objection to the actions taken by the Quality Bank Administrator to implement the change to the Heavy Naphtha quote. Exxon Reply Brief at p. 341. It notes that, although Petro Star agrees that the new quote is suitable, both parties assert that the Quality Bank Administrator exceeded his authority. *Id.* at pp. 341-42. In addition, Unocal/OXY object to the use of the new Gulf Coast Heavy Naphtha price assessment to value West Coast Naphtha based on Unocal/OXY's contention that the use of any Gulf Coast price overvalues West Coast Naphtha and, therefore, advocates no adjustment to the Gulf Coast price that would raise the value of West Coast Naphtha. *Id.* at p. 342. Exxon argues that both contentions are without merit. *Id.*

2574. In Exxon's view, the procedural objection raised by Petro Star and Unocal/OXY is based on an untenably narrow reading of the Quality Bank Administrator's authority under the Tariff to deal with unanticipated implementation issues. *Id.* According to Exxon, the 1993 order of the Commission provided that the Quality Bank Naphtha cut would be valued based on Platts quoted price for Gulf Coast spot waterborne Naphtha. *Id.* At that time, notes Exxon, there only was one Platts price assessment for Gulf Coast spot waterborne Naphtha. *Id.* As a result of Platts February 2003 decision to publish two Naphtha prices, continues Exxon, the Quality Bank Administrator was confronted with the need to pick one of the two prices. *Id.* It argues that this situation falls squarely within the provision in Section III.J. of the TAPS Tariff authorizing the Quality Bank Administrator to resolve unanticipated implementation issues, and states that the Tariff provision makes clear that the Quality Bank Administrator is expressly authorized to resolve such implementation issues in accordance with the Administrator's best understanding of the intent of the Commission subject to review by the Commission. *Id.* at pp. 342-43.

2575. Exxon asserts that it was clearly not anticipated that Platts would begin to publish two separate assessments, and the Quality Bank Administrator's conclusion that the intent of the Commission was to select the Platts Gulf Coast Naphtha price assessment that best reflects the market value of the Quality Bank Gulf Coast Naphtha cut is not challenged. *Id.* at pp. 343-44. Further, Exxon notes, no party disagrees with the conclusion of the Quality Bank Administrator that the specifications for Platts Heavy Naphtha price assessment are closer to the specifications of the Quality Bank Naphtha cut. *Id.* at p. 344.

2576. In these circumstances, Exxon maintains, there is plainly no merit to the claim of Petro Star and Unocal/OXY that the publication of the new Platts Heavy Naphtha quotation did not present an unanticipated implementation issue under Section III.J. of the Tariff because Platts continued to publish the original Full Range Gulf Coast Naphtha price assessment and the Quality Bank Administrator could have continued to use that price. *Id.* Exxon argues that the discontinuance of a proxy price is plainly not a prerequisite to action by the Quality Bank Administrator under Section III.J. of the Tariff. *Id.* at pp. 344-45. In fact, notes Exxon, the discontinuance of a proxy price is specifically addressed in a completely different section – Section III.G.5. – of the TAPS Tariff. *Id.* Therefore, it concludes, the provisions of Section III.J. for dealing with unanticipated implementation issues do not even apply to the discontinuance of a proxy price, and they cannot be limited to that situation as Petro Star and Unocal/OXY suggest. *Id.*

2577. Exxon asserts that Unocal/OXY's further argument that, because the evidence allegedly indicates that the Gulf Coast price overvalues West Coast Naphtha, the Gulf Coast price should not be adjusted in any manner that would increase the current valuation of West Coast Naphtha is based on an obviously incorrect premise. *Id.* It states, the evidence in this case is overwhelming that the Platts Gulf Coast price assessment in fact substantially undervalues West Coast Naphtha, and there is absolutely no credible evidence that it has ever overvalued West Coast Naphtha. *Id.* Accordingly, Exxon declares, there is no valid basis whatsoever for Unocal/OXY's opposition to the use of the Platts Heavy Naphtha price assessment on the Gulf Coast. *Id.*

2578. In his discussions with Sharp at Platts, states Exxon, the Quality Bank Administrator also learned that, in assessing Naphtha prices, Platts bases its published Gulf Coast Naphtha prices on the assumption that Naphtha has an N+A of 40, and that Platts adjusts for higher values of N+A by adjusting the price by 0.15¢/gallon per percent N+A above 40 up to an N+A of 50 (or an adjustment of 1.5¢/gallon for any Naphtha with an N+A over 50). Exxon Initial Brief at p. 327. In light of this new information, Exxon and Phillips propose that the Quality Bank Administrator add 1.5¢/gallon to the Platts Heavy Naphtha price to reflect the higher N+A of Quality Bank Naphtha. *Id.* Further, states Exxon, although the Quality Bank Administrator took the position that he was not authorized to adjust the published Platts price without Commission authorization, and he took no position either for or against the proposed 1.5¢/gallon adjustment, he testified that it would be administratively feasible to add 1.5¢/gallon to the Platts Gulf Coast Heavy Naphtha price in order to reflect the higher value of the N+A content of Quality Bank Naphtha. *Id.* at p. 328. It notes that Williams, Unocal/OXY, BP, and Petro Star oppose this proposal. Exxon Reply Brief at p. 346.

2579. Exxon asserts that both the factual evidence and relevant legal principles reveal that the Commission should adopt the proposed N+A adjustment to the Platts published price to reflect the higher value of Quality Bank Naphtha. *Id.* It asserts that the evidence clearly establishes that the Gulf Coast Naphtha prices published by Platts are based on an N+A of 40. Exxon Initial Brief at p. 328. It is also undisputed, according to Exxon, that the Naphtha produced from ANS crude has an N+A that is greater than 55. *Id.* It therefore follows, claims Exxon, that the Quality Bank Naphtha, which has an N+A substantially higher than 50, would receive the maximum Platts N+A adjustment of 1.5¢/gallon. *Id.*

2580. The evidence is also overwhelming, Exxon claims, that Naphtha with a higher N+A is more valuable than Naphtha with a lower N+A. *Id.* at p. 329. It explains that this is because naphthenes are easily transformed into aromatics in the reforming process and because aromatics have a very high octane and produce high octane gasoline, which sells for a higher price because it is not prone to knocking. *Id.* Exxon goes on to suggest that a higher N+A permits the reformer to be operated at a lower level of severity, or lower temperature, to produce a reformate of a given octane, which both reduces the cost of operation and significantly increases the yield or volume of gasoline that is produced from a barrel of Naphtha feed. *Id.* In addition, notes Exxon, a higher N+A increases the yield of valuable hydrogen and extends the life of the catalyst used in the reforming process. *Id.* As a direct result of the many benefits of high N+A Naphtha, Exxon states, it is more profitable to operate a refinery using Naphtha with a higher N+A, and refineries pay a higher price for such Naphtha. *Id.* at pp. 329-30. It states that this viewpoint is corroborated by Sorenson's studies which were presented at the hearing. Exxon Reply Brief at pp. 347-48. His studies prove, in Exxon's view, that high N+A improves refinery economics under all scenarios, including the California Air Resources Board specifications. *Id.* at p. 348.

2581. Despite this overwhelming evidence, Exxon states, Williams claims that the high levels of benzene, benzene precursors, and heavy aromatics make ANS Naphtha less desirable for manufacturing finished gasoline, particularly in California's restrictive California Air Resources Board regime.[728] *Id.* at p. 348. It asserts that Williams has presented no credible evidence to support its contention. *Id.* Most importantly,

[728] Exxon notes that Unocal/OXY also make this argument, although it asserts they provide little or no analysis supporting it. Exxon Reply Brief at p. 348, n.218.

according to Exxon, its witnesses, Sanderson and Sarna, presented no counter-study in response to Sorenson's analysis, despite their extensive experience running linear programming models and their having had access to Sorenson's model. *Id.*

2582. Instead, explains Exxon, Williams relies only on its witnesses's unsubstantiated hypotheses about N+A. *Id.* at p. 349. For example, Exxon notes that Williams cites Sanderson's view that West Coast refiners would prefer Naphtha with lower or no benzene or its precursors. *Id.* This supposition is squarely contradicted by Sorenson's testimony and study, yet, Exxon states, Williams cites no evidence to back up Sanderson's view and Williams's brief does not even discuss Sorenson's study. *Id.* Moreover, Exxon suggests, this alleged importance of benzene is contradicted by the fact that much of the data at Sanderson and Sarna's firm, Purvin & Gertz, does not include benzene. *Id.* If West Coast refiners were as severely limited by benzene restrictions as Williams now contends, Exxon asserts, one would certainly expect that Sanderson and Sarna's firm would have an abundance of this information. *Id.*

2583. Furthermore, Exxon argues, directly contrary to Williams's claim, Purvin & Gertz published a Global Petroleum Market Outlook study in 2001 that states that N+A is highly valued by gasoline producers in the reforming process. *Id.* at pp. 349-50. The evidence clearly shows, according to Exxon, that Purvin & Gertz specifically advises its refining industry clients that a high N+A content adds significant value to Naphtha. *Id.* at p. 350. Exxon notes that Williams ignores this study in its brief. *Id.*

2584. Although Sanderson claimed on redirect examination that this Purvin & Gertz study supported his position because it also recognized that there are U.S. environmental restrictions that limit the amount of aromatics in gasoline, Exxon asserts, that fact does not support his position. *Id.* It maintains that, while no party disagrees that there are restrictions on aromatics and benzene in gasoline, these restrictions, even in California, do not erase the significant value that high N+A content brings to CARB gasoline producers, as shown by Purvin & Gertz.[729] *Id.*

2585. Exxon asserts that Sarna's testimony suffered from several shortcomings that were exposed at the hearing. *Id.* at pp. 350-51. First, Exxon argues that Sarna was not a credible witness, was evasive during his testimony, and for that reason his testimony should not receive much weight. *Id.* at p. 351. Second, Exxon states, Sarna's exhibits

[729] Exxon states that Sanderson's claim that low utilization levels for West Coast catalytic reformers demonstrate that stringent benzene and aromatics requirements have lowered N+A values in California is also refuted by a report prepared by Purvin & Gertz which states that reforming capacities in California were utilized approximately 90% on average during 2000. Exxon Reply Brief at p. 350, n.219. It points out that Williams does not mention this Purvin & Gertz report in its initial brief either. *Id.*

were shown to contain several errors and unwarranted assumptions. *Id.* For example, Exxon explains, Sarna's list of what he called desirable and undesirable N+A components in Exhibit No. WAP-275, which Williams cites in its brief, had boiling points listed that are highly misleading. *Id.* In particular, notes Exxon, the depiction of undesirable C_6 components incorrectly suggests that all this material would boil off at 176°F, when in fact substantial portions (possibly as much as 50%) would boil off at temperatures below the Quality Bank Naphtha cut range. *Id.* Further, continues Exxon, Sarna admitted that he could not quantify how much of the undesirable C_{10} components would fall within the Quality Bank Naphtha cut range and that he had done no investigation of the evidence in the record to support his assumptions on this point. *Id.* at pp. 351-52. Exxon also suggests that the only point that Exhibit No. WAP-275 clearly demonstrates is that, as Sarna agreed, the Quality Bank Naphtha cut range of 175-350°F contains all of the desirable N+As. *Id.* at p. 352. It argues that this exhibit actually cuts squarely against Williams's position and instead supports the need for an N+A adjustment.[730] *Id.*

2586. Third, Exxon claims, the 1991 article contained in Exhibit No. WAP-278 undermines Williams's position. *Id.* Using an approach similar to Sorenson's study, explains Exxon, the article sets forth an economic analysis of refining margins which shows that the benzene saturation process discussed in the article is the best option on the West Coast. *Id.* Thus, according to Exxon, UOP, a major supplier of reformer technology, was marketing technology to mitigate substantially whatever negative impact so-called undesirable C_6 N+A components might have on the value of West Coast Naphtha at least five years in advance of the introduction of California Air Resources Board specifications in 1996. *Id.* at pp. 352-53. Exxon points out that Sorenson's testimony and Exhibit Nos. PAI-259 through PAI-261 demonstrate that mitigation of this nature is exactly what nearly all West Coast refiners have done within the last decade.[731] *Id.* at p. 253.

[730] Exxon notes that another shortcoming with Exhibit No. WAP-275 is that it erroneously suggested that all of the so-called "undesirable" N+A components actually go into a reformer; whereas, as Sarna conceded, refiners do not run all of these components into a reformer, but rather only a small percentage. Exxon Reply Brief at p. 352, n.220.

[731] Exxon contends that Williams's reliance on a quote in Exhibit No. WAP-278 regarding ANS's benzene content in connection with Sarna's exhibit comparing ANS to other crudes is weak. Exxon Reply Brief at p. 354, n.222. Exxon notes that Sarna admitted that he did not know the date of the assay utilized for the March 1991 article nor what changes in benzene content might have occurred in the intervening twelve-plus years resulting from, for example, the addition of the Alpine and Northstar fields. *Id.* Indeed, states Exxon, Sanderson conceded that the properties of ANS crude have been changing over time as new fields have been added to the TAPs stream. *Id.*

2587. Exxon asserts that another reason Sarna's exhibit, comparing ANS to other crudes, is entitled to no weight is because it is riddled with unwarranted assumptions. *Id.* At the hearing, notes Exxon, it was demonstrated that Sarna selected the crudes for his chart in such a manner as to render this exhibit totally unreliable. *Id.* In the first place, states Exxon, Sarna had virtually no understanding regarding the information contained in the database (Exhibit No. WAP-281) on which he based his calculations. *Id.* It explains that, according to Sarna, there were no directions as to how the database works, and he made no further efforts to either inquire or understand the nature and source of the data. *Id.* In Exxon's view, this fact weighs heavily because Sarna admitted that he did not know, for example, why multiple data-entry dates appeared for the same crudes or at what temperature all of the benzene boiled off in the sample tests. *Id.* Furthermore, continues Exxon, Sarna used this database despite finding data for some crudes that he knew were inaccurate and he also did not verify the database against any other available assay information. *Id.* at p. 354.

2588. As for the four specific crudes listed in Exhibit No. WAP-279, which Sarna selected from the ETC database of approximately 450 crudes, Exxon notes, he could not say that they were representative of all the crudes contained in the database; nor could he say how many of the 450 total were processed in California. *Id.* It states that Sarna also did not know crucial information about the specific assays for the crudes that he selected for inclusion in his analysis. *Id.* For example, according to Exxon, Sarna admitted that he did not know how long before 1993 the Arabian Light sample was taken. *Id.* Further, notes Exxon, Sarna also conceded that he did not know if the Oriente assay was taken before or after the Oriente composition changed significantly in the mid-1990s, and thus he did not know if the Oriente data is representative of Oriente in 2002, when the comparison to 2002 ANS crude was done. *Id.* Finally, Exxon points out that Sarna further admitted that he did not know when the sample was taken for the Point Arguello Light crude on his exhibit. *Id.* at pp. 354-55.

2589. It was also demonstrated, according to Exxon, that, even looking past the serious deficiencies in Exhibit No. WAP-279, the exhibit provides no useful comparison for purposes of resolving the N+A question at issue in these proceedings. *Id.* at p. 355. For example, explains Exxon, Exhibit No. PAI-258 demonstrates that, if Sarna had chosen other marker crudes to compare to ANS, he would have found that there are some well known crudes in the world market which have benzene contents that are higher than ANS and considerably higher than the three crudes he did choose.[732] *Id.* Additionally, notes

[732] Exxon comments that Williams attempted to explain away Exhibit No. PAI-258 by contending that the additional marker crudes listed were not processed in California and therefore not relevant to Sarna's analysis. Exxon Reply Brief at p. 355, n.223. It asserts that the weight of this claim is significantly undercut by the fact that Sarna could not say that the crudes he chose were representative of all the crudes

Exxon, Exhibit No. EMT-661 demonstrates that, on both a total crude and Quality Bank Naphtha basis, ANS has significantly more toluene and xylene (as well as benzene) than the three crudes (Arabian Light, Oriente, and Port Arguello Light) that Sarna chose for comparison.[733] *Id.* Exxon contends that it is undisputed that toluene and xylene are valuable properties, a fact which Sarna ignored in his analysis. *Id.* at p. 356. Thus, Exxon's position is that Exhibit No. WAP-279 provides no useful comparison of ANS to these other crudes. *Id.*

2590. Exxon claims that the Circuit Court already has held that the Quality Bank should adjust reported price assessments used to value Quality Bank cuts where there are differences between the qualities specified for the product valued by the reported price assessment and the qualities of the Quality Bank cut. Exxon Initial Brief at p. 330. For example, Exxon asserts that, in *OXY,* the Circuit Court directed that adjustments be made to the reported price assessments for jet fuel and No. 2 fuel oil to reflect differences in the quality of those products versus the Light Distillate and Heavy Distillate Quality Bank cuts, and the Commission established such adjustments. *Id.* (citing *OXY,* 64 F.3d at pp. 693-94; *Trans Alaska Pipeline System*, 81 FERC at pp. 62,462-63). Exxon also contends that the Circuit Court further found that a failure to take into account the quality differences between the Quality Bank cuts and the products underlying the published reference prices would unfairly distort the Quality Bank valuation. *Id.* (citing *OXY,* 64 F.3d at p. 693).

2591. For the same reasons, Exxon advocates adjusting the Gulf Coast Naphtha price assessments reported by Platts to reflect what it considers the undisputed fact that Quality Bank Naphtha has a significantly higher N+A than the Naphtha priced by Platts, which Exxon asserts renders Quality Bank Naphtha more valuable than the Naphtha on which the Platts price is based. *Id.* at pp. 330-31. As in *OXY*, Exxon views a failure by the Commission to take into account the higher quality of Quality Bank Naphtha would unfairly distort the Quality Bank valuation by penalizing some producers and providing a

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contained in the database or how many of the 450 total crudes were processed in California. *Id.* Exxon also notes that this concern is substantially mitigated by the fact that Sarna admitted that the five additional crudes added in Exhibit No. PAI-258 are marker crudes, i.e., crudes which traders use to price other crudes. *Id.* This is particularly significant, Exxon argues, as the crudes Sarna did select were not large volume crudes in California. *Id.*

[733] Exxon points out that although Sarna attempted to argue that there was a distinction between the total crude and Quality Bank Naphtha basis, he admitted that he had done no calculations to support this claim even though he had been provided a version of Exhibit No. EMT-661 in advance of his appearance at the hearing. Exxon Reply Brief at p. 356, n.224.

windfall to others. *Id.* at p. 331.

2592. Exxon notes that BP argues, on the other hand, that *OXY* counsels against the adjustment, stating that using an adjustment would treat the Naphtha cut differently than all other cuts. Exxon Reply Brief at p. 356. This argument is without merit, Exxon claims and notes that the Circuit Court stated, in *OXY*: "The goal of the Quality Bank valuation methodology, as all parties agree, is to assign accurate relative values to the petroleum that is delivered to TAPS and becomes part of the common stream." *Id.* (quoting *OXY*, 64 F.3d at p. 693). According to Exxon, the Quality Bank already makes quality adjustments to the Light and Heavy Distillate cuts based on *OXY*'s holding that a failure to take into account quality differences between the Quality Bank cuts and the products underlying the published reference prices would unfairly distort the Quality Bank valuation. *Id*. Here, according to Exxon, it is known – by virtue of the Quality Bank Administrator's testimony and Exhibit No. PAI-222 – that Platts makes specific adjustments for N+A in developing its Gulf Coast Naphtha and Heavy Naphtha price assessments. *Id.* at p. 357. Exxon notes that no other evidence of similar adjustments has been presented by any party. *Id.* Thus, Exxon contends, the Commission should adjust the Gulf Coast Naphtha price assessments reported by Platts to reflect the undisputed fact that Quality Bank Naphtha has a significantly higher N+A than the Naphtha price assessments reported by Platts. *Id.* As is clear from the evidence, asserts Exxon, the N+A content of the Platts price assessments is not close enough to the known actual value of higher N+A content of Quality Bank Naphtha to justify ignoring the proposed adjustment. *Id.* Because that is true, Exxon maintains that, as in *OXY*, a failure by the Commission to take into account the higher quality of Quality Bank Naphtha would unfairly distort the Quality Bank valuation by penalizing some producers and providing a windfall to others. *Id.*

2593. Exxon asserts that there is also no merit to BP's argument that, because other processing cost adjustments relate to proxy prices for finished products, the N+A adjustment would be inconsistent because it would be an adjustment to an intermediate product reference price to value a comparable intermediate product. *Id.* at p. 358. It argues that the important thing is that the value of the proxy price be adjusted to reflect the quality of the Quality Bank product. *Id.* In Exxon's view, it makes no difference whether that proxy price is characterized as a product for a finished product or an intermediate product, and BP presents no basis for making that distinction. *Id.*

2594. The evidence, Exxon argues, also strongly supports the reasonableness of the adjustment used by Platts of 1.5¢/gallon for Naphtha with an N+A over 50. Exxon Initial Brief at p. 331. First, it notes that the 1.5¢/gallon N+A adjustment is supported by the increased value of the higher octane gasoline produced by Naphtha with an N+A of 55 as compared to Naphtha with an N+A of 40 as assumed by Platts. *Id.* For example, continues Exxon, when the higher market value of the higher octane gasoline that results from a higher N+A is calculated on the basis of cents per gallon per N+A, the evidence shows that each additional N+A point is worth about 0.27¢/gallon on the Gulf Coast and about 0.51¢/gallon on the West Coast. *Id.* According to Exxon, both of these numbers exceed the value of 0.15¢/gallon per N+A (with a cap of 1.5¢/gallon) used by Platts, thus demonstrating that the N+A adjustment used by Platts is conservative. *Id.*

2595. Similarly, explains Exxon, if one holds the octane level constant and values the resulting differences in yields produced by Naphthas with different levels of N+A, the evidence shows an increase in value in going from an N+A of 40 (the Platts specification) to an N+A of 57 (Quality Bank Naphtha) ranging from 1.24¢ to 2.06¢/gallon on the Gulf Coast, and from 1.27¢ to 2.63¢/gallon on the West Coast, depending on what period is used and how the reformate is valued. *Id.* at pp. 331-32. Exxon notes that these numbers are consistent with the 1.5¢/gallon adjustment that Platts applies, which is near the lower end of the range of added values for higher N+A. *Id.* at p. 332. The 1.5¢/gallon adjustment used by Platts was also validated by Sorenson, states Exxon. *Id.*

2596. The evidence further shows, according to Exxon, that the proposed N+A adjustment necessary to bring the published Platts Naphtha prices to the quality level of the Naphtha produced from ANS crude would have a sufficient dollar impact on the parties to the Quality Bank to justify the proposed N+A adjustment. *Id.* Further, notes Exxon, the evidence also shows that the proposed N+A adjustment is consistent in magnitude and impact with other adjustments that either are made by the Quality Bank or have been proposed for other Platts reference prices. *Id.* In particular, claims Exxon, the evidence shows that the proposed N+A adjustment for Naphtha is comparable to the 0.5¢/gallon price deduction that is made to the Light Distillate reference price and to the 1.1¢/gallon logistics adjustment that has been proposed by the Eight Parties for the Heavy Distillate cut. *Id.* at pp. 332-33.

2597. Exxon argues that the additional criticisms presented by those parties which oppose the N+A adjustment are equally without merit. Exxon Reply Brief at p. 360. It notes that Williams and BP both argue that the information in Exhibit No. PAI-222 is not sufficient evidence upon which the Commission can accept the proposed N+A adjustment. *Id.* at p. 361. Exxon asserts that this contention is clearly incorrect. *Id.*

2598. According to Exxon, page 8 of Exhibit No. PAI-222 provides sufficient grounds for the Commission to accept the N+A adjustment, especially in light of the Quality Bank Administrator's testimony as to its accuracy. *Id.* Specifically, notes Exxon, the Quality Bank Administrator stated that N+A adjustments had been done in the past for Full Range Naphtha and this practice would be continued for the new adjustments. *Id.* Therefore, states Exxon, BP is incorrect in arguing that no adjustment is appropriate now because adjustments had never been made before. *Id.* at n.228. Given the Quality Bank Administrator's testimony at the hearing that he confirmed this practice with Sharp and the testimony of Sanderson that he also confirmed this practice in a later telephone conversation with Sharp, Exxon contends there is more than enough proof to establish that Platts makes this adjustment and that, consequently, the Quality Bank should also make an N+A adjustment. *Id.* at pp. 361-62.

2599. Exxon also finds it ironic that, in its discussion of the Naphtha contracts, BP lauds the editorial discretion exercised by Platts in formulating its assessments, yet it refuses to accept Sharp's report to the Quality Bank Administrator that Platts makes this kind of editorial adjustment.[734] *Id.* at p. 362. It suggests that the inconsistency of these positions is highlighted by the fact that BP urges the Commission to adopt Ross's governor which is purportedly designed to simulate a transparent market, but dismisses Sharp's real-world adjustment as too speculative. *Id.*

2600. Similarly, Exxon notes, Williams contends that the Commission should take the word of its witness, Sanderson, over that of the Quality Bank Administrator because some key questions were not asked of Sharp. *Id.* It asserts that the record makes it clear that greater weight should be given to the testimony of the Quality Bank Administrator. *Id.* at pp. 362-63. Exxon explains that the Quality Bank Administrator twice confirmed at the hearing that Sharp, in answer to an open ended question on quality adjustments, mentioned only the N+A adjustments to Naphtha and Heavy Naphtha. *Id.* at p. 363. By contrast, Exxon states, Sanderson claims to have asked Sharp leading questions about the Platts assessment during conversations which occurring between March 2003 and June 2003, but did not take any notes or otherwise memorialize these conversations. *Id.* Moreover, Exxon asserts that Sanderson, apparently, did not attempt to verify Exhibit No. PAI-222's accuracy with Sharp during those conversations. *Id.* Furthermore, Exxon notes, Sharp did not give Sanderson any indication of adjustment factors for specifications other than N+A even when pressed.[735] *Id.* at pp. 363-64. In Exxon's view, therefore, Sanderson's testimony strongly corroborates the Quality Bank Administrator's memorandum and testimony regarding the N+A adjustment made by Platts. *Id.* at p. 364. There is nothing in the record, asserts Exxon, to support Sanderson's speculation that

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[734] Exxon takes exception to BP's description of Sharp as merely a Platts's employee. Exxon Reply Brief at p. 362, n.229. It explains that Sharp is the person at Platts who does the price assessment for the Naphtha quotes utilized by the Quality Bank. *Id.* Further, Exxon believes that the Commission should ignore BP's speculative argument concerning the consequences of Sharp's being replaced and should, instead, rely on the regular course of business in which Sharp does set the price and applies the N+A adjustment he discussed with the Quality Bank Administrator. *Id.*

[735] Exxon disagrees with Williams's argument that the Commission should not adopt this proposal because Sharp does not apply his N+A adjustment to all Naphtha transactions. Exxon Reply Brief at p. 364, n.231. It points out that the Quality Bank Administrator stated the adjustment was always applied unless Sharp did not know the N+A content of the Naphtha being sold. *Id.*

Sharp also considers specifications like Reid Vapor Pressure, sulfur, sometimes mercaptans and distillation, and certainly nothing to suggest that he makes any specific adjustment to the Platts price based on anything other than N+A. *Id.*

2601. Exxon states that Williams, Unocal/OXY, and BP also claim, erroneously, that adopting the N+A proposal here would open the Quality Bank up to another level of overly-complicated analysis. *Id.* at pp. 364-65. It asserts that this argument is belied by the fact that no other quality adjustments have been proposed by, or are apparently known to, any party. *Id.* at p. 365. According to Exxon, Sharp told the Quality Bank Administrator he only made an N+A adjustment (as well as the Heavy Naphtha adjustment discussed above). *Id.* Thus, in Exxon's view, this "Pandora's Box" argument is nothing more than an unsubstantiated doomsday scenario designed to discourage the Commission from adopting this known quality adjustment.[736] *Id.* For the Pandora's Box to open, Exxon contends, a party would have to gather information that is not currently known, bring it to the Commission's attention, and carry its burden to prove that an adjustment is required. *Id.* By virtue of Exhibit No. PAI-222, the Quality Bank Administrator's testimony, and the overwhelming evidence discussed above, Exxon believes that it and Phillips have carried this burden. *Id.*

2602. The use of the Platts Heavy Naphtha price on the Gulf Coast and the need for the proposed N+A adjustment to that price to accurately reflect the value of the Quality Bank Gulf Coast Naphtha cut, Exxon claims, does not change its position that Quality Bank Naphtha should be valued on the West Coast in accordance with the regression formula presented by Tallett.[737] Exxon Initial Brief at p. 333.

2603. In accordance with the Commission's order of March 28, 2003, Exxon states that the Quality Bank Administrator began valuing Quality Bank Naphtha on both the Gulf Coast and the West Coast using the new Platts Heavy Naphtha price rather than the Platts Full Range Naphtha price on March 1, 2003, subject to refund. *Id.* at pp. 333-34 (citing

[736] Exxon claims that this argument clearly is a red herring. Exxon Reply Brief at p. 365, n.233. It explains that, while Williams contends that implementing the proposed N+A adjustment is not simply a matter of adding 1.5¢/gallon to the quoted price, the dispositive answer is that the Quality Bank Administrator testified that it was exactly that simple and making an N+A adjustment would not affect the feasibility elements. *Id.*

[737] Exxon asserts that a strong argument could be made that Tallett's regression formula undervalues West Coast Naphtha by 2.5¢/gallon (or $1.05/barrel) because his regression analysis was based on the Platts Gulf Coast price assessment for Full Range Naphtha rather than the Platts Heavy Naphtha price assessment, and because the Gulf Coast Naphtha price that he used was predicated on an N+A of 40, far below the N+A of Quality Bank Naphtha. Exxon Reply Brief at p. 366, n.234.

BP Pipelines (Alaska) Inc., 102 FERC ¶ 61,345 (2000)). Exxon asserts that this change to the use of the Platts Heavy Naphtha price to value the Quality Bank Naphtha cut on the Gulf Coast – a step that is supported by overwhelming evidence and was not opposed by any party – should be approved by the Commission with an effective date of March 1, 2003. *Id.* at p. 334. Exxon also states that the proposal to value the Quality Bank Naphtha cut on the Gulf Coast by adding 1.5¢/gallon to the Platts Gulf Coast Heavy Naphtha price to account for the higher N+A of the Quality Bank Naphtha cut should also be made effective as of March 1, 2003. *Id.*

2604. Exxon states that Williams agrees that the Platts Heavy Naphtha price should be effective on March 1, 2003.[738] Exxon Reply Brief at p. 367. It notes that Unocal/OXY also agrees that any resolution to the Heavy Naphtha price should be implemented as of March 1, 2003, and BP does not address the effective date issue regarding the Heavy Naphtha issue. *Id.* Petro Star, Exxon continues, appears willing to agree to a March 1, 2003, effective date so long as the effective date for the change in the West Coast VGO reference price is also March 1, 2003. *Id.* Exxon indicates that it has no problem with Petro Star's position so long as the issue of what price is to be used for valuing West Coast Naphtha is resolved and made effective as of March 1, 2003. *Id.* It suggests that it would not be appropriate to allow a West Coast VGO reference price to become effective in advance of resolution of the issue of whether a West Coast based price is going to be used to value West Coast Naphtha. *Id.* Accordingly, Exxon would object to a decision in which the West Coast VGO reference price became effective on March 1, 2003, but West Coast Naphtha continued to be valued on the basis of a Gulf Coast price (whether it be a Full Range Naphtha price or a Heavy Naphtha price) pending resolution of all the issues presented in this proceeding. *Id.* at pp. 367-68.

2605. According to Exxon, Williams, Unocal/OXY, and BP argue that, if an N+A adjustment is adopted by the Commission, it only should be implemented prospectively. *Id.* at p. 368. According to Exxon, Williams, the only party that provided a basis for this position, argues that this change was not recommended by the TAPS Carriers and that the Quality Bank Administrator chose not to include this adjustment; but Williams provides no substantive analysis of this position. *Id.* As an initial matter, Exxon points out that the Quality Bank Administrator did not make the proposed adjustment only because he believed that he did not have authority, absent an order from the Commissions, to make any adjustment to the published prices. *Id.*

2606. Further, Exxon argues, the fact that the Quality Bank Administrator made no recommendation on this matter is of no legal significance. *Id.* It contends that the Commission plainly has the authority under Section 15(7) of the Interstate Commerce

[738] Exxon notes they assume that Williams's statement of the date in its initial brief as March 3, 2003, is a typographical error. Exxon Reply Brief at p. 367.

Act, 49 U.S.C. § 15(7)(1988), to allow challenged rate increases to take effect while it investigates their reasonableness. *Id.* Accordingly, Exxon maintains, there is no statutory impediment to the use of a March 1, 2003, effective date for all of the proposed revisions to the Naphtha valuation. *Id.* at p. 369.

2607. On June 18, 2003, states Exxon, the Quality Bank Administrator filed with the Commission a "Notice of TAPS Quality Bank Administrator Regarding Proposed Replacement Product Price To Value Naphtha Component On The U.S. Gulf Coast And U.S. West Coast." Exxon Supplemental Brief at p. 2. In that Notice, explains Exxon, the Quality Bank Administrator informed the Commission that the Platts Gulf Coast "Heavy Naphtha" assessment -- which he had previously recommended be adopted as the Quality Bank reference price on February 27, 2003 – had been "radically altered" under the TAPS Carriers's Tariff, thereby requiring him to "propose an appropriate replacement product price, with explanation and justification." *Id.* According to Exxon, the specific change that prompted this filing was that "beginning on May 1, 2003, Platts began publishing two Gulf Coast waterborne assessments for Heavy Naphtha," one entitled "Heavy Naphtha" and the other entitled "Heavy Naphtha Barge." *Id.*

2608. As part of this Notice, continues Exxon, the Quality Bank Administrator indicated that he had discussed the two new Heavy Naphtha assessments with Sharp, the analyst responsible for Platts various Naphtha assessments, and that Sharp had confirmed that: (1) in May 2003 Platts had begun to report Heavy Naphtha barge and cargo price assessments separately; and (2) "numerous transactions" supported both assessments. *Id.* at pp. 2-3. Based on this information, states Exxon, the Quality Bank Administrator concluded that using a simple average of the separate cargo and barge assessments would best represent the market value of Heavy Naphtha and, for this reason, he "propose[d] that the replacement price for the Naphtha component on both the Gulf Coast and the West Coast be the arithmetic average of the average monthly price for Gulf Coast Waterborne 'Heavy Naphtha' and Gulf Coast Waterborne 'Heavy Naphtha Barge' as reported by Platts." *Id.* at p. 3.

2609. According to Exxon, there are two basic matters at issue: first, was the Quality Bank Administrator's June 18, 2003, decision to propose a replacement price for the valuation of Gulf Coast Naphtha justified?; second, does his proposal to use the arithmetic average of the average monthly price assessments for Platts Gulf Coast Waterborne "Heavy Naphtha" and Gulf Coast Waterborne "Heavy Naphtha Barge" assessments produce a just and reasonable result? Exxon Supplemental Brief at p. 5. Exxon argues that the Quality Bank Administrator's decision to propose a replacement price was justified and that his averaging proposal produces a just and reasonable result for valuation of the Quality Bank Naphtha cut on the Gulf Coast. *Id.*

2610. Exxon agrees with the Quality Bank Administrator's determination that the change that occurred in the Platts assessments on May 1, 2003, constituted a radical alteration under Section III.G.5.b of the Tariff. *Id.* According to it, the evidence clearly establishes that prior to May 1, 2003, the Platts "Heavy Naphtha" assessment was based on prices from both cargo and barge transactions and that the resulting price assessment constituted neither a cargo assessment nor a barge assessment. *Id.* at p. 6. For example, notes Exxon, on September 15, 2003, Sharp told the Quality Bank Administrator, Toof and Jones that Platts pre-May 2003 Heavy Naphtha assessment was not solely a cargo and not solely a barge assessment, but was influenced by both types of transactions. *Id.*

2611. According to Exxon, BP, Unocal/OXY, Williams, and Petro Star take issue with the Quality Bank Administrator's decision to recommend a new reference price and argue that the existing reference price was not radically altered under the TAPS Carriers's Tariff.[739] Exxon Reply Brief at p. 372. It states that BP and Unocal/OXY go so far as to suggest that no change at all occurred to the Platts Heavy Naphtha assessment that was in place between February-April 2003. *Id.* This latter assertion, Exxon declares, is clearly false. *Id.* It contends that the evidence plainly demonstrates there definitely had been a change in the Platts Gulf Coast Heavy Naphtha assessment on May 1, 2003, and that the combined cargo-barge Heavy Naphtha assessment ceased to exist after May 1, 2003, when Platts split the cargo and barge transactions into separate assessments. *Id.*

2612. Similarly lacking in merit, in Exxon's view, is Williams's argument that the existing Heavy Naphtha (cargo) assessment is consistent with the pre-May 2003 combined cargo-barge assessment. *Id.* at p. 373. Exxon states that, contrary to Williams's claims, this contention is not supported by statements made by Exxon's counsel at the August 26, 2003, status hearing. *Id.* at p. 373. As is clear from the Transcript, notes Exxon, the matter being discussed at that hearing was whether, in fact, there had been a change in the Platts Heavy Naphtha assessment. *Id.* Exxon points out that the reason the Quality Bank Administrator was directed to again contact Sharp was to ensure that, in fact, a change had occurred. *Id.*

2613. Exxon also charges that the suggestion that the change in the Heavy Naphtha assessment was not radical is deficient. *Id.* It notes that the Tariff itself recognizes that the magnitude or financial impact of a change is not a legitimate ground upon which to assess whether or not a reference price change is radical. *Id.* Moreover, Exxon characterizes the idea that parties would assert that they will be injured by the Quality Bank Administrator's proposal while at the same time arguing that the change should not

[739] Exxon asserts that the fact that Platts did not alter the name of its new Heavy Naphtha cargo assessment to make clear that it was different from its earlier assessment of the same name (which included both cargo and barge assessments) does not undermine this conclusion. Exxon Supplemental Brief at p. 7, n.7. It states that one of the purposes of the September 15, 2003, call was to make sure that in fact the pre- and post-May 2003 assessments were different. *Id.*

be implemented because it is not large enough as ridiculous. *Id.* at pp. 373-74.

2614. Furthermore, Exxon asserts, the claim that the change in the Platts assessment is too small is not consistent with the valuation of other Quality Bank cuts which have similarly-sized adjustments. *Id.* at p. 374. For example, Exxon notes, the reference price for the Light Distillate cut is Platts West Coast Waterborne Jet Fuel assessment minus approximately 0.5¢/gallon. *Id.* It is also worth noting, in Exxon's view, that a number of the specific adjustments that are at issue in this proceeding with regard to the Resid and Heavy Distillate cuts involve amounts comparable to the difference in the Platts "Heavy Naphtha" assessments before and after May 1, 2003. *Id.*

2615. Finally, even were the change in the Platts Heavy Naphtha assessment to not constitute a radical alteration under the TAPS Carriers Tariff, Exxon argues, the Quality Bank Administrator's actions would still be appropriate. *Id.* According to Exxon, on February 27, 2003, the Quality Bank Administrator recommended that the Commission adopt Platts new Gulf Coast Heavy Naphtha assessment as the reference price for Naphtha in the Quality Bank. *Id.* at pp. 374-75. While the Commission accepted this recommendation on an interim basis, it did not issue a final order accepting that price on a permanent basis. *Id.* at pp. 374-75 (citing *BP Pipelines (Alaska) Inc.*, 102 FERC at p. 62,160). Consequently, Exxon states, the Quality Bank Administrator was under a clear duty to inform the Commission when, less than three months after his recommendation, the Platts Heavy Naphtha assessment changed again. *Id.* at p. 375 (citing 18 CFR § 385.403(d)(2)(2004)). Furthermore, Exxon suggests, the Quality Bank Administrator's action here could have been justified under the Tariff's provision governing "unanticipated Implementation Issues." *Id.* (citing Exhibit No. TC-3 at p. 8).

2616. Exxon asserts that the Quality Bank Administrator's proposal to use the arithmetic average of the average monthly price for Platts Gulf Coast Waterborne "Heavy Naphtha" and "Heavy Naphtha Barge" assessments produces a just and reasonable result. Exxon Supplemental Brief at p. 7. According to it, the Quality Bank Administrator's averaging proposal best reflects Heavy Naphtha's market value on the Gulf Coast. *Id.* Exxon points out that both the Commission and the Circuit Court have stated several times that market value is the standard to be applied under the distillation methodology. Exxon Reply Brief at p. 376.

2617. Furthermore, according to Exxon, the Quality Bank Administrator's proposal is consistent with his previous recommendations regarding VGO and LSR, which both focused on choosing an assessment which best represented the market value for the proxy product. *Id.* at pp. 376-77. It states that the evidence clearly establishes, that Sharp told the Quality Bank Administrator that "there are numerous transactions for both full range and heavy naphtha in both barge and cargo lots, although for heavy naphtha, barge transactions may slightly predominate." Exxon Supplemental Brief at pp. 7-8 (quoting Exhibit No. TC-20 at p. 1). Based on this information, explains Exxon, the Quality Bank

Administrator reasonably concluded that "[b]oth markets are therefore representative of the market for Heavy Naphtha on the Gulf Coast" and recommended that an average of the two assessments be used. *Id.* at p. 8 (quoting Exhibit No. TC-19 at p. 4). Given past precedent establishing that each cut should reflect its market value, Exxon states that the Quality Bank Administrator's recommendation plainly produces an appropriate result on the Gulf Coast. *Id.*

2618. Exxon also states that the Quality Bank Administrator's proposal to use an average of the two post-May 2003 Heavy Naphtha assessments also constitutes the best way of replicating the values produced by the single "Heavy Naphtha" assessment that existed prior to May 1, 2003, which the Quality Bank Administrator earlier proposed be adopted by the Commission. *Id.* As noted above, states Exxon, that assessment included both cargo and barge transactions. *Id.* Exxon points out that Sharp indicated that, in making the earlier assessment, he "sometimes used barge transactions for the high for the day and cargo transactions for the low." *Id.* (quoting Exhibit No. TC-22 at p. 2). Moreover, notes Exxon, no party objected at the hearings to the Quality Bank Administrator's proposal that the pre-May assessment be used. *Id.* at pp. 8-9. Consequently, Exxon concludes, the Quality Bank Administrator's new proposal — which attempts to replicate Platts pre-May 2003 "Heavy Naphtha" assessment — produces a reasonable result. *Id.* at p. 9.

2619. In addition, Exxon asserts, there is no merit to the claim by Williams, Unocal/OXY, and BP that use of an average of the two Heavy Naphtha assessments is not consistent with the Commission's purported policy of choosing "the largest available quantities" to value each cut. *Id.* at p. 9; Exxon Reply Brief at p. 377. According to it, the Commission has never adopted such a policy. Exxon Supplemental Brief at p. 9. Exxon points out that, to the contrary, Ross testified at the hearing that the VGO cut is currently valued on both the West Coast and Gulf Coast on the basis of OPIS's Gulf Coast High Sulfur VGO barge price assessment, which is associated with transactions that are much smaller than the transactions associated with OPIS's Gulf Coast High Sulfur VGO cargo assessment. *Id.* It notes that Ross further acknowledged that the barge price was selected for VGO because on the day it was picked it was a more reliable indication of the actual spot market. *Id.* at pp. 9-10.

2620. Exxon notes that the same observation applies to the Quality Bank Administrator's proposal to average Platts two separate Heavy Naphtha assessments, both of which are supported by numerous transactions. *Id.* at p. 10. Consequently, Exxon states, the Quality Bank Administrator's proposal better captures the market value of Heavy Naphtha on the Gulf Coast than simply using one assessment or the other and, as such, constitutes the most "acceptable [indicator] of market value." *Id.* (quoting *Tesoro*, 234 F.3d at p. 1289).

2621. Williams, Unocal/OXY, BP, and Petro Star, Exxon states, make a number of arguments in opposition to the Quality Bank Administrator's averaging proposal, none of which are valid. Exxon Reply Brief at p. 377. It contends that the evidence clearly refutes these parties's assertions. *Id.* In 1998, notes Exxon, the Commission adopted the Quality Bank Administrator's recommendation that the OPIS High Sulfur VGO barge assessment be used as the reference price rather than the OPIS High Sulfur VGO cargo assessment notwithstanding the fact that the VGO cargo assessment was for much larger parcels. *Id.* at pp. 377-78. While BP and the other parties seek to distinguish that decision, it is revealing, Exxon maintains, that, in supporting the Quality Bank Administrator's VGO barge recommendation in 1998, none of those parties mentioned the supposed convention upon which they now rely or sought to distinguish it.[740] *Id.*

2622. Exxon asserts that Williams's attempt to suggest that the Quality Bank Administrator's 1998 recommendation somehow supports use of only the Heavy Naphtha (cargo) assessment is also misplaced. *Id.* It points out that Williams misquotes the Quality Bank Administrator's 1998 VGO notice by substituting the word "the" for the word "neither" in the sentence describing the liquidity of the Gulf Coast market for High Sulfur VGO, thereby completely mischaracterizing the factual context supporting the Quality Bank Administrator's proposal in that case. *Id.* Furthermore, Exxon asserts, resolution of the VGO issue in 1998 cuts squarely against the position that only the Heavy Naphtha (cargo) assessment should be used. *Id.* at pp. 378-79. It argues that, if anything, the VGO case – which used the barge price – indicates that the more predominant Heavy Naphtha Barge assessment should be the Quality Bank reference price if the Commission rejects the Quality Bank Administrator's averaging proposal. *Id.* at p. 379. In any event, Exxon agrees with the TAPS Carriers who point out that to ignore one assessment over the other where a number of transactions support both assessments would be arbitrary in the circumstances presented here. *Id.*

2623. The Quality Bank Administrator's averaging proposal, according to Exxon, also is simple and straight-forward: it takes an arithmetic average of the average monthly prices of the two Platts Heavy Naphtha assessments. Exxon Supplemental Brief at p. 10. Thus, Exxon asserts, BP's concern regarding the additional complexity of the proposal is misguided. *Id.*

2624. Moreover, Exxon states, it is not significant that no other Quality Bank cut is valued using an average of two separate prices. *Id.* As noted above, points out Exxon, the Quality Bank Administrator's averaging proposal best represents the market value of Gulf Coast Heavy Naphtha. *Id.* at pp. 10-11. Consequently, explains Exxon, his proposal is entirely consistent with the "goal of the Quality Bank valuation methodology .

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[740] Exxon suggests that Williams's further argument, that the Quality Bank Administrator's proposal would contravene the convention of using waterborne prices when available, is baseless since both of the Platts assessments are waterborne. Exxon Reply Brief at p. 378, n.246.

to assign accurate relative values to the petroleum that is delivered to TAPS and becomes part of the common stream." *Id.* at p. 11 (quoting *OXY*, 64 F.3d at p. 693). Further, Exxon argues, an unduly rigid interpretation of the Circuit Court's expression of the value of consistency would elevate form over substance if it prevented the Quality Bank from using an easily-ascertainable and well-documented market value of a product. *Id.* (quoting *Exxon*, 182 F.3d at p. 42). Also, notes Exxon, the Quality Bank Administrator's proposal is consistent with his previous recommendations regarding VGO and LSR, which both focused on choosing an assessment which best represented the market value for the proxy product. Exxon Reply Brief at pp. 376-77.

2625. Similarly lacking in merit, in Exxon's view, is the claim that such an approach would not be consistent with the so-called key premise of using a single intermediate feedstock price from an independent reporting service that, whenever possible, has not been modified. *Id.* at p. 379. According to Exxon, Williams, the primary advocate for this position, points to no authority in support of this premise. *Id.* Furthermore, Exxon argues, such an aspiration does not trump the clear goal of the Quality Bank that each cut should reflect the market value of the reference product price. *Id.*

2626. Exxon also argues that the claims that adopting the Quality Bank Administrator's averaging proposal will unduly complicate the Quality Bank are completely baseless. *Id.* at p. 380. It points out that there are no administrative feasibility problems with the Quality Bank Administrator's averaging proposal, and argues that this averaging methodology is quite similar to how the Quality Bank Administrator already uses the Platts and OPIS high and low price assessments under the Tariff. *Id.* Exxon also notes that the claim that adoption of the Quality Bank Administrator's averaging recommendation could result in future proposals that other product prices should be averaged is, at best, exaggerated. *Id.* It points out that no party has made any such proposal, and, even should they, they would still have to meet their burden to show that their averaging proposal better reflects the market value of the product than does the use of a single assessment. *Id.*

2627. Exxon's position is that, on the West Coast, the Quality Bank value of Naphtha should be based on the methodology proposed by Tallett in the ongoing Quality Bank proceedings, and that refunds should be provided based on that methodology back to March 1, 2003. *Id.* at pp. 380-81. Further, it asserts that the Commission should grant reparations for the period prior to March 1, 2003, back to June 19, 1994, based on Tallett's methodology. *Id.* at p. 381.

2628. Exxon states that the Quality Bank Administrator and most of the other parties take the position that the effective date should be August 17, 2003, the date on which the Commission accepted the Quality Bank Administrator's proposal on an interim basis subject to refund. Exxon Reply Brief at p. 381. Exxon also notes that Williams argues that the effective date should be when the Commission finally determine whether to accept the Quality Bank Administrator's averaging proposal rather than August 17, 2003, because to adopt the August 17, 2003, date would encourage the Quality Bank Administrator to make a recommendation without conducting a thorough investigation first. *Id.*

2629. According to Exxon, there is no merit to Williams's position. Exxon Reply Brief at p. 382. It points out that Williams has not cited any authority to support its proposal that there must be delay in order to teach the Quality Bank Administrator some sort of lesson. *Id.* Furthermore, delaying implementation of the averaging proposal would not have any impact on the Quality Bank Administrator, who has no financial stake in the Quality Bank. *Id.* Exxon also argues that the real punishment would be inflicted upon those parties who are penalized by the continued undervaluation of the Naphtha cut on both the Gulf Coast and West Coast. *Id.* Conversely, Exxon states, the party with the most to gain by such a delay would be, not surprisingly, Williams. *Id.*

2630. As to the proposal supported by most of the parties that the effective date should be August 17, 2003, Exxon agrees that this date would be appropriate under the TAPS Carriers's Tariff had the Commission previously approved the change in the Quality Bank reference price on a permanent basis. *Id.* at p. 383. Exxon notes that that is not the case here. *Id.* Because no final order on this matter has been issue, it does not make sense to allow for a period in which an interim price is frozen under the Tariff.[741] *Id.* Instead, Exxon advocates that the more sensible approach would be for the Commission to adopt an effective date of March 1, 2003, to April 30, 2003, for the pre-May 1, 2003, Platts Gulf Coast "Heavy Naphtha" assessment. *Id.* at pp. 383-84. Then Exxon argues, the effective date for the arithmetic average of the new Platts reported Gulf Coast "Heavy Naphtha" (cargo) and "Heavy Naphtha Barge" price assessments for the U.S. Gulf Coast should be May 1, 2003, and that refunds for the period May 1, 2003, to August 17, 2003, should be provided.[742] Exxon Supplemental Brief at pp. 11-12. For the West Coast, Exxon's position is stated above. *Id.* at p. 12.

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[741] The situation here is distinguishable from the Heavy Distillate case in 2000, according to Exxon. Exxon Reply Brief at p. 383, n.255. There, states Exxon, the Commission ordered the continued use of the previously-approved reference price, the West Coast High Sulfur (0.5%S) Waterborne Gasoil price, "until the final decision on the appropriate processing cost adjustment." *Id.* (quoting *Trans Alaska Pipeline*, 97 FERC at p. 61,650).

[742] Exxon points out that the Platts Gulf Coast "Heavy Naphtha" assessment for April 2003 was frozen in place by the Quality Bank Administrator from May 1, 2003, until the Commission accepted the Quality Bank Administrator's proposal on August 17, 2003. Exxon Supplemental Brief at p. 12, n.14.

G. IMPACT OF POTENTIAL PUBLICATION OF A WEST COAST NAPHTHA PRICE

1. TAPS Carriers

2631. The TAPS Carriers state that it would be desirable if a reliable West Coast price assessment suitable for valuing the Naphtha component of ANS were published. TAPS Carriers Initial Brief at p. 16. To date, explain the TAPS Carriers, no West Coast Naphtha price assessment is available. *Id.* At my request, note the TAPS Carriers, the Quality Bank Administrator contacted Platts and OPIS, the two principal reporters of price assessments, to determine if they would consider publishing a Naphtha price assessment for the West Coast. *Id.* As of the date of the hearing and as of the date of their brief (September 2003), state the TAPS Carriers, neither company had made a decision. *Id.*

2. Williams

2632. Williams notes that, at the hearing, Sanderson was asked a hypothetical question about the substitution of a published West Coast Naphtha price for valuing the Quality Bank West Coast Naphtha Component. Williams Initial Brief at p. 95. It states that the key to Sanderson's answer was the qualification contained in the hypothetical "assume you've had enough time" to do an analysis of a West Coast Platts price assessment and determined, based on your analysis, that it is "a good price." *Id.* Assuming those conditions had been met, Williams points out, Sanderson answered that, at that point in time, the substitution could be made. *Id.* Williams notes that what Sanderson was not asked was were there any details about what would be "enough time" and what would constitute a "good price." *Id.* It also suggests that Sanderson testified at one point during the hearing, regarding the Mars crude oil quotation on the Gulf Coast, that he believed that it was necessary to look at the reliability of the quotation over some period of time and look at its liquidity and relationship to other materials before it was adopted. *Id.* at pp. 95-96. Williams suggests, therefore, should either Platts or OPIS publish a West Coast Naphtha price, there should not be a rush to immediately utilize it for Quality Bank purposes; rather, there likely would be a considerable period of time lapse before all shippers were comfortable that a sufficiently liquid spot Naphtha market existed on the West Coast so that the quoted prices were not notional and the published prices were reliable. *Id.* at pp. 98-99. In other words, Williams argues, the publishing of a West Coast Naphtha price likely would not, and should not, have an immediate impact on the TAPS Quality Bank and the valuation of its West Coast Naphtha component. *Id.* at p. 99.

3. BP

2633. At the moment, BP states, there is no available reported West Coast price for Naphtha. BP Initial Brief at p. 73. As a result, explains BP, there is a need to develop a replacement price to value Naphtha on the West Coast. *Id.* The Quality Bank Administrator has advised the parties that OPIS and Platts are actively considering publishing a West Coast price assessment for Naphtha. *Id.* Should Platts or OPIS commence reporting such a price assessment, BP's position is that the Commission should use the published West Coast naphtha price assessment. *Id.*

2634. Currently, explains BP, the value of all of the Quality Bank cuts on the West Coast, with the exception of the VGO and Naphtha cuts, are based on West Coast price assessments. *Id.* BP notes that VGO shortly should also be based on a West Coast price assessment, however. *Id.* All of the parties, BP notes, have taken the position that the value of the VGO cut on the West Coast should be based on an existing West Coast price assessment for that product. *Id.* In this light, BP asserts that, should a published price assessment for Naphtha on the West Coast also become available, that price should be used to value the Naphtha cut so that all of the cuts are valued on a consistent basis. *Id.* Further, BP notes that none of the parties has challenged this position. BP Reply Brief at p. 88.

2635. BP states, in reply, that although none of the parties have challenged the notion that the preferred method of valuing Quality Bank cuts is by reference to published prices, not all of the parties have recommended immediate adoption should a West Coast Naphtha price be published by a reputable pricing service. BP Reply Brief at p. 89. It states that all of the record evidence, however, establishes that, were a reputable price reporting service to publish a price for West Coast Naphtha, it would be the appropriate reference price to use for its West Coast valuation. *Id.* A number of the witnesses, such as Pulliam, Ross, and Sanderson, according to BP, stated at the hearing that the use of a published price would make sense and is preferable. BP Initial Brief at pp. 73-74 (citing Transcript at pp. 7556-59, 9740-41, 11237-40). Consequently, should Platts, OPIS, or another reputable reporting service commence reporting such a price assessment, BP's position is that the Commission should use the published West Coast Naphtha price assessment. *Id.* at p. 74.

4. Petro Star

2636. Petro Star recommends that a hearing should be held on whether or not to adopt any West Coast Naphtha price, if and when Platts or OPIS announce that they will publish one. Petro Star Initial Brief at p. 28.

5. Exxon

2637. Exxon also points out there is a possibility that either Platts or OPIS might publish a West Coast Naphtha price at some time in the future, but neither company has as yet reached any decision on whether or not to do so. Exxon Initial Brief at p. 337. It asserts that it is clear that the existence of such a price assessment would make continued reliance on the Platts Gulf Coast price assessment to value West Coast Naphtha wholly unreasonable. *Id.* Exxon does agree with Phillips that such a development would constitute an unanticipated implementation issue within the scope of Section III.J. of the TAPS Tariff, and grounds for the Quality Bank Administrator to begin valuing West Coast Naphtha on the basis of the new West Coast price assessment, pending resolution of the matters at issue in this proceeding. *Id.* at pp. 337-38; Exxon Reply Brief at p. 384.

2638. According to Exxon, it also strongly disagrees with Williams's attempt to postpone indefinitely any future use of such a published West Coast Naphtha price assessment on the ground that no such published assessment of the value of West Coast Naphtha could possibly be reliable and, therefore, the Commissions must allow a significant period of time before adopting any such price assessment as a Quality Bank proxy. Exxon Reply Brief at pp. 384-85. Although Williams does not state what might be an appropriate length of time, Exxon believes that its lengthy discussion of the West Coast VGO pricing history in which nine years elapsed before the parties agreed to use the OPIS West Coast High Sulfur VGO weekly price assessment suggests that Williams wants to stall any possible adoption – or even consideration – of any new West Coast Naphtha price assessment for a long number of years. *Id.* at p. 385.

6. Phillips

2639. Phillips's position is that any published West Coast Naphtha price should be employed as soon as possible after it is published. Phillips Initial Brief at p. 176. It suggests that the Quality Bank Administrator would be obligated to implement the use of a published West Coast Naphtha price under Section III.J of the Quality Bank Tariff which requires the Quality Bank Administrator to resolve "unanticipated issues" that may arise "in accordance with the best understanding of the intent of the [Commission] that the Quality Bank Administrator can derive from [its] orders regarding the Quality Bank methodology." *Id.* (quoting Section III.J of the Quality Bank Tariff). However, in order to make this completely clear, Phillips asserts, the Commission should order the Quality Bank Administrator to switch to the use of a published West Coast Naphtha price by a reputable, independent entity as soon as is reasonably practicable. *Id.* To the extent that any party believes that the published West Coast price is not reliable, Phillips believes they will be able to raise this claim in a protest of the Quality Bank Administrator's action filed with the Commission. *Id.* at pp. 176-77. Phillips believes that Williams's recommendation for a long time lag before any new Naphtha price goes into effect has no merit and appears to be intended to preserve the use of a lower Gulf Coast Naphtha price for as long as possible. Phillips Reply Brief at p. 110.

H. ADMINISTRATIVE FEASIBILITY

1. TAPS Carriers

2640. According to the TAPS Carriers, the Quality Bank Administrator found that all four proposals for valuing West Coast Naphtha were administratively feasible. TAPS Carriers Initial Brief at p. 16. They point out that Petro Star modified its proposal (which is an alternative to its fundamental position that the valuation basis for West Coast Naphtha should not be changed) to eliminate certain administrative problems that would have arisen if the proposal were implemented as originally proposed. *Id.* at pp. 16-17. During the course of the hearing, state the TAPS Carriers, BP also modified its proposal so that it is now proposing only a cap and a floor. *Id.* at p 17. The TAPS Carriers explain that the Quality Bank Administrator concluded that BP's modified proposal for a cap and floor was administratively feasible. *Id.*

2641. There was also some evidence, note the TAPS Carriers, suggesting that Phillips's proposal might be modified by inclusion of a benzene saturation unit, or by subtracting a certain number of cents per gallon from the Naphtha value. *Id.* According to the TAPS Carriers, the Quality Bank Administrator concluded that Phillips's proposal would still be feasible to administer with such modifications. *Id.*

2642. Finally, state the TAPS Carriers, the Quality Bank Administrator confirmed that it would be administratively feasible to add 1.5¢/gallon to Platts Heavy Naphtha price assessment to reflect the higher N+A content of ANS crude in order to value ANS on either the West Coast or Gulf Coast. *Id.*

2. BP

2643. According to BP, the Quality Bank Administrator stated that the proposal BP submitted for the valuation of Naphtha is administratively feasible. BP Initial Brief at p. 74. It asserts that no party has suggested it is not. *Id.* Further, in reply, BP asserts that there is no record evidence that would support a conclusion that it would not be administratively feasible to implement the Ross governor. BP Reply Brief at p. 90. Therefore, BP states, the Quality Bank could use BP's proposal on a going-forward basis to value Naphtha on the West Coast. *Id.*; BP Initial Brief at p. 74.

3. Phillips

2644. Phillips agrees with Mitchell's view that all of the Naphtha valuation proposals presented in this proceeding are administratively feasible (including the N+A adjustment), equally objective, and approximately equal in terms of implementation cost. Phillips Initial Brief at p. 177.

4. Exxon

2645. Exxon states that the Quality Bank Administrator testified that its proposal to value the West Coast Naphtha cut on the basis of the regression formula presented by

Tallett is administratively feasible, and that that conclusion was not disputed by any party. Exxon Initial Brief at p. 338. Further, states Exxon, the Quality Bank Administrator has testified that the proposal of Phillips and Alaska for valuing the West Coast Naphtha cut on the basis of O'Brien's proposed valuation methodology is administratively feasible. *Id.* It notes that, although Williams quotes the testimony of the Quality Bank Administrator that any change in methodology might require a little more work each month, Williams also concedes that any additional costs would probably not be significant. Exxon Reply Brief at p. 386, n.256.

5. Williams

2646. Williams notes that Mitchell testified that there would be no impact to the Quality Bank Administrator's costs to administer the Quality Bank if the current methodology is left in place; however, if any of the other methodologies are adopted by the Commission, the Quality Bank would "require some reprogramming and perhaps a little more work each month to do the calculations" although probably not a significant amount more than the current costs. Williams Initial Brief at pp. 99-100.

2647. Mitchell concluded, according to Williams, that Exxon's proposal for West Coast Naphtha valuation is administratively feasible. Williams Initial Brief at p. 100. As to whether it would be administratively feasible to implement Exxon's proposal retroactively, it notes, Mitchell testified that it would be feasible only for the shippers of record. *Id.* As to them, Williams states that Mitchell noted that there are probably some legal issues regarding changes in shippers of record, albeit noting that not many changes occurred over the course of the retroactive period. *Id.* Additionally, it explains, Mitchell testified that performing the retroactive calculations could be considerably expensive on a one-time basis adding to the fees charged by the Quality Bank Administrator but perhaps not significant when considering the dollars exchanged in the Quality Bank from month to month. *Id.*

2648. Williams points out that O'Brien is no longer recommending Exhibit No. PAI-149 (the benzene saturation proposal) as his proposed valuation and continues to stand by his proposal in Exhibit No. PAI-39. *Id.* at p. 101. It states that Mitchell testified that O'Brien's proposal in Exhibit No. PAI-39 is administratively feasible and notes Mitchell testified that the hypothetical proposal including the cost of processing benzene in a saturation unit as set forth in Exhibit No. PAI-149 is also administratively feasible. *Id.* Additionally, Williams asserts that Mitchell testified that if "O'Brien's proposed methodology could be adjusted by subtracting a certain number of cents per gallon from the naphtha value and the amount subtracted might be a fixed amount or the amount adjusted by the Nelson-Farrar index," it would be administratively feasible as well. *Id.*

2649. Because BP's proposal changed during the course of the proceeding, Williams states, Mitchell sought clarifications from Ross regarding how Ross proposed the governor would work. *Id.* It notes that Mitchell testified that, although the BP proposed governor as amended and described in Exhibit No. TC-16 is more complicated than BP's previous proposal, the proposal is nevertheless administratively feasible. *Id.*

2650. Williams explains that Dudley on behalf of Petro Star proposed an alternative Naphtha valuation to be used only should the Commission determine that the West Coast Naphtha valuation be West Coast-based. *Id.* at p. 102. It notes that Mitchell testified that Petro Star's alternative proposal set forth in Exhibit No. PSI-7 is administratively feasible.[743] *Id.* Initially, Williams notes, Mitchell explained that this methodology might result in a delay finalizing the pricing each month. *Id.* However, it continues, Dudley advised that the methodology could be revised to use prior month ratios. *Id.* Williams states that this modification alleviates Mitchell's concerns regarding the administrative feasibility of Dudley's proposal. *Id.*

ISSUE 3 - DISCUSSION AND RULINGS

A. LEGAL STANDARD AND BURDEN OF PROOF

2651. Exxon concedes that, in a complaint case such as this is, the complainant bears the burden of proving that the existing rate is unjust or unreasonable. Exxon Initial Brief at p. 191. It errs, however, in suggesting that the *Tesoro* court held that the Gulf Coast Naphtha price is not an appropriate proxy for valuing West Coast Naphtha.[744] Rather, the Circuit Court's ruling merely was that there was sufficient evidence presented by Exxon and Tesoro to avoid summary disposition of their complaints.[745] *See Tesoro*, 231 F. 3d at p. 1294. In any event, as I previously indicated,[746] nothing which took place in a previous proceeding has any bearing on this Initial Decision; rather, here, the ruling is based on the record established here. Exxon, also, appears to concede that it, as a complainant, carries the burden of establishing changed circumstances warranting a conclusion that the existing value is not just or reasonable.

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[743] Williams notes that Exhibit No. PSI-7 was modified and substituted in the record and additionally was clarified by Exhibit Nos. PSI-13 and PSI-14. Williams Initial Brief at p. 102, n.68. It notes that the changes were typographical errors and/or errors in calculation which do not effect the substance of the proposal. *Id.*

[744] Exxon Initial Brief at p. 192.

[745] Contrary to Exxon's bold assertion that the Court held that the complainants established a *prima facie* case, the Court held that their *prima facie* case was "supported." *See Tesoro* 234 F.3d at p. 1294.

[746] Transcript at pp. 22-23, 114-15.

2652. Phillips also concedes that the complainant in these proceedings has the burden of proving that the existing rate should change. Phillips Initial Brief at pp. 11-12. It goes on to argue that the *OXY* decision requires that West Coast Naphtha be valued on a West Coast basis so that it is valued on a consistent basis with the method for valuing the remaining cuts on the West Coast. *Id.* at pp. 6-7. Phillips concedes, however, that use of a Gulf Coast price would be an acceptable proxy were that price shown to match Naphtha's West Coast value over time. *Id.* at p. 7. It adds that, under *Exxon*, the Gulf Coast price must be shown to have a rational relationship with the West Coast value of Naphtha. *Id.* at p. 9.

2653. Williams, correctly, notes that, in *OXY,* the Circuit Court affirmed the Commission's determination to change from the gravity method to the distillation method for Quality Bank calculation. Williams Initial Brief at p. 4. It is also correct that the Circuit Court only disapproved the Commission's determination as to the method for valuing the Distillates and Resid. *Id.* Accordingly, Williams suggests, and I agree, that the Circuit Court approved the Commission's determination that Naphtha ought to be valued on both the Gulf Coast and the West Coast using a reported Gulf Coast price. *Id.*

2654. Williams and Unocal/OXY agree with Exxon and Phillips that the complainants have the burden of proving that changed circumstances warrant a conclusion that the current method for valuing West Coast Naphtha is unjust or unreasonable. Williams Initial Brief at p. 7; Unocal/OXY Initial Brief at pp. 2-3. According to them, however, the complainant must go further and prove that the changed circumstance requires a change in methodology. Williams Initial Brief at p. 10; Unocal/OXY Initial Brief at p. 3.

2655. Based on the above brief summary of the parties positions, it is clear that they all agree that the complainants have the burden of proving that it is no longer just or reasonable to value West Coast Naphtha on a Gulf Coast basis. Once that level of proof is reached, the parties agree that any party suggesting a new methodology must establish that its proposal is just and reasonable. In other words, consistent with the Circuit Court's rulings in *OXY, Exxon* and *Tesoro*, the new manner of valuing West Coast Naphtha must be shown to be consistent with the manner of valuing the remaining eight cuts.

B. STIPULATED MATTERS AND AREAS OF DISPUTE

2656. Exxon notes that Petro Star, Williams and Unocal/OXY submit that no change in the current manner of valuing West Coast Naphtha is necessary; while the remaining parties contend it should be valued on a West Coast basis. Exxon Initial Brief at p. 194. It also acknowledges that even those who agree that West Coast Naphtha should be valued on a West Coast basis disagree on how that should be accomplished. *Id.* All of the parties agree with this summary. *See* Phillips Initial Brief at p. 14; BP Initial Brief at

p. 4; Williams Initial Brief at p. 15; and Unocal/OXY Initial Brief at p. 4.

C. IS THE CURRENT NAPHTHA VALUE JUST AND REASONABLE?

2657. Leaving aside, for the moment, the questions regarding the 2003 changes in the Platts Gulf Coast Naphtha assessment which are addressed below, the issue here, more precisely, is whether it is appropriate to continue valuing West Coast Naphtha on the basis of Platts Gulf Coast Naphtha price report. As noted by the parties, in 1993, the Commission determined that West Coast Naphtha should be valued on the basis of Platts Gulf Coast Naphtha assessment when it adopted the distillation method to value the Quality Bank.[747] Whether this determination continues to be appropriate is the next question which must be decided. Exxon, Phillips, BP and Alaska contend that it is not, while Unocal/OXY, Williams and Petro Star support continuation.

2658. In its 1993 Order in which the current manner of valuing Naphtha was established, the Commission laid out these broad principles:

> We will, therefore, require the use of unadjusted quoted market prices, as generally provided in the settlement or as specified in this order, as the valuation basis for all of the specified refinery cuts. Nothing in the broad authority granted to the Quality Bank Administrator by the proposed settlement will authorize him to deviate from this use of unadjusted market prices as the valuation basis for the quality bank [sic] distillation streams. However, if or when market prices for a given product are not posted in one of the two markets rather than making the adjustments specified in the settlement, we will require the use of prices quoted in the single market to value the entire cut.

Trans Alaska Pipeline System, 65 FERC at p. 62,289. As there was no West Coast Naphtha price assessment, the Commission determined that the Gulf Coast assessment would be used for both coasts.[748] *Id.* In 1997, the Commission moved away from the no

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[747] The Commission's 1993 determination regarding Naphtha was not challenged on appeal. *See OXY*, 64 F.3d at p. 679. Consequently, Exxon's sub-rosa attack on the Commission's holding regarding West Coast Naphtha, *see, e.g.,* Exxon Reply Brief at p. 214, is an impermissible collateral attack on the Commission's 1993 order. *Dynegy Power Marketing, Inc.*, 101 FERC ¶ 61,369 at P 18-19 (2002).

[748] The Commission acknowledged that the settlement proposed that West Coast Naphtha be valued on the basis of a ratio of the Gulf Coast prices of Naphtha gasoline applied to the Platts Los Angeles pipeline spot quote for gasoline. *Trans Alaska Pipeline System*, 65 FERC at pp. 62,288-89.

adjustment policy. *See Trans Alaska Pipeline System*, 81 FERC ¶ 61,319 (1997).[749] Thus, it appears, the primary basis on which the Commission ruled that West Coast Naphtha should be valued on the basis of Gulf Coast prices no longer provides it support.

2659. As a preliminary matter, it must be decided whether there are changed circumstances warranting a review of the current manner of valuing West Coast Naphtha.

2660. Williams suggest that there is no change in circumstances. Williams Initial Brief at p. 22. It claims that neither Exxon nor Phillips provided evidence of changed circumstances and that O'Brien, in fact, testified that there were not.[750] It does acknowledge that Tallett testified that the Commission had abandoned its "no adjustment" policy,[751] but claimed that Tallett did not "characterize" this as a changed circumstance. Moreover, it claims that Tallett testified that there have been no changed circumstances since October 2000.[752] Whether or not there have been changed circumstances since October 2000 is irrelevant, as is how Tallett "characterized" the Commission's policy change. The simple truth is that there has been a change in the policy on which the Commission based its 1993 holding.

2661. In response to the arguments of Phillips and Exxon that the cessation of ANS deliveries to the Gulf Coast represent a changed circumstance, Williams claims that the evidence reflects that Platts Gulf Coast Heavy Naphtha (cargo) price assessment is the equivalent of the West Coast ANS price plus $4.00. Williams Reply Brief at p. 25. From this point, Williams claims that, therefore, the evidence reflects that the Gulf Coast Naphtha price is linked to the West Coast ANS price. *Id.* Its argument, however, is a non sequitur. It is a fact that shipments of ANS are no longer being made to the Gulf Coast, and it is clear that this is a circumstance which has changed since 1993. That Platts Gulf Coast Heavy Naphtha (cargo) price assessment may be the equivalent of the West Coast ANS price plus $4.00 also may be true. It is interesting, no doubt, but it clearly is totally unrelated to the fact that ANS no longer is being shipped to the Gulf Coast. And, just as clear, is that the fact that ANS is no longer being shipped to the Gulf

[749] *See also Tesoro*, 234 F.3d at pp. 1292-93.

[750] Actually, O'Brien stated, in the testimony cited by Williams, that "there have been no material changes in the West Coast or Gulf Coast Naphtha markets since the time the Commission held that all Naphtha should be valued on the Gulf Coast price." Exhibit No. PAI-33 at p. 6.

[751] *See* Exhibit No. EMT-11 at p. 13.

[752] *See* Transcript at pp. 6654-57. It should be noted that Unocal/OXY makes the same argument. *See* Unocal/OXY Initial Brief at p. 22.

Coast represents a circumstance which has changed since 1993.

2662. Unocal/OXY argue that merely because the Commission abandoned its "no adjustment" policy is no reason to conclude that there are changed circumstances as the Commission has not changed the policy, according to Unocal/OXY, requiring the Quality Bank Administrator to use one coast's price assessment to value the other coast's Quality Bank cut when the latter has no published price assessment. Unocal/OXY Reply Brief at p. 17. In support, it cites *Trans Alaska Pipeline System*, 66 FERC at p. 61,418. There, the Commission was specifically discussing the valuation of Heavy Distillates, not Naphtha. Thus, the policy cited by Unocal/OXY does not appear to be applicable to Naphtha. In any event, that matter was decided in 1994 at a point when ANS was still being shipped to the Gulf Coast. As it no longer is, I cannot find that the 1994 ruling, even were I to believe that it was applicable to Naphtha, and I do not, would still control.

2663. According to Unocal/OXY, which concedes that the CARB gasoline requirements may be a changed circumstance, these requirements decrease Naphtha's value and, therefore, do not constitute a changed circumstance warranting reconsideration of the Commission's 1993 holding. Unocal/OXY Reply Brief at p. 20. Their argument, perhaps, may have a bearing on whether or not the use of the Platts Gulf Coast Naphtha assessment continues to be just and reasonable as a proxy for the value of West Coast Naphtha, but it does not impact the question of whether changed circumstances exist.

2664. Based on the witnesses's testimony at the hearing, as well as the exhibits submitted through them, I am satisfied that there have been material changes in circumstance since the Commission determined, in 1993, that West Coast Naphtha should be valued on a Gulf Coast basis. The Commission has changed its policy and no longer refuses to consider adjusted proxy prices for ANS cuts. Moreover, virtually no ANS is being shipped to the Gulf Coast any longer; in fact, on the whole, ANS production has greatly diminished since 1993. Furthermore, the parties have agreed that West Coast VGO will no longer be valued on a Gulf Coast basis, rather, it will be valued using published OPIS West Coast High Sulfur VGO weekly price.[753] Thus, after that change takes place, West Coast Naphtha would be the only ANS cut valued on a Gulf Coast basis. Moreover, it is clear that the restrictive CARB and reformulated gasoline specifications have impacted the West Coast market. All of these together, if not any one, compel a holding that circumstances have changed since the Commission's 1993 holding.

2665. Having decided that circumstances sufficiently have changed since 1993 to warrant a review of the 1993 Commission holding, the question now becomes whether,

[753] *See* Issue 4, below; *see also* Eight Parties Initial Brief at p. 161; Exxon Initial Brief at p. 340.

despite the changed circumstances, the use of Platts Gulf Coast Naphtha assessment to value West Coast Naphtha continues to be just and reasonable. Exxon notes that all of the parties agree that continuing to value West Coast VGO, the only other West Coast cut valued on a Gulf Coast basis, on a Gulf Coast basis is no longer just or reasonable. Exxon Initial Brief at p. 203. It submits, therefore, that continuing to base West Coast Naphtha's value on a Gulf Coast basis would no longer be consistent with the Circuit Court's *OXY* ruling.[754] *Id.* at p. 204; Exxon Reply Brief at p. 213.

2666. According to Exxon, the Gulf Coast and West Coast markets are entirely different. Exxon Initial Brief at p. 198. In support it claims that, during the 1994-2001 period, not only was the gasoline price significantly different on both coasts, but so were the prices of intermediate products. *Id.* at p. 204. Exxon argues that this is caused by the different supply and demand factors in existence on the two coasts. *Id.* at pp. 205-06. On the West Coast, it points out, Naphtha is used to make gasoline and jet fuel, while on the Gulf Coast it also is used as a petrochemical feedstock.[755] *Id.* at pp. 206-07. Moreover, Exxon notes, West Coast gasoline is, for the most part, more expensive than that on the Gulf Coast because of the more stringent environmental controls on CARB gasoline in California and reformulated gasoline in Nevada and Arizona. *Id.* at pp. 207-08. Further, it suggests that West Coast Naphtha is of a higher quality than that on the Gulf Coast. *Id.* at pp. 209-10.

2667. Exxon claims that the Commission and all interested parties have agreed, since implementation of the distillation method, that Quality Bank cuts ought to be valued on a market basis. Exxon Initial Brief at p. 203. Recognizing that the Gulf Coast market and the West Coast market have different supply and demand factors and prices, Exxon urges, the parties have proposed coast-specific proxies for each of the cuts except for VGO and Naphtha, both of which were valued only on a Gulf Coast assessment. *Id.* Exxon notes that the parties now have agreed that West Coast VGO should be valued on a West Coast basis.[756] *Id.* Referring to *OXY*, Exxon suggests that when all of the West Coast ANS cuts, except for Naphtha, are valued on a West Coast basis, use of the Platts Gulf Coast Naphtha assessment for West Coast Naphtha no longer is just and reasonable because it would be "inconsistent" with the manner in which the other cuts are valued. *Id.* at p. 204; Exxon Reply Brief at p. 213.

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[754] Many of the arguments that follow attributed to Exxon were also made by Phillips and BP. Their arguments are more fully detailed above.

[755] Exxon also claims that its use as a petrochemical feedstock on the Gulf Coast does not affect its price as the Naphtha used for this purpose is a lighter product than the reformer grade Naphtha used to make gasoline. Exxon Initial Brief at p. 207.

[756] *See* Issue 4 below.

2668. In addition, Exxon notes the following other differences:

- On the West Coast, Naphtha solely is used to make gasoline and jet fuel; while, on the Gulf Coast, it also is used as a petrochemical feedstock.[757]

- The Naphtha used as a petrochemical feedstock is a lighter Naphtha than the reformer grade Naphtha used on the West Coast in the production of gasoline and, therefore, this use does not impact the price of Quality Bank Naphtha.[758]

- Virtually all of the gasoline made on the West Coast is CARB or reformulated gasoline and must meet more stringent environment standards than exist on the Gulf Coast and, therefore, West Coast gasoline prices consistently have been higher than those on the Gulf Coast by several cents per gallon.[759]

- The Gulf Coast gasoline market is much larger than that on the West Coast and, therefore, is less volatile and better able to absorb supply shortages caused by refinery outages.[760]

- Gulf Coast refineries routinely import Naphtha from the Caribbean, while virtually no Naphtha is imported on the West Coast because refineries supply their needs from internal sources.[761]

- West Coast refineries have a higher capacity (in terms of percentage of capacity) to hydrocrack crude than those on the Gulf Coast giving them an ability to produce a higher percentage of Naphtha from crude.[762]

Id. at pp. 207-10.

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[757] *See* Exhibit Nos. EMT-11 at p. 16, PAI-33 at p. 4, BPX-8 at p. 3; Transcript at pp. 5286-7, 6041, 6488, 8318, 8817, 9028, 11593.

[758] *See* Transcript at pp. 6703, 7123-24, 7215, 12067-68, 12112.

[759] *See* Exhibit Nos. PAI-33 at pp. 8-9, WAP-224; Transcript at pp. 8820, 8823-24.

[760] *See* Transcript at pp. 8821-22.

[761] *See* Exhibit Nos. BPX-8 at p. 3, PAI-33 at p. 4, PAI-52 at p. 16, PAI-53 at pp. 7-8, UNO-1 at pp. 13-14; Transcript at pp. 7232-34, 7356, 9804, 11041-42, 11045, 12069.

[762] Exhibit No. WAP-244; Transcript at pp. 11159-62, 11477-79.

2669. Exxon also discusses the quality of ANS Naphtha in comparison with the Gulf Coast Naphtha assessed by Platts and asserts that the N+A of ANS Naphtha is 55+, while the N+A of the Heavy Naphtha and Full Range Naphtha assessed on the Gulf Coast by Platts was 40 making ANS Naphtha a higher quality. *Id.* at pp. 209-10.

2670. According to Exxon, Sanderson's theory, that because, he believed, the price of crude oil was similar on both coasts,[763] that the prices of Naphtha and its other components ought to be similar. *Id.* at p. 219. However, Exxon notes, Sanderson admitted that this theory did not prove true for VGO or LSR, the two cuts at which he looked, or any other Quality Bank cut.[764] *Id.* at pp. 223-24. Also, Exxon states, the evidence reflects that crude oil prices, as well as prices for intermediate and finished petroleum product prices widely vary between the two coasts.[765] *Id.* at p. 224. In addition, citing Exhibit No. PAI-176, Phillips asserts that there are significant differences between the two coasts on a wide variety of petroleum products. Phillips Initial Brief at p. 38. From this, it argues, Sanderson has failed to explain why only the value of Naphtha would be the same on both coasts. *Id.*

2671. As noted above, Phillips agrees with Exxon that continuing to value West Coast Naphtha on a Gulf Coast basis, when all other West Coast cuts are valued on a West Coast basis, violates the consistency requirement of *OXY*. *Id.* at p. 15. It adds that, were the Commission to continue to value West Coast Naphtha on a Gulf Coast basis, it must find that such a manner of valuing it was "consistent" with the valuation of the other cuts. *Id.* at p. 16. Phillips contends that the West Coast Naphtha market is subject to different forces, different supply and demand factors, and different environmental standards

[763] In fact, Sanderson admitted that he did not compare all crude oils on both coasts, he only compared ANS on the West Coast and Isthmus on the Gulf Coast. Transcript at p. 9030. He also admitted that the qualities of the two crude oils are not the same, that the percentages of Quality Bank cuts in the two crudes are not the same, and that the properties of the Naphtha in the two crude oils are not the same. *Id.* at pp. 9030-31. Moreover, Sanderson also admited that the N+A of Isthmus crude is considerably lower than that of ANS. *Id.* at pp. 9047-48. Furthermore, he also admited that, while the quality of Isthmus crude has been constant, the quality of ANS has varied over time as new fields have joined the TAPS common stream. *Id.* at pp. 9038-42, 11126-27; Exhibit No. PAI-205.

[764] *See* Transcript at pp. 9019-23, 9062, 9071, 9073-81, 10626-27, 11135-37; Exhibit Nos. EMT-533, EMT-534, PAI-201, PAI-202, PAI-210 at p. 3, PAI-211 at p. 3.

[765] *See* Exhibit Nos. BPX-35, EMT-14, EMT-453, EMT-477, EMT-478, EMT-479, EMT-480, EMT-481, EMT-482, PAI-176; Transcript at pp. 10721-22.

affecting the supply of gasoline and intermediate products (like Naphtha) than the Gulf Cost. *Id.* at pp. 16-17. Also, Phillips notes, gasoline prices on the West Coast average 2.5-18¢/gallon more than those on the Gulf Coast. *Id.* at p. 17.

2672. The TAPS Carriers, Phillips maintains, presented evidence that there has been no delivery of ANS to the Gulf Coast since July 1999, and that, during the period January 1998 through the end of July 1999, less than 3% of ANS production was delivered to the Gulf Coast. *Id.* at p. 23. It also points out that the Commission has abandoned the no adjustment policy it previously had followed. *Id.*

2673. BP admits that, when the Commission decided to value West Coast Naphtha on a Gulf Coast basis, the decision made sense. BP Initial Brief at p. 5. It contends, however, that, with the decision to no longer value West Coast VGO on a Gulf Coast basis, it no longer is just and reasonable to continue to base West Coast Naphtha's value on a Gulf Coast reported price. *Id.* According to BP, as the values of both Naphtha and VGO are driven by their use in making gasoline, both should be valued consistently. *Id.*

2674. Williams argues that the Commission ought to continue requiring that West Coast Naphtha be valued on the basis of Platts Gulf Coast price assessment.[766] Williams Initial Brief at p. 17. It states that the Gulf Coast Naphtha price is representative of a robust market, and is reasonable and reliable. Williams Initial Brief at p. 23. Further, Williams notes, no one challenges its use to value Gulf Coast Naphtha. *Id.* at p. 24. Therefore, it suggests, there is no reason for anyone to question its use in establishing a value for West Coast Naphtha.[767] *Id.* Williams also argues that Platts Gulf Coast Naphtha assessment provides an objective, rather than a subjective, basis on which to value West Coast Naphtha.[768] *Id.* at pp. 26-27. It suggests that the use of an objective price assessment is a basic tenet of the Quality Bank. *Id.* at p. 26. Moreover, Williams argues, as it is the only Naphtha price assessment made by an industry-wide accepted source, use of Platts Gulf

[766] Unocal/OXY makes some of the same arguments as are made by Williams.

[767] This argument lacks logic. There are no Gulf Coast deliveries of ANS crude. Consequently, there is no reason why any party would waste its time in challenging that Tariff provision. But, more importantly, it does not follow that the appropriateness of using the Platts Gulf Coast Naphtha assessment for Gulf Coast deliveries of ANS also makes it appropriate for use in valuing West Coast ANS deliveries.

[768] This argument, however, is based on Sanderson's testimony. Williams Initial Brief at p. 26. In arguing this, Williams fails to acknowledge that, on cross-examination, Sanderson admitted that, while he contended that the Platts assessment was objective, he exercised his "subjective judgment that the Gulf Coast Platt's assessment would be a suitable proxy for the West Coast value." Transcript at pp. 8836-37.

Coast Naphtha price assessment is consistent with the manner in which other Quality Bank components are valued. *Id.* at p. 28.

2675. My analysis began with a review of the Circuit Court's *OXY* ruling which Exxon and Phillips claim requires, in the context of this issue, that West Coast Naphtha be valued on a West Coast basis as all of the other West Coast ANS cuts (after implementation of the parties's agreement on West Coast VGO) will be valued on a that basis. I am not as sure as they are that the Circuit Court's ruling mandates that conclusion. What the Court was addressing in *OXY* was the value of a cut, i.e., whether or not its value involved processing costs;[769] it was not addressing the geographical location where the Commission found an appropriate proxy. In my opinion, therefore, the question raised by *OXY* is not, as argued by Exxon and Phillips, answered solely by reference to geography, but must be answered by a more substantive look at whether Platts Gulf Coast Naphtha assessment values West Coast Naphtha in a manner consistent with the value of the other West Coast ANS cuts.

2676. The record, which has already been amply discussed in this section as well as in other areas of this Initial Decision, contains more than sufficient evidence to establish that the West Coast market for gasoline and intermediate petroleum products differs greatly from that on the Gulf Coast. On the West Coast, for example, Naphtha is used almost exclusively to manufacture gasoline and jet fuel, while on the Gulf Coast it also is used as a petrochemical feedstock. Furthermore, it appears that not all of the Naphtha assessed by Platts on the Gulf Coast matches the quality of that derived from ANS. Under these circumstances, it is difficult to see how a Gulf Coast Naphtha assessment could be said to represent the value of West Coast Naphtha.

2677. Moreover, it is clear that, while at least some ANS was shipped to the Gulf Coast in the early 1990s, by 1999, this trade had totally ended. Also, the record reflects that virtually no Naphtha is imported into the West Coast, while substantial imports are being made into the Gulf Coast from the Caribbean. In other words, while there is a robust trade in Naphtha on the Gulf Coast, there is virtually no trade in Naphtha on the West

[769] The Circuit Court states:

> [I]f the agency chooses to value some cuts of petroleum at the prices they command in the market without the benefit of processing, as it appears to have done, it must attempt, to the extent possible, to value all cuts at the price they would command without processing. It cannot, consistent with the requirement of reasoned decisionmaking, value some cuts precisely and other haphazardly.

OXY, 64 F.3d at p. 694.

Coast as refiners there supply their own needs from internal sources. These facts further add to the difficulty of concluding that a Gulf Coast Naphtha assessment is representative of the value of West Coast Naphtha.

2678. I give no credence whatsoever to the theory espoused by Williams and Unocal/OXY that use of Platts Gulf Coast Naphtha assessment to value West Coast Naphtha is just and reasonable because the West Coast and Gulf Coast markets are linked by transportation factors.[770] Their evidence on this point relates to the ability of West Coast refiners to import crude oil, and the increasing amounts of crude oil being imported, to the West Coast as production of ANS declines.[771] For example, Culberson claims that the cost of shipping crude oil from foreign sources to each coast is about the same.[772] However, even while this may be true, and I note that its accuracy is vigorously disputed by other parties,[773] as the parties all are aware, virtually no Naphtha is imported to the West Coast because West Coast refineries satisfy their needs for it from internal sources. Thus, I conclude, Williams and Unocal/OXY have failed to establish a connection between the importation of crude oil and the question of whether Platts Gulf Coast Naphtha assessment is a reasonable approximation of the value of West Coast Naphtha.[774]

2679. The position espoused by Williams and Unocal/OXY is supported by the testimony of Sanderson and Culberson and the exhibits submitted through them, while the testimony of Tallett, Toof, Baumol, Pulliam, Ross, and O'Brien supports the positions of Exxon, Phillips, Alaska and BP. On the whole, I find the latters's testimony on this point more logical and, therefore, more credible. I find, too, that many of the arguments made by Williams and Unocal/OXY go to the question of how West Coast Naphtha should be valued rather than as support for their claim that Platts Gulf Coast Naphtha assessment is a just and reasonable proxy for West Coast Naphtha.

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[770] *See* Exhibit Nos. UNO-1 at pp. 2-6, WAP-1 at pp. 5-9.

[771] *See, e.g.,* Exhibit Nos. WAP-1 at p. 6, WAP-4.

[772] Exhibit No. WAP-1 at p. 7.

[773] *See, e.g.,* Exxon Initial Brief at pp. 226-27.

[774] There was a significant amount of testimony at the hearing, as well as a number of exhibits, surrounding the cost of importing crude oil and petroleum products to the West Coast, including discussions of the costs of transportation, the cost of storage, etc. I find that none of this evidence is relevant or material to the question of whether Platts Gulf Coast Naphtha assessment continues to be a suitable proxy for the value of West Coast Naphtha.

Based on the record, therefore, I find that there is substantial evidence that continuing to base the value of West Coast Naphtha on the basis of Platts Gulf Coast Naphtha assessment no longer is just or reasonable.

D. THE RELEVANCE OF THE WEST COAST NAPHTHA CONTRACTS

2680. One of the most contentious issues litigated involved West Coast Naphtha contracts discovered by the parties. Exxon, Phillips and Alaska vigorously argued that the contracts were reflective of the value of West Coast Naphtha, and their view was just as strenuously opposed by the remaining parties. During the hearing, listening to the witnesses's testimony, I became skeptical of the probative value of the contracts; subsequent to the hearing, after reviewing the testimony, the parties's exhibits, and their arguments, that skepticism became conviction.

2681. As I previously stated, and as the parties are well-aware, there is virtually no trade in Naphtha on the West Coast. Rather, refiners supply their own needs from internal sources. No reporting service assesses Naphtha's West Coast value because the trade is not robust and not transparent. Indeed, the West Coast trade is so secret that the parties had to disguise the names of buyers and sellers when presenting evidence related to purchases and sales of Naphtha.

2682. After a diligent search by the parties of each other and of third parties, they only were able to discover about 350 contracts involving the purchase and sale of West Coast Naphtha. When duplicates were removed, that number dwindled. Then, each person who analyzed the contracts removed those (s)he did not believe matched Quality Bank Naphtha specifications,[775] or those for which (s)he could not establish a price,[776] and at least one removed small, trucklots, which he considered too small to reflect a true market value.[777] The result was that each analysis involved around 200 contracts spread over an eight year period[778] – an average of fewer than 25 each year or no more than two per

[775] The contracts contained at least 38 different descriptions of the product purchased and sold. *See* Exhibit No. UNO-7 at pp. 38-39.

[776] Even so, there still remained difficulties in establishing the price of certain contracts in which the price was tied to delivery dates which the parties did not have.

[777] See Exhibit No. UNO-7 at pp. 33-34.

[778] Despite the fact that the 200 contracts were spread over 1994-2001 period, 61% of the Naphtha volumes included were traded in the last two of those years (1999-2001). Exhibit No. SOA-1 at p. 7. The parties have disagreed as to whether this two year period

month.[779] It strains credulity to suggest that these few contracts could represent anything, much less the value of the Naphtha which refiners supplied to themselves.

2683. While Exxon and Phillips argue that the number of contracts and the amount of Naphtha involved are no less than a statistician would use when sampling data, they miss the point. This wasn't a random sampling of a larger number, rather, these were ALL the contracts which the parties could discover.[780] Moreover, the "experts" could not even agree on which of the contracts were representative of the whole; each used a different subset in his/her analysis.

2684. It also is true that the West Coast Naphtha contracts "discovered" by the parties are not the equivalent of a Platts or OPIS assessment. The latter assessments are made based on spot sales; the former represent, for the most part, term contracts. Moreover, the reported price assessments are based on purchases and sales of a product in a robust market, while there is no market for Naphtha on the West Coast.

2685. I must say that I find that the testimony of all of the witnesses who suggested that the contracts represented the value of West Coast Naphtha to be strained and not quite credible. The testimony of those who stated that the contracts did not reflect the value of

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was anomalous, but there is no need for me to reach that question.

[779] Besides the number of contracts being small, it appears that four buyers dominated the market. *See* Exhibit Nos. WAP-200, WAP-202, SOA-34 through SOA-37. This is further evidence that the marketplace is less robust than one would find acceptable to represent a product's value.

[780] A random sample consists of items that have been selected from the entire population in such a way that *each* item in the population had an equal opportunity to be selected. Am. Statistical Ass'n, *What is A Margin of Error?* 7 (1998) *available at* http://www.amstat.org/sections/srms/brochures/margin.pdf; Michael S. Lewis-Beck et al., *The SAGE Encyclopedia of Social Science Research Methods* 913 (2004); David J. Sheskin, *Handbook of Parametric and Nonparametric Statistical Procedures* 1 (3rd ed. 2004); United States General Accounting Office, Program Methodology Division, *Using Statistical Sampling* 34 (rev. 1992).

The sample must be representative of the population to be useful in making "inferences about the larger population from which it was drawn." David J. Sheskin, *Handbook of Parametric and Nonparametric Statistical Procedures* 1 (3rd ed. 2004). No item or items can be completely excluded from the selection process or the results of the sample will be biased. Michael S. Lewis-Beck et al., *The SAGE Encyclopedia of Social Science Research Methods* 913 (2004).

Naphtha was much more believable. I agree with Unocal/OXY that, at best, the contracts "provide isolated or anecdotal evidence respecting West Coast naphtha transactions, particularly for the pre-1999 time period." Unocal/OXY Initial Brief at p. 35. Based on this evidence, and for the specific reasons stated above, I find that the contracts do not reflect the value of West Coast Naphtha and are unusable for any purpose in this proceeding.

E. IF CURRENT NAPHTHA VALUE IS NOT JUST AND REASONABLE, WHAT METHODOLOGY SHOULD BE USED

2686. From the record, it is clear that there were two focal points for the litigation. The first was Resid and the second is West Coast Naphtha. Resid was previously addressed; here the question of how West Coast Naphtha should be valued for Quality Bank purposes will be addressed. I am convinced that, while there is no perfect way to establish its value, continuing to value West Coast Naphtha on the basis of a Gulf Coast assessment, as I previously indicated, is not appropriate. Consequently, I am left to choose the best from among the parties's proposals.[781] For clarity sake, each will be individually discussed.

1. Petro Star

2687. While it supports continued use of the Gulf Coast Naphtha assessment to value West Coast Naphtha, Petro Star, through Dudley, offered an alternative should the Commission determine that its continued use was no longer just or reasonable.[782] Petro Star Initial Brief at p. 9. According to Petro Star, Dudley's proposed methodology contains three steps: (1) the price differentials between West Coast and Gulf Coast VGO and West Coast and Gulf Coast LSR are determined; (2) the percentages of VGO and LSR in the ANS common stream are determined; and (3) the volume weighted LSR and VGO price differentials are applied to the reported Gulf Coast Naphtha price assessment to determine the imputed West Coast price to be used by the Quality Bank. *Id.* It explains that Dudley's proposal uses Quality Bank data already available to quantify how differently the West Coast values gasoline blendstocks in comparison with the Gulf

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[781] During the course of the hearing, other possible methods for valuing Naphtha were discussed with the witnesses by me, Judge Wilson, and counsel for various parties. In this comment, I include, though I am not limiting my comment to it, the proposal by Williams's witness Sanderson to value West Coast Naphtha at the price of ANS plus $4.00. As I conclude that the record does not contain substantial evidence supporting any of these proposals, there is no need to discuss them any further.

[782] Unocal/OXY, on brief, also support the Dudley proposal. Unocal/OXY Initial Brief at p. 38.

Coast, and suggests that only Naphtha, VGO and LSR qualify to meet those criteria.[783] *Id.* at p. 10.

2688. Petro Star concedes that LSR has a high Reid Vapor Pressure and, consequently, is much less valuable on the West Coast than on the Gulf Coast for use as a gasoline blendstock. *Id.* at p. 13. LSR's value as a petrochemical, Petro Star also admits, may contribute to its higher Gulf Coast value. *Id.* at p. 14. Moreover, Petro Star agrees that the economics surrounding LSR and VGO are different when comparing the West Coast and the Gulf Coast, and that their usages on both coasts have different economics as well. Petro Star Reply Brief at p. 17.

2689. Williams claims that it does not support the substitution of the Dudley proposal for the Gulf Coast Naphtha assessment to value West Coast Naphtha, but that the Dudley proposal demonstrates the validity of continuing to use the Gulf Coast assessment as a proxy for it.[784] Williams Initial Brief at p. 80. It does add that, of all of the remaining proposals, Dudley's should be adopted were the Commission to hold that the Gulf Coast Naphtha assessment can no longer be used and should it reject the ANS plus $4.00 proposal. *Id.* at pp. 80-81.

2690. Exxon describes the Petro Star proposal as being based on the relationship between the prices of Gulf Coast Naphtha and a weighted incremental differential between the prices of Gulf Coast and West Coast VGO and the prices of Gulf Coast and West Coast LSR. Exxon Initial Brief at p. 311. According to it, the structure of the proposal ignores the fact that over 90% of West Coast Naphtha is made into gasoline. *Id.* at 312. Exxon correctly claims that Dudley did nothing to establish the validity of the proposal he made on Petro Star's behalf. *Id.* at p. 312.

2691. According to Phillips, Dudley's proposal was doomed from the start because he was asked to derive a method for valuing West Coast Naphtha which did not rely on the price of finished gasoline. Phillips Initial Brief at p. 142. As did Exxon, it correctly notes that the fallacy of this approach arises from the simple fact that, as virtually all West Coast Naphtha is used to make gasoline, doing so ignores the value of the resulting finished product. *Id.* Phillips also points out that Dudley admitted that this approach is contrary to the advice he gives other clients, and caused him to create a methodology for valuing West Coast Naphtha which is not used by any refinery, not even by Petro Star.

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[783] Petro Star notes that, like Naphtha, LSR and VGO are intermediate products derived from crude oil, refined on both coasts, and used to make gasoline blendstocks. Petro Star Initial Brief at p. 11.

[784] I believe that this reflects the fact that the Dudley proposal results in a value virtually the same as the Gulf Coast Naphtha assessment.

Id.

2692. In essence, the major challenge which Phillips makes to the Dudley proposal concerns the subjective nature of the choices he made in the cuts with which to compare the values of West Coast and Gulf Coast Naphtha.[785] Phillips notes that Dudley chose to compare the differential between Naphtha, LSR and VGO. *Id.* at p. 143. Dudley testified, Phillips declares, that he choose LSR and VGO because, as is Naphtha, they are used to make gasoline. *Id.* at p. 144. It states that LSR has a lower West Coast than a Gulf Coast value because of its high Reid Vapor Pressure which severely limits its use on the West Coast. *Id.* at pp. 143-44. On the other hand, Phillips points out, Naphtha has a low Reid Vapor Pressure and all of the experts agree would not have as great a differential in a Gulf Coast/West Coast comparison. *Id.* at p. 144. Therefore, suggests Phillips, though I am not sure that I follow the reasoning, Dudley has failed to establish a compelling reason to use LSR in his formula. *Id.* at p. 145. I find, however, because of the Reid Vapor Pressure variance, that Dudley has failed to establish a nexus linking the differential between West Coast and Gulf Coast LSR and the differential between West Coast and Gulf Coast Naphtha.

2693. Had Dudley chosen to use a combination of other cuts, VGO and Isobutane for example, Phillips points out, his formula would have assigned Naphtha a higher West Coast value. *Id.* at p. 145. It argues that the outcome of the choices Dudley made, in comparison with those he could have made, demonstrates that his proposal is arbitrary. *Id.* at pp. 145-46. In fact, it is unlikely that Dudley's choice of LSR and VGO was arbitrary; rather, more likely, his choice was outcome driven to satisfy the needs of his client. While I do not fault him (or it) in this regard, I do not find his testimony convincing.

2694. As I indicated at the hearing, I am sympathetic to the simplicity of the approach taken by Dudley. However, as noted above, I am not convinced that the specifics of the choices he made accurately reflect the value of West Coast Naphtha. As a consequence, therefore, I cannot find it to be either just or reasonable.

2. Phillips

2695. Phillips explains that its proposal for valuing West Coast Naphtha, put forth by O'Brien, is premised on the fact that virtually all of the Naphtha produced by refineries on the West Coast is first processed through catalytic reformers to produce reformate, which subsequently is used as a blendstock in the production of gasoline. Phillips Initial Brief at pp. 76-77. It explains that the first step of O'Brien's methodology is to develop a

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[785] Exxon agrees with Phillips. *See* Exxon Initial Brief at pp. 312-15; Exxon Reply Brief at pp. 329-31.

before-cost value of Naphtha on the West Coast by first determining the product yields from running Naphtha through a reformer. *Id.* at p. 77. The product yields are then multiplied by their published prices to derive a before-cost Naphtha value. *Id.* Phillips concedes that O'Brien had to develop prices for reformate[786] and hydrogen[787] because no published prices are available. *Id.* at pp. 77-78.

2696. While, Phillips concedes, O'Brien had to make assumptions regarding the three-component blend as well as regarding the value of reformate, it argues that his proposal has been subjected to a number of tests which validate its reasonableness. *Id.* at p. 83. Moreover, it argues that, applying his formula to Gulf Coast prices indicates that it is more than just randomly related to the value of Naphtha. *Id.* at p. 84. Thus, it suggests, O'Brien's proposal satisfies the *Exxon* requirement that the proxy price be rationally related to West Coast Naphtha's actual market value. *Id.* at p. 90.

2697. Answering the charge that, for several months in 2000-2001, O'Brien's calculated Naphtha price exceeded the published Seattle regular gasoline price,[788] Phillips notes that such criticism ignores the fact that Naphtha is used to make products other than gasoline, such as hydrogen. *Id.* at p. 92. Thus, it contends, the price of Naphtha is affected by the value of products other than gasoline, and that, in 2000-2001, the price of natural gas, from which hydrogen is normally made, increased which, in turn, increased the value of hydrogen. *Id.* When the natural gas price normalized, Phillips argues, so did the price of hydrogen. *Id.*

2698. Phillips also defends O'Brien's three-component gasoline blend as a simple blend while recognizing that more complex blends are used. *Id.* at p. 98. It adds that the more complex blends are more difficult to model, particularly since not all of their blendstocks have published prices. *Id.* However, O'Brien has failed to convince me that his three-component blend adequately represents even West Coast conventional gasoline,

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[786] O'Brien, as reformate is solely used to make gasoline, derived its value using the published prices of other gasoline blendstocks based on a three-component gasoline blend. Phillips Initial Brief at p. 78. Phillips concedes that it is necessary to use some judgment in selecting the gasoline blend. *Id.* at p. 79.

[787] O'Brien based his hydrogen value on the cost of making it from natural gas in a hydrogen plant. Phillips Initial Brief at p. 80. He adjusted the cost of natural gas on a monthly basis as the published price changed. *Id.* at p. 82.

[788] In its reply brief, Phillips defends O'Brien's use of the Seattle regular unleaded gas price stating that the Seattle market for conventional gasoline is robust and growing while the Los Angeles market for it is small and shrinking. Phillips Reply Brief at pp. 72-73.

much less CARB or reformulated gasoline. I would reject his proposal on this one factor alone, but there are other reasons as well.

2699. Even Phillips concedes that the annual exhaust toxics (133.6) which it claims for O'Brien's three-component blend's far exceeds the statutory baseline threshold for annual exhaust toxics (104.5).[789] Phillips Initial Brief at p. 111. While it suggests that this is irrelevant because all of the West Coast refineries were in operation in 1990 and, therefore, have their own baselines,[790] Phillips fails to cite any record evidence in support of its claim. However, a review of the record indicates that Phillips admits that the three-component blend's annual average exhaust toxic (133.6) it claims is higher than at least three West Coast refineries.[791] Exhibit No. PAI-167 at p. 1. As a result, Phillips's defense of the three-component blend fails.[792]

2700. Ross suggests that O'Brien's[793] methodology only considers the demand side of the supply/demand curve as it does not consider the opportunities for imports to affect the value of Naphtha on the West Coast. Transcript at pp. 9703-04. The record, however, fails to establish that the opportunity for importing Naphtha into the West Coast exists anywhere but in Ross's imagination.

2701. Exxon contends that O'Brien's approach appropriately treats the West Coast and the Gulf Coast as different markets. Exxon Initial Brief at p. 279. However, it

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[789] Williams, on brief, challenges this figure noting that it is based on Phillips Ferndale Washington refinery in which only 75% of the crude processed is ANS. Williams Reply Brief at p. 77 (citing Transcript at p. 5996). It suggests that, had Phillips used the true values of O'Brien's three-component blend based on the PIMS model, the benzene level would have increased to 210.8 mg/mile, far exceeding all of the West Coast refineries. *Id.* at pp. 77-78.

[790] Phillips Initial Brief at p. 111.

[791] The baselines for Phillips Ferndale (WA) refinery is noted as 129.8; that for the Tacoma (WA) U.S. Oil refinery is listed as 122.6; and that for the Tesoro Anacortes (WA) refinery is 114.9. Exhibit No. PAI-167 at p. 1.

[792] Phillips also suggests that, if emissions are a problem, a benzene saturation unit could be installed in the conceptual refinery and further suggests how the costs of such a plant could be computed. Phillips Initial Brief at p. 112. Doing so would make O'Brien's complex formula even more complicated and would add more subjectivity to it. I do not find this acceptable in any regards.

[793] Ross makes the same charge regarding Tallett's proposal.

suggests,[794] and I agree, that his methodology is rampant with subjective determinations and is, besides, highly complex. *See* Exhibit No. EMT-76 at p. 15; Transcript at pp. 7206-7. Moreover, as I noted he did with regard to Resid, by failing to use a West Coast location factor, O'Brien understates the cost of reforming gasoline. Exhibit Nos. EMT-84 at pp. 12-13, EMT-76 at p. 16; Transcript at pp. 5315, 6164, 6411, 6570-72, 7217.

2702. In view of the above, I am convinced that O'Brien's proposal is so rampant with subjective determinations that it cannot meet the objectivity standard set out by the Circuit Court in *Exxon*, 182 F.3d at p. 42. Moreover, I find that it is too complex. Consequently, it cannot be considered either just or reasonable.

3. Exxon

2703. Exxon's proposal was put forth by Tallett. The record reflects that, after discarding several other methods, Tallett focused on the "relationship between the value of Naphtha and the published prices of the products that are made from Naphtha – namely gasoline and jet fuel – to value Naphtha on the West Coast." Exxon Initial Brief at p. 252. After determining, through the use of a standard regression formula,[795] that there was a relationship between the prices of Naphtha and unleaded regular gasoline, he further concluded that, when the price of jet fuel was added to the equation, "the price of Naphtha is almost entirely explained." *Id.* at p. 253. For the 1992 through 2001 period, Tallett established that the value of West Coast Naphtha averaged $24.91/barrel or $2.44/barrel higher than the average Gulf Coast value. *Id.* at p. 257.

2704. Tallett's analysis is supported, Exxon suggests, and I agree, by O'Brien's independent analysis, and by the rule of thumb used by an experienced Naphtha trader. *Id.* at pp. 267-68 (citing Transcript at pp. 10213-14; Exhibit Nos. UNO-9 at p. 1, EMT-76 at pp. 12, 14, EMT-77 at p. 6). Exxon correctly states that

> the reasonableness of Mr. Tallett's methodology is also confirmed by the results derived when Naphtha's value is calculated as a function of gasoline and crude oil prices. Thus, . . . if the price of Naphtha is determined as a percentage of the range between the price of gasoline and the price of crude oil using Gulf Coast prices, and this same percentage is then used to calculate a West Coast price of Naphtha using the price of gasoline and the price of ANS crude oil on the West Coast, the result is very close to Mr.

[794] Exxon Initial Brief at p. 281.

[795] Baumol explained, for the record, how a regression analysis works. Transcript at pp. 5085-5106.

Tallett's average West Coast Naphtha value for the same period.

Id. at pp. 269-70.

2705. Contrary to the criticism of other parties, it appears that Tallett did not use Gulf Coast prices to value West Coast Naphtha. Exhibit No. EMT-11 at pp. 16-21. Rather, the record reflects that Tallett used his regression formula to establish relationships between Gulf Coast Naphtha's value as a feedstock and the prices of end-products derived from it. *Id.* at p. 18; Transcript at pp. 7204-06. He then used those relationships and *West Coast* prices for those same end-products to calculate the value of West Coast Naphtha. Exhibit No. EMT-11 at p. 19. It does not appear that West Coast refining margins skew the results, as the record contains no evidence supporting this claim.

2706. In connection with Tallett's proposal, Williams claims that Tallett assumes that refining margins are the same on both coasts. Williams Initial Brief at p. 70. In fact, it claims, they are different, that the margins on the West Coast are higher. *Id.* at pp. 70-72 (citing Exhibit Nos. WAP-8 at p. 5-7, WAP-9, WAP-10, WAP-11, WAP-12 at p. 2). It cannot be argued that Tallett's proposal does not apply the Gulf Coast margin relationship between Naphtha and gasoline and jet fuel to the calculated value for Naphtha on the West Coast. However, the question is whether imputing that same relationship to the higher prices of finished products on the West Coast prevents the calculation of a West Coast Naphtha value which is just and reasonable.

2707. William's argument focuses on the differences in the refining margin between conventional gasoline and low sulfur No. 2 fuel oil minus the price of crude oil on the two coasts. *Id.* at p. 71. However, as Exxon points out,[796] all of the evidence on which Williams relies[797] relates to the higher West Coast price differential of those products relative to the price of crude oil, assuming crude oil prices on both coasts are the same, as Williams apparently does, and does not provide any information regarding the West Coast value of Naphtha. Exhibit No. EMT-133 at pp. 32-34. In other words, Williams assumes that the relationship between the price of crude oil and the cost of these finished products fully explains the difference in the refining margin between the coasts with regard to gasoline and jet fuel. Williams fails, however, to consider that, in doing so, it attributes none of the finished product margin on the West Coast to Naphtha.[798]

[796] Exxon Reply Brief at pp. 280-82.

[797] *See* Williams Initial Brief at pp. 70-71 (citing Exhibit Nos. WAP-8 at pp. 5-7, WAP-9, WAP-10).

[798] In addition, the record indicates that some of the increased margin associated with the relative higher prices for gasoline and jet fuel on the West Coast may not be fully captured by the refiners, contrary to Williams's assertion. Transcript at pp. 12056,

2708. In his Rebuttal Testimony, Tallett admitted that the West Coast margin between the prices of finished products and the price of crude oil was higher that that on the Gulf Coast, but added that this did not conflict with his "proposal to use West Coast gasoline and jet fuel prices to value West Coast Naphtha." Exhibit No. EMT-133 at pp. 32-33. He stated that what is relevant to his proposal "is whether the relationship between unleaded gasoline, jet fuel and Naphtha prices on the Gulf Coast is similar to the relationship among those same prices on the West Coast." *Id.* at p. 33. Tallett notes that, therefore, while the margin between unleaded gasoline prices and Naphtha prices have some relevance, the margin between finished product prices and the price of crude oil does not. *Id.* According to him, though it was alleged, neither Ross nor Sanderson provided evidence that the margin between gasoline prices and Naphtha values on the West Coast exceeded that on the Gulf Coast. *Id.* at pp. 33-34. On the other hand, Tallett did provide evidence that Gulf Coast Naphtha values tracked Gulf Coast gasoline prices. *Id.* at pp. 34-35, Exhibit Nos. EMT-11 at pp. 17-22, EMT-16, EMT-17, EMT-18, EMT-19, EMT-84 at p. 38. Further, he theorized that, citing Exhibit No. EMT-15, as the primary use of Naphtha on both coasts was to make gasoline and jet fuel, "one would expect Naphtha prices to be strongly correlated with the prices of gasoline and jet fuel on both the West Coast and the Gulf Coast" and created a regression formula which proved his theory. Exhibit No. EMT-11 at pp. 16-17.

2709. I find that the evidence submitted by and through Tallett satisfactorily proves that his regression formula establishes the relationship between gasoline, jet fuel and Naphtha on the West Coast. Williams has failed to convince me that the appropriate margin which ought to be attributed to Naphtha on the West Coast is anything other than that assumed by Tallett.[799] Moreover, it is clear to me that, of all the proposals put forth by the parties, only the Tallett method establishes a reasonable relationship between the values of gasoline, jet fuel and Naphtha on the Gulf Coast and applies that relationship to the same finished product prices on the West Coast. Consequently, it is more than satisfactory for Quality Bank purposes.

2710. Moreover, contrary to Williams's assertion, we have seen throughout this hearing that certain finished petroleum products are more closely associated, on a value basis, with their intermediate feedstock substances than to crude oil prices. *See* Exhibit No. EMT-476; Transcript at pp. 11037-38. This evidence demonstrates that the Gulf Coast

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12101. Moreover, although I do not apply any weight to the contract analyses contained in the record as evidence of the value of West Coast Naphtha, I do note that the overwhelming majority of Naphtha sellers on the West Coast tied the price of their sales to the price of gasoline on the West Coast. Exhibit No. EMT-133 at pp. 44-45; Transcript at pp. 6639, 7521-22, 7642-46, 8299, 11066-67, 11142.

[799] *See* Exhibit No. EMT-133 at p. 32.

value of Naphtha tracks more closely the cost of Gulf Coast gasoline than it does crude oil. *Id.* The same pattern of significance is shown from results of Tallet's West Coast calculated Naphtha values against the prices of West Coast gasoline and crude oil. Exhibit Nos. EMT-541, EMT-542. However, the record reflects that this pattern was not found when the Gulf Coast Naphtha price was tracked against the prices of West Coast gasoline and crude oil. Exhibit No. EMT-536; Transcript pp. 11058–59.
2711. Accordingly, what all this evidence does, contrary to Williams's assertions, is support the application of the Gulf Coast relationship of the refining margins inherent in the Tallett proposal to the prices of West Coast finished products to derive a West Coast value for Naphtha. In others words, both the higher West Coast gasoline and jet fuel prices and the resulting higher West Coast refining margins have been shown to contribute directly to higher West Coast Naphtha values.[800] This conclusion is consistent with the Tallett proposal.

2712. Moreover, the record reflects that Naphtha is not, contrary to Ross's claim, less valuable because of the introduction of CARB gasoline. Rather, it appears, Naphtha is more attractive because its aromatics have a high octane rating; and because it has a low Reid Vapor Pressure, no olefins and virtually no sulfur. Transcript at pp. 5997-98, 13218-19.

2713. It does not appear that Tallett's calculated value for West Coast Naphtha is subjective as it is entirely based on West Coast gasoline and jet fuel prices published by Platts. Exhibit Nos. EMT-397, EMT-17 at p. 11. In connection with this allegation, Exxon states that Tallett's regression formula "is derived by a standard statistical formula that can be run on any computer, with the result that no 'judgment' is required to calculate the formula, and anyone running the same analysis will 'come up with exactly the same answer'" and, therefore, it cannot be said to be subjective. Exxon Reply Brief at p. 280 (citing Transcript at pp. 5088-91). I agree with Exxon that the record supports its comment.

2714. Contrary to allegations[801] that Tallett's formula should have been based on current prices, not prices for the 1992 through 2001 period, it appears that he uses the formula to calculate the current value of West Coast Naphtha using current prices for unleaded gasoline and jet fuel. Moreover, as Exxon notes,[802] there is, apparently, no significant

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[800] Supporting this conclusion, further, is the evidence that there is no structural difference in the market relationships between the coasts. Exhibit Nos. EMT-11 at pp. 16–17, 20– 21, EMT-133 at pp. 19, 28–29; Transcript at pp. 6772–73, 7242–43.

[801] *See* Petro Star Initial Brief at pp. 20-21.

[802] Exxon Reply Brief at p. 287.

difference in whether Tallett's formula is derived using ten years of Gulf Coast price data or a smaller portion of that period. Exhibit No. EMT-398; Transcript at pp. 7108-13. In any event, Tallett's regression analysis can be updated periodically to ameliorate such a circumstance. Transcript at p. 6768.

2715. Answering charges that the demands of the petrochemical industry on the Gulf Coast affect the value of Naphtha there, Exxon accurately states that, as its value as a gasoline and jet fuel feedstock is higher than its value as a petrochemical feedstock, the former use creates a ceiling on its use for the latter. Exxon Initial Brief at pp. 274-75 (citing Exhibit Nos. EMT-123 at p. 33, EMT-133 at pp. 30-31, UNO-9 at p. 3). Tallett's regression analysis, Exxon also correctly argues, confirms this by showing that "over 98% of the variation in Gulf Coast Naphtha prices can be explained by changes in gasoline and jet fuel prices." *Id.* at p. 275 (citing Exhibit Nos. EMT-11 at pp. 18-19, EMT-17, EMT-343). Furthermore, it appropriately notes that the "Naphtha used as a petrochemical feedstock on the Gulf Coast is a different, lighter Naphtha than the heavier reformer-grade Naphtha and is used in steam crackers to produce ethylene." *Id.* at p. 276 (citing Transcript at pp. 7122-23, 12067-69, 12112-13).

2716. BP claims that Tallett has failed to take differences in the Gulf Coast and West Coast markets into consideration. BP Reply Brief at p. 30. In particular, it notes that West Coast operating margins are higher, and that supply and demand factors differ because of the demands of the petrochemical market on the Gulf Coast. *Id.* at pp. 30-31. Answering the former charge, Exxon accurately asserts that the higher West Coast refining margin has no bearing on the margin between unleaded regular gasoline and the value of Naphtha. Exxon Initial Brief at pp. 272-73 (citing Exhibit No. EMT-133 at pp. 32-35). Exxon further notes that, in any event, every witness has agreed that, on the Gulf Coast, the price of Naphtha closely tracks the price of gasoline and it concludes that this same relationship exists on the West Coast.[803] *Id.* at p. 273 (citing Transcript at pp. 11170-71, 12082; Exhibit No. EMT-476). In response to the latter charge, Exxon correctly notes, the record reflects that most of the Naphtha used by Gulf Coast petrochemical plants is not comparable to the heavy reformer grade Naphtha made from ANS crude as it is a lighter Naphtha used in steam crackers to produce ethylene. *Id.* at p. 276 (citing Transcript at pp. 7122-23, 12067-69, 12112-13). Moreover, as Exxon claims, even the benzene produced on the Gulf Coast by the heavier Naphtha does not impact the price of Gulf Coast Naphtha.[804] *Id.* at p. 277 (citing Transcript at pp. 7119-20). Therefore, based on the record, I cannot find that BP's claim regarding the West Coast refining margin and the demands of the Gulf Coast petrochemical industry has any merit.

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[803] *See also* Transcript at pp. 12085-86; Exhibit Nos. EMT-84 at p. 22, EMT-89, EMT-123 at p. 33, EMT-133 at p. 34, EMT-541, EMT-542, PAI-214 at p. 4.

[804] *See* Transcript at pp. 5287, 7116-19.

2717. Petro Star suggests that Tallett's regression formula would not accurately describe the West Coast relationship between Naphtha, jet fuel and gasoline if that relationship was different from the relationship between the same variables on the Gulf Coast. Petro Star Initial Brief at p. 17. However, it fails to cite to any evidence in the record which proves that the relationships are different.[805] In any event, even were relationships to change, and were such change verified through testing, Tallett suggests that modifying the coefficients in his regression formula would rectify that circumstance. Transcript at p. 6768.

2718. Phillips compares O'Brien's cost-based proposal with Tallett's, which it classifies as market-based. Phillips Initial Brief at p. 89. It states that the value derived from each is in the same general range. *Id.* (citing Exhibit No. SOA-28). Phillips further states that Tallett's proposal represents a rational approach to developing a market-based value for West Coast Naphtha. *Id.* at pp. 114-15.

2719. Turning around the argument that Tallett's proposal is faulty because the West Coast market is too different from the Gulf Coast market to support the kind of correlation done by him, Phillips notes that this is precisely the reason why the Gulf Coast Naphtha price cannot be used as a proxy for West Coast Naphtha. Phillips Reply Brief at pp. 75-76. While I cannot say that this argument supports Tallett's proposal, I certainly can agree that it is inconsistent for a party to argue in favor of continuing to use the reported Gulf Coast Naphtha price to value West Coast Naphtha and also to argue that Tallett's proposal is faulty for using Gulf Coast prices in a correlation to value West Coast Naphtha.

2720. Baumol's testimony regarding regression formulae has convinced me that they may be used to establish the approximate value of West Coast Naphtha, and Tallett's testimony convinced me that his regression formula did just that. I do not find that the testimony of witnesses who challenged Tallett's support for his proposal convincing; nor, I find, are the arguments made by parties opposing it persuasive. Therefore, of all the proposals presented by the parties, I am compelled by the record to hold that, because of its relative simplicity and lack of subjectivity, Tallett's proposal, which, as noted above, is supported by substantial record evidence,[806] and is a just and reasonable manner in

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[805] Petro Star does cite to evidence that Tallett admitted that the relationship between jet fuel and unleaded regular gasoline differed on the two coasts (Transcript at p. 6857; Exhibit No. WAP-180 at p. 1), but fails to explain how that establishes that the relationship between Tallett's three variables (Naphtha, jet fuel and gasoline) is different on the two coasts. *See* Petro Star Initial Brief at p. 17.

[806] While some of the evidence supporting Tallett's proposal is discussed here and in the section summarizing Exxon's argument, it is more than amply discussed in the

which to establish the value of West Coast Naphtha. I further hold that the Quality Bank Administrator should have the discretion to re-compute the value of West Coast Naphtha whenever circumstances require, but not less than once each year.

4. BP

2721. While agreeing with Phillips and Exxon that it is not appropriate to value West Coast Naphtha on other than a West Coast basis, BP claims that the O'Brien and Tallett proposals overvalue it as a result of spikes in the West Coast gasoline market. BP Initial Brief at pp. 29-30. Consequently, it suggests that a governor and a floor are required to protect against these market distortions.[807] *Id.* at p. 29.

2722. According to BP, while the value of West Coast Naphtha initially may be based on the reported West Coast gasoline price, such a valuation may not reproduce the same value Naphtha would have in a transparent market. *Id.* In support of this assertion, BP points to West Coast gasoline price anomalies which it claims cannot be attributed to a rise in the value of Naphtha or other gasoline feedstock. *Id.* at p. 30. The cap should represent, it claims, the value of Naphtha from other markets which could be imported into the West Coast were there a transparent market. *Id.* However, BP also concedes that the governor needs a floor to prevent the price from falling below the value of the local supply. *Id.* at p. 31.

2723. Phillips notes that Ross's governor proposal was a "moving target" that changed directions any number of times during the course of the litigation; besides abandoning his initial proposal for a cost-based Naphtha value, Ross made multiple changes to his governor value and also changed theories supporting it. Phillips Initial Brief at p. 116-21.[808] By the end of the hearing, Phillips points out, the level of Ross's governor had changed, the justification of why it was needed had changed, and the explanation of why it was needed had changed. *Id.* at p. 121. It argues that, as Ross was so willing to make changes to his proposal as his inability to defend his proposal against criticism increased, it suggests that there really was no principle underlying it and, therefore, it represents an end result looking for a theory on which to be based.[809] *Id.* BP claims that the changes

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evidence section of this Initial Decision.

[807] On brief, Unocal/OXY state that they do not oppose the use of a governor should a decision be made to adopt a West Coast Naphtha valuation. Unocal/OXY Reply Brief at p. 85.

[808] *See also* Exxon Initial Brief at pp. 284-85.

[809] In my mind, this is the most significant of Phillips's critique of Ross's proposal. A fuller summary of its criticism of the proposal is contained above. That I find no need to mention the others again here is no indication that they are not

were made only where necessary to meet the goal of placing the value of West Coast Naphtha on a basis consistent with that of other ANS cuts. BP Reply Brief at pp. 43-44. I cannot agree. The record clearly reflects that Ross changed his proposal whenever it became apparent that he could not continue to justify it in the face of the criticism of other parties.

2724. Exxon correctly notes that, despite the fact that Ross's governor is theoretically based on the value of Gulf Coast Naphtha plus the cost of diverting Caribbean shipments from the Gulf Coast to the West Coast, the record is devoid of any evidence that such diversions ever had occurred.[810] Exxon Initial Brief at p. 283. It also discussed Ross's claim, during the hearing, that his governor was an attempt to model a transparent market stating, correctly, that there was no evidence to support it. *Id.* at p. 291; Exxon Reply Brief at p. 305. Moreover, Exxon also accurately points out that Ross ignored certain cost factors (transportation costs as well as the costs of switching crude slates, and terminal and storage costs) which would have affected the amount of his governor. Exxon Initial Brief at pp. 300-04.

2725. It is clear to me that Ross and BP miss the point. There is no opportunity to attract imports of Naphtha to the West Coast because the West Coast supply and demand for Naphtha is in balance as West Coast refiners provide all of the Naphtha they need from internal sources.[811] As a result, there is virtually no trade in Naphtha on the West Coast and, consequently, there is no transparent market. Nor will there be so long as West Coast refineries continue, internally, to meet their own demand for it. Ross's testimony that his governor/floor proposal simulates a transparent market is simply not credible.

2726. The suggestion that, were the price of West Coast Naphtha high enough, imports would flow into the West Coast and West Coast refiners would buy that Naphtha rather than produce their own also is unsupported by any credible evidence. In point of fact, as there is no reported West Coast Naphtha price, there is no way for importers to know

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meritorious. It is clear from what I state below that repeating them here would amount to overkill.

[810] As with Phillips, I am highlighting Exxon's criticism of the Ross proposal here, but have more fully discussed it above. That I am not discussing Exxon's further comments is not an indication that they are invalid. Rather, it is an indication that they are additional justifications for my rejection of Ross's proposal which do not add to my discussion.

[811] While I have rejected the use of the West Coast Naphtha contracts for any purpose, I feel safe in commenting that, if they do have any probative value, it is to establish that only an insignificant amount of Naphtha is traded on the West Coast.

what price they would receive for the Naphtha they have available for sale were it shipped to the West Coast rather than the Gulf Coast.[812] Moreover, the suggestion that West Coast refiners would buy that Naphtha and somehow change their crude slate so that they would produce none, or less, of their own Naphtha also is unsupported by credible evidence. Ross simply has failed to convince me that this is a logical progression.[813]

2727. I also find that Ross's argument is self-defeating. Were West Coast refiners to purchase and import Naphtha because its cost was less than their cost to produce it, they would be competing for Naphtha on the world market. The record does not support a conclusion that such purchases could be made without affecting the world market price for Naphtha. It follows that, unless there were a significant surplus of Naphtha for sale on the world market, and the record also does not support such a conclusion, sales of Naphtha to West Coast refiners would cause the price of Naphtha on the world market to rise. Were that to happen, those same refiners, undoubtedly, would begin distilling their own Naphtha once again. Thus, Ross's cap proposal is an unworkable solution to the theoretical conundrum he created.

2728. As noted, Ross also proposed, in response to criticism of his cap proposal, that a floor price be set for West Coast Naphtha to be calculated by averaging the high and low of Platts West Coast ANS assessment plus $4.00. He derived the $4.00 figure from one of the contracts discovered by the parties. His attempt to validate this figure on the basis of the difference between the price of Gulf Coast Naphtha and West Texas sour crude (based on his theory that the latter was comparable to ANS crude) and the difference between Gulf Coast Naphtha and VGO (on the theory that West Coast Naphtha and VGO would have the same relationship) was not convincing. Moreover, even were I to have given any weight whatsoever to the Naphtha contracts discovered by the parties, I could not find that a term in one contract over a 10 year period was meaningful.[814]

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[812] Thus there is no transparent market for Naphtha on the West Coast and, I find that Ross's claim that his proposal will create a virtual transparent West Coast Naphtha market not credible. Moreover, were there, in fact, a transparent market on the West Coast, a reporting service undoubtedly would report the market price ending our difficulty of having to calculate one.

[813] I find Ross's background in economics, at best, to be superficial. *See* Transcript at pp. 8034-37.

[814] In any event, the contract referred to as support by Ross did not even involve Heavy Naphtha comparable to the Naphtha derived from ANS, but was for the purchase and sale of Full Range Naphtha, which is not its equivalent. Exhibit Nos. EMT-133 at pp. 39, 44, SOA-1 at pp. 16-17; Transcript at pp. 8405-06. Moreover, the cap in that contract was twice as high as Ross's proposed cap for a product that was less valuable

2729. As I find that neither the Ross governor nor his floor proposal is supported by credible record evidence for the reasons just stated, they are rejected.[815]

5. Conclusion

2730. As indicated above, based on the record as a whole, of all the proposals presented by the parties, I am compelled to hold that, because of its relative simplicity and lack of subjectivity, Tallett's proposal, which, as noted, is supported by substantial record evidence, should be used to value West Coast Naphtha.

2731. The formula suggested by Tallett should be implemented on a prospective basis. While there have been suggestions that it be implemented at an earlier date, substantial evidence does not support such a determination.

2732. I further hold that the Quality Bank Administrator should have the discretion to re-compute the value of West Coast Naphtha whenever circumstances require, but not less than once each year.

F. APPLICABILITY OF PLATTS HEAVY NAPHTHA PRICE

2733. Two decisions of the Quality Bank Administrator are at issue, both involve changes made by Platts regarding its Gulf Coast Naphtha assessment. Each of these decisions will be addressed on their individual merits. In addition, Exxon and Phillips have proposed that the Gulf Coast Naphtha assessment be adjustment for N+A content. This suggestion also will be separately addressed.

2734. The TAPS Carriers claim,[816] and I agree, that the Quality Bank Administrator is an independent neutral expert who attempts to resolve issues in accordance with his best professional judgment to whose expertise the Commission ought to show great deference.

1. February 2003

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than ANS Naphtha. *See* Transcript at p. 8142.

[815] It should be noted that I agree with many, if not all, of the criticisms of the Ross proposals made by the other parties which are described above. However, as I rejected it because his basic premise is unsupported by credible evidence, there is no need for me to address them.

[816] TAPS Carriers Reply Brief at p. 2.

2735. On February 27, 2003, the TAPS Carriers filed Tariff revisions amending their TAPS Quality Bank Methodology Tariffs. *BP Pipelines (Alaska), Inc.*, 102 FERC ¶ 61,345 at P 1. In the Tariff filings, the TAPS Carriers indicate that they are seeking to implement a determination of the Quality Bank Administrator that the Gulf Coast Naphtha value should be determined by using Platts newly reported Gulf Coast *Heavy* Naphtha assessment rather than its Gulf Coast Naphtha assessment. *Id.* at P 2, 11. The TAPS Carriers stated, in their notice to the Commission, that the Quality Bank Administrator determined that the API gravity and initial boiling points of the Quality Bank Naphtha cut are more similar to the Heavy Naphtha assessed by Platts than to the Naphtha it assesses. Exhibit No. PAI-222 at p. 2. They further declared that, because Platts informed the Quality Bank Administrator that as there were "plenty of [Heavy Naphtha] transactions, [it] had no trouble assessing [the] price and expected . . . to do it for the future," it was clearly reasonable for him to determine that the effective date of the change to the Gulf Coast Naphtha price should be March 1, 2003. TAPS Carriers Initial Brief at pp. 15-16 (citing and quoting Transcript at pp. 13174-75).

2736. Petro Star does not disagree with the TAPS Carriers's determination to use Platts Heavy Naphtha assessment to value Gulf Coast Naphtha, but claims that the Quality Bank Administrator exceeded his authority in doing so because, when the Quality Bank Administrator implemented the change on March 1, 2003, there was no evidence that the Full Range Naphtha assessment previously used had changed. Petro Star Initial Brief at pp. 25-26. However, it cited no record evidence in support of this claim.[817] In any event, the record establishes that Petro Star errs. It is clear that Platts had altered the manner in which it assessed Gulf Coast Naphtha. Petro Star's suggestion that Platts was still publishing the same Full Range Naphtha assessment which it previously had is simply not based on fact.

2737. Unocal/OXY make a similar argument to Petro Star's and cite to Mitchell's agreement with its counsel that the "price that was previously used was still employed, was still published by Platts."[818] Unocal/OXY Initial Brief at p. 45. In reply, the TAPS Carrier's point out that the Quality Bank Administrator was required by the Tariff to use Platts Gulf Coast Naphtha assessment to value ANS Naphtha. TAPS Carriers Reply Brief at p. 3. They further assert that, once Platts started publishing two different Gulf Coast Naphtha price assessments, the Quality Bank Administrator had to decide which of the two assessments to use. *Id.* The TAPS Carriers add:

[817] In fact, the only evidence offered on this matter supported the TAPS Carriers's position. *See* Transcript at pp. 13339, 13341-43, 13551; Exhibit Nos. EMT-640, EMT-641.

[818] Transcript at p. 13186.

> Because the publication of a second naphtha price assessment was unanticipated, the prior orders of the Commission[] did not expressly answer that question, and therefore the [Quality Bank Administrator] was forced to use his authority under Item III.J. of the Quality Bank tariff, Ex. TC-3 at 8, to choose the price that best reflects the value of the Quality Bank naphtha component in the Gulf Coast market.

Id. This argument is clearly supported by substantial evidence.[819]

2738. Moreover, there also was no error in the TAPS Carriers's decision to implement the change on March 1, 2003, as the Commission approved the implementation subject to refund and subject to further order of the Commission. *BP Pipelines (Alaska), Inc.*, 102 FERC P 13.

2739. I find, therefore, that substantial record evidence supports the TAPS Carriers's determination to replace the previously used Platts Gulf Coast Naphtha assessment with Platts Gulf Coast Heavy Naphtha assessment for all Quality Bank purposes, that such a substitution is just and reasonable, and that such determination should be implemented effective March 1, 2003.

2. June 2003

2740. On June 18, 2003, the Quality Bank Administrator filed a notice with the Commission that, effective May 1, 2003, Platts intended to publish two Gulf Coast Heavy Naphtha assessments, one for "Heavy Naphtha" and the other for "Heavy Naphtha Barge." Exhibit No. TC-19 at p. 2.[820] He further stated that he determined that Platts was assessing two separate markets – the Heavy Naphtha assessment is an assessment of ship's cargo transactions (up to 250,000 barrels) while the Heavy Naphtha Barge transactions are for the contents of barges (up to 50,000 barrels). *Id.* at p. 3. The Quality Bank Administrator further stated that there are numerous transactions for each and that no available data will allow for a volume-weighted or transaction-weighted average to be calculated. *Id.* at p. 4. Therefore, he recommended that "the arithmetic average of the

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[819] Unocal/OXY also argue that use of Platts Gulf Coast Heavy Naphtha assessment overvalues West Coast Naphtha and that the "pricing changes initiated by the [Quality Bank Administrator] have the effect of freezing in place the prior month's value until the issues raised by the [Quality Bank Administrator] initiative are resolved by the Commission." Unocal/OXY Initial Brief at p. 46. They do not cite to any evidence in the record to support either claim nor do they sufficiently explain either of them. Consequently, I must reject both their arguments out-of-hand.

[820] *See Trans Alaska Pipeline System*, 104 FERC ¶ 61,201(2003).

average monthly price for Gulf Coast Waterborne 'Heavy Naphtha' and Gulf Coast 'Heavy Naphtha Barge' as reported by Platts" replace Platts Gulf Coast Waterborne Heavy Naphtha for Quality Bank calculations. *Id.* at p. 5.

2741. BP suggests that, as Platts continues to publish the Heavy Naphtha assessment, it ought to continue to be used. BP Supplemental Brief at pp. 2-3. That argument, however, ignores the fact that Platts has split what previously was the Heavy Naphtha assessment into a Heavy Naphtha assessment that relates to cargo sized transactions and a Heavy Naphtha Barge assessment that only relates to barge-sized transactions. That it failed to change the name of the Heavy Naphtha assessment is irrelevant; after the change, it simply was not the same as before. Ergo, BP's argument has no merit.

2742. Williams argues that introduction of the barge quote does not constitute a "radical alteration in the basis for reporting one of the products used to calculate the TAPS Quality Bank adjustments."[821] William's Supplemental brief at p. 3 (citing Exhibit No. TC-19 at p. 1). It notes that Mitchell reported that Sharp, an employee of Platts, stated that the Gulf Coast Heavy Naphtha assessment was "an assessment of cargo transactions." *Id.* at p. 4 (citing Exhibit No. TC-20 at p. 1). Williams also notes that, in a subsequent conversation, Sharp, when asked about the foregoing, repeated that the Heavy Naphtha assessment was "primarily a cargo number" and that barge quotes were minimized. *Id.* at p. 4 (citing Exhibit No. TC-22 at p. 1).

2743. Exhibit No. TC-22 reflects, however, that Williams fails to note the following follow-up to the discussion to which it refers. Mitchell states as follows:

> I reiterated what I had told him in my earlier call that while we were interested in the types of transactions that he took into account in making the assessment, we were primarily interested in how he would describe the nature of the resulting assessment. I asked him about the responses he had

[821] Petro Star indicates that it agrees with Williams, admitting that there has been a change, but claiming that it wasn't "radical." Petro Star Supplemental Brief at pp. 2-3. In doing so it refers to a 1998 Quality Bank Administrator determination not to use an arithmetic average to value the VGO cut because it would not "accurately reflect the market price." *Id.* at pp. 3-4. BP and Williams also refer to the Quality Bank Administrator's VGO decision. BP Supplemental Brief at pp. 6-7; Williams Supplemental Brief at pp. 7-8. I find, however, that just because the Quality Bank Administrator made that decision in 1998, under the facts involved in those circumstances, does not bar him from making a different determination in 2003 (or, in fact, anytime) under different circumstances. In other words, a factual determination does not establish any precedent prohibiting a different decision with a different fact situation.

> given to my questions two weeks ago regarding the nature of the assessments. I read his previous answer to my question as to whether the earlier assessment was meant to be a cargo assessment or an overall assessment of the market. His reply had been that, "the assessment was weighted toward cargo but was not exclusively a cargo assessment." He had also said that the assessment, "was not exclusively one or the other." He responded that those earlier responses were correct. Mr. Sharp further stated that not all barge deals were included in the assessment.

Exhibit No. TC-22 at p. 1. Mitchell also quotes Sharp as saying that the "Heavy Naphtha assessment was a, 'general market assessment'; it was neither solely cargo nor barge but was, 'influenced by both' although cargo transactions predominated." *Id.* Sharp also stated, according to Mitchell, that he "sometimes used barge transactions for the high for the day and cargo transactions for the low." *Id.* at pp. 1-2.

2744. Based on the above, it is clear to me that Williams's claim that the manner in which Platts assessed Gulf Coast Naphtha was not radically changed by its decision to report barge and cargo transactions separately has no basis in fact.[822]

2745. Williams also argues that the Quality Bank Administrator's averaging proposal is inconsistent with the way other cuts are valued.[823] Williams Supplemental Brief at p. 5. This is disputed by the TAPS Carriers who note the following:

> - For each reference price the Quality Bank averages the high and the low price for each day. The Quality Bank then averages the daily averages to obtain a monthly average price for each component on the Gulf Coast and the West Coast.
>
> - A location factor is then used to calculate a weighted average of the Gulf Coast and the West Coast for each component. (In recent years the weighting has been 100 percent West Coast and zero percent Gulf Coast.)

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[822] Unocal/OXY also suggest that the splitting of the Heavy Naphtha assessment into cargo and barge assessments was not a radical change because the pricing change is not significant. Unocal/OXY Supplemental Brief at pp. 9-10. They do not explain, however, why the range of the change in values is relevant and material. In any event, I find that Sharp's comments to Mitchell, Toof and Stephen Jones, referred to above, clearly reflect that the change was significant and I, consequently, also find that the Unocal/OXY argument has no merit.

[823] Unocal/OXY and BP make virtually the same argument. Unocal/OXY Supplemental Brief at pp. 10-12; BP Supplemental Brief at pp. 4-5.

- The location factor is based on averaging shipping data obtained from the Maritime Administration over a six-month period to determine the percentage of ANS being transported to the Gulf Coast and the West Coast.

- The gravity differential used for the Valdez quality bank is calculated from the averages of the gravity differentials for several companies. The overall differential is a weighted average using the location factor.

- The Nelson Farrar Index used to adjust the size of the deductions in the pricing basis for the Light Distillate, Heavy Distillate and Resid components is developed by calculating annual averages of the monthly refinery operating inflation factors.

TAPS Carriers Reply Brief at pp. 11-12 (citations omitted). They also note that the Commission has not adopted a policy against using an average of two reference price assessments in the same region. *Id.* at pp. 12-13. In addition, the TAPS Carriers note that, in the current litigation, "all parties support the adoption of a method for valuing the resid component that will use a weighted average of *nine* reported price assessments." *Id.* at p. 13 (emphasis in original).

2746. Finally, I note that the Quality Bank Administrator's determination is supported by Phillips and Exxon. Phillips Supplemental Brief at pp. 4-5; Exxon Supplemental Brief at pp. 5-11.

2747. I find that the TAPS Carriers argument is compelling, and the weight of the evidence supports a conclusion that averaging the cargo and barge assessments would not be alien to the manner in which Quality Bank cuts are valued.

2748. Based on the record as a whole, as indicated in the above discussion, I find that the Quality Bank Administrator's determination is supported by substantial evidence and establishes a just and reasonable Naphtha value. I further find that that the replacement price proposed by him should be made effective on August 17, 2003.[824] *Trans Alaska Pipeline System*, 104 FERC ¶ 61,201 at P 9.

3. N+A Adjustment

2749. Exxon and Phillips have suggested that Platts Gulf Coast Naphtha assessment be

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[824] I find that Williams's argument that the Quality Bank Administrator's determination was premature and based on a superficial examination, and that, therefore, it ought to be made effective only on a prospective basis to be specious. *See* Williams Supplemental Brief at pp. 11-14.

adjusted by 1.5¢/gallon (based on a 0.15¢ adjustment for each increase in N+A above 40 to a maximum of 50 N+A). The other parties are opposed to this adjustment. I have sufficiently detailed the evidence adduced by the parties regarding the N+A issue, as well as their arguments in favor of it or opposed to it, in prior discussions. Suffice to say, here, that the N+A adjustment is similar to other intra-cut quality issues which the parties have agreed to defer until the next phase of this proceeding. Accordingly, I find that it would be unjust and unreasonable to consider such an adjustment at this time. It will be considered, if at all, at the same time as all other intra-cut quality issues are addressed.

2750. Moreover, as all of the evidence relating to whether Platts makes an N+A adjustment and, if so, what the amount of that adjustment is and how it is applied consists of hearsay reports of comments by one employee of Platts, which comments have been interpreted differently by various witnesses, I am not in a position, at this time, to find that substantial evidence in the record supports a conclusion that such an adjustment should be made.

2751. In view of the above, at this time I am rejecting the Exxon/Phillips proposal that the Platts Gulf Coast Naphtha assessment be adjusted for N+A content. They are free to raise it again during the next phase of these proceedings when other intra-cut quality issues will be addressed.

G. IMPACT OF POTENTIAL PUBLICATION OF A WEST COAST NAPHTHA PRICE

2752. While the parties briefed this matter, their arguments for and against the use of such an assessment are purely speculative as no such assessment is being published. Consequently, there is nothing on which a ruling is required.

H. ADMINISTRATIVE FEASIBILITY

2753. There is no dispute regarding the conclusion reached by the Quality Bank Administrator[825] that all of the proposals put forth by the parties to establish a West Coast Naphtha value are administratively feasible.

[825] *See* TAPS Carriers Initial Brief at pp. 16-17.

ISSUE NO. 4: IS THE CURRENT METHOD FOR VALUING THE WEST COAST VACUUM GAS OIL CUT JUST AND REASONABLE, AND IF NOT, WHAT IS THE APPROPRIATE METHOD FOR VALUING THE VACUUM GAS OIL CUT? WHAT SHOULD BE THE EFFECTIVE DATE OF ANY CHANGE TO THE WEST COAST VACUUM GAS OIL CUT?

A. STIPULATED MATTERS

2754. All parties agree that West Coast Vacuum Gas Oil should be prospectively valued based on the published Oil Price Information Service West Coast High Sulfur VGO weekly price. Eight Parties Initial Brief at p. 161; Exxon Initial Brief at p. 341. Further, the Eight Parties note, all parties also agree that, if a new West Coast Naphtha valuation methodology is adopted in this proceeding, both it and the new West Coast VGO value should have the same effective date. Eight Parties Initial Brief at p. 161.

B. AREAS OF DISPUTE

2755. The area of dispute with respect to Issue No. 4 is the effective date for the new West Coast VGO value. According to the Eight Parties, this new value only should have a prospective application from the date the Commission issues its final order in this proceeding. *Id.* They disagree with Exxon's position that the value should be applied retroactively to June 19, 1994. *Id.* at pp. 161-62. Exxon's reasoning that the damages can be recovered for a period of two years prior to the filing of a complaint, the Eight Parties argue, is an inappropriate reason for retroactively applying the new valuation. *Id.* at p. 162. They also note that Exxon argues that damages should at least be retroactively applied back to August 1998 when Tesoro filed its complaint challenging the VGO price. *Id.* The Eight Parties believe that nothing in the analysis of the past and present circumstances underlying the VGO market on the West Coast suggests that anything other than prospective application of the new, agreed upon, VGO value is appropriate. *Id.*

2756. VGO valuation became an issue, according to the Eight Parties, in May of 1994 when the Commission determined there was record evidence which suggested that the OPIS West Coast high sulfur VGO price, utilized for a short period to value West Coast VGO, was thinly traded and could be subject to manipulation.[826] *Id.* Consequently,

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[826] The Eight Parties acknowledge that, in 1994, their own witness Ross did not share the Commission's concern about potential manipulation, but that, nonetheless, the Commission had those concerns and ordered that a Gulf Coast price be used to value

explain the Eight Parties, the Commission ordered that the West Coast VGO cut be valued using the OPIS Gulf Coast VGO price. *Trans Alaska Pipeline System*, 67 FERC ¶ 61,175 at p. 61,531 (1994). They note that this order has never been appealed. Eight Parties Initial Brief at p. 163.

2757. The Eight Parties argue, however, that, since 1994, and especially between 2000 and 2002, changed circumstances in the West Coast VGO market should dispel the concerns which the Commission previously had regarding the potential for market manipulation. *Id.* They point out that a redistribution of refining assets has taken place on the West Coast with the result that the three major ANS producers and Tesoro all now have direct access to West Coast VGO markets. *Id.* According to the Eight Parties, this was not so in 1994. *Id.* When the Commission issued its 1994 order expressing concern about potential manipulation, they note, there were just a limited number of Quality Bank participants who also participated in the West Coast VGO market. *Id.* (citing Exhibit No. BPX-26 at p. 4). The recently broadened presence in the West Coast VGO market of Quality Bank participants and those who own refineries and trade in VGO should, in the opinion of the Eight Parties, remove any concerns the Commission had regarding the potential for manipulation. *Id.* at pp. 163-64. Thus, under these newly realized market conditions, the Eight Parties argue, the West Coast VGO price is appropriate to use in the Quality Bank, but only on a prospective basis. *Id.* at p. 164.

2758. Exxon provides no justification, assert the Eight Parties, for retroactive application of the new reference price to June 19, 1994, except that it is two years before the filing of the Tesoro complaint. *Id.* They take the position that Exxon's recommendation for retroactive application is not proper. *Id.* Since 1994, the Eight Parties argue, Quality Bank participants have relied upon the use of the Gulf Coast VGO price to value West Coast VGO in making pricing and other business decisions. *Id.* Indeed, they note, the Commission's order valuing West Coast VGO using Gulf Coast prices has neither been appealed nor subject to remand. *Id.* Thus, the Eight Parties explain, prudent business practices since 1994 would, and did, reasonably lead companies to rely on the Gulf Coast price in making irreversible business decisions. *Id.*

2759. It was still reasonable to rely on the existing valuation, argue the Eight Parties, and not a proposed valuation in making business decisions even after Tesoro filed its complaint in August 1998 challenging the VGO price. *Id.* To make irreversible business decisions using a value other than what was ordered by the Commission simply because that value is being challenged would be unwarranted according to the Eight Parties, because it would require speculation: (1) that the challenge would be successful; (2) that the new value would be applied retroactively; and (3) that the new value is known. *Id.* at pp. 164-65. Taking all of these uncertainties together, the Eight Parties assert that the

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West Coast VGO. Eight Parties Initial Brief at p. 162, n.97.

only reasonable course of action for a business was to continue to rely on the existing Gulf Coast reference price as the value for their West Coast VGO. *Id.* at p. 165.

2760. Further, the Eight Parties point out, application of the new reference price back to June 19, 1994, would result in the implementation of a revised West Coast VGO price to take effect just one month after the Commission ordered, in May 1994, that the Gulf Coast price should be used for both the Gulf Coast and the West Coast. *Id.* In the Eight Parties's opinion, Exxon presents no evidence to justify essentially overturning the Commission's final order, which was not appealed, so soon after it took effect. *Id.*

2761. Moreover, there is no evidence, according to the Eight Parties, that the West Coast VGO price now to be used has been valid since 1994. *Id.* What the Eight Parties believe is known is that no stress was placed on this price because it was not used as a Quality Bank reference price. *Id.* If it had been, the Commission's concern for potential manipulation could have proven justified. *Id.*

2762. In conclusion the Eight Parties argue that prospective application only of the West Coast High Sulfur VGO weekly price is the appropriate course of action. *Id.*

2763. Exxon points out that the VGO cut is being valued on both the West Coast and the Gulf Coast at the OPIS Gulf Coast price for high sulfur VGO because of Commission decisions issued in 1994.[827] Exxon Initial Brief at p. 340. It claims that all parties to the proceeding agree that the current method of valuing the West Coast VGO cut on the basis of the OPIS Gulf Coast price for high sulfur VGO does not produce a just and reasonable result and should be changed. *Id.* Further, Exxon asserts, all parties agree that the West Coast VGO cut should be valued based on West Coast market prices, rather than on the basis of a Gulf Coast proxy price.[828] *Id.* at pp. 340-41. This is especially true, according to Exxon, in view of the undisputed facts that none of the ANS streams are currently delivered to the Gulf Coast, and that deliveries to the Gulf Coast have been less than three percent since 1998. *Id.* at p. 341. Further, Exxon argues, the evidence demonstrates that, historically, the value of VGO on the West Coast has been

[827] Exxon notes that on February 11, 1994, the Commission ordered that the VGO cut should be valued on the Gulf Coast at the OPIS Gulf Coast price for high sulfur VGO and on the West Coast at the OPIS West Coast price for high sulfur VGO. Exxon Initial Brief at p. 340. Three months later, however, on May 12, 1994, Exxon notes, the Commission concluded that the OPIS Gulf Coast price for high sulfur VGO should be used as the proxy price for the VGO cut on *both* the Gulf Coast and the West Coast. *Id.*

[828] Exxon points out that it has agreed that West Coast, rather than Gulf Coast, market prices should be used to value VGO on the West Coast, even though such a change is contrary to Exxon's economic interest. Exxon Initial Brief at p. 341, n.120.

significantly different from its value on the Gulf Coast, thereby requiring that an appropriate West Coast proxy price be used to value the West Coast VGO cut. *Id.* According to Exxon, all parties have also stipulated that the VGO cut should be valued on the West Coast on the basis of the OPIS West Coast High Sulfur VGO weekly price. *Id.* at pp. 341-42.

2764. The evidence strongly confirms, in Exxon's view, that the OPIS West Coast High Sulfur VGO price is a reliable and appropriate indicator of the value of the VGO cut on the West Coast. *Id.* at p. 342. Further, Exxon states, the parties agree that there is no longer any reason to be concerned that the OPIS West Coast High Sulfur VGO price might be somehow subject to manipulation. *Id.* According to Exxon, the following is true: (1) Sulfur VGO price has always been a valid indicator of the value of VGO during the entire 1994-2002 period; (2) VGO has never been manipulated; and (3) no party has ever even had any incentive to engage in manipulation of the price of VGO. *Id.* Under these circumstances, then, Exxon argues that the Commission should find that the OPIS West Coast High Sulfur VGO weekly price is the appropriate reference price to be used by the Quality Bank to value the VGO cut on the West Coast. *Id.*

2765. Exxon agrees that the only dispute between the parties concerns the effective date for this change in the valuation of the West Coast VGO cut. *Id.* at pp. 342-43. Its position is that the effective date for the new West Coast VGO valuation should be March 1, 2003,[829] whereas, Exxon notes, it is the position of the Eight Parties that the change to the OPIS West Coast VGO price should be implemented only prospectively. *Id.* at p. 343. Exxon suggests, however, that in individual briefs addressing the Naphtha valuation issue, certain of the Eight Parties appear to agree with the use of March 1, 2003, as the effective date for valuing both the West Coast VGO and Naphtha cuts. Exxon Reply Brief at p. 390 (citing Phillips Initial Brief at pp. 170-75; Unocal/OXY Initial Brief at p. 48; Petro Star Initial Brief at p. 28). However, Exxon notes, the parties have agreed that, if a different West Coast Naphtha valuation methodology is adopted in this proceeding, it and the new West Coast VGO value should have the same effective date. Exxon Initial Brief at p. 343.

2766. The TAPS Carriers point out that all parties support use of the OPIS West Coast High Sulfur VGO weekly assessment as the value for the gas oil component on the West Coast. TAPS Carriers Initial Brief at p. 17. The only dispute, according to the TAPS

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[829] Exxon believes refunds should be awarded for the period between March 1, 2003, and the date of the Commission's decisions in these proceedings. Exxon Initial Brief at p. 343, n.121. It also believes that reparations equal to the difference between the valuations that have previously been in effect for the VGO cut and the new, revised, valuation for West Coast VGO should be ordered for the period June 19, 1994, to March 1, 2003. *Id.*

Carriers, is with regard to the effective date of the implementation of the revised gas oil valuation. *Id.* at pp. 17-18. They note that the Quality Bank Administrator has testified that either prospective implementation of this proposal, as the Eight Parties propose, or a June 19, 1994, effective date, as Exxon proposes, would be administratively feasible. *Id.*

ISSUE 4 - DISCUSSION AND RULING

2767. The parties have stipulated that West Coast VGO ought to be valued on the basis of the OPIS West Coast High Sulfur VGO weekly price. They disagree as to the effective date. The Eight Parties argue that the new price should be put into effect on a prospective basis. Eight Parties Initial Brief at p. 165; Eight Parties Reply Brief at p. 130. Exxon, on the other hand, suggests that the effective date for the new price should be March 1, 2003. Exxon Initial Brief at p. 408; Exxon Reply Brief at p. 389.

2768. In support of its position, Exxon points out that the parties have stipulated that the effective dates for any new Naphtha value and the agreed upon VGO value should be the same. *See* "Joint Stipulation of the Parties," filed October 3, 2002, at p. 4. Further, it refers to the Commission's March 28, 2003, "Order Accepting and Suspending Tariffs, Subject to Refund and Conditions, and Consolidating Proceeding for Hearing." *BP Pipelines (Alaska), Inc.*, 102 FERC ¶ 61,345 (2003). In that Order, the Commission addressed the TAPS Carriers request for permission to change their Tariffs to "change the TAPS Quality Bank pricing basis used to value the Quality Bank Naphtha cut from Platts Oilgram Price Reports (Platts) reported Gulf Coast Naphtha price assessment to Platts newly reported Gulf Coast Heavy Naphtha price assessment." *Id.* at P 2. The Commission "accept[ed] the filings to be effective March 1, 2003." *Id.* at P 3.

2769. Unless Exxon was conceding that the Naphtha issue should be resolved in favor of the continued use of the Gulf Coast Heavy Naphtha price assessment to value West Coast Naphtha, I cannot fathom how it can suggest that the Commission's March 28, 2003, Order supports its suggestion that the stipulated VGO price be effective on March 1, 2003. But, Exxon was not doing so![830]

2770. I cannot find any evidence in the record which supports making the agreed upon West Coast VGO price effective retroactively, and Exxon cites none in its brief. Therefore, I hold that West Coast VGO ought to be valued on the basis of the OPIS West Coast High Sulfur VGO weekly price only on a prospective basis. As I have determined that the new West Coast Naphtha value also should be made effective on a prospective basis, my ruling coincides with the parties's October 3, 2002, Stipulation.

[830] *See* Exxon Initial Brief at p. 253.

ISSUE NO. 5: SHOULD THE REVISED VALUES FOR THE CUTS SUBJECT TO THE D.C. CIRCUIT REMAND IN *OXY USA, INC. v. F.E.R.C.*, 64 F.3d 679 (D.C. CIR. 1995) (RESID, FUEL OIL, HEAVY DISTILLATE AND LIGHT DISTILLATE) BE MADE RETROACTIVE TO DECEMBER 1, 1993?

A. LEGAL AND EQUITABLE STANDARDS

2771. The Eight Parties, citing *Exxon*, 182 F.3d at pp. 49-50, argue that the Commission has the discretion to determine whether and when a new rate should be applied retroactively. Eight Parties Initial Brief at pp. 166-67. Further, the Eight Parties assert, this discretion, which comes from the Interstate Commerce Act, 49 U.S.C. § 101, *et seq.* (2000), as well as analogous requirements of the Federal Power Act, 16 U.S.C. § 791a, *et seq*. (2000), and the Natural Gas Act, 15 U.S.C. § 717, *et seq.* (2000), is rooted in equitable considerations. *Id.* They also note that the Circuit Court stated that there is a "strong equitable presumption in favor of giving" the 1997 TAPS settlement a retroactive effect so as to "make the parties whole," but that the Court nonetheless cautioned that "[t]his is not to say that [the Commission] must [order a retroactive effect] in every case if the other considerations properly within its ambit counsel otherwise." *Id.* (citing *Exxon*, 182 F.3d at p. 49). The Eight Parties urge that the Commission make use of this equitable discretion when determining whether retroactive refunds are appropriate in this proceeding. *Id.*

2772. In exercising its discretion, the Eight Parties state that, according to the Circuit Court, "when the Commission commits legal error, the proper remedy is one that puts the parties in the position they would have been in had the error not been made." *Id.* at p. 167 (quoting *Public Utilities Com'n of State of Cal. v. F.E.R.C.*, 988 F.2d 154, 168 (D.C. Cir. 1993)). This discretion, note the Eight Parties, must also be exercised reasonably and in accordance with the doctrine, outlined in *Towns of Concord, Norwood, & Wellesley v. FERC*, 955 F.2d 67, 76 (D.C. Cir. 1992), that characterizes customer refunds as a type of restitution to be ordered only when "money was obtained in such circumstances that the possessor will give offense to equity and good conscience if permitted to retain it." Eight Parties Initial Brief at pp. 167-68. Further, continue the Eight Parties, because this aspect of an agency's role is intertwined with its core regulatory function, no presumption of refunds has been imposed by the Circuit Court. *Id.* at p. 168.

2773. Accordingly, the Eight Parties argue, refunds are not automatic, but are discretionary, and should be ordered only when they would advance the core purposes of the regulatory statute. *Id.* Further, in determining the propriety of refunds, the Eight Parties point out, "the agency need only show that it 'considered relevant factors and . . . struck a reasonable accommodation among them,'. . . and that its order granting or denying refunds was 'equitable in the circumstances of this litigation.'" Eight Parties Initial Brief at pp. 168-69 (quoting *Towns of Concord*, 955 F.2d at p. 76).

2774. The Eight Parties argue that case law, including *Exxon*, indicates that the Commission must balance all relevant interests, including the public interest, when it determines whether to grant or deny equitable restitution. *Id.* at p. 169. This is particularly true in proceedings such as this one, state the Eight Parties, which is not a rate case within the meaning of the Interstate Commerce Act, where the core purpose is to ensure just and reasonable rates charged by a carrier to its shipper customers. *Id.* Instead, the Eight Parties note, this is a proceeding to adjust the valuation of oil streams in the Quality Bank to balance rights among TAPS shippers and not to determine the rate charged the shippers by the TAPS Carriers. *Id.* Further, the Eight Parties point out, the Commission has characterized this proceeding as the settlement of a private conflict among Quality Bank participants which will not impact consumers. *Id.* Therefore, the Eight Parties argue, the Commission must recognize that the Quality Bank proceeding is different from the rate provision portion of the TAPS tariff. *Id.*

2775. According to the Eight Parties, if the 1993 values for the Resid and Distillate cuts are not changed, this will not result in the TAPS Carriers being unable to recover transportation costs incurred in moving shippers's barrels. *Id.* at p. 170. In addition, the Eight Parties argue, because the transportation rates on TAPS that are the primary focus of the Interstate Commerce Act are unrelated to the Quality Bank assessments, declining to give retroactive effect to the new cut values will not be contrary to statutory design. *Id.*

2776. A similar analysis guided the United States Court of Appeals for the First Circuit, in *Sithe New England Holdings, LLC v. F.E.R.C.*, 308 F.3d 71 at p. 76 (1st Cir. 2002), according to the Eight Parties, when it affirmed the Commission's decision not to impose higher charges retroactively for certain capacity requirements in a power pool governed by the rate provisions of the Federal Power Act. *Id.* In *Sithe*, explain the Eight Parties, the Circuit Court based its holding, in part, on the fact that the issues in dispute did not involve core ratemaking principles under the Federal Power Act. *Id.* Because the court in *Sithe* was concerned with transactions between utilities, the Eight Parties argue, the filed rate doctrine's corollary prohibition against retroactive ratemaking would not necessarily apply to transactions between utilities. *Id.* at pp. 170-71.

2777. The primary purpose of the corollary, according to the Eight Parties, is to assure that buyers who paid the tariff rate for a service are not surprised by subsequent regulatory decisions requiring them to pay more for past services. *Id.* at p. 171. Therefore, the Eight Parties explain, claims for retroactive restitution as a result of agency error are typically granted when that error has imposed losses on customers served by the regulated entity, and that entity was on clear notice that the precise rates being charged were under challenge before the agency. *Id.*

2778. Because the issue before the Commission in this proceeding is equity among shippers, not relationships between shippers and the carrier, the Eight Parties advocate for the Commission to exercise its equitable discretion by considerations of equity using Justice Cardozo's guidance found in *Atlantic Coast Line Railroad v. Florida*, 295 U.S. 301 (1935). Eight Parties Initial Brief at p. 171. Specifically, the Eight Parties argue, retroactive payments should only be ordered if equity and the conscience would be offended by a failure to order retroactive payments. *Id.* at p. 172. Here, equity and good conscience, in the opinion of the Eight Parties, call for examination of the entire history of the effort to achieve a just and reasonable adjustment of Quality Bank payments among TAPS shippers. *Id.*

2779. Arguing that the issue of distinguishing the value of one shipper's oil from another shipper's oil is difficult and complicated, the Eight Parties note that both the Commission and the courts have recognized that there is no one right way to draw that distinction. *Id.* Not surprisingly, explain the Eight Parties, the determination of the relative values of crude streams among TAPS shippers has been contentious since the inception of the Quality Bank. *Id.* Each time this issue has been before the Commission, the Eight Parties point out, the Commission has applied a change in valuation prospectively unless the parties agreed otherwise. *Id.* at pp. 172-73.

2780. The Eight Parties explain that the current dispute began in 1989, when OXY and Philips challenged the gravity valuation methodology of determining the relative values of each shipper's oil in the stream.[831] *Id.* at p. 173. In 1993, the Commission determined that the gravity methodology was no longer just and reasonable, state the Eight Parties, and required the adoption of the distillation methodology, to be effective on a prospective basis only. *Id.* Following that order, the Eight Parties note, the Circuit Court twice reversed and remanded the Commission's valuation of the Resid cut, while affirming other aspects of the Commission's rulings. *Id.*

2781. Under the applicable legal and equitable standards discussed above, the Eight Parties argue, heavy oil producers and refiners should not be required to make refunds resulting from the retroactive adjustment of the remanded cuts. *Id.* Refunds that would result from a retroactive application of the Resid revaluation and Fuel Oil, Light Distillate, and Heavy Distillate 1998 valuations would not, in the Eight Parties's opinion, serve the purposes of the Interstate Commerce Act, would inequitably impact the parties that would be required to pay the retroactive Quality Bank adjustments, and would not "make the parties whole." *Id.* In other words, a determination that the Resid revaluation and Fuel Oil, Light Distillate, and Heavy Distillate 1998 valuations should be applied prospectively would, the Eight Parties advocate, strike a reasonable accommodation among the relevant factors and would be equitable in the circumstances of this litigation.

[831] *OXY*, 64 F.3d. at p. 679.

Id.

2782. The Eight Parties argue, however, that Exxon's contention that the Commission must order refunds is not supported by law or the circumstances of this case. Eight Parties Reply Brief at p. 132. They point out that both the courts and the Commission have refused to order retroactive remedies when it was impossible or difficult to return the parties to the positions in which they would have been absent agency error. *Id.* at pp. 132-33. The Eight Parties assert that that is the case here. *Id.* at p. 133. They maintain that the retroactive application of the new valuations of the remanded cuts to December 1, 1993, would not put the parties in the positions in which they would have been had error not been made. *Id.*

2783. Moreover, note the Eight Parties, as the Circuit Court recognized in *Exxon*, the Commission is not required to attempt to put the parties in the position in which they would have been absent Commission error, "if the other considerations properly within the ambit counsel otherwise." *Id.* (quoting *Exxon*, 182 F.3d at p. 49). Thus, continue the Eight Parties, the Circuit Court firmly rejected a claim that, after Commission error, refunds equal to the difference between the newly-established lawful rate and the last lawfully established rate must be automatically ordered. *Id.* In this case, explain the Eight Parties, no party obtained money in such circumstances that the possessor will "give offense to equity and good conscience" if permitted to retain it. *Id.* Therefore, the Eight Parties's position is that a proper weighing of the equities in this case precludes the retroactive application of the new valuations of the remanded cuts and the ordering of refunds. *Id.*

2784. Exxon argues that the Resid and Distillate cut valuations that were remanded in *OXY*, and the Resid valuation that was remanded in *Exxon*,[832] constituted legal error. Exxon Initial Brief at p. 344. According to Exxon, the proper remedy for legal error is one that places parties where they would have been if the error had not been committed. *Id.* Exxon asserts that the Circuit Court has explicitly stated that there is a presumption in favor of retroactive application of refunds to make the parties whole as an equitable principle. *Id.*

2785. The *Exxon* court, Exxon relates, did not identify any factors – equitable or other – that might overcome this presumption in favor of retroactivity. *Id.* at p. 345. However, it explains, the court did address the list of equitable factors on which the Commission had

[832] Exxon claims that, although not mentioned in Issue 5, the "Fuel Oil" (or "Light Resid") cut – i.e., the material that boils between 1000° and 1050°F – was also remanded in *OXY*, 64 F.3d at p. 696, and is thus covered by Issue 5. Exxon Initial Brief at p. 344, n.122. It also points out that, in addition to being remanded in *OXY*, the valuation of the Resid cut was remanded a second time in *Exxon*. *Id.* at p. 344, n.123.

relied in its decision to apply prospectively the revised valuations the Commission had ordered on remand from *OXY*. *Id*. Those factors included: (1) that parties supported the Nine Party Settlement only if it were implemented prospectively, (2) that all prior TAPS cases resolved by settlements have been on a prospective basis, (3) that the changes adopted by the Settlement Order only modify limited aspects of the distillation methodology put in place in 1993, and (4) that the TAPS Quality Bank is *sui generis*. *Id.* Exxon notes, however, that the court found that these factors have no bearing on the decision and do not explain the Commission's decision not to make parties whole who are clearly injured by undervaluation. *Id.* Thus, if there are any equitable factors in this case that could outweigh the presumption in favor of retroactivity, Exxon asserts that none has been identified to date by either the Commission or the Circuit Court. *Id.* at pp. 345-46.

B. STIPULATED MATTERS

2786. The Eight Parties assert that the parties stipulated as follows: "The Parties agree that the effective date for the new West Coast Heavy Distillate price will be February 1, 2000." Eight Parties Initial Brief at p. 174. Hence, the Eight Parties argue that with respect to the resolution of Issue No. 2, the parties agree that the new Heavy Distillate value established thereby will be retroactive to February 1, 2000. *Id.*

2787. With respect to the Light Distillate, Heavy Distillate, and Light Resid (Fuel Oil) cut values approved by the Commission in 1998 and affirmed by the *Exxon* court, the area of dispute, according to the Eight Parties, is whether retroactive effect should be given to these previously approved values for the period December 1, 1993, to February 1, 1998. *Id.* The Eight Parties contend that there should be no retroactive adjustments for these three cuts, while noting that Exxon proposes to give them retroactive effect. *Id.* With respect to the Resid cut, the area of dispute, according to the Eight Parties, is whether the Resid value to be determined here should be given retroactive effect from the date of a final decision to December 1, 1993. *Id.* They assert that the revised value for the Resid cut should be implemented prospectively only from the date that it is adopted by the Commission. *Id.* Exxon takes the position, according to the Eight Parties, that the revised Resid value should be made retroactive to December 1, 1993. *Id.* They add that neither the TAPS Carriers nor the Commission Trial Staff takes a position on Issue No. 5. *Id.*

2788. According to Exxon, the parties have not stipulated as to any matters concerning Issue No. 5. Exxon Initial Brief at p. 348. It points out that errors in Quality Bank invoices, whether arising from errors in valuation methodology or in the implementation of the methodology, are routinely corrected and the Quality Bank accounts of shippers are credited or debited on a retroactive basis to reflect those corrections. *Id.* For example, notes Exxon, all parties to this case have agreed that, when the valuation of the Heavy Distillate cut in Issue No. 2 is finally resolved, that valuation should be made effective retroactive to February 1, 2000 (when the proxy product changed), and that refunds should be awarded for the period February 1, 2000, to the effective date of a decision in this case. *Id.* Exxon asserts that this correction alone will result in refunds, with interest, totaling about $70 million through December 2002. *Id.*

2789. Exxon notes that the retroactive application of the new Heavy Distillate reference price is consistent with past and current Quality Bank practice. Exxon Reply Brief at p. 402. For example, Exxon explains that, in 1984, the Commission awarded substantial refunds to compensate certain shippers for differences between the newly-approved methodology and the methodology that had been in place since the Quality Bank was first implemented in 1979.[833] *Id.* Similarly, continues Exxon, in orders implementing the distillation methodology in 1994, the Commission held that changes in the valuation bases for the Resid and VGO cuts should be applied retroactively to December 1, 1993, when the distillation methodology was first implemented.[834] *Id.* Thus, Exxon maintains that there is no basis for the Eight Parties's claim that the Commission has "consistently required" that methodological changes be applied only on a prospective basis. *Id.* at pp. 402-03.

2790. The parties's dispute with respect to Issue No. 5, Exxon explains, focuses on the effective date to be assigned the corrected values for the cuts remanded in *OXY*. Exxon Initial Brief at p. 349. Exxon takes the position that the corrected values for such cuts should be made retroactive to December 1, 1993, while the Eight Parties propose a prospective only implementation based on the effective date of a decision in this case. *Id.* If the Commission concludes that the revised values for the cuts remanded in *OXY* should be made retroactive to December 1, 1993, Exxon contends, then refunds, with interest, should be ordered for the periods during which the remanded cut values were in effect.[835]

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[833] Exxon cites *Trans Alaska Pipeline System*, 29 FERC ¶ 61,123 at pp. 61,238-40 (1984). Exxon Reply Brief at p. 402, n.266.

[834] Exxon cites *Trans Alaska Pipeline System*, 66 FERC ¶ 61,188 at pp. 61,419-20, 61,423 (1994) and *Trans Alaska Pipeline System*, 67 FERC ¶ 61,175 at pp. 61,531-33 (1994). *Id.* at n.267.

[835] Exxon notes that the refund periods for each of the remanded cuts are as follows: For the Light Distillate and Heavy Distillate cuts, the refund period runs from December 1, 1993, to February 1, 1998, when revised valuations for those cuts were put into effect pursuant to a 1997 settlement and not later challenged; for the Fuel Oil or Light Resid cut, the refund period also runs from December 1, 1993, to February 1, 1998; as of the latter date, the Light Resid cut was folded into the VGO cut (as part of the 1997 settlement), and that action was later upheld on appeal. Exxon Initial Brief at p. 349, n.127. Exxon states the refund period applicable to the Resid cut begins on December 1, 1993, and is currently open-ended; that is, because a lawful valuation for the Resid cut

Id.

C. SHOULD REFUNDS BE AWARDED?

2791. The Eight Parties argue that the revised values for the remanded Resid, Fuel Oil, Heavy Distillate and Light Distillate cuts should not be made retroactive to December 1, 1993, and that, therefore, refunds should not be awarded. Eight Parties Initial Brief at p. 175. They note that all of the parties who would receive refunds, except Exxon, agree that it would be inequitable to heavy oil producers and refiners to award them. *Id.* According to the Eight Parties, Exxon claims refunds from retroactive application which would total about $141 million, including interest, through 2002. *Id.* Combined with its reparations claim, the Eight Parties claim, the amount of retroactive payments that Exxon claims totals $176 million, including interest, through 2002. *Id.*

2792. According to the Eight Parties, the retroactive adjustment is unlike a claim for refunds in a typical rate case. *Id.* They point out that the TAPS Carriers have not collected excessive charges for a regulated service that, after the passage of time, have been found to be unjust and unreasonable. *Id.* Were that the case, the Eight Parties explain, the regulated carriers could be required to refund the portion of their rates deemed to be excessive. *Id.* Instead, the refunds claimed here would be paid through retroactive assessments against the in-State refiners connected to the Pipeline – Williams and Petro Star – and certain heavy oil producers, including Unocal and OXY. *Id.* The actual mechanism for making the retroactive adjustments involves a complex recalculation of Quality Bank assessments and payments which is described, according to the Eight Parties, in Exhibit No. PAI-230. Eight Parties Initial Brief at pp. 175-76.

2793. The Eight Parties explain that the retroactive adjustment issue is further complicated by the different cuts and different time periods impacted. *Id.* at p. 176. They state that the 1997 Settlement achieved a final resolution respecting the values of three cuts that had been remanded in the *OXY* decision: Light Distillate, Heavy Distillate, and Fuel Oil. *Id.* With respect to these three cuts, the Eight Parties note, the retroactive issue only affects the time period from December 1, 1993, to February 1, 1998, the date that the 1997 Settlement was approved, and involves adjusting for only one value for each cut. *Id.* The question, according to the Eight Parties, is whether the final resolution of cut values as of February 1, 1998, should be made retroactive to December 1, 1993, a period of a little over four years.[836] *Id.*

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has never been established, the refund period for that cut will run until a just and reasonable valuation is established. *Id.* Exxon cites Joint Exhibit No. 11 at p. 2 for a graphic illustration of the Issue 5 refund periods. *Id.*

[836] The Eight Parties explain that there is an additional retroactive adjustment affecting the Heavy Distillate cut that is not a disputed issue. Eight Parties Initial Brief at

2794. The Resid cut, as the Eight Parties explain, is different. *Id.* No final valuation was achieved in 1998, because the Commission's approval of the 1997 Settlement value for Resid was reversed and remanded. *Id.* For Resid, according to the Eight Parties, the question is whether to make the valuation that is determined in this proceeding retroactive to December 1, 1993. *Id.* Furthermore, the Eight Parties note, Resid is valued as a coker feedstock based on prices used for nine different products produced by coking, three of which are being litigated in this case—Naphtha, Heavy Distillate and VGO. *Id.* Additionally, the Eight Parties point out, the issues in dispute with respect to calculating Resid value include valuation issues affecting the coker model product outputs and the costs of the coking process. *Id.* at pp. 176-77. Depending on how these issues are resolved, they explain, impacts on different parties affected by retroactive adjustments will vary widely. *Id.* at p. 177.

2795. The Eight Parties state that the *Exxon* court remanded the Commission's decision to apply the valuations of the remanded cuts prospectively because, in the Circuit Court's view, the Commission had not adequately justified its decision. *Id.* They note that the Commission unquestionably has the discretion to decide, on equitable grounds, that revaluations of the cuts not be given retroactive effect. *Id.* The Eight Parties strongly believe that the equities weigh in favor of the prospective only application of the new valuations for the following four reasons: (1) the heavy oil producers would be unfairly disadvantaged by the retroactive application of the revaluations, (2) the refiners would be unfairly disadvantaged, and retroactive adjustments would not make the parties whole, (3) retroactive adjustments would be contrary to the public interest, and (4) there is no evidence in the record that the imposition of the new Resid valuations is just and reasonable as applied during the period December 1, 1993, through 2004. *Id.*

2796. According to them, the record in this case demonstrates that the gravity methodology remained in place during the four years of litigation that led to its replacement in 1993. *Id.* at p. 178. During that period, according to them, heavy oil producers paid excessive Quality Bank assessments, ultimately determined to be unjust and unreasonable, due to natural gas liquids blending. *Id.* Having paid more prior to 1993 because refunds were not available, the Eight Parties contend they would again pay more if refunds are ordered for the period after 1993. *Id.* By contrast, the Eight Parties point out, light oil producers, particularly Exxon, enjoyed a windfall from their Quality Bank receipts due to the natural gas liquid effect prior to 1993. *Id.* Because of the

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p. 176, n.99. According to them, the Heavy Distillate price approved in 1998 was discontinued in 2000, and the Quality Bank Administrator was forced to select a replacement. *Id.* They add that the parties have agreed as to a replacement price, but not how to adjust that price. *Id.* As a result, the Eight Parties note, the price adjustment issue will be determined in this case, and the parties have stipulated that the revised valuation will apply retroactively to February 1, 2000. *Id.*

windfall benefits that Exxon realized prior to 1993 while challenges to the gravity methodology were pending, the Eight Parties argue, refunds are not now necessary to make Exxon whole. *Id.* Instead, the Eight Parties maintain, refunds, if imposed in this proceeding, would only aggravate an existing inequity. *Id.*

2797. The Eight Parties take exception to Exxon's argument that, even if it did not have to pay refunds for the period up to December 1, 1993, it should nevertheless be entitled to refunds for the portion after December 1, 1993. *Id.* at pp. 178-79. They maintain that this would not be fair. *Id.* at p. 179. Light oil producers retained tremendous benefits, in the Eight Parties's view, because the gravity methodology continued in place during the litigation that led to the 1993 settlement, and heavy oil producers absorbed corresponding detriments. *Id.* The Eight Parties explain that these impacts stemmed from the practice of natural gas liquid blending that began in 1986 at Prudhoe Bay. *Id.* According to them, the Commission did not find any changed circumstance or practice that made December 1, 1993, the line of demarcation. *Id.* Rather, the Commission determined, properly in the Eight Parties's view, that it lacked the authority to order refunds prior to that date. *Id.* Consequently, the Eight Parties note, those who benefited from the natural gas liquid blending were permitted to keep this financial gain from a valuation method that was subsequently determined to be unjust and unreasonable. *Id.*

2798. Dayton, according to the Eight Parties, analyzed the impact of possible refund scenarios by dividing the litigation period into a First Period, from January 1990 through November 1993, when the gravity methodology remained in place, and a Second Period, from December 1993 onward, after gravity had been replaced by the distillation methodology.[837] *Id.* at p. 180. They note that Dayton compared the impacts that refund orders would have had in the First Period (when refunds were not available) to the impacts that refund orders would have in this proceeding (i.e., the Second Period) under both the Eight Parties's and Exxon's methodologies. *Id.* According to the Eight Parties, Dayton's calculations are straightforward. *Id.* They note that Dayton compared the results that would have been obtained in both periods with retroactive application of the proposals to the actual results under whatever Quality Bank methodology was in place both by field and producer for Pump Station 1, the Golden Valley Electrical Association connection, and the Petro Star Valdez Refinery connection. *Id.*

2799. According to the Eight parties, Dayton's analysis shows that light oil producers benefited, because refunds were not available in 1993, in the following ways: (1) under the Eight Parties's Resid proposal, producers from the light oil fields – Prudhoe Bay and Lisburne – would have owed $381.9 million without interest during the First Period, while Exxon, which produces light oil predominantly, would have owed over $88

[837] Dayton testified on behalf of Phillips, but her testimony is supported by the remainder of the Eight Parties. Exhibit No. PAI-22 at p. 2.

million, (2) under Exxon's Resid proposal (which assigns lower values to heavy oil and therefore higher relative values to light oil), the light oil fields would have owed $288.1 million, and Exxon would have owed $68.7 million, (3) Unocal and OXY, which produce heavy oil exclusively, together would have received refunds of $19.3 million under the Eight Parties's proposal and $13.9 million under Exxon's proposal (BP and Phillips, which produce both light and heavy oil, would also have received refunds), and (4) when the refinery connections are taken into account, Exxon would have owed overall refunds of $83.6 and $58.3 million (without interest) under the Eight Parties's and Exxon's proposals, respectively, and Unocal and OXY, together, would have received $19.6 and $14.7 million under the respective proposals.[838] *Id.* at pp. 180-81.

2800. If refunds are granted in this proceeding (i.e., for the Second Period under Dayton's analysis), the Eight Parties argue, they will amplify the impacts of refunds being unavailable in the prior proceeding in the following ways: (1) under the Eight Parties's proposal, Exxon would receive $13.9 million at Pump Station 1 and $18.9 million overall in addition to the windfall associated with not having had to pay refunds during the First Period, (2) Unocal and OXY together would have to pay an additional $3.8 million at Pump Station 1 or $3.4 million overall, and (3) there would be additional payments to Exxon of $62.7 and $92.4 million at Pump Station 1 overall, and additional bills to Unocal and OXY of $13.9 and $12.8 million at Pump Station 1 and overall.[839] *Id.* at pp. 181-82.

2801. The Eight Parties disagree with Pavlovic's and Toof's assertions that there were a number of flaws in Dayton's analysis. *Id.* at p. 182. First and foremost, the Eight Parties insist, Dayton's focus on ownership rather than shipped barrels is a major strength of her analysis, not a weakness. *Id.* Producer data, in their opinion, are necessary to show equitable relationships, and shipper data can obscure these relationships. *Id.* The Eight

[838] The Eight Parties note that refiners would owe refunds for both the First Period and the Second Period under either the Eight Parties's or Exxon's methodology. Eight Parties Initial Brief at p. 181, n.102. Consequently, the position of each of the producers becomes more favorable when the refinery connections are considered. *Id.*

[839] The Eight Parties also note that producers such as BP and Phillips whose production is more balanced between light and heavy oil would experience impacts according to their precise interests. Eight Parties Initial Brief at p. 182, n.103. Under either the Eight Parties's or Exxon's proposal, the Eight Parties argue, both would have been owed significant refunds at Pump Station 1 during Period 1 and would pay smaller, but significant amounts, during Period 2. *Id.* Receipts at the refinery connections would make them overall refund payees under either proposal in Period 2, although the effects of interest would cause Phillips to owe a small amount under the Eight Parties's proposal. *Id.*

Parties note that shippers may or may not ultimately bear or enjoy the Quality Bank adjustments on the barrels they ship. *Id.* at pp. 182-83. They cite two examples: Quality Bank adjustments affect Alaska through its royalty provisions, although the State is never a shipper and Petro Star is heavily impacted by the Quality Bank, but reimburses assessments made against return oil shipped by its crude supplier. *Id.* at p. 183.

2802. Second, contrary to Pavlovic's assertion, the Eight Parties assert that Dayton had ample data to do the First Period calculations which were necessary to her analysis. *Id.* The Eight Parties concede that systematic data comparable to those obtained by the Quality Bank Administrator for Period 2 were not available, but they assert that sufficient production data were available to enable Dayton to extrapolate back in time from the May 1, 1994, through April 30, 1995, period and achieve the accuracy necessary to demonstrate her basic point that it would be unfair to award refunds to Exxon for the Second Period. *Id.*

2803. Third, the Eight Parties argue, Pavlovic's and Toof's waiver arguments have no merit. *Id.* They disagree with Pavlovic's assertions that ANS heavy oil producers's active participation in natural gas liquid blending meant they were not its "unwitting victims." *Id.* In fact, although they concede that Exxon's experts are correct that heavy oil producers were aware of natural gas liquid blending (the Eight Parties state that Dayton never contended they were not), the Eight Parties assert that Pavlovic was wrong in his conclusion that heavy oil producers acquiesced in the gravity methodology's treatment of natural gas liquid blended streams. *Id.* According to the Eight Parties, Phillips and OXY were not able to anticipate how natural gas liquid blending would distort their Quality Bank assessments. *Id.* Other producers, the Eight Parties explain, expressed concern and Phillips and OXY filed protests in 1989. *Id.* at pp. 183-84. Moreover, according to the Eight Parties, Quality Bank issues and impacts were not considerations in the ultimate decision whether or not to proceed with the natural gas liquid blending project at Prudhoe Bay. *Id.* at p. 184. Once the producers determined that the project would enhance economic recovery from the field, the Eight Parties assert, they were obligated to Alaska to undertake it. *Id.* at p. 184.

2804. Toof's arguments are no more persuasive, in the view of the Eight Parties. *Id.* In his direct testimony, he pointed out that some producers owed First Period refunds would also be owed Second Period refunds. *Id.* Moreover, although many producers were aware of the impacts of natural gas liquid blending, the Eight Parties point out, only two sought First Period refunds, and they used a "bendover" methodology to calculate them, rather than a distillation methodology. *Id.* Furthermore, the Eight Parties assert, nothing in the Interstate Commerce Act required any party to seek refunds either now or during the First Period. *Id.* Moreover, after Phillips's and OXY's unsuccessful attempt to get First Period refunds, the Eight Parties state, they have consistently advocated the position that Quality Bank methodology changes should be prospective except in very unusual circumstances.[840] *Id.*

2805. The Eight Parties note, Pavlovic argued that, under Exxon's Resid valuation methodology, refunds owed to Exxon for the Second Period would be greater than its excess receipts for the First Period. *Id.* They suggest that, for at least two reasons, substitution of Exxon's Resid valuation proposal for that of the Eight Parties does not undermine Dayton's conclusion that having been overpaid during the First Period, Exxon should not be awarded refunds for the Second Period. *Id.* First, the Eight Parties note, Dayton's calculations start in January 1990. *Id.* at p. 185. However, the Eight Parties assert that Exxon began to benefit from the impact of natural gas liquid blending on Quality Bank gravity calculations in 1986, when natural gas liquid blending began. *Id.* Therefore, according to them, Dayton's calculations understate the excess payments that Exxon received because of natural gas liquid blending during the First Period. *Id.* Second, the Eight Parties acknowledge that Toof is correct that, under every Second Period scenario, the bulk of the money that Exxon would be paid in refunds would come from refiners. *Id.* They explain that the refiners are likely to have refund obligations under any retroactive scenario, because they will not have had a chance to optimize[841] against Exxon's methodology in either the First or the Second Period. *Id.* According to the Eight Parties, because more money from the refiners always helps Exxon, using the Exxon methodology in Dayton's calculations increases the refunds that Exxon would receive in the Second Period and decreases the refunds Exxon would owe in the First.[842] *Id.*

2806. According to Exxon, the Eight Parties state, Dayton's analysis is little more that a repetition of an argument already made and rejected by the Circuit Court, and that the *Exxon* decision therefore eliminates any argument that the Eight Parties might make based on that analysis. Eight Parties Reply Brief at p. 152. They note that the *Exxon*

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[840] The Eight Parties note that the frozen reference price for Heavy Distillate presented one such unusual circumstance. *Id.* at p. 184, n.104.

[841] The Eight Parties explain that refiners optimize their operations by running their facilities efficiently and making those fuels that they can place in the market at profitable prices. Eight Parties Initial Brief at p. 186. According to the Eight Parties, refiners consider Quality Bank impacts when they determine what products to make as well as when they decide how much product they can sell at a profit. *Id.*

[842] The Eight Parties note that Toof criticizes Dayton's conclusions because the refiners would owe refunds for both the First and Second Periods. Eight Parties Initial Brief at p. 185, n.105. But, according to the Eight Parties, this result is not surprising because refiners normally optimize to current conditions. *Id.* Thus, they always will lose if the rules are changed after the game is played. *Id.*

court found that the four reasons enunciated by the Commission in support of prospective application of the settlement were insufficient to explain its action.[843] *Id.* In the Eight Parties view, however, nothing in *Exxon* precludes the Commission from considering all of the evidence adduced on remand, hearing any arguments based upon it, or deciding in its discretion that the evidence supports prospective only application of the new methodology. *Id.* Further, the Eight Parties assert, Dayton's analysis has not yet been before either the Commission or the Circuit Court. *Id.* Moreover, continue the Eight Parties, there is no reference to similar testimony in the *Certification of Contested Settlement and Ruling on Motion to Omit the Initial Decision*, 80 FERC ¶ 63,015 (1997), the *Order Approving Contested Settlement*, 81 FERC ¶ 61,319 (1997), or *Exxon* itself. *Id.* Therefore, they assert that Dayton's analysis can be considered in this proceeding. *Id.*

2807. According to the Eight Parties, none of Exxon's arguments designed to undercut Dayton's analysis are persuasive, and none detract from the conclusion that, in light of the history of the litigation, refunds are not necessary to make Exxon whole. *Id.* at p. 156. First, the Eight Parties claim, even if Exxon's argument that the refiners would owe refunds in both the First and Second Period under Dayton's analysis were true, absent extraordinary circumstances, the refiners optimize their operations to whatever Quality Bank methodology is in effect. *Id.* Therefore, according to them, if a different methodology had been in effect during the First Period, the refiners would have optimized differently. *Id.* Consequently, explain the Eight Parties, the "glaring inequity" that Exxon describes is nothing more than a demonstration of the fact that, if a distillation methodology is applied to the refiners while they are optimizing to a gravity methodology, their Quality Bank payments will go up. *Id.*

2808. Second, the Eight Parties maintain, the fact that certain producers who might receive refunds nevertheless acknowledge that refunds would be inequitable underscores, not undermines, the inequity of awarding refunds. *Id.* at p. 157.

2809. Third, continue the Eight Parties, the fact that producers other than OXY and Phillips did not seek refunds in the past does not detract from their position that refunds should not be awarded now. *Id.* They claim that parties other than Exxon consistently have favored prospective application for Quality Bank methodology changes and argue that Exxon's characterization of these parties as "aggrieved by the Commission['s] past decisions not to award refunds" is misleading. *Id.* (quoting Exxon Initial Brief at p. 369).

[843] According to the Eight Parties, the four reasons were (1) the Nine Parties supported the settlement only if it were implemented prospectively, (2) prior TAPS settlements had applied prospectively, (3) the settlement only modified limited aspects of the original distillation methodology put in place in 1993, and (4) the TAPS Quality Bank is *sui generis*. Eight Parties Reply Brief at p. 152, n.67 (citing *Exxon*, 182 F.3d at pp. 48-49).

2810. Fourth, explain the Eight Parties, BP and Phillips (or their predecessors) were constrained under their leases with Alaska to approve any project (including the natural gas liquid blending project) that enhanced economic recovery from the field. *Id.*

2811. Fifth, contrary to Exxon's assertions, the Eight Parties declare that Dayton's analysis is accurate and based on ample, reliable data. *Id.* According to the Eight Parties, Exxon misses the point in its attempts to demonstrate that the data available to Dayton were inadequate to allow her to do a rigorous "apples to apples" comparison. *Id.* The Eight Parties claim that she was not attempting to calculate Exxon's receipts during the First Period so that they can be set off against Second Period refunds in a "dollars to dollars" comparison. *Id.* Instead, state the Eight Parties, what Dayton's analysis shows is simply that, because these proceedings began in 1989, it would be inequitable (and would unfairly benefit Exxon) to have the Second Period subject to refund when the First Period could not be. *Id.*

2812. In light of this, the Eight Parties state, Exxon's more detailed attacks are either irrelevant or inaccurate. *Id.* at p. 158. Thus, they note that, although systematic samples like those used by the Quality Bank Administrator are available only from the Second Period, production and other data from the First Period are easily sufficient for Dayton's analysis. *Id.* The Eight Parties explain that Exxon's assertion that use of such data for the First Period is in conflict with her testimony that the Caleb Brett assays were indispensable to determining stream qualities is misleading because those assays were used to determine the inputs to the PIMS Coker Feedstock Model, while the First Period data were used to approximate stream compositions. *Id.* Each, they state, "is reliable for the use to which it was put." *Id.*

2813. Similarly, the Eight Parties argue, Exxon is wrong to accuse Dayton of "simply *assum[ing]* that the yield for the year May 1, 1994, to April 30, 1995, would be the same as the yield for each of the months in the period January 1, 1990 to the end of 1993." *Id.* (quoting Exxon Initial Brief at p. 372, n.147) (emphasis in original). They explain that Dayton was referring solely to the Endicott and Kuparuk streams, and that she immediately explained why her assumption was reasonable and, in the case of Kuparuk, confirmed by assay data and her own experience as a field manager. *Id.*

2814. The Eight Parties, referring to Exxon's claims that they did not account for the fact that Exxon does not sell crude oil to the refiners and that they should have corrected the "misvaluation" of Naphtha and VGO values in the Second Period, state that separating Exxon out from other producers and Alaska in Dayton's analysis would not have made a significant difference. *Id.* at pp. 158-59. While, as they note that Exxon acknowledges, and the Eight Parties explain, data showing the impact of Naphtha and VGO valuations are available, it sheds little light on the question of whether it is equitable to have refunds available for the Second Period when they are not available for the First Period. *Id.* at p. 159.

2815. Resid valuation is a major part of these Quality Bank considerations, according to the Eight Parties. Eight Parties Initial Brief at p. 187. They point out that Dayton testified that changing the Resid valuation has a leveraged impact on the refiners's cost structures because, if a refiner returns all the Resid it receives, its return stream contains a higher percentage of Resid than the common stream. *Id.* Moreover, the Eight Parties note, Resid is both a relatively high volume constituent of ANS crude and a very low priced part of it. *Id.* They assert that lower Resid valuations greatly increase Quality Bank assessments against the refiners. *Id.*

2816. The Eight Parties note that Boltz, a Petro Star executive, explained that, because assessments against refinery return oil must be borne by products made from the much smaller volume of oil that the refinery retains, increased Quality Bank assessments have a great impact on a refinery's business operation. *Id.* at pp. 187-88. According to the Eight Parties, Petro Star retains approximately 25% of the crude it receives, or about one barrel for every three it returns. *Id.* at p. 188. Consequently, explain the Eight Parties, the $1.00/barrel assessment against return oil illustrated in Exhibit No. PSI-17 translates into a $3.00/barrel (or approximately 7¢/gallon) cost added to products that Petro Star makes for sale or its own use.[844] *Id.*

2817. Costs of this magnitude directly affect a refiner's ability to make a profit, the Eight Parties suggest. *Id.* They point out that refining "is a business of fractions of a penny per gallon" and that, if costs increase relative to prices, it can become unprofitable for Petro Star to sell to some of its customers. *Id.* As Quality Bank costs are a significant part of Petro Star's overall cost, the Eight Parties explain, it must consider them when it decides whether fuel can be manufactured and sold at a profit. *Id.* In the real world, margins on jet fuel can be very small, and high volume jet fuel customers are likely to be the first ones to become unprofitable. *Id.* When this happens, and it does, the Eight Parties note, Petro Star adjusts by retaining less crude and making less product. *Id.* at pp. 188-89.

2818. The Eight Parties state that ordering refiners to pay refunds would not, as Exxon asserts, put them in the position in which they would have been had the new valuations of the remanded cuts been in effect since 1993. Eight Parties Reply Brief at p. 163. This is so because, state the Eight Parties, there is no mechanism to determine what payments into and out of the Quality Bank would have been if the new valuations had been in effect on December 1, 1993. *Id.* Even if there were, they point out that the refiners could not

[844] The Eight Parties note that the assessment against Petro Star's return oil is calculated from the data presented in Exhibit No. PSI-17 by subtracting the stream value of the Petro Star Valdez Refinery return stream ($18.22371) from $19.22516, which is the weighted average of the return stream and the Petro Star Valdez Refinery passing stream value. Eight Parties Initial Brief at p. 188, n.107. They state that $3.00/barrel is converted to cents/gallon by dividing by 0.42. *Id.*

now seek to recover the cost of the refunds from their current customers under current market conditions. *Id.*

2819. Under the circumstances of this proceeding, the Eight Parties argue, the Commission cannot recreate the optimization opportunities that would have been available to the refiners if the new valuation had been in effect as of December 1, 1993, because no one knows what they would have been. *Id.* at pp. 165-66. Therefore, according to the Eight Parties, the refiners had no choice but to plan and run their operations based on the known Quality Bank valuations in effect at the time. *Id.* at p. 166. Based on this fact and on the Commission and court precedents, they argue that refunds are not appropriate. *Id.*

2820. Refiners cannot, the Eight Parties suggest, optimize to a Quality Bank methodology unless they know in advance what the methodology will be and when it will be effective. Eight Parties Initial Brief at p. 189. Then, the Eight Parties explain, they can decide whether to change product slates or fuel usage, to reduce their production runs because they will no longer make a profit selling to some of their customers, or to increase production to better manage their costs or sell to wider markets. *Id.* Dayton explained how this is a crucial, continuous process with the refiners's goal always to minimize to the maximum extent possible their Quality Bank assessments. *Id.* If a new methodology is imposed retroactively, the Eight Parties point out, the refiners will have no chance to make any of the adjustments that Dayton describes. *Id.*

2821. Further, the Eight Parties point out, refiners do not have the ability to recoup retroactive Quality Bank assessments from their customers except in very unusual circumstances. *Id.* They note that Boltz testified that Petro Star sells most of its fuel to the major airlines, the Armed Forces, and the fishing industry, and its customers would not enter into agreements that provided for future price increases on fuel already delivered and paid for. *Id.* at pp. 189-90. The Eight Parties point out that Boltz also testified that Petro Star only has a single contract with a local public utility which provides for a limited pass-through of retroactive Quality Bank adjustments. *Id.* at p. 190. They further state that Dayton similarly testified that, in her experience, except in the case of public utilities, fuel sales contracts do not typically allow for retroactive adjustments. *Id.* In addition, they note that Toof, Exxon's witness, acknowledged that the likelihood of building such provisions into sales contracts was limited. *Id.*

2822. The Eight Parties argue that the refiners cannot recover the ground they lose if they forego opportunities, because there might be retroactive Quality Bank assessments in the future. *Id.* For example, the Eight Parties reiterate that Petro Star's larger customers tend to have the thinnest margins, and a few pennies difference in cost can be the difference between profit and loss. *Id.* Thus, they conclude, should Petro Star mistakenly predict that a future methodology will significantly increase costs and be imposed retroactively, and on that basis foregoes sales that otherwise would be profitable, those sales — both their profits and their contributions to fixed cost burdens — will be lost for good. *Id.* They cite Dayton's testimony as support for this conclusion. *Id.* at pp. 190-91.

2823. Moreover, the Eight Parties assert, it is disingenuous for Exxon to suggest that any attempt by the refiners to resolve the controversy over the valuation of the remanded cuts through settlement negotiations is relevant to the Commission's weighing of the equities. Eight Parties Reply Brief at p. 161. After the *OXY* remand, explain the Eight Parties, the Commission responded to the request of a number of parties that settlement discussions be held before any further hearings were ordered. *Id.* The 1997 Settlement was, according to the Eight Parties, a direct and good faith result of the Commission's clear preference for settlement in this case. *Id.* at p. 162. However, they argue, the terms of the 1997 Settlement have no substantive relevance to the Commission's determination of the equities of ordering refunds. *Id.*

2824. The Eight Parties state that, contrary to Exxon's assertion, testimony filed by the parties in litigation resulting from the Commission's orders on remand from the *Exxon* court also is irrelevant to a determination of the equities of ordering refunds. *Id.* They explain that the development of litigation strategy, like settlement strategy, requires the balancing of many competing factors. *Id.* Further, note the Eight Parties, the fact that the refiners, like the other parties, including Exxon, have changed positions regarding the appropriate valuation of the remanded cuts reflects their attempt to balance all of the relevant factors to reach a workable resolution. *Id.* at pp. 162-63. It should not, argue the Eight Parties, provide any basis for a determination that, as a matter of equity, the refiners should pay refunds. *Id.* at p. 163.

2825. According to the Eight Parties, none of the events that led up to the current proceeding provided useful foreknowledge of what Resid valuation the Commission ultimately will adopt in this proceeding. Eight Parties Initial Brief at p. 192. They note that the 1993 settlement and associated orders established the distillation methodology, and that the Commission selected FO-380 as the Resid reference price. *Id.* According to the Eight Parties, Exxon, among others, had complained that the Commission's proposed methodology would overvalue Resid, but proposed as alternatives either the unmodified 1993 settlement (i.e., viscosity blending) or a return to the gravity methodology as alternatives. *Id.* They note that the Commission rejected both of these approaches. *Id.* On rehearing, as on appeal in *OXY*, state the Eight Parties, the range of choices consisted of: (1) the FO-380 valuation selected by the Commission, (2) the discarded gravity methodology, or (3) the unmodified 1993 settlement – the latter two already rejected by the Commission. *Id.* at p. 192-93.

2826. In the opinion of the Eight Parties, the 1997 settlement proposals presented a choice between the Nine Party Settlement, ultimately approved by the Commission, and the Exxon position, which continued the Resid blending argument. *Id.* In its own unilateral settlement proposal, according to the Eight Parties, Exxon proposed a modified gravity methodology for Pump Station 1 but a distillation methodology based in part on Resid viscosity for the return streams. *Id.* The Eight Parties point out that, once again, the Exxon alternatives to the Commission-approved methodology did not survive. *Id.*

2827. The Eight Parties explain, the Circuit Court in *Exxon* accepted the coker feedstock value approach but found an insufficient correlation between the Resid proxy price (FO-380, 4.5¢) and calculated coker feedstock values. *Id.* Therefore, the Eight Parties state, it remanded for determination of a valuation method that better tracked Resid's value as a coker feedstock, and the 2000 settlement proposals followed. *Id.* at pp. 193-94.

2828. Contemporaneously with the *Exxon* decision, according to the Eight Parties, Exxon filed its complaint challenging the distillation methodology in its entirety and advocating a return to gravity. *Id.* at p. 194. They state that the Commission dismissed Exxon's complaint; however, its decision was reversed and remanded on appeal. *Id.* This, according to the Eight Parties, left the way clear for Exxon to resuscitate its argument for the gravity methodology. *Id.*

2829. Against this history of the parties's shifting positions and legal uncertainty, the Eight Parties argue, it was reasonable for the refiners to optimize against the methodologies in effect. *Id.* This is so, according to the Eight Parties, because, except for Exxon, no other participant in the Quality Bank was seeking retroactive application of any proposed valuation methodology change and to base operational actions on a mistaken prediction on how a change would be imposed would not have been prudent. *Id.* In the Eight Parties view, it would have led producers to incur needless losses which they would be unable to recover. *Id.* The Eight Parties conclude, therefore, that refiners thus had no reasonable choice other than to optimize based on the valuation methodologies in place. *Id.* at p. 195.

2830. According to the Eight Parties, Exxon witnesses offered up three suggestions as to how the refineries should have operated since 1993. *Id.* First, they suggested that the refiners should have made better contracts with their crude suppliers and thereby reduced the risk of retroactive Quality Bank assessments. *Id.* Second, they asserted the refiners should have reserved against either the worst case or most likely outcome of this proceeding. *Id.* Finally, the Exxon witnesses suggested that the refiners should have optimized their operations to either the worst case or most likely outcome. *Id.* According to the Eight Parties, none of these suggestions is realistic. *Id.*

2831. With respect to the first suggestion, the Eight Parties assert, refiners are in no position to pass Quality Bank risks on to their crude oil suppliers. *Id.* They point out that the Petro Star and Williams refineries receive all their crude from TAPS. *Id.* Thus, according to the Eight Parties, they must either buy their crude oil from the ANS producers (whether or not through intermediaries) or from the State. *Id.* Their sellers, the Eight Parties note, produce a fungible product that can be sold on the open market or used at their own West Coast refineries. *Id.* They suggest that this is not a buyer's market. *Id.*

2832. Moreover, the Eight Parties explain, the refiners's Quality Bank liability is not incurred on the barrels that the refiners buy, but on barrels they borrow. *Id.* The Eight Parties note that refiners need to process significantly more crude than they retain – in Petro Star's case, about four times as much. *Id.* at pp. 195-96. In essence, according to the Eight Parties, they borrow this oil and then reimburse their suppliers for the Quality Bank assessments that result when they return it to TAPS. *Id.* at p. 196. The Eight Parties assert that, although Exxon witnesses may be correct in assuming that the agreements that govern these arrangements are bargained for, they have adduced no shred of evidence that the refiners did not get the best bargain they could. *Id.*

2833. Contrary to Exxon's second suggestion, the Eight Parties argue, establishing reserves would not have kept the refiners whole. *Id.* According to the Eight Parties, both Pavlovic and Toof testified that, had the refiners been prudent, they would have set up reserves. *Id.* However, the Eight Parties point out Pavlovic and Toof are inconsistent in whether they would have recommended that the refiners reserve against some undefined worst case or most likely case scenarios. *Id.* Nonetheless, the Eight Parties argue, the Commission-determined methodologies reasonably appeared at the times in which they were in effect to be the most likely, and reserves against most likely case scenarios therefore would not have been necessary. *Id.* More importantly, however, the Eight Parties assert that neither Pavlovic nor Toof address the fact that reserves cannot remedy the effects of optimizing to the wrong methodology. *Id.*

2834. The Eight Parties also argue that reserves cannot address cash flow impacts. *Id.* at p. 197. From a cash standpoint, the Eight Parties point out that it is not possible for a seller of crude oil or refined petroleum products to recover the years of refunds prospectively in the marketplace. *Id.* Its only option to "hedge" on the cash side, according to the Eight Parties, is to have tried to charge higher prices over the years to cover the possibility of having to pay refunds, thereby prematurely passing the risk of refund costs to primarily Alaskan consumers. *Id.* However, the Eight Parties argue that, even then, there is no assurance that the marketplace would allow the charging of higher prices. *Id.*

2835. Moreover, the Eight Parties state, Exxon misattributes the sentiment to Boltz that Petro Star "could have established a reserve to protect itself from retroactive liability with respect to the Resid valuation." Eight Parties Reply Brief at p. 161 (quoting Exxon Initial Brief at p. 377 n.152). They claim that Boltz was answering the question whether "at no point in the last 10 years has Petro Star been in a position to set any sort of reserve associated with the resid issue" when he stated that "[w]ith the Eight Party settlement position that we have come out with for this hearing, that put us certainly in a position that we could start to reserve resid impacts." *Id.* (quoting Transcript at pp. 11718-19).

2836. The Eight Parties argue that the public interest would not be served by the imposition of retroactive refunds. Eight Parties Initial Brief at p. 198. According to them, prospective implementation of Quality Bank methodologies facilitates efficient economic planning while retroactive implementation frustrates it. *Id.* They disagree with Exxon's claim that refunds are necessary for efficiency because, without them, parties would delay and "game the system." *Id.* at p. 199. According to the Eight Parties, Exxon failed to adduce any evidence that gaming the system is a real problem. *Id.* They point out that, in this very proceeding, all parties agreed to retroactive implementation of the Heavy Distillate valuation despite the enormous magnitude of the refunds that must be paid by the refiners. *Id.* The Eight Parties explain that this allowed Petro Star to accrue a reserve against its refund liability, but only because the price had been frozen and the parties agreed to within a penny on the correct price. *Id.* Moreover, because the new price would be consistent with the old one, the Eight Parties point out that it was unnecessary to re-optimize Petro Star's refineries.[845] *Id.* at pp. 199-200.

2837. In addition, the Eight Parties argue that retroactivity would have a negative impact on consumers. *Id.* at p. 200. They state that, as discussed above, inefficiency is inherent in the uncertainty that attaches to the possibility of refunds except in unusual circumstances. *Id.* To the extent that parties could trigger a serious danger of refund obligations simply by filing a complaint or appeal, the Eight Parties argue that an aggressive competitor could attempt to cause its rivals to cut production or forego sales that would be profitable unless there were refunds. *Id.* This would be particularly true, in the opinion of the Eight Parties, if Exxon's views on refunds were adopted and refiners were obliged to plan for worst-case outcomes. *Id.*

2838. Contrary to the argument of Exxon,[846] the Eight Parties state, refiners do not claim to be entitled to rely on the Commission's 1993-94 valuation orders. Eight Parties Reply Brief at p. 160. Instead, argue the Eight Parties, the refiners acted reasonably by basing their operations on the methodologies ordered by the Commission. *Id.* They maintain

[845] Toof noted, the Eight Parties point out, that Exxon's Heavy Distillate receipts from the refiners would approximately balance payments that Exxon would make to other producers at Pump Station 1. Eight Parties Initial Brief at p. 200, n.111. They state that Toof considered the Heavy Distillate issue to be "very similar" to the issues surrounding Resid valuation after 2000 and hinted that the parties's alignments, not the frozen price, distinguished the Heavy Distillate and Resid issues. *Id.* The Eight Parties, on the other hand, believe that the Heavy Distillate issue is unique for the reasons stated by Boltz and that the situation in 2000 was uncertain. *Id.*

[846] Exxon Initial Brief at pp. 376-78.

that to act otherwise would have caused the refiners to forego sales that they would have no way of ever recouping. *Id.* Further, the Eight Parties argue, Exxon's position that the mere possibility of reversal should prompt the refiners to optimize their refineries to guard against the possibility of higher Quality Bank assessments would create the policy nightmare where a competitor could cause its rivals to cut production or forego sales merely by filing a notice of appeal. *Id.*

2839. A decision giving retroactive effect to the new Resid value would have to rest, according to the Eight Parties, on a finding that the new value determined in this proceeding is also the just and reasonable value for the Resid cut from December 1, 1993, through 2004 (and that the 1998 values for Light Resid, Light Distillate, and Heavy Distillate were the just and reasonable values for the period December 1993 through January 1998). Eight Parties Initial Brief at p. 201. In the usual refund case, the Eight Parties state, this is not a problem because the just and reasonable rate is determined based on the cost of service for the serving utility. *Id.* They note that, in such a case, the utility is a party to the proceeding and can submit actual cost evidence for all prior years that are subject to a refund order. *Id.*

2840. The Eight Parties argue that a Quality Bank case is different. *Id.* Here, they state, the Commission is attempting to set cut values based on prices used as proxies, adjusted by costs used by an entire industry or industry segment. *Id.* According to the Eight Parties, industry practices change over time, and change in different ways for different types of costs. *Id.* Further, they note that all industry participants are not parties to this case and there is not an agreed or accepted approach to cost analysis. *Id.* Accordingly, the Eight Parties argue, the Commission cannot merely decide what is just and reasonable today and project that outcome retroactively over some hypothetical refund period. *Id.*

2841. By far the most contentious and complex of these effective date issues, according to the Eight Parties, is that related to Resid. *Id.* at p. 202. In the period since December 1, 1993, the Eight Parties note that three different sets of values have been in place for the Resid cut: (1) Platts West Coast Waterborne FO 380 for both the West Coast and Gulf Coast from December 1, 1993 through February 9, 1996, (2) Platts Pipeline West Coast FO 380 for both coasts from February 10, 1996 through January 31, 1998, and, since February 1, 1998, (3) the values used in the 1997 Nine Party Settlement of Platts West Coast Pipeline FO 380 minus 4.5¢/barrel, and Platts Gulf Coast FO #6 3% Sulfur minus 4.5¢/barrel. *Id.*

2842. The Eight Parties argue that Exxon has not met its burden of proving that retroactive application of its new Resid value would be just and reasonable. *Id.* at p. 203. According to the Eight Parties, what is at issue here is not really refunds, as that term is used in the utility industry. *Id.* at p. 205. They state that the term "refunds" refers to a pay back of some amount of an increased rate that is over and above what the previously effective rate was. *Id.* In the Eight Parties's opinion, that is not what is claimed by

Exxon here. *Id.* Rather, in their view, Exxon is demanding a complete recalculation of debits and credits between and among all shippers on TAPS that covers, with respect to the Resid cut, a period of time exceeding ten years. *Id.* The Eight Parties assert that such wholesale rate recalculations are not favored as a remedy, and Exxon's request for what the Eight Parties call an extraordinary remedy is not warranted by the equities of this case. *Id.*

2843. In the cases cited by Exxon,[847] the Eight Parties maintain, when courts ordered the application of rates retroactively to correct the Commission's legal error, the positions that the parties would have been in absent agency error were readily ascertainable. Eight Parties Reply Brief at p. 135. According to the Eight Parties, in contrast, both the courts and the Commission have declined to order the imposition of rates retroactively when such order would not return the parties to the positions they would have held absent Commission error, or when it would be difficult or impossible to determine what those positions were.[848] *Id.*

2844. Similarly, the Eight Parties state that, in *ANR Pipeline Co.*,[849] the Commission reversed a prior decision in which it had determined that ANR Pipeline Company should be allowed to recover certain costs related to service it received from another pipeline from November 1, 1993, through April 30, 1994, even though ANR had no tariff provision in effect to authorize such recovery during that period. Eight Parties Reply Brief at p. 137. On rehearing of its prior decision, however, the Eight Parties point out, the Commission found this approach to be "inappropriate and unworkable," based in part on the realization "that it is fruitless to attempt to reconstruct ANR's prior filings as they might have appeared in the absence of the Commission's legal error." *Id.* at p. 138 (quoting 88 FERC at pp. 61,539-40). The Commission further noted that there was no erroneously rejected rate proposal that can now be put in effect, state the Eight Parties, and what would have happened had the error not been committed would be mere speculation. *Id.*

2845. In this case, the Eight Parties state, there is no erroneously rejected cost-based rate schedule that can be put into effect to put the parties in the same positions in which they

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[847] *Natural Gas Clearinghouse v. F.E.R.C.*, 965 F.2d 1066 (D.C. Cir. 1992); *Public Utilities Com'n of State of Cal. v. F.E.R.C.*, 988 F.2d 154 (D.C. Cir. 1993) ("*CPUC*"); *National Fuel Gas Supply Corp. v. F.E.R.C.*, 59 F.3d 1281 (D.C. Cir. 1995); *Public Service Co. of Colorado v. F.E.R.C.*, 91 F.3d 1478 (D.C. Cir. 1996).

[848] In support, the Eight Parties cite *Panhandle Eastern Pipeline Co. v. F.E.R.C.,* 907 F.2d 185 (D.C. Cir. 1990).

[849] 88 FERC ¶ 61,160 (1999).

would have been had the rate schedule not been erroneously rejected. *Id.* at p. 140. Further, note the Eight Parties, there are no quantifiable taxes, take-or-pay payments, or demand charges the recovery of which the Commission previously erroneously denied. *Id.* at pp. 140-41. Here, the Eight Parties argue, the payments into or out of the Quality Bank would have been different if the new valuations had actually been in effect on December 1, 1993, and it would be difficult, if not impossible, now to determine what those payments would have been. *Id.* at p. 141. In any event, the Eight Parties assert that the application of the new valuations of the remanded cuts would not put the Quality Bank participants back in the same positions they would have been absent Commission error. *Id.*

2846. According to the Eight Parties, Exxon has offered no evidence to support its argument that ordering refunds is necessary to put the parties in the position in which they would have been and to make the parties whole. *Id.* Specifically, the Eight Parties assert, Exxon has offered no evidence demonstrating that, if the Commission had adequately supported its Distillate and Resid valuations in 1993, Exxon would have received payments from the Quality Bank equal to the refunds Exxon is demanding now. *Id.* at pp. 141-42.

2847. The Eight Parties state that the closest Exxon comes is its argument that "there is virtually no evidence to support the assertion that the refiners in fact optimized their operations in light of Quality Bank valuation decisions." *Id.* at p. 142 (quoting Exxon Initial Brief at p. 376). They explain that, in support of this interpretation of the evidence, Exxon asserts that Boltz testified that Petro Star's refinery operations were not driven by Quality Bank decisions. *Id.* However, the Eight Parties point out, this statement rests on Boltz's testimony that Petro Star expanded its North Pole operations despite the decrease in Resid valuation effected by the Nine Party Settlement in 1997. *Id.* They argue that Exxon overlooks the fact that the decreased Resid valuation was partially offset by changes to the other Remand Cuts contained in the Nine Party Settlement; elimination of the 1000° - 1050°F Light Resid cut and classifying that material as VGO (effectively raising the value of material that the refiners return) and adjusting Light and Heavy Distillate valuations to reflect processing costs (decreasing the values of materials that the refiners retain). *Id.*

2848. Exxon similarly relies on Dayton's purported inability to identify any actions the refiners actually took to optimize their operations, the Eight Parties claim. *Id.* They assert that that Dayton actually explained that her knowledge was limited to what she could observe without being privy to the refiners's internal decisions. *Id.* According to the Eight Parties, it is more decisive that Dayton testified that, as an executive of a company that received Quality Bank payments from the refiners, she had observed that the refiners regularly were successful at mitigating Quality Bank impacts. *Id.* at pp. 142-43.

2849. The Eight Parties maintain that they have introduced extensive evidence demonstrating that, if the new valuations of the remanded cuts had been in effect in 1993, the payments to Exxon out of the Quality Bank would not have been equal to the difference between the Commission's 1993 cut valuations and the values that were/are ultimately found to be just and reasonable. *Id.* at p. 143. To the contrary, the Eight Parties assert, the payments into and out of the Quality Bank would have been different. *Id.* Further, according to the Eight Parties, under every scenario the bulk of the refunds that would be paid to Exxon would be paid by the refiners. *Id.* at pp. 143-44. Because the Quality Bank assessments paid by the refiners are shared among the producers, including Exxon, the Eight Parties assert that Exxon's Quality Bank receipts also would have been different. *Id.* at p. 144. Under these circumstances, the Eight Parties maintain that refunds would not put the parties in the positions they would have been in and should not be ordered. *Id.*

2850. Exxon correctly states that the Quality Bank "attempt[s] to place each [shipper on TAPS] in the same economic position it would enjoy if it received the same petroleum at Valdez that it delivered to TAPS on the North Slope," according to the Eight Parties. *Id.* at p. 145 (quoting *OXY*, 64 F.3d at p. 684). However, the Eight Parties state that this undisputed premise sheds little light on the refund issue as the only testimony that Exxon offers to show what its economic interest would have been had it received the same crude oil out that it placed into TAPS only reflects that, were a different Quality Bank methodology in effect, Exxon would have received different payments. *Id.* at pp. 145-46. The Eight Parties argue that this restatement of the obvious offers no support for Exxon's assertion that this goal of the Quality Bank requires the award of refunds. *Id.* at p. 146.

2851. In the opinion of the Eight Parties, Exxon ignores the fact that both the Quality Bank's own history of settlement and the filed rate doctrine establish the general rule that changes in Quality Bank methodology are prospective. *Id.* Instead, state the Eight Parties, Exxon argues that examples of instances in which shippers have agreed to the retroactive adjustments of Quality Bank valuations require the retroactive application of the new valuations of the remanded cuts here. *Id.* Further, they assert that Exxon is wrong when it states that the remanded cuts have been found to be unjust and unreasonable. *Id.* at n.62. The Eight Parties claim that the Commission is not required to find that the valuations of the remanded cuts are just and reasonable. *Id.* Far from supporting Exxon's contentions, the Eight Parties argue that Exxon's examples are simply exceptions that prove the rule that the standard practice is to implement Quality Bank methodology changes prospectively. *Id.* at p. 146.

2852. The Eight Parties also disagree with Exxon's attempt to use the stipulated February 1, 2000, effective date for the replacement Heavy Distillate valuation and the parties's agreement to refunds retroactive to that date as justification for the general applicability of refunds in this proceeding. *Id.* at p. 147. The Eight Parties note that the Commission has recognized that the Heavy Distillate valuation represented a unique situation. *Id.* Moreover, they point out, the parties reached a quick agreement on the replacement price, the processing costs in dispute differed by less than a penny a gallon, and the adjusted replacement price would be in the same ballpark as the discontinued price. *Id.* at p. 148. Finally, the Eight Parties assert, Exxon ignores the most crucial fact – all of the parties have agreed on the effective date and the Eight Parties speculate that this agreement may be a requirement for retroactive implementation of distillation methodologies. *Id*. at n.63.

2853. Exxon's third example, the Eight Parties contend, the retroactive application of the VGO valuations contained in the Commission's May 1994 Order on Rehearing, also provides no support for ordering refunds in this proceeding. *Id.* The Eight Parties point out that the 1993 settlement provided for a December 1, 1993, effective date, but the settling parties had agreed that the new methodology could not physically be implemented on that date. *Id.* Therefore, explains the Eight Parties, the settlement provided for a test period during which any Quality Bank adjustments made would be temporary. *Id.* Consequently, they continue, the settlement provided that final adjustments, which could not be made until after the implementation period, would be "retroactive" to December 1, 1993. *Id.* The Eight Parties assert that the Commission, in that ruling, did not order a retroactive change; instead it declined to change an effective date contained in a settlement which it already had approved. *Id.* at p. 149.

2854. Given the long history of shifting positions by the complainants, lack of precise notice of potential liability, and the consequent inability of the parties to alter their operations or make provision for the potential liability, the Eight Parties argue, the equities in this case do not support giving retroactive effect to revised cut valuations. Eight Parties Initial Brief at p. 205. According to them, the primary beneficiary of retroactivity, Exxon, did not change its position or take any action in reliance on the Commission's 1993 valuations of the Resid cut. *Id.* at pp. 205-06. They assert that there is no doubt that Exxon was aware of the Commission's history of doing exactly what it objects to here: applying changes to the Quality Bank only prospectively. *Id.* at p. 206. Further, the Eight Parties claim that Exxon has neither abandoned options that would otherwise have been available to it nor made any commitments in reliance on the prior erroneous ruling. *Id.* They note that Toof admitted that both reparations and refunds were calculated in the same way, and that any recovery by Exxon would be all profit. *Id.*

2855. In contrast, the Eight Parties explain, some of parties who oppose retroactive correction – the in-State refiners connected to TAPS, Williams and Petro Star – had no choice but to make commitments and to change positions in reliance on the Commission's prior rulings, and would be prejudiced by a retroactive correction of the prior orders. *Id.* Further, according to them, were the new valuations in place as of December 1, 1993, the refiners would have optimized differently than they actually did. *Id.* Therefore, the Eight Parties conclude that retroactive imposition of the new valuations now would allow Exxon to collect more from the refiners in refunds than it would have if the valuations had been in place as of December 1, 1993. *Id.*

2856. The Eight Parties [850] position is that the same equitable considerations that preclude the ordering of any refunds in the circumstances of this case also preclude the award of interest. Eight Parties Reply Brief at p. 166. They state that there is ample authority that, where the Commission determines that it cannot put the parties in the positions in which they would have been had there been no Commission error, it can craft an equitable remedy or it can deny retroactivity. *Id.*

2857. According to them, Exxon argues that the Eight Parties's position violates the filed rate doctrine and the rule against retroactive ratemaking. *Id.* at p. 153. They assert that neither the filed rate doctrine nor its corollary, the rule against retroactive ratemaking, prohibit the Commissions from weighing the excess profits that Exxon reaped under the gravity methodology as it considers the equities of awarding refunds. *Id.* The Eight Parties do not contend that payments that Exxon received from the Quality Bank under the gravity methodology should be considered in any way in determining the appropriate prospective valuations of the remanded cuts. *Id.* Nor do they claim that Exxon's gravity methodology receipts should be set off against payments otherwise due Exxon from the Quality Bank under re-determined valuations for post-1993 deliveries. *Id.*

2858. The Eight Parties claim that, contrary to Exxon's argument, the Commission exercises fundamentally different authority when it fashions remedies than it does when it approves or prescribes prospective rates. *Id.* at p. 155. When it prescribes rates, according to the Eight Parties, the Commission's authority is precisely defined by statute. *Id.* In deciding whether or not to order refunds, continue the Eight Parties, the Commission acts within broad equitable discretion. *Id.* Correspondingly, state the Eight Parties, the filed rate doctrine, as well as its corollary, the rule against retroactive ratemaking, apply with full force to prevent the Commission from adjusting what otherwise would be just and reasonable rates to account for past over- or under-collections by a carrier. *Id.* They point out that these are legal constraints, not blinders, however, and the reach of the filed rate doctrine is precisely prescribed by statute. *Id.*

2859. In contrast, the Eight Parties assert, it is well established that the Commission's power to order refunds, while limited by statute, is inherently equitable. *Id.* The Eight Parties note that the Circuit Court made this distinction quite clear in *Towns of Concord*. *Id.* at pp. 155-56. First, explain the Eight Parties, the court inspected the underlying statute to determine the consequences of the utility's having violated its filed tariffs by passing through spent nuclear fuel disposal costs to its customers in fuel adjustment charges. *Id.* at p. 156 (citing *Towns of Concord*, 955 F.2d at pp. 71-72). Having found

[850] The Eight Parties note that Phillips does not join in the section of their Reply Brief regarding payment of interest. Eight Parties Reply Brief at p. 166, n.73.

that the statute did not mandate refunds, the Eight Parties state that the Circuit Court rejected the argument that the Commission must order refunds and that "denying refunds equals the Commission's authorizing the utility to violate the filed rate doctrine (or retroactively approving a different rate)." *Id.* (quoting 955 F.2d at p. 73).

2860. As indicated above, reiterate the Eight Parties, four different cuts are affected by the retroactivity issue. Eight Parties Initial Brief at p. 207. They state that:

- With respect to the proper cost deduction for the replacement West Coast Heavy Distillate price which is the subject of Issue No. 2 in this case, the parties have stipulated that the effective date is February 1, 2000, the date that the Quality Bank Administrator implemented a replacement for the previously approved Heavy Distillate price. According to the Eight Parties, the Gulf Coast Heavy Distillate price is unaffected.

- With respect to the Light Distillate and Fuel Oil cuts valuations, and with respect to the price used for the West Coast Heavy Distillate cut prior to February 1, 2000, the Eight Parties explain that the revised valuations for these three cuts were implemented and approved as of February 1, 1998. Both West Coast and Gulf Coast prices are affected, according to the Eight Parties, and there is no dispute as to their value. According to the Eight Parties, the only issue for resolution here is whether the values approved and implemented as of February 1, 1998, should be given retroactive effect to December 1, 1993. They submit that the effective date for these cuts should remain as February 1, 1998, with no retroactive effect given. However, in the event the Resid cut is made retroactive to December 1, 1993, the Eight Parties advocate that these cuts should also be made retroactive to December 1, 1993.

- With respect to the Resid cut, both the West Coast and Gulf Coast values are at issue. The proper valuation of this cut is the subject of Issue No. 1 in this case. *Id.* According to the Eight Parties, the issue to be resolved is whether the valuation for Resid determined here should be given retroactive effect to December 1, 1993. They submit that no retroactive effect should be given, and that the effective date for the evaluation determined here should be the date of the Commission's final decision in this case.

Id. at pp. 207-08.

2861. In *Exxon*, state the Eight Parties, the Circuit Court remanded the Commission's decision to apply the new valuations of the remanded cuts prospectively, because the record before the court failed to provide adequate explanation of the Commission's decision not to make the new valuations retroactive to 1993. Eight Parties Reply Brief at p. 168. It is the Eight Parties position that the current record shows that the circumstances of this case support the prospective application of the new valuations and they do not warrant the retroactive application of the new valuations to 1993, because:

- Retroactive application of the new valuations of the remanded cuts would not put the parties back in the positions in which they would have been in 1993. Were the new valuations in effect in 1993, the payments into and out of the Quality Bank would have been different. It would be difficult if not impossible now to determine what those payments would have been.

- Here, there is no erroneously rejected rate schedule that the Commission can now simply put in place retroactively.

- There is no record evidence that new valuations would have assigned accurate relative values among all of the cuts beginning in 1993.

- The refiners's reliance on the Commission's 1993 and 1997 valuations was not discretionary; they had no choice but to optimize their operations based on those valuations.

- In the context of the history of the Quality Bank, a decision to award refunds to Exxon would result in a windfall profit to Exxon to the detriment of the heavy oil producers and the refiners.

- The heavy oil producers and refiners acted in good faith in entering into settlement agreements in 1993 and 1997 in which they (like all the parties) gave up valuable benefits in order to reach settlement. There is no charge that they have "unclean hands" or are in any way at fault for the Commissions "errors."

- A decision by the Commission not to order refunds would offend neither equity nor good conscience.

Id. at pp. 168-70.

2862. Exxon submits that, with respect to each cut valuation that was remanded in *OXY*, as well as the Resid valuation later remanded in *Exxon*, the Commission should award refunds equal to the difference between the cut values that were remanded by the Circuit Court and the values that were/are ultimately found to be just and reasonable. Exxon Initial Brief at p. 350. It asserts that this would have the effect of making the revised cut values retroactive to December 1, 1993, and further asserts that the remedy for legal error – putting parties in the position in which they would have been had the errors not been made – is controlling here. *Id.* Moreover, Exxon continues, equitable considerations likewise support the awarding of refunds, because there is a presumption in case law in favor of retroactivity that would make the parties whole. *Id.*

2863. The Commission, Exxon explains, in its order implementing the distillation methodology for the TAPS Quality Bank, valued the Fuel Oil ("Light Resid") cut at the price of No. 6 Fuel Oil, and the Resid cut ("1050°+F Resid") at the price of Fuel Oil 380, without any adjustments to those prices. *Id.* at pp. 350-51. Further, according to Exxon, the Commission also valued the Light Distillate and Heavy Distillate cuts at the unadjusted prices for Jet Fuel and No. 2 Fuel Oil, respectively. *Id.* at p. 351. On judicial review of the Commission orders, notes Exxon, the Circuit Court held, in *OXY,* that the Light and Heavy Distillate valuations and the Resid valuations were arbitrary and capricious and remanded them to the Commission for further consideration. *Id.* With respect to the Commission's valuation of Resid, states Exxon, the Circuit Court found that "the record demonstrates no more than that the price of FO-380 bears some remote relationship to the value of 1050+ resid as a feedstock." *Id.* (quoting *OXY*, 64 F.3d at p. 695).

2864. On remand, claims Exxon, the Commission adopted a settlement (the 1997 Settlement) that, *inter alia*: (1) adjusted the reference prices for Light and Heavy Distillate to account for processing costs; (2) folded the Fuel Oil cut into the VGO cut by raising the final cut point for the VGO cut from 1000°F to 1050°F; and (3) for the Resid cut, subtracted 4.5 ¢/gallon from the reference prices for Fuel Oil 380 (West Coast) and No. 6 fuel oil (Gulf Coast). *Id.* The Circuit Court in *Exxon*, on review of the Commission's order, it states, upheld the valuations of the Light Distillate, Heavy Distillate and Fuel Oil cuts, but again set aside the Resid valuation. *Id*. at pp. 351-52. In remanding the Resid valuation, notes Exxon, the Circuit Court ruled that the Commission still had not demonstrated more than a remote relationship between FO-380 and 1050°+ F Resid. *Id.* at p. 352.

2865. Based on the foregoing, Exxon argues, there can be no doubt that the Commission committed legal error in valuing the Resid and Distillate cuts in its 1993-94 orders. *Id.* That is evident, in Exxon's opinion, because the *OXY* court granted the petitions for review on these issues and because it is explicit in the *Exxon* court's treatment of the valuations set aside in *OXY* as legal error. *Id.* Exxon asserts that the Commission again committed legal error in 1997 in valuing the Resid cut, because the *Exxon* court "grant[ed] the petition for review in part and vacate[d] and remand[ed] for further proceedings [that] part … of [the Commission's] order approving the use of proxies for the market valuation" of Resid. *Id.* at pp. 352-53 (quoting *Exxon*, 182 F.3d at p. 34). It concedes that neither the *OXY* nor *Exxon* decisions foreclosed the Commission from providing, on remand, a reasonable explanation for their prior valuations. *Id.* at p. 353. However, on remand from *OXY*, Exxon points out, the Commission declined to provide such an explanation, and abandoned its initial valuation approach (at the request of the Nine Parties) in the 1997 Settlement. *Id.* Moreover, on remand from *Exxon*, Exxon notes that no party has even attempted to defend the valuation set aside by the *Exxon* court. *Id.*

2866. Following the Commission's 1993 valuations of the Resid and Distillate cuts, Exxon explains it moved for a stay on the ground that it could suffer economic loss if the Commission's valuations were later found to be erroneous and set aside on judicial review. *Id.* But, notes Exxon, in 1994, the Commission declined to stay the effectiveness of its newly-adopted distillation methodology "because of the possible economic loss Exxon could suffer if a court set aside the [November 30, 1993] order. In that event the Commission could correct any legal error." *Id.* (citing *Trans Alaska Pipeline System*, 66 FERC ¶ 66,188 at p. 61,423 (1994)). Even though the Commission's valuations of the Distillate and Resid cuts were later set aside, Exxon notes, the Commission nevertheless ruled on remand that the revised valuations for those cuts should be applied only prospectively – resulting in precisely the economic loss, according to Exxon, that their motion to stay was designed to prevent and which the Commission had promised to "correct" in denying the stay. *Id.* at pp. 353-54.

2867. Exxon argues that the Commission's initial inclination in 1994 – to correct the adverse effects of its error on the parties – was the proper one. *Id.* at p. 354. It asserts that the Supreme Court has confirmed that this is a proper course of action when an order of an agency that never became final is later overturned by a reviewing court. *Id.*

2868. Moreover, Exxon argues, in a line of cases dating back to at least *Tennessee Valley Mun. Gas Ass'n v. Federal Power Com'n*, 470 F.2d 446, 452 (D.C. Cir. 1972), the Circuit Court has consistently ruled that the proper remedy for legal error is to place the parties in the position in which they would have been had the error not been committed. *Id.* It claims there is no dispute that there has yet to be a final decision on the just and reasonable valuation of the Resid cut for the period December 1, 1993, through the present date. Exxon Reply Brief at p. 393. Nor is there any disagreement, in Exxon's view, over the question of whether Resid has been or continues to be overvalued. *Id.* Exxon points out that both the Eight Parties's and Exxon's proposed valuations of Resid produce values for Resid that are substantially lower than the values for Resid previously and currently in place. *Id.* As a result, Exxon asserts, there can be no legitimate dispute that parties who have injected crude oil streams with higher than average proportions of Resid have been enriched by the prior over-valuations and that parties that have injected crude oil streams with lower than average proportions have been economically harmed. *Id.* at pp. 393-94. Applying the *Exxon* court's legal standard to these circumstances, Exxon argues, the only way to put the parties in the position in which they would have been is to require the parties who have benefited financially from the over-valuation of Resid to refund those benefits, and make whole the parties who have been harmed from the over-valuation. *Id.* at p. 394.

2869. Exxon also asserts that the Circuit Court has applied this principle even where the resulting retroactive relief goes back more than a decade. Exxon Initial Brief at pp. 354-55. For example, notes Exxon, the Circuit Court has ordered retroactive refunds for a period commencing almost 13 years prior to the date of its decision requiring such refunds.[851] Exxon Initial Brief at p. 355.

2870. The Commission itself, Exxon contends, in the past, has changed orders as a result of their being overturned by a reviewing court. *Id.* Exxon cites several examples to substantiate this point. First, it cites *Natural Gas Clearinghouse v. F.E.R.C.*, 965 F.2d 1066 (D.C. Cir. 1992) in which the Circuit Court cited Commission decisions ordering the retroactive recoupment of refunds that were found on judicial review to have been improperly ordered, as well as decisions where the Circuit Court said the commission invoked a remedial authority to impose retroactive surcharges upon purchasers of pipeline transport service in order to allow the pipeline to collect a rate that was erroneously disallowed by the Commission. *Id*. Second, Exxon notes, in a recent order in a California electric rate refund proceeding, the Commission included an analysis of its authority to order retroactive refunds under the Federal Power Act, and noted that it can order retroactive refunds to correct legal error in order to put consumers in the same position in which they would have been had no error had been made. *Id.* at pp. 355-56.

2871. In addition, Exxon argues that the Eight Parties do not address the necessary implications of that *Exxon* standard. Exxon Reply Brief at p. 394. Instead, according to Exxon, they contend that, for two reasons, the Commission need not put the parties in the position in which they would have been had the error not been made. *Id.* First, notes Exxon, the Eight Parties argue that equitable considerations control whether or not refunds are granted. *Id.* Second, continues Exxon, they argue that "refunds are . . . discretionary and should be ordered only when they would advance the core purposes of the regulatory statute." *Id.* (quoting Eight Parties Initial Brief at p. 168). In advancing these arguments, Exxon argues that the Eight Parties misstate and ignore the pertinent legal and equitable standards. *Id.*

2872. The core purpose of the Quality Bank, according to Exxon, is to assign accurate relative values to the petroleum that becomes part of the TAPS common stream. Exxon Initial Brief at p. 356. It asserts that, based on the *OXY* ruling, the Commission must value all cuts in the stream accurately or over or undervalue them all to the same extent, and concludes that this necessarily requires retroactive application of the corrected valuations for the Resid and Distillate cuts; otherwise, streams rich in these cuts will be

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[851] Exxon notes that, in *Public Service Co. of Colorado v. F.E.R.C.*, 91 F.3d 1478 (D.C. Cir. 1996), the court stated: "Absent detrimental and reasonable reliance, anything short of full retroactivity . . . allows [some parties] to keep some unlawful overcharges without any justification at all. The court strongly resists the Commission's implication that the Congress intended to grant the agency the discretion to allow so capricious a thing." Exxon Initial Brief at p. 355, n.132 (quoting 91 F.3d at p. 1490).

overvalued and their owners will receive a windfall in Quality Bank credits. *Id*. at p. 356-57. Exxon asserts that, unless lawful valuations are applied as of the date on which the Commission adopted the prior, unlawful valuations, shippers will not be placed in the economic position in which they would have been had they received the same petroleum from the pipeline at Valdez that they deliver to the pipeline on the North Slope. *Id.*

2873. Consistent with the above principles, Exxon points out, errors in Quality Bank invoices, whether arising from errors in valuation methodology or in the implementation of the methodology, are routinely corrected and parties's Quality Bank accounts are trued up (that is, the accounts are credited or debited on a retroactive basis) to reflect those corrections. *Id.* For example, Exxon explains, all parties to this case have agreed that, when the valuation of the Heavy Distillate cut in Issue No. 2 is finally resolved, that valuation should be made effective retroactive to February 1, 2000, (when the proxy product changed), and that refunds should be awarded for the period February 1, 2000, to the effective date of a decision in this case. *Id.*

2874. In addition, Exxon argues, the Commission has ordered retroactive application of changes in Quality Bank cut valuations on other occasions. *Id.* For example, notes Exxon, in May 1994 – more than five months after the Commission had ordered the distillation methodology put into effect – the Commission, on rehearing of its original distillation order, decided to use the Gulf Coast high-sulfur VGO price to value the VGO cut on both the West and Gulf Coasts (rather than use the West Coast high-sulfur VGO price to value the West Coast VGO cut). *Id.* at pp. 357-58. Exxon explains that the reason the Commission ordered the change made retroactively was to avoid allowing a prior methodology that it had found was unjust and unreasonable to continue to govern after it had put parties on notice of the prior effective date of the discarded method. *Id.*

2875. Exxon contends that, because the cut valuations remanded in *OXY* were abandoned by the Commission in favor of other valuations in the 1997 remand proceedings, the remanded valuations have, as a practical matter, been found unjust and unreasonable as well. *Id.* Similarly, Exxon notes that, although the Resid valuation remanded in *Exxon* has not yet been formally abandoned on remand, no party presented any evidence in support of that valuation in the remand hearings just completed. *Id.* Thus, according to Exxon, under the logic of the May 1994 order described above, the valuations ultimately found lawful for the cuts remanded in *OXY* and *Exxon* should be applicable as of December 1, 1993. *Id.* To do otherwise Exxon argues, would, in effect, allow unlawful valuations to continue to govern. *Id.*

2876. According to Exxon, the Circuit Court in *Exxon* expressly stated there is a presumption of retroactivity that is applicable to claims for refunds based on agency error in valuing an ANS crude cut, a strong presumption in favor of making parties whole, and a resulting incentive for parties to litigate agency errors and for agencies to correct those errors. *Id.* at pp. 358-59. In this case, Exxon argues that this equitable presumption should apply with particular force, where Exxon sought a stay of the 1993 valuation orders based on the economic harm it would suffer – and now has suffered – from erroneous valuation orders set aside after judicial review. *Id.* at p. 359. It notes that the Commission denied a stay on the ground that it could correct any such errors. *Id.* In Exxon's view, the Eight Parties's position that a balancing of the equities leads to the conclusion that no refunds can be ordered is directly controverted by the result in *Exxon*. Exxon Reply Brief at p. 395. Further, Exxon argues, the Eight Parties should not have ignored the fact that the Circuit Court rejected the Commission's four grounds for applying the new valuations at issue in the *Exxon* case on a prospective basis only. *Id.*

2877. Furthermore, Exxon asserts, neither of the two cases cited by the Eight Parties – *CPUC,* 988 F.2d at p. 168 and *Towns of Concord,* 955 F.2d at p. 76 – supports their position. *Id.* (citing Eight Parties Initial Brief at pp. 167-68). Exxon points out that, in *CPUC*, the Circuit Court, after reciting the equitable considerations that informed the Commission's judgment, nevertheless held that the Commission cannot substitute use of equitable considerations for adherence to the law. *Id.* at pp. 395-96. Further, notes Exxon, in *Towns of Concord*, the Circuit Court stated that the exceptional facts of that case meant there was little potential for unjust enrichment making the Commission's exercise of its discretion to refuse to award refunds acceptable and that the refusal did not involve the filed rate doctrine or contravene any statutes. *Id.* at p. 396, n.262. In the instant case, by contrast, Exxon states, the Eight Parties were on notice that the Quality Bank valuations in question were subject to modification, and there is no question that the prior erroneous valuations are unfair to Exxon and that some refiners have been unjustly enriched. *Id.*

2878. Exxon explains that the equitable presumption in favor of retroactivity is buttressed by at least two other factors in this case. Exxon Initial Brief at p. 359. First, as noted above, Exxon states, it has been the practice in the Quality Bank to correct errors in valuations or invoices in order to make participants in the Quality Bank whole. *Id.* Second, in considering any equities here, Exxon asserts that there is no issue of "unclean hands." *Id.* Exxon avers that its conduct with respect to Quality Bank matters has at all times been beyond reproach. *Id.* During the relevant time period, Exxon states that its Quality Bank debits and credits have been assessed strictly in accordance with the TAPS Carriers's tariffs. *Id.* According to Exxon, no party has even alleged that it has engaged in any fraud or other untoward conduct that would justify withholding refunds otherwise owed to Exxon. *Id.* In fact, Exxon notes the Eight Parties's witness on Issue No. 5 – Dayton – could not identify any inequitable conduct on the part of Exxon that would justify withholding refunds. *Id.* at pp. 359-60.

2879. According to Exxon, the Eight Parties advance two equitable arguments – one asserted by the producers, the other by the refiners – in support of their contention that the Commission's erroneous Resid and Distillate valuations should not be corrected on a retroactive basis. *Id.* at p. 360. First, it explains, the producers identify two time periods, a First Period (from January 1, 1990 through November 30, 1993), during which the gravity methodology was in effect; and a Second Period (from December 1, 1993 through December 31, 2002),[852] during which the distillation methodology was in effect. *Id.* Exxon notes that, because retroactive relief for the First Period was precluded as a matter of law, the Eight Parties argue that, as a matter of equity, there should be no retroactive application of the revised cut values for the Second Period. *Id.* Similarly, Exxon states that, based on their calculations of alleged overpayments received by Exxon and other parties during the First Period (alleged overpayments Exxon was not required to refund), the Eight Parties argue that it would be inequitable for Exxon to receive refunds in the Second Period. *Id.* Second, states Exxon, the Eight Parties argue that it would be inequitable to order the refiners to pay refunds because they optimized their operations based on the 1993-94 valuation orders (as well as subsequent valuation orders), and cannot now go back and adjust past operations to fit a new valuation methodology. *Id.* at pp. 360-61.

2880. Exxon suggests that these arguments are legally and factually flawed. *Id.* at p. 361. Accordingly, Exxon asserts they plainly provide no basis for overcoming the equitable presumption in favor of retroactivity. *Id.*

2881. In approving the 1997 Settlement, Exxon points out, the Commission adopted revised valuations for the Distillate and Resid cuts remanded in *OXY*. *Id.* It notes, in making those revised valuations effective only prospectively – and in rejecting the arguments of Exxon and Tesoro that such valuations should apply retroactively to December 1, 1993 – the Commission advanced four equitable factors in support of its decision, including that prior TAPS settlements were implemented on a prospective basis. *Id.*

2882. On appeal, according to Exxon, the Circuit Court rejected all of the arguments advanced by both the Commission and the settling parties in support of prospective only application. *Id.* Exxon states that, of particular relevance here, the Circuit Court held that the Commission's reliance on the fact that all prior TAPS cases were resolved on a prospective basis did not support its decision regarding the effective date of the 1997 Settlement.[853] *Id.* at pp. 361-62 (citing *Exxon*, 182 F3d at pp. 48-49).

[852] Exxon notes that the Eight Parties extended the end-point of this "Second Period" through December 2002 in exhibits introduced during the hearing. Exxon Initial Brief at p. 360, n.135.

[853] Exxon misstates the Court's holding as its reference is to the Court's description of the Commission's litigation position. In fact, the Circuit Court held that the Commission "does have a measure of discretion in determining when and if a rate should apply retroactively." *Exxon*, 182 F3d at p. 49. It did indicate, however, that, under the circumstances presented, the Commission "abused its discretion when it failed

2883. Moreover, claims Exxon, even if not already precluded by the *Exxon* opinion, the Eight Parties's two-period argument runs counter to the filed rate doctrine and the rule against retroactive ratemaking.[854] *Id.* at pp. 363-64. According to Exxon, the rule against retroactive ratemaking prohibits adjustment of past rates by the Commission to make up for a utility's over or under collection in prior periods. *Id.* at p. 364. Moreover, asserts Exxon, it is a logical conclusion of the filed rate doctrine that the Commission is prohibited from doing indirectly what it cannot do directly. *Id.* Therefore, argues Exxon, by seeking to avoid paying refunds in the Second Period because of alleged overpayments in the First Period, the Eight Parties are urging the Commission to do indirectly what it cannot do directly. *Id.*

2884. On November 30, 1993, according to Exxon, the Commission issued an order adopting, with modifications, a proposed settlement to change the Quality Bank methodology from a gravity-based formula to a distillation formula. *Id.* Among other things, notes Exxon, the Commission ruled that its modification of that formula in the 1993 Settlement was governed by the filed-rate doctrine, because it viewed the Quality Bank formula as a rate charged under a tariff. *Id*. In addition, states Exxon, the Commission recognized the filed rate doctrine also precluded any retroactive changes and therefore ruled that the 1993 settlement would be applied only prospectively. *Id.* Further, explains Exxon, recognizing that the filed-rate doctrine prevents any retroactive changes to a rate, the Commission concluded that the 1993 Settlement could be applied only prospectively. *Id*. at pp. 364-65.

2885. On appeal, contends Exxon, the Circuit Court affirmed the Commission's ruling that the 1993 Settlement should apply only prospectively. *Id.* at p. 365. According to it, the Circuit Court agreed with the Commission that the Quality Bank methodology was an integral element of the TAPS tariff structure and that the filed-rate doctrine governed modification of that methodology. *Id*. Therefore, claims Exxon, because of the filed-rate doctrine, the Circuit Court held that the Commission properly determined that the new methodology could not be applied retroactively. *Id.* Further supporting this conclusion, according to Exxon, was the fact that, in their 1989 filing initiating the earlier litigation, the TAPS Carriers did not propose a change in the methodology and thus the filing did not act as notice that a change to the assay methodology was possible.[855] *Id.* Under these

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without adequate explanation to make the revaluation and concomitant Quality Bank adjustments retroactive to 1993, when the distillation method was adopted." *Id*. at p. 50.

[854] Exxon explains that the rule against retroactive ratemaking is a corollary of the filed rate doctrine. Exxon Initial Brief at p. 364, n.138.

[855] By contrast, Exxon asserts that the Circuit Court has already found that all the parties to the current Quality Bank litigation have been on notice, since 1993, that valuations of certain cuts were contested and that reliance on the rates in effect was

circumstances, declares Exxon, the *OXY* court held that it was proper for the Commission to apply the 1993 Settlement prospectively, because to do otherwise would have constituted retroactive rulemaking. *Id.*

2886. Here, Exxon argues, the producers are seeking to avoid payment of refunds for the Second Period that would otherwise be owed based on alleged overpayments during the First Period. *Id.* This amounts to, according to Exxon, an indirect, post-hoc modification of the rates charged and collected during the First Period in contravention of the filed-rate doctrine. *Id.* at p. 366. Exxon points out that, despite the fact that the filed-rate doctrine required the Commission to apply the 1993 Settlement only prospectively, the Eight Parties argue that, as a result of this prospective application during the First Period, they made hundreds of millions of dollars of overpayments into the Quality Bank during the First Period, and that Exxon received substantial overpayments during the First Period. *Id.* This argument is legally erroneous, in Exxon's opinion, because both the Commission and the Circuit Court have ruled that the payments made during the First Period were compelled by the requirements of the filed rate doctrine. *Id.* But, more importantly, according to Exxon, this argument also asks the Commission to adjust the rates that would otherwise apply during the Second Period to make up for a possible over collection in prior years. *Id.* Exxon asserts the law is clear that, even had there been an over collection in the First Period, this kind of post-hoc modification proposed by the Eight Parties is unlawful under the filed rate doctrine. *Id.*

2887. According to Exxon, the Circuit Court's decision in *Public Utilities Com'n of State of Cal. v. F.E.R.C.*, 894 F.2d 1372 (D.C. Cir. 1990), is particularly instructive in this case. In that case, the Commission ordered El Paso, a natural gas company, to refund to its customers, through reduced current rates, a tax fund, which was composed of rate revenue that El Paso had already collected. 894 F.2d at p. 1383. Exxon states that the Circuit Court rejected that approach because it would require El Paso to return a portion of rates approved by the Commission and collected by El Paso and held that the Commission's action would undermine the predictability which the filed rate doctrine seeks to protect. *Id.* In addition, the Circuit Court rejected the notion that the Commission's position could be justified on equity grounds, saying that earlier opinions were not intended to give the Commission the authority to ignore the rule against retroactive ratemaking even if the Commission thought that was necessary in order to achieve an equitable result. *Id.*

2888. The argument rejected in *Public Utilities Com'n of State of Cal.* is the same argument, according to Exxon, based on the same theory (equity), advanced by the Eight Parties in this case. Exxon Initial Brief at p. 367. That is, in the name of equity, Exxon contends that the Eight Parties seek to retain increased Quality Bank revenues for the

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unwarranted. Exxon Initial Brief at p. 365, n.139 (citing *Exxon*, 182 F.3d at p. 49).

Second Period with which to offset what they, erroneously according to Exxon, contend were overpayments made by some of them during the First Period. *Id.* Exxon argues that this action is prohibited by the filed rate doctrine and its corollary, the rule against retroactive ratemaking. *Id.* at p. 368.

2889. Even assuming that the producers's two-period equitable argument was not barred as a matter of law, Exxon insists it is riddled with inconsistencies and founded on erroneous factual premises. *Id.* According to Exxon, it cannot overcome the presumption in favor of retroactivity that Exxon believes is required to make it whole. *Id.* Further, Exxon asserts that the two period argument actually supports a claim for refunds because approximately 90% of the requested refunds are to be paid by the refiners. Exxon Reply Brief at p. 407.

2890. First, the Eight Parties's two-period argument underscores a glaring inequity that, according to Exxon, would be aggravated if refunds are not awarded: the refiners owe refunds in both periods under the Eight Parties's analysis, a fact that Exxon notes was conceded at the hearing by the Eight Parties's witness, Dayton. Exxon Initial Brief at p. 368. This is so, Exxon points out, because the refiners benefited significantly from the gravity methodology in the First Period, and would now benefit if refunds are not assessed in the Second Period. *Id.*

2891. Second, according to Exxon, the Eight Parties have not shown why equity requires that heavy oil producers should be relieved from paying refunds associated with the over-valuation of Resid since 1993. Exxon Reply Brief at p. 408. Exxon notes that, although the two-period analysis is advanced by the Eight Parties, several producers (including BP and Phillips) do not owe refunds, but, rather, are owed refunds for the Second Period. Exxon Initial Brief at p. 369.

2892. Third, Exxon asserts that, with two exceptions (OXY and Phillips), the parties that now claim to have been aggrieved by the Commission's past decision not to award refunds in the First Period did not even seek such refunds at that time. *Id.* For example, explains Exxon, neither BP nor ARCO, the predecessor of Phillips, sought refunds for the First Period, nor did they seek judicial review of the Commission's ruling that the 1993 Settlement (implementing the distillation methodology) should not be applied retroactively. *Id.* Thus, Exxon argues, they are now in no position, as a matter of equity, to argue for relief because of the alleged harm they suffered from that ruling. *Id.*

2893. Fourth, neither BP nor Phillips, in the opinion of Exxon, is in a position to complain now about the effects of applying the gravity valuation methodology after natural gas liquid blending began at Prudhoe Bay, when those parties (or their corporate predecessors) explicitly approved such blending with the knowledge it could significantly impact the Quality Bank. *Id.* Exxon explains that the event that led to the gravity methodology's being discarded at the end of the First Period was the large-scale blending of natural gas liquids with crude from the Prudhoe Bay Unit. *Id.* However, notes Exxon, both ARCO (Phillips's corporate predecessor) and BP explicitly approved this program knowing full well its impact on the Quality Bank. *Id.* at pp. 369-70. Exxon's witness, it states, explained (Exhibit No. EMT-102 at pp. 25-26) that natural gas liquid blending could be undertaken only with the approval of both BP and ARCO, companies that collectively owned a majority interest in the Prudhoe Bay Unit. *Id.* at p. 370.

2894. Moreover, Exxon asserts, the record evidence confirms that these companies knew that blending could significantly impact Quality Bank debits and credits under a gravity methodology. *Id.* For example, Exxon cites Exhibit No. PAI-72 and argues that this exhibit leaves no doubt that ARCO was aware of the impact of natural gas liquid blending in the mid-1980s, and that ARCO had concluded that the benefits of natural gas liquid blending offset any detriment and made ARCO whole. *Id.*

2895. Additionally, states Exxon, the Eight Parties's two-period analysis conflicts with the principle that, "when the Commission commits legal error, the proper remedy is one that puts the parties in the position they would have been in had the error not been made." Exxon Reply Brief at p. 410 (quoting *Exxon*, 182 F.3d at p. 49). According to Exxon, if the Commission had not over-valued Resid beginning in 1993, (i) for the First Period, all of the parties would have been left with Quality Bank accounts calculated pursuant to the gravity methodology; and (ii) for the Second Period, all of the parties would have been left with Quality Bank accounts calculated pursuant to a just and reasonable Resid valuation. *Id.* If refunds are provided, Exxon asserts, the parties will be in an identical position. *Id.* It argues that the Eight Parties simply have no answer to this point. *Id.*

2896. Fifth, the Eight Parties's calculations of purported under- and overpayments are, in the opinion of Exxon, seriously flawed. Exxon Initial Brief at p. 371. To begin with, Exxon asserts, there is no basis for suggesting that the methodology used by the Eight Parties's to calculate over- and underpayments for the First Period – that is, using the cut values from the 1997 Modified Nine Party Settlement, and the Resid value proposed by the Eight Parties witness O'Brien – is the method the Commission would have used had they applied a distillation methodology retroactively.[856] *Id.* Thus, one can only speculate, in the opinion of Exxon, as to whether the Eight Parties's calculations bear any similarity to the relief the Commission would have granted had they attempted to apply a distillation method retroactively to the First Period. *Id.*

[856] Exxon states that its witness, Pavlovic, explained that the use of O'Brien's valuation overvalues Resid by understating coking costs and, thus, that Dayton's refund calculation is biased in favor of shippers of heavier crude. Exxon Initial Brief at p. 371, n.144. As a result, according to Exxon, Dayton's calculation overstates refunds for the First Period, and understates refunds for the Second Period. *Id*. In fact, Exxon claims, shippers of lighter crude (such as Exxon) are owed more in the Second Period than they owe for the First Period when the proper values are used. *Id*.

2897. There is also, in Exxon's view, no basis for the Eight Parties's assertion that there was ample data for the First Period calculation. Exxon Reply Brief at p. 411. It states that the Eight Parties's support for this assertion rests on about 45 pages of testimony, but that the Eight Parties fail to state how this testimony supports their position. *Id.*

2898. For example, Exxon points out that the methods and data the Eight Parties used to calculate over- and underpayments for the First Period differ from those they used to do calculations for the Second Period. Exxon Initial Brief at p. 371. This prevents a reliable comparison between the calculations in the two periods, according to Exxon. *Id.* Specifically, Exxon explains that in calculating over- and underpayments for the Second Period, the Eight Parties rely on the Caleb Brett assays to measure stream qualities. *Id.* By contrast, Exxon claims, because the individual streams that comprise the TAPS common stream were not assayed during the First Period, the Eight Parties's calculations for this Period are based on numerous assumptions about the composition of those streams.[857] *Id.* at pp. 371-72. For example, Exxon states, Dayton acknowledges that, in the case of the Lisburne field, she used multiple data sources to build the data for a single stream. *Id.* at p. 372. Exxon asserts that some of the assumptions relied upon to build the data for the First Period are in direct conflict with the Eight Parties's position on assays for use in valuing Resid,[858] and many are demonstrably flawed, as shown on cross-examination.[859] *Id.*

[857] According to Exxon, such assay data is lacking for the First Period because Caleb Brett did not begin to perform the monthly assays now used by the Quality Bank to determine the characteristics of the TAPS common stream until after the distillation methodology was adopted in 1993. Exxon Initial Brief at p. 372, n.145.

[858] Exxon asserts that Dayton's testimony, with respect to Issue No. 5, that there are a lot of data besides assay data that can be used to measure the petrochemical properties of the production streams during the First Period, conflicts with her testimony concerning what constitutes reliable assays for Issue No. 1. Exxon Initial Brief at p. 372, n.146. For Issue No. 1, Exxon states she testified the Caleb Brett assays were indispensable to determining the characteristics of the streams. *Id.*

[859] On cross-examination, according to Exxon, Dayton admitted that she had simply assumed that the yield for the period May 1, 1994, to April 30, 1995, would be the same as the yield for the period January 1, 1990, to the end of 1993. Exxon Initial Brief at p. 372, n.147. However, Exxon asserts that there were significant changes in stream composition during the 1993-94 time period, a period which straddles the end of the First Period and the beginning of the Second Period, and that Dayton's analysis fails to account for these changes. *Id.* According to Exxon, five new streams came on line during this straddle period, and throughout the entire period the Prudhoe Bay crude and condensate production was in decline while natural gas liquid production was increasing.

2899. Yet another flaw, in the opinion of Exxon, in the Eight Parties's calculations of over- and underpayments is their erroneous assumption that Exxon sells crude oil at the Golden Valley Electrical Association and Petro Star Valdez Refinery connections. *Id.* at pp. 372-73. It explains that the Eight Parties assumed that all producers sell on a pro rata basis to the refiners and, therefore, that the return stream, as well as the diverted stream, are shared pro rata among the producers that have production in the passing stream. *Id.* at p. 373. In fact, asserts Exxon, this assumption is not true with respect to Exxon, which does not sell at either the Golden Valley Electrical Association or the Petro Star Valdez Refinery connections. *Id.* According to Exxon, this flawed assumption leads to additional inaccuracies in the Eight Parties's calculations. *Id.* It adds that Dayton admitted during the hearing that her calculations will be inaccurate if her pro rata assumption is not valid. *Id.*

2900. In addition to their allegedly flawed "First Period" calculations, Exxon notes, the Eight Parties also take the erroneous position that the calculation of "Second Period" refunds should ignore the impact of the incorrect valuation of Naphtha and VGO during that period. *Id.* However, Exxon asserts that, to the extent that equity plays any role in deciding whether the revised cut valuations should be applied retroactively, any fair balance of the equities as between the First and Second Periods should account for all the benefits and harms the parties received from all of the cuts whose valuations are at issue in this proceeding. *Id.* at pp. 373-74.

2901. In Exxon's view, Exhibit No. EMT-609 provides a more complete assessment of the First Period versus the Second Period under- and overpayments on which the Eight Parties's equitable theory is based, because it includes an analysis of the total amounts each party would owe, or be owed, for Naphtha, VGO, Resid and Heavy Distillate combined.[860] *Id.* at p. 374. With VGO and Naphtha included, Exxon notes that it would be owed $172.2 million for the Second Period,[861] while it would owe $122.9 million for

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Id. Exxon argues that the Eight Parties's questionable assumptions regarding yields during the First Period have a large impact, because even small differences between estimated and actual distillation yields for the streams can have very large impacts on the over- and underpayments calculated for the streams and the parties shipping the streams. *Id.*

[860] Exxon notes that these calculations assume that Exxon's proposals for the valuation of all of those cuts were applied during both the First and Second Periods. Exxon Initial Brief at p. 374, n.148.

[861] Exxon states that Exhibit No. EMT-589 illustrates that it would be owed an even larger amount – $188.3 million – in the Second Period if O'Brien's Naphtha valuation methodology were employed as of July 1, 1994. Exxon Initial Brief at p. 374, n.149.

the First Period. *Id.* Thus, points out Exxon, it would be owed approximately $40 million more in the Second Period than it would have owed in the First Period.[862] *Id.* Exxon claims, therefore, that Dayton's assertion that the overpayments in the First Period far exceed the amounts claimed for the Second Period is undermined. *Id.* By wrongly ignoring Naphtha and VGO, Exxon contends, the Eight Parties's First Period/Second Period calculations distort the balance of the equities and drastically underestimate the considerable amount of harm that Exxon has suffered in the Second Period. *Id.* at pp. 374-75. It concludes that this casts serious doubt on the Eight Parties's claim that refunds are unnecessary to make Exxon whole and that refunds would exacerbate an already inequitable situation. Exxon Reply Brief at p. 414.

2902. Exxon notes that, despite the *Exxon* case, the Eight Parties argue that equitable principles should shield them from the regulatory and business risks stemming from the uncertainty associated with the valuation of Resid over the past decade. Exxon Reply Brief at p. 417. However, Exxon asserts, the Eight Parties can cite no legal authority supporting their argument because there is none. *Id.* In addition to its decision in *Exxon*, which Exxon states should govern this case, Exxon states that the Circuit Court has made clear that only "reasonable" reliance on subsequently overturned decisions should be considered as a basis for rejecting retroactive relief. *Id.* (quoting *Public Service Co. of Colorado*, 91 F.3d at p. 1490).

2903. In the instant case, according to Exxon, there was clear and unmistakable notice that relying on the 1993-1994 valuation decisions (and subsequent valuation decisions) was unreasonable. *Id.* Exxon points out that Boltz acknowledged that the refiners were on notice from 1993 onward that the agency orders upon which they relied in allegedly "optimizing" their operations were being challenged on judicial review. *Id.*

2904. Moreover, Exxon notes, subsequent to 1994, the refiners – by their own actions – acknowledged that the 1993-94 and subsequent Resid valuations were erroneous. Exxon Initial Brief at p. 378. For example, Exxon points out, both Petro Star and Williams were signatories to the 1997 Settlement, in which they effectively agreed that the 1993-94 valuation orders overvalued Resid by 4.5¢/gallon. *Id.* Similarly, states Exxon, both in 2000 and 2003, the refiners sponsored testimony that not only shows that Resid continues to be overvalued, but also quantifies the range of potential refunds that would required if

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[862] Exxon points out that Dayton's calculations produce similar results. Exxon Initial Brief at p. 374, n.150. It explains that with VGO and Naphtha included, Dayton calculated that Exxon is owed $168.7 million for the Second Period and that Exxon received overpayments of $127.8 million for the First Period (assuming Exxon's Resid methodology.) *Id.* Thus, Exxon notes, according to Exhibit Nos. PAI-235 and PAI-236, Exxon would be owed approximately $40 million more in the Second Period (including VGO and Naphtha) than it was overpaid in the First Period. *Id.*

a new Resid valuation were applied retroactively.[863] *Id.* Under these circumstances, Exxon maintains, it is entirely fair that the refiners bear the financial consequences of their continued reliance on the Commission's valuations. *Id.*

2905. Exxon also takes exception to the Eight Parties's claim that retroactive application of the revised valuations would not put Exxon in the position it would have been in had the Commission not erred. Exxon Reply Brief at p. 418. It notes that the Eight Parties claim that, had revised valuations been in place as of December 1, 1993, the refiners would have optimized differently than they did. *Id*. Thus, the Eight Parties contend, states Exxon, that retroactive imposition of the new valuations "would allow [Exxon] to collect more from the refiners in refunds than it would have if the valuations had been in place as of December 1, 1993." *Id.* (quoting Eight Parties Initial Brief at p. 206). Exxon argues that the Eight Parties's argument again conflicts with clear legal authority, including the Commission's orders in *Tarpon Transmission Company*, 51 FERC ¶ 61,310 (1990), and the decision of the Circuit Court affirming those orders in *Natural Gas Clearinghouse v. F.E.R.C.*, 965 F.2d 1066 (D.C. Cir. 1992). *Id*. at pp. 418-19.

2906. Exxon notes that the Circuit Court agreed with the Commission that Tarpon's shippers had been on notice that the lower rate was subject to an appeal, and that Tarpon was entitled to recoup the revenues it would have collected were it not for the Commission's earlier erroneous decision. *Id.* at p. 419. In upholding these orders, Exxon explains, the Circuit Court concluded, "the open-access shippers [on which the surcharge was imposed] had the necessary notice that they might end up paying the originally filed rate." *Id.* at p. 420 (quoting *Natural Gas Clearinghouse*, 965 F.2d at p. 1075).

2907. The instant case, according to Exxon, presents a situation very similar to the one that was before the Commission and the Circuit Court in the *Tarpon/Natural Gas Clearinghouse* litigation. *Id.* Here, explains Exxon, all parties were on notice that the Commission's orders (here, the 1993, 1994 and 1997 valuation orders) were being appealed. *Id.* In this case, states Exxon, the Commission itself notified all parties in February 1994 that, in the event a court set aside its valuation orders, it "could correct any legal error," citing the *Natural Gas Clearinghouse* decision. *Id.* (quoting *Trans Alaska Pipeline System*, 66 FERC at p. 61,423). Under these circumstances, it is Exxon's view that all TAPS shippers, including the refiners, assumed any risks of reliance on the valuation orders when the validity of those orders was contingent on court review. *Id.* (citing *Exxon*, 182 F.3d at p. 49). Therefore, according to Exxon, it makes no difference that the refiners might have optimized differently had different valuations been in place as of December 1, 1993. *Id.* Given notice that the 1993 Resid valuation might be disallowed, Exxon asserts that there is nothing unfair about imposing revised valuations

[863] Exxon cites the following in support of this point: Exhibit Nos. EMT-586, pp. 17-24, PAI-28 through PAI-31, PAI-48. Exxon Initial Brief at p. 378, n.153.

as of that date and ordering refunds consistent with such valuations. *Id.* at pp. 420-21.

2908. In Exxon's view, the Eight Parties's position boils down to the erroneous contention that parties such as Exxon, who had no control over the refiners's operating decisions, should nonetheless pay for the refiners's unwarranted reliance on incorrect valuations. *Id.* at p. 421. It asserts that, if the refiners's equity argument is accepted, it would perpetuate over a decade of inequity stemming from erroneous Quality Bank valuations. Exxon Initial Brief at p. 379. The result, according to Exxon, would be a windfall for the refiners, who would be permitted to retain the competitive advantages they realized simply as a result of Quality Bank cuts being wrongly valued.[864] *Id.* Again, Exxon argues that this is manifestly contrary to the purpose of the Quality Bank. *Id.* There is certainly nothing equitable, in Exxon's view, about permitting one set of parties to retain the financial fruits associated with erroneous administrative decisions and requiring another set of parties to continue to bear the adverse financial consequences of such decisions. *Id.*

2909. Further underscoring the inequity of denying refunds for the Resid cut, according to Exxon, is the fact that the Eight Parties, who vigorously oppose those refunds, have agreed to refunds (now totaling over $70 million[865]) attributable to the incorrect valuation of the Heavy Distillate cut. *Id.* There is no lawful basis in Exxon's view for distinguishing between these two sets of refunds, as they arise in both instances from erroneous Quality Bank valuations. *Id.* at pp. 379-80. No one has suggested that BP or Phillips forego the refunds due them for incorrect valuation of the Heavy Distillate cut, nor have they argued that Williams and Petro Star should be spared from paying Heavy Distillate refunds because of the resulting financial impact on those parties. *Id.* at p. 380. Under these circumstances, Exxon argues, equity does not require honoring the Eight Parties's agreement that refunds arising from the prior incorrect valuations of the Resid cut should be denied Exxon. Exxon Reply Brief at p. 422.

2910. Exxon states that, even if the refiners could show that they optimized their operations to reflect the Quality Bank Resid valuation in place in 1993 and took reasonable steps to mitigate the risk that this valuation would change, any reliance on such valuations was not warranted. *Id.* Moreover, Exxon argues, the Eight Parties clearly have not borne the burden of proving either of the two factual predicates which

[864] Exxon points out that Exhibit No. EMT-590 illustrates that Petro Star would avoid paying from $14.56 million to $58.76 million, while Williams would avoid paying from $71.99 million to $267.13 million, as a result of a no-retroactivity decision in both the First and Second Periods. Exxon Initial Brief at p. 379, n.154.

[865] Exxon cites Exhibit No. EMT-610 in support of this point. Exxon Initial Brief at p. 379, n.155.

underlie their equitable claims. *Id.*

2911. First, Exxon asserts, there is virtually no evidence to support the Eight Parties's claim that "the refiners continuously optimize their operations to reflect the Quality Bank." *Id.* (quoting Eight Parties Initial Brief at p. 186). It states that it bears emphasis that Williams did not even present a company witness to describe its operations or present any evidence to explain how it had relied on Quality Bank valuations to its detriment. *Id.* Exxon reiterates its assertion that the Eight Parties bear the burden of proving that equitable considerations should overcome the presumption in favor of retroactivity contained in *Exxon*. *Id.* at pp. 422-23. It states that the Eight Parties, in general, and Williams, in particular, have failed to meet this burden. *Id.* at p. 423. Instead, notes Exxon, the Eight Parties merely assert that they optimized their operations to the later-invalidated valuations. *Id.*

2912. Boltz's testimony provides no better support for the refiners's claim that they optimized their operations in reliance on the valuations then in effect, according to Exxon. *Id.* at p. 424. Although Boltz testified that Petro Star changed its product mix and maximized its through-put in light of changes in the Quality Bank, Exxon points out, he also conceded that Petro Star's refinery operations were not driven by Quality Bank decisions. *Id.* Likewise, continues Exxon, in the wake of the Commission's 1997 decision, Williams expanded its refinery notwithstanding the alleged uncertainty created by Quality Bank proceedings. *Id.* at pp. 424-25. Exxon maintains that this evidence shows that the Eight Parties have not borne their burden of proving that different Quality Bank valuations would have driven different refinery optimizations. *Id.* at p. 425. In Exxon's view, the above-cited evidence regarding plant expansions suggests the exact opposite. *Id.*

2913. Second, Exxon declares, the Eight Parties have not proven that they took any reasonable steps to mitigate the risks created by the pending appeals and administrative litigation over the 1993 Quality Bank valuations. *Id.* To the contrary, according to Exxon, it is undisputed that both Williams and Petro Star aggravated those risks by expanding their plants. *Id.* Faced with this evidentiary record, Exxon points out, the Eight Parties do not even argue that they attempted to mitigate their risks, claiming instead that mitigation would have been impossible or, alternatively, would have required that the refiners bear costs which they would have avoided if they had known in 1993 what the final, lawful Resid valuation methodology would be. *Id.*

2914. Exxon's position is that the Eight Parties have plainly failed to carry their burden of proving that any mitigation would have been impossible, while at the same time distorting the meaning of the term, implying that it involves conduct taken after an event and not during the happening of an event. *Id.* In the face of uncertainty, states Exxon, Boltz conceded that Petro Star could have established a reserve to mitigate the possible financial impact of having to pay refunds with respect to the Resid valuation, such as the one done for Heavy Distillate. *Id.* at pp. 425-26. Exxon also points out that the refiners could have opted not to expand their operations or they could have declined to participate in settlement agreements.[866] *Id.* at p. 426, n.283.

2915. Alternatively, according to Exxon, the Eight Parties assert that mitigation steps might have raised their costs and that, in competitive markets, they could not bear such additional costs. *Id.* at pp. 426-27. In advancing these arguments, Exxon asserts that the Eight Parties rely on the very premise rejected in *Exxon* – that the refiners were entitled to rely on the valuations in the Commission's 1993-1994 orders. *Id.* at p. 427. Under *Exxon*, the issue is not, states Exxon, whether mitigation would have kept the refiners perfectly whole or would have addressed all cash flow impacts. *Id.* It states that the *Exxon* finding necessarily means that reasonable parties in the refiners's position (i.e., parties not entitled to rely on the 1993-1994 valuation orders) would have to take some steps to mitigate the risk of an award of refunds; that the refiners's failure to take any such steps was therefore unreasonable; and that the refiners's conduct does not deserve to be rewarded now in the name of equity. *Id.* Exxon argues that the Eight Parties identify no legal authority to support the proposition that they, as an equitable matter, should be shielded from regulatory risk or spared the costs of taking reasonable steps to mitigate such risks. *Id.*

2916. Exxon asserts that the Eight Parties's arguments that the Interstate Commerce Act should be interpreted as a bar to refunds in this case are misguided. *Id.* at p. 397. To begin with, Exxon states, they represent just a repackaged version of the Commission's argument before the Circuit Court in the *Exxon* case that the TAPS Quality Bank is "*sui generis*." *Id.* Exxon points out that the court held that this argument (along with others) "ha[d] no bearing on the decision and do[es] not explain [the Commission's] decision not to make whole parties who are clearly injured by undervaluation." *Id.* (quoting *Exxon*, 182 F.3d at p. 49).

[866] Exxon notes that the refiners attack Toof's assertion that the refiners should have established a reserve against worst case or most likely scenarios, claiming that "the Commission-determined methodologies reasonably appeared at the times they were in effect to be the most likely, and reserves against most likely case scenarios therefore were unnecessary." Exxon Reply Brief at p. 426, n.283 (quoting Eight Parties Initial Brief at p. 196). However, Exxon states that the *OXY* and *Exxon* decisions clearly foreclosed any claim that the continuation of the existing Resid valuations was the "most likely" scenario by remanding those valuations and holding that reliance on those valuations was "unwarranted." *Id.* In Exxon's opinion, the refiners unreasonably optimized their operations to the least likely outcome, because they relied on the continuation of the Distillate and Resid valuations found to be "arbitrary and capricious" in *OXY*, and the Resid valuation found to be "arbitrary and capricious" for a second time in *Exxon*. *Id.*

2917. Moreover, Exxon argues, the Interstate Commerce Act does not have different standards for transportation rates and Quality Bank assessments; both of which are required to be "just and reasonable." *Id.* (quoting 49 U.S.C. App. §1(5)(1988)). In addition, Exxon maintains, the Quality Bank addresses the core statutory purpose of preventing unlawful preferences and rebates to TAPS shippers because some shippers may take out higher quality crude than they insert, in violation of Sections 3(1) and 2 of the Interstate Commerce Act. *Id.* at pp. 397-98 (citing *Trans Alaska Pipeline System*, 23 FERC ¶ 63,048 at pp. 65,144-45 (1983)).

2918. Exxon also maintains that the Eight Parties's claim that declining to give retroactive effect to the new cut values would not violate the statute also flies in the face of the Circuit Court's three decisions – *OXY, Exxon,* and *Tesoro* – that have addressed the TAPS Quality Bank. *Id.* at p. 398. Each of those decisions, notes Exxon, has relied on prior decisions interpreting and applying the Interstate Commerce Act and its analogs, the Federal Power and Natural Gas Acts. *Id.* According to Exxon, none of those decisions suggested that Quality Bank cut valuations have a legal status, insofar as ratemaking is concerned, that is different from pipeline or electric transmission rates. *Id.* at pp. 398-99. Indeed, asserts Exxon, the Eight Parties's "statutory design" claim is clearly refuted by the *Exxon* court's "hold[ing] that [the Commission] abused its discretion when it failed without adequate explanation to make the [Resid] revaluation and concomitant Quality Bank adjustments retroactive to 1993, when the distillation method was adopted." *Id.* at p. 399 (quoting *Exxon*, 182 F.3d at p. 50).[867]

2919. There also is no support whatsoever, argues Exxon, for the Eight Parties's claim that a ratepayer is entitled to "notice of the precise nature of its potential [refund] liability" before refunds may be ordered, or that "whether the regulated entity is able to assess its risks and alter its operations or contingency planning appropriately" is a "major factor" governing whether revised rates may be retroactively applied. *Id.* at p. 400 (quoting Eight Parties Initial Brief at p. 171). To the contrary, Exxon explains, all that is required for retroactive application of revised rates is that ratepayers have "adequate notice that resolution of some specific issue may cause a later adjustment to the rate being collected at the time of service." *Id.* (quoting *Exxon*, 182 F.3d at p. 49 (internal citations omitted)). Exxon also points out that one of the cases cited by the Eight Parties – *Public Service Co. of Colorado v. F.E.R.C.*, 91 F.3d 1478, 1490 – specifically held that, to avoid refunds in a case of agency error, a ratepayer's reliance on the prior, erroneous rates must be "reasonable." *Id.* Any claim that reliance on the lawfulness of the Commission's 1993 valuations was reasonable must necessarily be rejected, asserts

[867] Exxon claims that the decision cited by the Eight Parties, *Sithe*, in which the court upheld the Commission's decision not to apply retroactively an increase in an "installed capacity deficiency charge," is readily distinguishable from the case at bar. Exxon Reply Brief at p. 399, n.264.

Exxon, because the *Exxon* court has already held that any reliance on those valuations was not warranted. *Id.*

2920. In advancing their public interest balancing test, Exxon asserts, the Eight Parties fail to consider the public interest considerations identified in *Exxon*, including: (i) that "when the Commission commits legal error, the proper remedy is one that puts the parties in the position they would have been in had the error not been made"; (2) the "strong equitable presumption in favor of retroactivity that would. . . . make whole parties who are clearly injured by undervaluation," and (3) "the incentive that [this strong presumption] creates for the parties to litigate regarding past errors and for the agency to correct those errors." Exxon Reply Brief at p. 429 (quoting *Exxon*, 182 F.3d at p. 49).

2921. Instead, Exxon claims, the Eight Parties advance the following public interest justifications for denying imposition of refunds: (1) that retroactive implementation of changes in valuation "frustrates efficient economic planning", (2) that Exxon has not shown that denial of refunds would provide incentives for parties to "game the system," and that, in any event, any suggestion of "gaming" is refuted by the Eight Parties's agreement to retroactive implementation of the revised Heavy Distillate valuation, and (3) that "retroactivity would have a negative impact on consumers." *Id.* at pp. 428-29 (citing Eight Parties Initial Brief at pp. 198-200). Exxon's position is that none of these considerations provides a justification for the denial of refunds. *Id.*

2922. Exxon asserts that the first public interest factor identified by the Eight Parties, the alleged economic inefficiency arising out of regulatory uncertainty, directly conflicts with the *Exxon* decision. *Id.* at p. 429. It maintains that the principle set forth in *Exxon* – that parties should be put in the position they would have been in had an administrative error not been made – cannot reasonably be overridden by the alleged uncertainty associated with the judicial and administrative review processes. *Id.* Exxon notes that, during the period when the merits of an administrative decision are being litigated, there is always uncertainty over whether that decision will be affirmed. *Id.* An "uncertainty" exception, in their view, would thus immediately swallow the legal principle and the equitable presumption set forth in *Exxon*. *Id.* at pp. 429-30. Indeed, the court in *Exxon* made this point in stating: "The goals of equity and predictability are not undermined when the Commission warns all parties involved that a change in rates is only tentative and might be disallowed." *Id.* at p. 430 (quoting *Exxon*, 182 F.3d at p. 49).

2923. With respect to the contention that it has not shown that a denial of refunds would provide an incentive for parties to game the system, Exxon states, the Eight Parties again ignore a fundamental aspect of the *Exxon* decision: its creation of a presumption in favor of retroactivity. *Id.* As a result, Exxon argues that it does not bear the burden of proving that the absence of retroactivity would provide an incentive for gaming. *Id.*

2924. Nonetheless, Exxon argues, the record strongly suggests that the settlement process in this litigation was seriously gamed. *Id.* In its view, the fact that the Eight Parties agreed to retroactive implementation of the Heavy Distillate valuation highlights the inequity of their opposition to retroactive implementation of the Resid valuation, and it is further evidence of a compromise among the Eight Parties to advance their economic interests at the expense of Exxon's. *Id.* Exxon also claims it is undisputed that, while Williams and Petro Star are the largest potential payers of both Heavy Distillate and Resid refunds, BP and Phillips are the principal beneficiaries of Heavy Distillate refunds, but relatively minor beneficiaries of Resid refunds. *Id.* at pp. 430-31. By contrast, explains Exxon, Exxon is the largest potential recipient of Resid refunds, but is virtually unaffected by Heavy Distillate refunds. *Id.* at pp. 431. Under these circumstances, continues Exxon, Williams, Petro Star, BP, and Phillips have agreed to pay and receive Heavy Distillate refunds, but have opposed the payment of Resid refunds. *Id.* As the Circuit Court recognized, concludes Exxon, all of these parties benefit from this arrangement, at the expense of Exxon. *Id.* (citing 182 F.3d at 50).

2925. Further, states Exxon, the Eight Parties view that retroactive refunds are acceptable when their amount can reasonably be estimated in advance (Heavy Distillate), but unacceptable when their amount is uncertain (Resid) can hardly be viewed as sound ratemaking policy. *Id.* at p. 432. Such a theory, argues Exxon, ignores the fundamental purpose of refunds, both in general (i.e., to compensate those who have paid excessive rates) and in instances where refunds are necessary to correct legal error (i.e., putting parties in the position in which they would have been but for the error). *Id.* It maintains that there can certainly be no equity in having an award of refunds depend on whether, in the subjective view of the potential refund payers, the amount of refund exposure is reasonably certain (as the Eight Parties claim with respect to the Heavy Distillate refunds) or uncertain (as they claim with respect to the Resid refunds). *Id.*

2926. Exxon notes that the Eight Parties assert that it "has not submitted evidence that would allow the [Commission] to determine the just and reasonable values for the Resid cut for every year covered by [Exxon]'s refund request." *Id.* (quoting Eight Parties Initial Brief at p. 201). According to Exxon, the Eight Parties argue that the Quality Bank is different from the typical refund case. *Id.* While the Eight Parties acknowledge that all parties used the same general approach to derive a Resid value, Exxon points out, they claim that disputes over the adjustments to be made to the coker outputs and over valuations of other cuts render the resulting Resid valuations unusable for retroactive application. *Id.* at pp. 433-34. Thus, states Exxon, the Eight Parties conclude the Commission "cannot merely decide what is just and reasonable today and project that outcome retroactively over some hypothetical refund period." *Id.* at p. 434 (quoting Eight Parties Initial Brief at p. 201).

2927. According to Exxon, this argument suffers from at least three serious defects. *Id.* First, states Exxon, if adopted, the argument would leave in place, for the period 1993 to the date of the decision in these proceedings, Resid valuations which have been found to be unlawful and which all parties now agree were too high. *Id.* Thus, notes Exxon, adoption of this argument would require that Quality Bank payments made and received pursuant to those erroneous valuations remain settled on an erroneous basis. *Id.* Second, continues Exxon, the Eight Parties's argument is undermined by the fact that, under the distillation methodology with respect to cuts other than Resid, processing costs based on any given year's technology and costs are routinely applied by the Quality Bank in other years, including for the purpose of calculating refunds. *Id.* Third, Exxon argues, there is no merit to the Eight Parties's contention that, because Exxon's refund calculations for the Resid cut incorporate (in the before-cost Resid value) Exxon's proposed valuations for Naphtha, VGO, and Heavy Distillate, and because such valuations are in dispute in this proceeding, there is a "conflict in the evidence as to the justness and reasonableness of the before-cost coker value." *Id.* (quoting Eight Parties Initial Brief at p. 204). Exxon asserts that such refund calculations are necessarily illustrative. *Id.* at pp. 434-35. Ultimately, states Exxon, the Quality Bank Administrator will take the cut values determined by the Commission and, if refunds are awarded, apply those valuations to each shipper's stream composition for the refund period in question. *Id.* at p. 435.

2928. Exxon states that the parties agree that there has yet to be a final decision on the just and reasonable valuation of Resid for the period December 1, 1993, through the present date. *Id.* The parties also agree, notes Exxon, that "[i]n the instant matter, the issue is to find a proxy for the Resid component that bears a rational relationship to the actual value of resid." *Id.* (quoting Eight Parties Initial Brief at p. 9); *see also Trans Alaska Pipeline System*, 97 FERC at pp. 61,151-52. Further, continues Exxon, there is no disagreement over the question of whether Resid is overvalued. Exxon Reply Brief at p. 435. Both the Eight Parties's and Exxon's proposed valuations of Resid produce values for Resid that are substantially lower than values for Resid in place between 1993 and 2002. *Id.*

2929. Because the Commission's prior attempts at Resid valuations have failed, Exxon explains, all Quality Bank accounts have been settled for the past decade on the basis of Resid valuations that have been found to be erroneous. *Id.* In attempting to fashion a just and reasonable Resid valuation in the instant proceeding, it should be clear, according to Exxon, that neither of the prior remanded valuations can be used. *Id.* at pp. 435-36. The first approach (valuing Resid based on the unadjusted price of F.O. 380) is unacceptable, asserts Exxon, because it was abandoned by the Commission itself on remand from *OXY;* and the second approach (valuing Resid at the price of F.O. 380 minus 4.5¢/gallon) is unacceptable because, on remand from *Exxon*, it has not been defended or advocated by any party. *Id.* at p. 436. Thus, Exxon argues that there is no evidentiary support in this record for either of those Resid valuations. *Id.* Accordingly, it is Exxon's position that the Commission must find a different approach to Resid valuation based on the record compiled in this proceeding. *Id.*

2930. Consistent with the foregoing, Exxon advocates that the corrected values for the cuts subject to remand in *OXY* – the Light Distillate, Heavy Distillate, Fuel Oil and Resid cuts – should be made retroactive to December 1, 1993. Exxon Initial Brief at p. 380. Refunds, with interest, should be ordered for the periods during which the remanded cut values were in effect. *Id.*

2931. The TAPS Carriers explain that the Quality Bank Administrator serves as stakeholder for the Quality Bank, collecting money from one set of shippers and redistributing it (after deducting expenses) to another set of shippers in accordance with the Commission's orders. TAPS Carriers Initial Brief at p. 18. They point out that they neither receive nor distribute Quality Bank adjustments. *Id.* Because they retain none of the Quality Bank adjustments, the TAPS Carriers state, it makes little sense to refer to their paying "refunds" of such adjustments. *Id.* Any refunds in their view must come from the shippers who allegedly received amounts in excess of what they would have received under a just and reasonable Quality Bank methodology. *Id.* While they take no position on whether any such refunds should be made by shippers, the TAPS Carriers note, however, that were such refunds to be ordered, they recommend that the Commission simply direct the Quality Bank Administrator to recalculate the Quality Bank adjustments for the period at issue, collect any amounts owed to the Quality Bank, and redistribute such collected monies to those shippers owed money as a result of the recalculations. *Id.*

2932. According to the TAPS Carriers, Common Carriers, their agents, and employees are required by the Interstate Commerce Act to comply with Commission orders. TAPS Carriers Initial Brief at p. 19 (citing, *inter alia*, 49 U.S.C. App. § 16(7)(1998)). Should a carrier not comply with the orders of the Commission, they point out, it is subject to significant penalties. *Id.* In this case, explain the TAPS Carriers, the Commission issued a series of orders prescribing the Quality Bank methodology to be implemented by the TAPS Carriers and finding that methodology to be just and reasonable. *Id.* at p. 20. The TAPS Carriers also assert that it is uncontested that they have complied with the orders of the Commission prescribing the Quality Bank methodology. *Id.* at p. 21. Thus, the TAPS Carriers argue, case law supports their contention that their compliance with those orders cannot be the basis for holding them liable for the payment of refunds or any other form of retroactive relief. *Id.* Specifically, the TAPS Carriers cite *OXY*, 64 F.3d at pp. 697-700, for the proposition that a new Quality Bank methodology can only be applied prospectively. TAPS Carriers Initial Brief at p. 22.

2933. The Commission has confirmed, according to the TAPS Carriers, that as long as a carrier "operates the [quality] bank in accordance with the tariff provisions, it is not subject to any independent obligations, nor to any claims for violations of the [Interstate Commerce Act]." *Id.* (quoting *All American Pipeline Co*., 67 FERC ¶ 61,094 at p. 61,267 (1994)). According to the TAPS Carriers, the *All American Pipeline* decision clarified that the TAPS carriers are not financially responsible for any refunds arising from quality bank adjustments. *Id.* Instead, the TAPS Carriers assert, the moneys will come from funds collected from shippers who have repaid amounts to which they were not entitled. *Id.*

2934. This conclusion, according to the TAPS Carriers, is based on the self-evident fact that a carrier operating a quality bank does not participate in the Quality Bank and therefore has not retained any funds to be refunded. *Id.* Thus, according to the TAPS Carriers, any refunds must be assessed against the shippers and not the TAPS Carriers. *Id.*

2935. Although the TAPS Carriers cannot lawfully be required to pay refunds, the TAPS Carriers note, orders requiring the recalculation of Quality Bank adjustments for past periods are not necessarily precluded. *Id.* at p. 23. The TAPS Carriers assert that, if a prior order was in error and needed to be corrected, an agency may do so without violating *Arizona Grocery* or the rule against retroactive ratemaking. *Id.* According to the TAPS Carriers, legal errors in a prior order may be corrected as long as the parties affected by that order are on adequate notice that resolution of some specific issue may cause a later adjustment to the amount being collected under the prior order. *Id.* In such circumstances, the TAPS Carriers point out, the remedy available is for the agency to retroactively redesign the rate or program that it had previously imposed in error. *Id.* at pp. 23-24. They take no position on whether this exception should be applied under the circumstances in this case. *Id.* at p. 24.

2936. A necessary corollary, explain the TAPS Carriers, is that adoption of a new Quality Bank methodology retroactively would not necessarily assure that a given shipper would receive every dollar of refunds to which it might believe it was entitled under the new methodology. *Id.* This is so, according to the TAPS Carriers, because they would pay out only those funds that they were able to collect from shippers that were required to pay money into the Quality Bank under the new methodology. *Id.* Thus, if for some reason the TAPS Carriers were unable to collect funds from a shipper, the TAPS Carriers explain, they would simply distribute the funds they were able to collect pro rata, in accordance with the TAPS Carriers's rules and regulations tariffs. *Id.* Each tariff, notes the TAPS Carriers, contains a provision providing for the distribution only of funds that have actually been collected. *Id.* Such tariff provisions are, according to the TAPS Carriers, consistent with the TAPS Carriers's role, acting through the Quality Bank Administrator, as stakeholders for, and not participants in, the Quality Bank. *Id.* at pp. 24-25.

ISSUE 5 -DISCUSSION AND RULING

2937. In *OXY*, 64 F.3d at pp. 692, 695, the Circuit Court, after finding no fault with the Commission's decision to change from the gravity methodology to the distillation methodology for valuing the ANS common stream, found that the Commission had failed to have good grounds for valuing Light and Heavy Distillate, Fuel Oil and Resid.

Subsequently, the Commission approved new proxies for each of these cuts and, with the exception of that for Resid, they were affirmed by the Circuit Court in *Exxon*. In the instant case, a new proxy for Resid has been determined.

2938. The question to be answered in Issue 5 is what should be the effective date of the proxy values approved by the Circuit Court in *Exxon* and what should be the effective date of the Resid proxy determined here. According to the Eight Parties, the parties agree that, if the new Resid proxy "is made retroactive to December 1993, the Nine Party Settlement valuations of the other three Remanded Cuts [i.e., those which were approved in *Exxon*] should be retroactive for the period between December 1993 and implementation of the Nine Party Settlement in 1998." Eight Parties Reply Brief at p. 131, n.58. *See also* Exxon Reply Brief at p. 401, n.265; Eight Parties Initial Brief at p. 176.

2939. Based on the parties's agreement, we need only analyze the situation regarding the Resid cut. As to Resid, it is beyond dispute that, since the adoption, by the Commission, of the distillation methodology for calculating cut values for Quality Bank purposes, that the Circuit Court has not accepted the Commission's designated Resid valuation. The Circuit Court, in disapproving the Commission's determination that 1050°+F Resid should be valued at the price of FO-380, stated:

> [T]he record demonstrates no more than that the price of FO-380 bears some remote relationship to the values of 1050+ resid as a feedstock. FERC offers two arguments in defense of its use of FO-380 as a proxy, neither of which is convincing. First, relying on expert testimony, the Commission claims that FO-380 can substitute for the 1050+ resid as a feedstock. Notably, neither the witness who so testified nor any other stated that it was a common industry practice to use FO-380 as a feedstock when resid would do the job. Consequently, although the cited testimony supports the conclusion that FO-380 and the 1050+ resid share some physical properties, it in no way suggests the two materials have equal or even near-equal market values. . . . The Commission's conclusion simply does not follow from its premise.
>
> The Commission's alternate justification is that it has assigned, as a proxy for this least valuable component of the common stream, the petroleum product having the lowest published price. The fact that FO-380 is cheaper than other petroleum products with active markets, however, in no way demonstrates that its value is even remotely commensurate with that of resid. . . . We therefore find the 1050+ resid portion of the assay methodology arbitrary and capricious and remand it to the Commission for further consideration.

OXY, 64 F.3d at p. 695.

2940. After the Commission, on remand, adjusted the Resid proxy prices,[868] the Circuit Court once again reversed and remanded the Commission's decision on Resid:

> We remand FERC's decision to value resid at the price of FO-380 less 4.5 cents on the West Coast and Waterborne 3% sulfur No. 6 fuel oil less 4.5 cents on the Gulf Coast. The figures derived from the use of these proxies with a subsequent adjustment do not bear a demonstrated relationship to the value of resid, either as a coker feedstock or as a blending agent for fuel oil.

Exxon, 182 F.3d at p. 40.[869] In doing so, the Circuit Court affirmed the Commission's determination "that resid is best valued based on the market value of its constituent products." *Id.* at p. 41. In all other regards, the Circuit Court upheld the Commission's order regarding calculation of the ANS Quality Bank. *Id.* at p. 50.

2941. As there never has been a Resid proxy since the Commission implemented the distillation method on December 1, 1993,[870] it follows that the value of the Resid proxy established by this order should be made effective on that date as well. However, the Eight Parties strenuously argue in support of a prospective only implementation.

2942. While recognizing that there has not been a value for Resid ordered by the Commission and approved by the Circuit Court, the Eight Parties suggest "equitable" grounds for implementation only on a prospective basis: (1) Exxon benefited from the manner in which Natural Gas Liquids were treated prior to 1993 while the gravity method was challenged, and would benefit again were the Resid proxy valuation be made effective on December 1, 1993; (2) the affected refiners were not able to arrange their operations to mitigate the impact of the new valuation; (3) allowing refunds is not in the public interest; and (4) the evidence does not reflect that the new proxy values were "just and reasonable" for the whole period from December 1, 1993, forward. Eight Parties Initial Brief at pp. 178, 186, 198, 201.

2943. On reply, they argue that, making the new Resid valuation effective on December 1, 1993, would not put the parties in the same position in which they would have been

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[868] *Trans Alaska Pipeline System*, 81 FERC ¶ 61,319 (1997).

[869] The Circuit Court also stated that the 4.5¢ adjustment was as arbitrary and capricious as was the Commission's choice to use FO-380 as the proxy price. *Exxon*, 182 F.3d at p. 41.

[870] *Trans Alaska Pipeline System*, 65 FERC at pp. 62,280, 62291-92.

had the Commission made a determination approved by the Circuit Court. Eight Parties Reply Brief at pp. 135, 143-45. Moreover, according to the Eight Parties, Exxon has failed to show that it would have received the monies it claims as refunds had the Commission previously made the determination which is made herein regarding the value of a Resid proxy. *Id.* at pp. 141-43.

2944. At first blush, the Eight Parties's argument has appeal. After all, on face value, their evidence makes a strong case, based on equitable considerations, for holding that the values of the remand cuts should be made effective on a prospective basis only. However, a closer analysis reflects that their argument is not well grounded.

2945. Where the Eight Parties argument fails is that they were unable to establish that, at any time since December 1, 1993, there was a Resid proxy which was determined to be, or could be determined to be, just and reasonable. While the Circuit Court found that the Commission properly replaced the gravity method with the distillation method, and while the Circuit Court has approved, in either *OXY* or *Exxon*, the Commission's ruling as to all of the remaining cuts, the two different proxies it determined were appropriate for valuing Resid were found to be arbitrary. Analyzed, these rulings indicate that the Commission determined that shippers's streams valued under the gravity method were no longer just and reasonable when it instituted the distillation method and this determination was affirmed by the Circuit Court. However, until now, there has been no proxy to value Resid which has been determined to be just and reasonable. Ergo, the proxy which is determined herein for Resid is the only just and reasonable value for it since December 1, 1993, and it must be made effective on that date notwithstanding any equitable considerations.[871]

2946. In any event, after first glance, the Eight Parties's argument is not convincing. First, their calculations of what financial benefits accrued during the period when replacing the gravity method was under consideration (which they designate the First Period) and the period since December 1, 1993, when the distillation method replaced it (which they designate the Second Period) are questionable.[872] Second, I am not

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[871] I am satisfied, based on a reading of the entire record, that the Resid value established in this Initial Decision is just and reasonable, and was just and reasonable throughout the period from December 1, 1993, forward.

[872] Exxon, on brief, greatly details these problems. *See* Exxon Initial Brief at pp. 371-75. Among other things, it notes that

> [T]he methods and data the Eight Parties used to calculate over- and underpayments for the First Period differ from those they used to do calculations for the Second Period. . . . In calculating over- and underpayments for the Second Period, the Eight Parties rely on the Caleb

convinced that there is a clear delineation between them (as a group) and Exxon with regard to being benefited during the period when the Commission was considering replacing the gravity method. For example, Exxon notes that Dayton agreed that Williams (one of the Eight Parties) as well as Exxon greatly benefited under the gravity method.[873] Moreover, were the Resid proxy determined here only made effective prospectively, Williams also would greatly benefit as well.[874] Furthermore, while Exxon will be owed a refund from the Quality Bank as a result of making December 1, 1993, the effective date of the Resid value established here, so will at least Alaska, BP and Phillips (three more of the Eight Parties).[875] Consequently, contrary to the Eight Parties's assertion, I find it difficult to see how equity demands a decision one way or the other.[876]

> Brett assays to measure stream qualities. By contrast, because the individual streams that comprise the TAPS common stream were not assayed during the First Period, the Eight Parties' calculations for this Period are based on numerous assumptions about the composition of those streams.

Id. at pp. 371-72 (footnote omitted).

[873] At the hearing, Dayton stated that Williams "had a significant benefit as a result of the gravity base" and agreed to characterize that benefit as a "windfall." Transcript at pp. 11884-85.

[874] *See* Exhibit No. EMT-590.

[875] *See* Transcript at pp. 12561-62.

[876] The First Period referred to by the Eight Parties involved the time during which the Commission investigated claims that the API gravity tariff mechanism for the Quality Bank was unlawful. While the Commission eventually determined that it was no longer just and reasonable, it further determined that, as no party violated the previously Commission-approved tariff, the distillation method was made effective on a prospective basis. Here, all parties have been on notice that, under the newly effective distillation method, there has never been a lawful proxy price for the Resid cut. In this decision, the vacuum of uncertainty created by the failure of the Commission to approve an appropriate proxy for the Resid cut from the inception of the distillation method, is filled. Consequently, what is being addressed here is not the replacement of a methodology which is currently in effect and which has been determined to be unjust and/or unreasonable, as during the First Period described by the Eight Parties. Instead, it is a proxy value for Resid to fill in an unknown in the formula used by the Quality Bank under the distillation method previously determined (and unchallenged) to be just and reasonable to value the individual streams which comprise ANS passing through TAPS. Ergo, the Eight Parties's argument that, because refunds were not awarded for the First

2947. In addition, I find unconvincing the Eight Parties's claim that they relied on the Commission's previous orders to operate their businesses and that, as a result, they should not be required to pay refunds into the Quality Bank because they might have operated their businesses differently had the Resid value ordered here been in effect throughout the period. The Eight Parties were aware, from the beginning,[877] that Exxon and Tesoro challenged the Commission's initial determination as to how Resid would be valued for Quality Bank purposes.[878] While they might not have known exactly how Resid eventually would be valued, they were on notice that it probably would not be valued as the Commission first did in 1993 since, at least, the issuance of the *OXY* decision by the Circuit Court in 1995. Under these circumstances, the prudent businessman would have taken steps to protect his business.[879] While the record does not reflect what they did, I assume that the affected members of the Eight Parties are operated by prudent businessmen.[880]

Period, equity requires that they not be awarded for the period since the distillation method became effective amounts to a non sequitur.

[877] Boltz agreed that Petro Star was aware that the Commission's 1993 and 1994 orders were being appealed, and that the Commission denied Exxon's request for a stay stating that it "could subsequently correct any legal errors." Transcript at p. 11711. *See also id.* at pp. 12400-02.

[878] *See Trans Alaska Pipeline System*, 65 FERC at pp. 62,283 and 62,284, n.29.

[879] Toof testified that "a prudent course of action would have been to establish a reserve against such a contingency as Petro Star has done for the Heavy Distillate cut." Exhibit No. EMT-123 at p. 44. *See also* Transcript at pp. 12394-410. I am not suggesting that this course was the only one available to Petro Star, but it certainly is one road that Petro Star could have taken.

[880] The Eight Parties also suggest that implementing the Resid value ordered here as of December 1, 1993, would not put the parties in the same position in which they would have been had the value been determined in 1993. Eight Parties Reply Brief at pp. 143-45. Inasmuch as about 15 years of litigation has passed since this matter first was initiated, and that, over that period, there have been multiple changes in the circumstances involving the ANS fields, the participants, and local, national and worldwide economic conditions, it is hard to argue with their claim. On the other hand, there may be parties injured by the Commission's failure to determine a Resid value which can be judged to be just and reasonable and there may be parties who benefited from those circumstances who should not have. Under these circumstances, the Commission has an obligation to do what it can to put salve on the wounds of those who were injured. It follows, therefore, that refunds, if warranted, must be paid to those who paid too much into the Quality Bank and that those who paid in too little must be billed

2948. As the facts do not support them, neither does the law sustain the Eight Parties's argument. They rely on *Towns of Concord, Norwood & Wellesley v. FERC*, 955 F.2d 67 (D.C. Cir. 1992), to support their claim that refunds are not appropriate here.[881] In that case, the Circuit Court was reviewing a Commission decision not to order refunds to the Towns after Boston Edison unlawfully passed on spent nuclear fuel storage and disposal charges. *Towns of Concord*, 955 F.2d at p. 67. The Circuit Court noted that the Commission found that Boston Edison, for the most part, was not aware that it was passing through unlawful charges. *Id.* at pp. 69, 75. It held that the rule against retroactive ratemaking did not compel the ordering of refunds. *Id.* at p. 75. Moreover, as noted by the Eight Parties, the Circuit Court stated:

> Customer refunds are a form of equitable relief, akin to restitution, and the general rule is that agencies should order restitution only when "money was obtained in such circumstances that the possessor will give offense to equity and good conscience if permitted to retain it." Because the "equitable aspects of refunding past rates are . . . inextricably entwined with the [agency's] normal regulation responsibility," absent some conflict with the explicit requirements or core purposes of a statute, we have refused to constrain agency discretion by imposing a presumption in favor of refunds. The agency need only show that it "considered relevant factors and . . . struck a reasonable accommodation among them," and that its order granting or denying refunds was "equitable in the circumstances of this litigation."

Id. at pp. 75-76 (internal citations omitted).

2949. In the instant case, as noted above, there never was a lawful value for Resid under the distillation methodology. No party was at fault for this. The TAPS Carriers simply administered the Quality Bank using the best information they had available, and everyone was aware that the formula which was being used might be changed through voluntary settlement between the parties, or might not be upheld either by the Commission or by the Circuit Court. Under these circumstances, I find that the equities lean in favor of granting refunds to those who overpaid into the Quality Bank. *See Tarpon Transmission Co.*, 51 FERC ¶ 61,310 at p. 62,028 (1990), *aff'd*, *Natural Gas Clearinghouse v. F.E.R.C.*, 965 F.2d 1066 (1992); *Exxon*, 182 F.2d at p. 49.

2950. Lastly, I acknowledge that the Eight Parties argue that the public interest requires that the Commission not order refunds here. Eight Parties Initial Brief at p. 198.

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for their underpayments.

[881] Eight Parties Initial Brief at pp. 167-69.

However, the public has no interest in this case which solely involves how a pool of money is to be divided amongst multi-billion dollar corporations.

2951. The parties have agreed that, if the new Resid value "is made retroactive to December 1993, the Nine Party Settlement valuations of the other three Remanded Cuts should be retroactive for the period between December 1993 and implementation of the Nine Party Settlement in 1998." Eight Parties Reply Brief at p. 131, n. 58. *See also* Exxon Reply Brief at p. 401, n.265. Furthermore, as noted by the Eight Parties, the West Coast "Heavy Distillate price approved in 1998 was discontinued in 2000, and the [Quality Bank Administrator] was forced to select a replacement." Eight Parties Initial Brief at p. 176, n.99. The parties agreed that "West Coast Heavy Distillate will be valued at the published Platt's West Coast price for Los Angeles Pipeline low sulfur (0.05%) No. 2 Fuel Oil," less the deductions determined in this proceeding, and that the new value shall be effective on February 1, 2000. Joint Stipulation of the Parties, filed October 3, 2002, p. 3.

2952. From the above, it is clearly appropriate that the Quality Bank Administrator re-calculate the Quality Bank from December 1993 forward and make appropriate refunds.[882] However, as it is clear that the TAPS Carriers are not liable for payment of such refunds, in the event that collections, less costs, do not equal the refunds due, such refunds are to be made on a pro rata basis. *See* Joint Exhibit No. 12 at P 1, 2. This procedure was suggested by the TAPS Carriers and not objected to by any party. *See* TAPS Carriers Initial Brief at pp. 23-24; Joint Exhibit No. 12 at P 3.

ISSUE NO. 9: ARE REPARATIONS AN ISSUE IN THIS PROCEEDING? IF SO, WHAT REPARATIONS, IF ANY, ARE APPROPRIATE?

A. LEGAL STANDARD

2953. According to the Eight Parties, Issue No. 9 is based on Exxon's claim for money damages, or reparations, for the period beginning June 19, 1994, two years before the filing of Exxon's complaint in Docket No. OR96-14-000, and extending to the date of a decision in this case. Eight Parties Initial Brief at p. 209. They explain that Exxon's witnesses calculated the difference between Exxon's actual Quality Bank receipts and what those receipts would have been had the Naphtha and VGO cuts been valued during the relevant time period using prices for Naphtha and VGO which Exxon now claims

[882] Such a holding is consistent with the commitment the Commission made in 1994 to correct any errors it made in replacing the gravity method with the distillation method. *See Trans Alaska Pipeline System*, 66 FERC at p. 61,423.

should have been used. *Id.* The reparations claim, explain the Eight Parties, is limited to the Naphtha and VGO cuts and is based on the reparations provisions of the Interstate Commerce Act. *Id.* Exxon's reparations claim for Naphtha totals some $64 million through 2002, offset by a negative $30 million (credit) for VGO reparations, for a net of some $34 million. *Id.*

2954. It is the Eight Parties's position that reparations are not properly at issue in this case because Exxon failed to establish a legal basis for the Commission to consider such a claim. *Id.* at pp. 209-10. In the first place, the Eight Parties assert, the Commission's prior rulings respecting the Naphtha and VGO cuts preclude any retroactive adjustment to those cuts. *Id.* at p. 210. Second, the Eight Parties point out that Exxon has not filed a complaint which qualifies under Section 13(1) of the Interstate Commerce Act for a reparations award for improper valuation of the Naphtha and VGO cuts. *Id.* Third, the award of reparations is an equitable remedy, and the Eight Parties believe that equitable considerations preclude granting Exxon's reparations claim. *Id.* Accordingly, the Eight Parties urge that reparations be denied. *Id.*

2955. The Eight Parties explain that the TAPS Quality Bank in its current form uses Gulf Coast prices to value West Coast volumes for both the Naphtha and VGO cuts. *Id.* In setting these values, state the Eight Parties, the Commission ruled that it was determining these issues as its own resolution of the Quality Bank, based on the hearing record and pursuant to its authority under the Interstate Commerce Act. *Id.* The Eight Parties point out that the Commission's ruling as to these two cuts was not disturbed on appeal, and no party appealed either valuation. *Id.*

2956. Such previously approved cut valuations in the existing TAPS Quality Bank methodology enjoy the protection of the filed rate doctrine, according to the Eight Parties. *Id.* The filed rate doctrine, assert the Eight Parties, precludes any retroactive change to a rate that has been previously approved by the Commission. *Id*. Accordingly, were the Commission to adopt Exxon's proposals for valuing the Naphtha and VGO cuts, the Eight Parties argue, it could not make those changes effective retroactively from the date of its decision. *Id.* at pp. 210-11. They urge that any change to the previously approved methodology be made only on a prospective basis. *Id.* at p. 211.

2957. The Eight Parties point out that the *OXY* court explained that the Interstate Commerce Act reflects the filed rate doctrine and the rule against retroactive ratemaking. *Id.* Under Section 15(1) of the Interstate Commerce Act, note the Eight Parties, the Commission is empowered to hold hearings upon a complaint to review a rate, and to set a new rate if it finds the existing rate to be unjust and unreasonable or unduly discriminatory. *Id.* However, it can only set the rate "to be thereafter observed." *Id.* (quoting 49 U.S.C. App. § 15(1)(1988)). Therefore, the Eight Parties assert, the Commission cannot order a retroactive rate change. *Id.* Similarly, the Eight Parties explain, the Commission may proceed under Section 13(2) of the Interstate Commerce

Act by its own motion to investigate rates, but it is prohibited from issuing "orders for the payment of money." *Id.* (quoting 49 U.S.C. App. § 13(2)(1988)). Section 15(7) authorizes the Commission to order refunds, but the Eight Parties assert that authority applies only to rate increases proposed by a carrier that are suspended by the Commission pending an investigation. *Id.* According to the Eight Parties, Section 15(7) does not apply to previously approved rates. *Id.*

2958. Recognizing that refunds are not available for the Naphtha and VGO cuts, the Eight Parties point out, Exxon has characterized its claim for retroactive relief for these cuts as reparations, thereby distinguishing them from the Resid and Heavy Distillate cuts. *Id.* The Eight Parties explain that a claim for reparations arises under Sections 8, 9 and 13(1) of the Interstate Commerce Act. *Id.* Sections 8 and 9 allow a person injured by a carrier's violation of the Act to sue the carrier for damages sustained as a result of the violation, according to the Eight Parties, while Section 13(1) allows such complaints to be filed with the Commission. *Id.* The Eight Parties note that the statute provides that a carrier can avoid liability under Section 13(1) by making reparation for the injury alleged, 49 U.S.C. App. § 13(1)(1988), hence the name for this type of relief. *Id.* at pp. 211-12. Under Section 13(1), state the Eight Parties, a shipper bears the burden of proof to show that the rate paid violated the Interstate Commerce Act and that the shipper suffered damage as a result. *Id.* at p. 212. If the shipper meets that burden, then, the Eight Parties explain, the Commission has discretion to order the carrier to pay reparations. *Id.*

2959. The Eight Parties note that the Interstate Commerce Act indicates that a reparations claim has the following elements: (1) an allegation that a carrier has violated the Act; (2) proof that the claimant has sustained injury as a result of the violation; and (3) reparation for the injury paid by the carrier. *Id.* With respect to showing a violation of the Act, the Eight Parties assert that, if the rate that the shipper challenges is a carrier-initiated rate on file with the Commission, it may nevertheless be unlawful if it is proven in the reparations hearing to be an unjust and unreasonable rate or an unduly discriminatory or preferential rate. *Id.*

2960. According to the Eight Parties, the required elements of a Section 13(1) claim are not present in this case. *Id.* at p. 213. They explain that neither Toof nor Pavlovic make any claim in their testimony that the TAPS Carriers have violated any provisions of the Act or any terms of their tariffs. *Id.* Further, note the Eight Parties, neither witness asserts that Exxon has suffered damages as a result of such a violation. *Id.* Instead, point out the Eight Parties, the claim is based on the assertion that the rate itself is not just and reasonable, even though it was previously approved by the Commission. *Id.* They maintain, however, that Section 13(1) of the ICA does not allow this type of collateral attack or end-run around the filed rate doctrine. *Id.*

2961. The Eight Parties state that Exxon relies primarily on *I.C.C. v. United States*, 289 U.S. 385 (1933) for its assertion that it need only show that the rate complained of is not just and reasonable and that reparations flow automatically as an entitlement from such a showing. Eight Parties Reply Brief at p. 171 (citing Exxon Initial Brief at pp. 382-83, 388). According to the Eight Parties, while Exxon's proposition provides the measure of damages for certain types of reparations claims, it does not provide a complete or accurate description of the law of reparations under the Act, nor is it applicable to the claim made here. *Id.* First, the Eight Parties declare that *I.C.C. v. United States* is inapplicable to the facts of this case, because it did not involve a claim that a rate paid by the claimant was not just and reasonable. *Id.* at pp. 171-72.

2962. More on point, according to the Eight Parties, is *Louisville & Nashville R.R. Co. v. Sloss-Sheffield Steel & Iron Co*., 269 U.S. 217, 235 (1925). *Id*. at p. 172. The Eight Parties state that this case makes sense out of apparently inconsistent holdings in various cases by explaining that a different standard for proof of damages applies depending on which section of the Interstate Commerce Act gives rise to the reparations claim. *Id*. (citing 269 U.S. at p. 235). They explain that, if a claimant sues for reparations because of rebates, or discrimination in rates, or violation of the longhaul/short-haul rule, special proof of specific injury arising from the violation is required. *Id*. If, continue the Eight Parties, the claim arises under Section 1(5), 49 U.S.C. App. § 1(5)(1988), which requires that all rates be just and reasonable, then the measure of damages is the difference between the rate paid and the just and reasonable rate that should have been paid and further proof of loss is not required. *Id*. at pp. 172-73; Eight Parties Initial Brief at pp. 216-17.

2963. Nonetheless, according to the Eight Parties, even correctly identifying the measure of damages for a potential reparations claim does not establish an entitlement to those damages. Eight Parties Reply Brief at p. 173. They state that the primary case barring any reparations claim for the Naphtha and VGO cuts is *Arizona Grocery* and assert that neither Exxon's contention that the Commission has yet to prescribe lawful rates for all features of the distillation methodology, nor its contention regarding the quality of the record underlying its previous rulings on the Naphtha and VGO cuts, renders *Arizona Grocery* inapplicable. *Id.* at pp. 173-74.

2964. The Eight Parties note that Exxon argues that the Commission will not have prescribed rates within the meaning of *Arizona Grocery* until all of the issues remanded for legal error are resolved. *Id.* at p. 174. They assert that there are several defects to this argument. *Id.* In the first place, the Eight Parties point out, the *OXY* court has explicitly ruled that the Commission's Quality Bank rulings made after hearing amount to Commission prescribed rates. *Id.* (citing *OXY*, 64 F.3d at p. 699). Secondly, the Eight Parties note that the *Exxon* court has already rejected the argument that the TAPS Quality Bank methodology is *sui generis*, an argument used by the Commission to attempt to justify its decision not to make certain changes to the method retroactive. *Id.* (citing *Exxon*, 182 F.3d at p. 49). Exxon cites this holding in support of its position, state the Eight Parties, and claims that the *sui generis* argument has no bearing on the issue of retroactive relief. *Id.* at pp. 174-75 (citing Exxon Initial Brief at p. 345).

2965. Exxon, the Eight Parties state, is making the same argument in advocating for reparations in an attempt to avoid the effect of *Arizona Grocery*. *Id.* at p. 175. They assert that Exxon's attempt fails because its argument ignores the explicit wording of *Arizona Grocery* and proceeds from a misunderstanding of the holding in that case. *Id.* In *Arizona Grocery*, state the Eight Parties, the Interstate Commerce Commission, acting on a complaint and after a hearing, set a maximum rate for the carrier. *Id.* They note that the carrier, in response, set a new rate below the maximum which was also challenged. *Id.* In proceedings on the new complaint, continue the Eight Parties, the Interstate Commerce Commission determined that the just and reasonable rate, both for the past and future, was lower than the previously ordered maximum and ordered that reparations be paid for the difference between what had been paid, 84¢, and the just and reasonable rate of 71¢. *Id.* The Eight Parties explain that the Supreme Court reversed and held that reparations could not be awarded under the facts of the case. *Id.* (citing *Arizona Grocery*, 284 U.S. at p. 390). They assert that the Supreme Court stated that the Interstate Commerce Commission has two different functions, legislative and judicial, and that when it prescribes rates, it is acting in a legislative function. *Id.* at p. 176. If the Interstate Commerce Commission later, in its judicial function, reviews those rates, it can repeal them and prescribe new rates for the future, but, note the Eight Parties, it cannot repeal its prior legislative enactment with retroactive effect. *Id.* (citing 284 U.S. 389).

2966. Further, the Eight Parties point out, the Supreme Court made no distinction between rate methodologies that have been fully worked out and those that are only partially finalized. *Id.* According to them, Exxon cites no authority for the proposition that *Arizona Grocery* is inapplicable if all aspects of a methodology have not been finally determined. *Id.* Rather, explain the Eight Parties, the critical element relied upon by the Supreme Court is that the prior rate be prescribed by the Commission after a hearing, so that the Commission's legislative function is triggered. *Id.* When the Commission acts in its legislative function, they state, its determination of the legal rate has the force of a statute and cannot be later challenged any more than could an act of Congress setting those rates. *Id.* (citing 284 U.S. at pp. 386, 388).

2967. According to the Eight Parties, that is exactly what happened in this proceeding. *Id.* They assert that the Commission was exercising its legislative function when it prescribed the Naphtha and VGO rates after a hearing. *Id.* The Eight Parties point out that the Commission explicitly declared that it was setting these rates as "the Commission's own independent resolution of the matters at issue." *Id.* at pp. 176-77 (65 FERC at p. 62,290). Whether or not the Naphtha and VGO valuations are part of a larger methodology that is not final is therefore irrelevant, argue the Eight Parties, because the Commission adopted these specific rates in the exercise of its legislative function. *Id.* at p. 177.

2968. The Eight Parties suggest that the non-final argument is not persuasive because the basic methodology, and all but one of its elements, has been approved, implemented, and sustained on judicial review. *Id.* According to the Eight Parties, the result of the *Exxon* and *OXY* cases is that the valuation of eight out of nine cuts, all cuts except Resid, has been finally approved. *Id.* Moreover, note the Eight Parties, in *Exxon*, the Circuit Court did not remand the Resid cut along with instructions to reexamine the entire methodology in light of any changes made to the Resid valuation. *Id.* To the contrary, assert the Eight Parties, the Circuit Court upheld the Commission's decision on all other cuts and remanded only those portions of the Commission's order dealing with the Resid cut and the issue of retroactive effect for remanded cuts. *Id.* Further, explain the Eight Parties, the two appeals of the Commission's implementation decisions did not disturb or remand the Naphtha and VGO cuts. *Id.* Thus, the Eight Parties maintain that arguing that the methodology has not been finally resolved is inconsistent with the *OXY* and *Exxon* rulings, which have treated the methodology as having been finally resolved for all cuts except the Resid cut. *Id.*

2969. Exxon states the reparations issue relates solely to the valuation of the West Coast Naphtha and VGO cuts. Exxon Initial Brief at p. 380. It notes that all parties agree that the current method of valuing the West Coast VGO cut on the basis of the OPIS Gulf Coast spot price for high sulfur VGO does not produce a just and reasonable result, and that the proxy price for valuing the VGO cut on the West Coast should be changed to the OPIS West Coast spot price for high sulfur VGO. *Id.* at pp. 380-81. It is also undisputed, according to Exxon, that this West Coast VGO price has been significantly different from the OPIS Gulf Coast High Sulfur VGO price that has served as the Quality Bank proxy price for West Coast VGO since December 1993, with the West Coast price at times being $9 per barrel higher than the Gulf Coast price.[883] *Id.* at p. 381. Exxon states that it, along with Alaska and Phillips, contend that West Coast Naphtha prices over the past decade have differed substantially from Gulf Coast Naphtha prices and, indeed, generally have been significantly higher than Gulf Coast Naphtha prices.[884] *Id.* As a result, these parties, Exxon states, maintain that the Quality Bank has substantially undervalued West Coast Naphtha. *Id.* According to Exxon, the issue of reparations must be evaluated with this background in mind. *Id.*

2970. These parties, Exxon asserts, have demonstrated that they are entitled to an award of reparations based on the difference between the West Coast Naphtha and VGO values that have been in effect and the values for those cuts ultimately determined to be lawful.

[883] Exxon cites Exhibit Nos. EMT-11 at p. 25, and EMT-25 to support this statement. Exxon Initial Brief at p. 381, n.157.

[884] Exxon cites Exhibit Nos. EMT-380 and SOA-28 in support. Exxon Initial Brief at p. 381, n.158.

Exxon Reply Brief at pp. 442-43. According to Exxon, the Eight Parties acknowledge that the Commission has awarded reparations in the past. *Id.* at p. 443. It notes that the Eight Parties nonetheless advance four arguments in support of their contention that reparations should not be awarded in this case: (1) that reparations claims have not been properly raised; (2) that reparations are barred by *Arizona Grocery*; (3) that there are other legal defects in the claims for reparations; and (4) that equity should bar an award of reparations. *Id.* Exxon asserts that none of these arguments is correct. *Id.*

2971. Furthermore, Exxon states, the Eight Parties have wholly failed to address an independent ground for retroactive relief with respect to the Naphtha and VGO valuations. *Id.* Even if reparations are not awarded, Exxon argues, the Circuit Court's decision in *Tennessee Valley Mun. Gas Assoc. v. Federal Power Com'n*, 470 F.2d 446 (D.C. Cir. 1972), requires retroactive application of the revised Naphtha and VGO values to compensate Exxon for the financial loss it suffered arising from the erroneous dismissal of the Exxon and Tesoro complaints. *Id.* Exxon's position is that it is clear that the Commission has both the legal authority and compelling evidence to award reparations for the West Coast Naphtha and VGO cuts. *Id.*

2972. According to Exxon, reparations is the term given to relief provided under Section 16 of the Interstate Commerce Act, in response to a complaint filed by a shipper under Section 13(1) of the Act, for damages sustained for payment of existing rates that are ultimately found not to be just and reasonable.[885] Exxon Initial Brief at pp. 381-82. Further, Exxon states, the parties are in agreement that the Commission has in the past awarded reparations based on the difference between rates actually paid and rates that should have been paid. Exxon Reply Brief at pp. 443-44. The basic standard for an award of reparations, in Exxon's view, is well-settled. Exxon Initial Brief at p. 382. It asserts that this standard is found in *I.C.C.*, 289 U.S. at p. 390, where the Supreme Court said recovery of the difference between the unlawful rate and the lawful is the measure of damages and no other evidence of loss need be shown.[886] *Id.* Exxon cites three cases that

[885] By contrast, according to Exxon, where a new or changed rate is initiated by a pipeline carrier, Section 15(7) of the Interstate Commerce Act authorizes the Commission to suspend the effectiveness of the proposed rate for up to seven months, and to order refunds, with interest, of that portion of the rates not justified. Exxon Initial Brief at p. 382, n.159.

[886] Exxon also cites the following cases in support of this point: *Louisville & Nashville R.R. Co. v. Sloss-Sheffield Steel & Iron Co.*, 269 U.S. 217, 235 (1925); *Chicago, Milwaukee, St. Paul & Pacific R.R. Co. v. Alouette Peat Products*, 253 F.2d 449, 455 (9th Cir. 1957) (holding that "if this filed rate was proved to be unreasonable upon complaint to the Commission, the shipper was entitled to recover the difference between what he had paid and what the Commission found to be the reasonable rate"). Exxon Initial Brief at p. 382, n.160.

it asserts reflect this standard.[887] *Id.* Thus, according to Exxon, the predicate for a successful claim for reparations is a showing that the rate complained of is not just and reasonable. *Id.* at pp. 382-83. The burden of proof as articulated in court cases, explains Exxon, is on the shipper. *Id.* at p. 383.

2973. Under Section 16 of the Interstate Commerce Act, as interpreted by Exxon, a shipper may be awarded reparations for up to two years prior to the date on which a complaint was filed. Exxon Initial Brief at p. 383; Exxon Reply Brief at p. 444 (citing 49 U.S.C. App. § 16(3)(b)(1998)). In addition, notes Exxon, the reparations period may extend to the date revised rates are put into effect prospectively. Exxon Initial Brief at p. 383 (citing *SFPP, L.P.*, 86 FERC ¶ 61,022 at p. 61,113 (1999)).

2974. Exxon points out that reparations have traditionally been considered an equitable remedy, within the Commission's discretion. *Id.* It notes that, in deciding whether to award reparations, the Commission cannot exercise its discretion in an arbitrary or capricious manner. *Id.* Among other things, the Commission must adhere to guidelines set down in other reparations cases, or explain why those guidelines are inapplicable in the instant case. *Id.*

2975. Although there is agreement on these fundamental legal standards, Exxon asserts, each of the four arguments advanced by the Eight Parties rests on demonstrably erroneous legal contentions and factual misrepresentations. Exxon Reply Brief at p. 445. First, explains Exxon, the Eight Parties's argument that reparations claims have not been properly raised is belied by the plain language of Exxon's and Tesoro's complaints and the *Tesoro* decision, and is founded on a clear misinterpretation of the *SFPP* cases and the *Exxon* decision. *Id.* Second, continues Exxon, the Eight Parties's *Arizona Grocery* argument is founded on a misapplication of that case to the circumstances presented here, in which the Commission has yet to prescribe lawful rates through a distillation methodology. *Id.* Third, comments Exxon, the Eight Parties's argument that there are other legal defects in the claims for reparations ignores the plain language of several Interstate Commerce Act provisions (notably §§ 1(5), 8, 9 and 13(1)) and the Commission's consistent decisions awarding reparations under those provisions, and rests on patent misinterpretations of the Commission's decisions in *Trans Alaska Pipeline System*, 65 FERC ¶ 61,277 at p. 62,292 (1993) and *Conoco, Inc. v. Trans Alaska Pipeline System*, 72 FERC ¶ 61,007 at p. 61,013 (1995). Exxon Reply Brief at p. 445. Fourth,

[887] *Union Oil Co. of California v. Cook Inlet Pipe Line Co.*, 71 FERC ¶ 61,300 at p. 62,184 (1995); *see also Kerr-McGee Refining Corp. v. Williams Pipe Line Co*., 63 FERC ¶ 61,349, at p. 63,224 (1993); *see also SFPP, L.P.*, 96 FERC ¶ 61,281, at p. 62,071 (2001). Exxon Initial Brief at p. 382, n.161. In light of these decisions, claims Exxon, the Eight Parties are flatly wrong when they suggest (Exhibit No. PAI-47 at p. 7) that it must prove lost sales and profits to make out a claim for reparations. Id.

concludes Exxon, the Eight Parties's argument that equity should bar an award of reparations is based on a demonstrably false premise – that the Eight Parties were not on notice until 2002 that Exxon was seeking reparations. *Id.* at pp. 445-46.

2976. The TAPS Carriers state that no retroactive relief, including reparations, may be awarded against the TAPS Carriers. TAPS Carriers Initial Brief at p. 26. In addition, they note, the complainants in this proceeding have clarified that they do not seek the assessment of reparations against the TAPS Carriers. *Id.* So long as the reparations sought by Exxon consist of payments from other shippers, the TAPS Carriers take no position on whether, against whom, or in what amount such reparations should be assessed. *Id.* With respect to the assessment of reparations against them, the TAPS Carriers assert, the Commission has no authority to award such reparations in these circumstances. *Id.* They maintain that they are required to comply with Commission orders and, as long as they comply with such orders, *Arizona Grocery*[888] supports their contention that they cannot be subject to liability for such compliance. *Id.* Because the Commission has prescribed the Quality Bank methodology, the TAPS Carriers state, they cannot be required to pay reparations unless they had violated their tariffs. *Id.* at pp. 26-27. (quoting *Conoco, Inc. v. Trans Alaska Pipeline System*, 72 FERC at p. 61,013. The TAPS Carriers state there is no evidence of any such violation. *Id.* at p. 27.

2977. Commission Staff points out that Section 13(1) of the Interstate Commerce Act provides for the resolution of complaints concerning "anything done or omitted to be done by any common carder subject to the provisions of this chapter in contravention of the provisions thereof." Staff Initial Brief at p. 4 (quoting 49 U.S.C. App. §13(1)(1988)). Therefore, notes Staff, the section provides for reparations by recognizing that a carrier will be relieved from liability for a complaint if the carrier "shall make reparation for the injury alleged to have been done." *Id.* (quoting 49 U.S.C. App. §13(1)(1988)). Further, notes Staff, Sections 8 and 9 of the Interstate Commerce Act permit suits against common carriers subject to the act for damages; however, Section 9 requires an election as to whether to sue or pursue a complaint before the Commission. *Id.*

2978. Staff further explains that the right to reparations is of statutory origin. *Id.* There can be no recovery of reparations, continues Staff, without damage to the claimant from the unreasonable rate or conduct of a carrier. *Id.* Consequently, Staff asserts, in order to recover reparations, a claimant must show some loss caused by a carrier's rates, practices or conduct that is unlawful. *Id.* In the present case, notes Staff, "for reparations to be awarded, there would have to be a finding of conduct in violation of the quality bank [sic] tariff." *Id.* at pp. 4-5 (quoting *Conoco*, 72 FERC at p. 61,013).

[888] *Arizona Grocery,* 284 U.S. at pp. 387-90.

B. STIPULATED MATTERS AND AREAS OF DISPUTE

2979. The Eight Parties explain that all parties stipulated that Exxon's reparations claim shall apply only to the West Coast VGO and Naphtha cuts. Eight Parties Initial Brief at p. 213. However, they argue that the December 14, 2001, stipulation signed by Exxon and the TAPS Carriers is inconsistent with the elements of a reparations claim. *Id.* In it, point out the Eight Parties, the signatories state that the TAPS Carriers have not violated the Interstate Commerce Act except to the extent that any implementation of Quality Bank changes ordered by the Commission may be a violation of the Act. *Id.* Further, note the Eight Parties, Exxon has stipulated that the Carriers have not violated their tariffs. *Id.* Clearly, in the Eight Parties view, Exxon has, by these stipulations, conceded that the TAPS Carriers have not violated the Interstate Commerce Act. *Id.* at pp. 213-14. Rather, according to the Eight Parties, their complaint appears to be that the Commission has violated the Interstate Commerce Act by putting in place an unjust and unreasonable rate, a matter that does not come within the scope of Sections 8, 9 and 13(1) of the Act. *Id.* at p. 214. In addition, the Eight Parties note that Exxon has stipulated that it is not seeking relief from the TAPS Carriers but instead is seeking a retroactive rate adjustment, to the extent that the TAPS Carriers can implement such an adjustment. *Id.*

2980. The Eight Parties note that Exxon contends that *Arizona Grocery* does not apply to the Naphtha and VGO valuations, because the Quality Bank methodology is not a Commission prescribed rate. Eight Parties Reply Brief at p. 178 (citing Exxon Initial Brief at pp. 393-396, 404). However, the Eight Parties point out, by stipulation entered into evidence in this case, Exxon has conceded that the Naphtha and VGO values are a Commission prescribed rate. *Id.* (citing Joint Exhibit No. 12 at ¶ 1). Clearly, state the Eight Parties, a rate that the Carriers were directed to implement is a Commission-prescribed rate. *Id.* The Eight Parties explain that the TAPS Carriers were legally obligated to abide by the Commission orders to implement the Naphtha and VGO valuations. *Id.* (citing *Arizona Grocery*, 284 U.S. at p. 387; *Atl. Coast Line R.R. Co. v. Florida*, 295 U.S. 301, 311 (1935)).

2981. Having stipulated that the TAPS Carriers have not violated the Commission approved Quality Bank tariff, that relief against the TAPS Carriers is not its goal, and because the Naphtha and VGO rates are final within the meaning of *Arizona Grocery*, the Eight Parties assert, there can be no basis for a reparations claim under the Interstate Commerce Act. Eight Parties Initial Brief at p. 214; Eight Parties Reply Brief at p. 178.

2982. According to Exxon, the parties have stipulated that Exxon's and Tesoro's claims for reparations shall apply only to the West Coast Naphtha and VGO cuts. Exxon Initial Brief at p. 384. It also notes that the parties have stipulated that, if a West Coast Naphtha valuation is adopted in this proceeding that is different from the West Coast Naphtha valuation that was put into effect in December 1993, such revised West Coast Naphtha valuation and the revised West Coast VGO valuation to which the parties have stipulated should have the same effective date. *Id.* In addition, Exxon states that it and Tesoro also have executed a separate stipulation with the TAPS Carriers to clarify the nature and scope of the reparations relief the two companies are seeking in their complaints. *Id.*

2983. In particular, Exxon states, it has stipulated that its contention that the TAPS Carriers have violated the Interstate Commerce Act is limited to the TAPS Carriers's implementation of the Quality Bank methodology, which has not produced just and reasonable results. Exxon Reply Brief at p. 446. It asserts that, contrary to the Eight Parties's argument (Eight Parties Initial Brief at pp. 213-14), this stipulation does not constitute a concession by it that there is no basis for a reparations claim. *Id.*

2984. Exxon argues that the Eight Parties's claim in this regard is based on several misstatements of law and misrepresentations of fact. *Id.* First, notes Exxon, the Eight Parties assert that there is no basis for a reparations claim because Exxon allegedly conceded in the stipulation that the TAPS Carriers have not violated their Quality Bank tariffs. *Id.* at pp. 446-47. However, it maintains, a tariff violation is not an essential element of a reparations claim, like Exxon's, which is based upon payment of unjust and unreasonable rates. *Id.* at p. 447. Second, Exxon states, the Eight Parties claim that reparations should not be awarded here because Exxon's goal is not relief against the Carriers is baseless. *Id.* In fact, Exxon points out that the captions of Exxon's complaints make clear that each complaint expressly seeks relief against the TAPS Carriers. *Id.*

2985. Further, Exxon argues, the Eight Parties misrepresent this stipulation as a concession on the part of Exxon that the TAPS Carriers have not violated the Interstate Commerce Act, and they misrepresent Exxon's complaints as contending only that the Commission has violated the Act, a matter which is outside the scope of a reparations claim. *Id.* In fact, states Exxon, both of the complaints and the stipulation clearly state that the TAPS Carriers have violated the Act by implementing a Quality Bank methodology, and specific elements thereof, that are not just and reasonable. *Id.* Moreover, continues Exxon, any doubt about whether this matter is within the scope of the Interstate Commerce Act is removed by Section 1(5), 49 U.S.C. App. § 1(5)(1988), which declares that "every unjust and unreasonable charge . . . or any part thereof is . . . declared to be unlawful," and Section 8, 49 U.S.C. App. § 8 (1988), which provides that a carrier is liable for a violation of the ICA every time it "shall do, cause to be done, or permit to be done any act . . . declared to be unlawful" or "omit[s] to do any act, matter, or thing in this chapter required to be done." *Id.* at pp. 447-48. It follows, according to Exxon, that the TAPS Carriers would be liable for violating the Act where, as alleged here, they charged an unreasonable rate, caused an unreasonable rate to be charged, or permitted an unreasonable rate to be charged. *Id.* at p. 448.

2986. There is also no dispute, according to the TAPS Carriers, over the fact that they have fully complied with the terms of their interstate tariff and prior Commission orders in their implementation of the various Quality Bank methodologies. TAPS Carriers Initial Brief at p. 28. They assert that all prior allegations that the TAPS Carriers had not complied with their respective tariffs have been settled and are no longer at issue in these proceedings. *Id.* (citing *Trans Alaska Pipeline System, Letter Orders Regarding Uncontested Partial Settlement* Filed May 13, 1997, (Aug. 4, 1997)). In fact, the TAPS Carriers point out, that Exxon has stipulated that the only violations of the ICA that it is alleging consist of compliance with the Commission's orders. *Id.* (citing Joint Exhibit No. 12 at p. 1).

2987. The TAPS Carriers deny that they have violated the Interstate Commerce Act by implementing a Quality Bank methodology that they have been ordered by the Commission to implement. *Id.* at p. 29. The Interstate Commerce Act requires that the TAPS Carriers comply with the Commission's orders. *Id.* (citing 49 U.S.C. app. §§ 16(7)-(8)(1988)). That issue is moot, according to the TAPS Carriers, given the stipulation by Exxon and Tesoro that they are not seeking any payments from the TAPS Carriers themselves. *Id.* (quoting Joint Exhibit No. 12 at P 3).

2988. The TAPS Carriers note that any party could have pursued a claim that reparations were due from them but chose not to do so. *Id.* at p. 30. As a result, they argue, there is no issue among the parties regarding any claim for reparations from them. *Id.* The TAPS Carriers take no position as to whether Exxon or Tesoro may recover reparations from other shippers. *Id.*

2989. According to Staff, Joint Exhibit No. 12 is a stipulation among the parties which limits the applicability of any reparations claims to the West Coast VGO and Naphtha cuts. Commission Staff Initial Brief at p. 5. Further, explains Staff, the Joint Exhibit also provides that there is no contention "that the TAPS Carriers have violated the Interstate Commerce Act except to the extent that implementation of the Quality Bank methodology that the [Commission] has directed the TAPS Carriers to implement constitutes such a violation." *Id.* at p. 5 (quoting Joint Exhibit No. 12 at P 1). In addition, the Staff points out that paragraph 3 of Joint Exhibit No. 12 clarifies that any reparation claims are for any over collections by other shippers under the Quality Bank methodology in effect during the relevant period if the Commission finds that methodology was unjust and unreasonable and that a different methodology should have been in effect during that period. *Id.* It adds that paragraph 3 of the stipulation further clarifies that reparations are not sought from the TAPS Carriers's own funds. *Id.*

C. SHOULD REPARATIONS BE AWARDED?

2990. The position of the Eight Parties is that reparations should not, and cannot, be awarded in this case. Eight Parties Reply Brief at p. 191. They assert that there is no legal basis under the Interstate Commerce Act to award the reparations sought by Exxon.

Id. Furthermore, even if there were no clear legal impediment to reparations, the Eight Parties argue, reparation relief should be denied for equitable reasons. *Id.*

2991. According to the Eight Parties, Exxon asserts that there was no evidentiary support for the Commission's 1993 and 1994 determinations of the Naphtha and VGO values, and that *Arizona Grocery* does not apply if the prior rate determination lacked evidentiary support. Eight Parties Reply Brief at p. 179. They state that this is a misstatement of both the law and the facts. *Id.* In the Eight Parties's view, if Exxon wanted to attack the underlying evidentiary support for those rulings, it should have filed an appeal in 1994. *Id.* As no such appeal was filed, they claim, therefore, the time to dispute the Commission's ruling on Naphtha and VGO has long passed. *Id.* (citing *Trans Alaska Pipeline System*, 57 FERC at pp. 65,040-41). Instead, note the Eight Parties, the Commission's decision was appealed on other grounds and affirmed by the Circuit Court on the Naphtha and VGO cut valuations. *Id.*

2992. In lieu of appealing the propriety of the Commission's 1993-1994 rulings on the Naphtha and VGO cuts, the Eight Parties explain that Exxon recommended, in various proposals, that Gulf Coast prices be used to value West Coast products. *Id.* They note that Exxon argued in sworn testimony, in 1997, that Gulf Coast natural gas liquid prices should be used to value West Coast natural gas liquids. *Id.* According to the Eight Parties, Exxon proposed in sworn testimony in 1996 and 1997 a distillation methodology for the Golden Valley Electrical Association interconnection that employed Gulf Coast prices for West Coast Naphtha, West Coast VGO and all other cuts of the methodology. *Id.* The Eight Parties point out that Exxon maintained this position as late as the year 2000. *Id.* at pp. 179-80. For Exxon to now claim that "no party had even suggested — much less presented any evidence — that the price for a product on one Coast was a reasonable basis for valuing that product on the other Coast," is, in the Eight Parties's view, entirely disingenuous. *Id.* at p. 180 (quoting Exxon Initial Brief at pp. 396-97).

2993. In addition, the Eight Parties argue that Exxon's collateral attack on the Commission's 1993-1994 rulings is legally impermissible and that *Arizona Grocery* explicitly so held. *Id.* In that case, state the Eight Parties, the Interstate Commerce Commission had argued that it was free to revisit its earlier determination that the 96.5¢ rate was just and reasonable, because the doctrine of *res judicata* did not apply to its earlier determination. *Id.* The Supreme Court held that the Commission was confused, note the Eight Parties, and that, while the Commission was not bound by *res judicata*, it was nevertheless "bound to recognize the validity of the rule of conduct prescribed by it and not to repeal its own enactment with retroactive effect." *Id.* (quoting 284 U.S. at p. 389). Here, assert the Eight Parties, the entire thrust of Exxon's argument is to do exactly that: to show that the earlier record was inadequate and that new evidence shows that "single market pric[ing]" is invalid. *Id.* (quoting Exxon Initial Brief at pp. 397-98). In the Eight Parties opinion, this is precisely the type of collateral attack that *Arizona Grocery* should prevent. *Id.*

2994. Finally, the Eight Parties state, Exxon suggests that *Arizona Grocery* allows a reopening of the prior determination of a rate if the evidence upon which it is based "clearly fails to support it." *Id.* (quoting Exxon Initial Brief at p. 397 n.179). The Eight Parties assert that this is wrong and that Exxon is using the cite from *Arizona Grocery* incorrectly. *Id.* at pp. 180-81. They believe that, while the quote does appear in the case, it is clear from the context of the cite that the Supreme Court was referring to judicial review in a direct appeal of a final agency determination and not to revisiting the issues underlying the prior rate determination in a subsequent agency proceeding. *Id.* at p. 181. In a footnote in *Arizona Grocery*, state the Eight Parties, the Supreme Court explained that when the Commission speaks in its legislative capacity, its rate could be declared void for violating the Constitution, just as a statute can, and that there is an additional element "that the courts will examine the question whether the administrative agency of the legislature has exceeded its statutory powers . . . or has based its order upon a finding without evidence or upon evidence which clearly fails to support it." *Id.* (quoting 284 U.S. at p. 386, n.15). Clearly, according to the Eight Parties, the Supreme Court was referring to judicial review of an agency decision pursuant to a timely appeal of the decision, and was not legitimizing the type of collateral attack being launched by Exxon some eight years after the rate was set. *Id.* It is the Eight Parties's position that, because Exxon chose, in 1994, not to appeal the Commission's Naphtha and VGO rulings, it gave up the right to challenge the evidentiary support for those rulings. *Id.*

2995. The Eight Parties state that Exxon's claim is something other than a reparations claim because (1) it is based on an allegation that a Commission mandated rate violates the Interstate Commerce Act, not on an allegation that the TAPS Carriers have violated the Act, and (2) the relief requested is not from the TAPS Carriers but from other shippers. *Id.* They note that Exxon argues that it has satisfied the first element because the Naphtha and VGO cut valuations can violate Section 1(5) of the Interstate Commerce Act even if they were established by the Commission and that it has satisfied the relief element because the TAPS Carriers act as a "conduit for Quality Bank payments among TAPS shippers." *Id.* (quoting Exxon Initial Brief at p. 400). According to the Eight Parties, neither point is valid. *Id.*

2996. Exxon has stipulated, according to the Eight Parties, that the only Section 1(5) violation at issue is that the TAPS Carriers "implemented the valuations for the West Coast Naphtha and VGO cuts that were ordered by the Commissions." *Id.* (quoting Exxon Initial Brief at p. 400). In the Eight Parties's view, this stipulation means that Exxon has conceded that the Naphtha and VGO cut valuations are protected by the *Arizona Grocery* holding that reparations are unavailable. *Id.* at pp. 182-83.

2997. In arguing that the Commission-mandated rate can be in violation of Section 1(5), the Eight Parties claim, Exxon again ignores the holding in *Arizona Grocery* that a rate initially established by the Interstate Commerce Commission became for the future the lawful, reasonable rate, and the carrier had no choice but to adopt a conforming rate. *Id.* at p. 183. The Eight Parties acknowledge that, while that rate did not preclude the Commission from revisiting the issue and setting a new rate for the future, it did preclude the Commission from changing that initial rate retroactively. *Id.* Hence, explain the Eight Parties, Exxon is simply wrong as a legal matter when it argues that the Commission-mandated rate for Naphtha and VGO can be retroactively declared unjust and unreasonable, in violation of Section 1(5) of the Interstate Commerce Act. *Id.*

2998. Further, state the Eight Parties, authority cited by Exxon to support its claim regarding retroactive violation is inapposite. *Id.* They point out that cases holding that reparations may be awarded for a rate declared to be unjust and unreasonable concern rates that were initiated by carriers, not rates that were set by the Commission.[889] *Id.* The Eight Parties explain that carrier-initiated rates remain subject to challenge by affected shippers and post-implementation review by the Commission pursuant to Section 13(1) complaint procedures. *Id.* If the rates are found to be unjust or unreasonable, state the Eight Parties, then retroactive relief may be awarded as reparations. *Id.* at pp. 183-84. They state that the *Arizona Grocery c*ourt recognized this. *Id.*

2999. The Eight Parties point out that the relief sought by Exxon is not against the TAPS Carriers, rather, the money to pay the reparations would be recovered from other shippers through retroactive assessments in amounts sufficient to pay Exxon. *Id.* at p. 185. As a legal matter, according to the Eight Parties, this kind of relief is not available under the reparations provisions of the Interstate Commerce Act. *Id.* Under Section 8 of the Act (49 U.S.C. App. § 8), the Eight Parties claim, a person injured by a carrier's violation of the Act may be awarded damages sustained as a result of such a violation. *Id.* The Eight Parties also note that, under Section 9 (49 U.S.C. App. § 9)(1988), the carrier is made liable for such damages. *Id.* They point out that there is no provision in the Act that makes shippers liable for damages sustained by the carrier or by other shippers and court decisions have so held. *Id.*

3000. In prior litigation over the Quality Bank, the Eight Parties state, the Commission has consistently required that changes in the methodology be applied on a prospective basis only and that reparations will not be awarded absent a violation of the tariff. Eight Parties Initial Brief at p. 214. In 1993, notwithstanding its determination that the then existing methodology was unjust and unreasonable, the Eight Parties explain, the

[889] According to the Eight Parties, carrier-initiated rates are distinguished from Commission-prescribed rates because they are not the product of a legislative function. Eight Parties Reply Brief at p. 184. They suggest that it is inexcusable for Exxon to confuse carrier-initiated rates with Commission-ordered rates when *Arizona Grocery* and other decisions have clearly distinguished these rates and the relief available for each. *Id.* at pp. 184-85.

Commission refused to order refunds or reparations. *Id.* Further, note the Eight Parties, in affirming the Commission on this issue, the Circuit Court opined that the Commission had no authority to apply the new rate retroactively because of the filed rate doctrine. *Id.* When Phillips subsequently argued that it should nevertheless be awarded reparations for the difference between the old, unjust and unreasonable rate and the new distillation-based rate, the Commission, explain the Eight Parties, again rejected the claim. *Id.* In rejecting Phillips's claim, the Eight Parties state, the Commission clearly reaffirmed that violation of the quality bank methods and/or tariff would be required in order for reparations to be awarded. *Id.* at p. 215. Because Exxon has stipulated that the TAPS Carriers have not violated the TAPS Quality Bank tariffs, the Eight Parties argue, there is no legal basis to award reparations. *Id.*

3001. Moreover, according to the Eight Parties, the Commission did not "announce a general rule of law to the effect that a tariff violation must be proven in all reparations cases" and the Eight Parties do not contend that it did. Eight Parties Reply Brief at p. 187 (quoting Exxon Initial Brief at p. 402). Rather, assert the Eight Parties, a tariff violation must be proven in order to obtain reparations under a Commission-prescribed rate, as opposed to a carrier initiated rate. *Id.*

3002. According to the Eight Parties, Exxon concedes that reparations cannot be sought for a Commission prescribed rate. Eight Parties Reply Brief at p. 190. They claim that Exxon's argument rests on the proposition that the Naphtha and VGO cut valuations are not the product of a Commission-prescribed rate. *Id.* As noted previously, the Eight Parties believe that this proposition is just plain wrong. *Id.* However, even if the Commission were to conclude that Exxon is correct on this point, the Eight Parties argue, it still would not resolve the problem that reparations against shippers cannot be awarded under the Interstate Commerce Act. *Id.*

3003. The Eight Parties also note that Exxon relies on the fact that the Commission, in a decision allowing a change to the Gulf Coast VGO price, has previously ruled that reparations would be available to Exxon "to correct any inaccuracies that have occurred." *Id.* (quoting *Trans Alaska Pipeline System*, 82 FERC at p. 62,352). To the extent that the Commission has previously intimated that reparations relief would be available, the Eight Parties assert that representation is explainable based on (1) the allegations set forth in Exxon's complaint filed in Docket No. OR96-14-000, which included allegations that the TAPS Carriers had violated their tariffs, and (2) the potential availability under Section 13(1) of the Interstate Commerce Act of reparations against a carrier for damages suffered as a result of a violation of the Act, including a tariff violation. *Id.* at pp. 190-91. The Eight Parties take the position that Exxon has voluntarily given up that potential remedy by stipulating that it does not seek reparations from the TAPS Carriers, but from the other shippers and by conceding that the TAPS Carriers have not violated their tariffs or the Act. *Id.* at p. 191. Denial of reparations here, according to the Eight Parties, would not be inconsistent with the Commission's prior rulings in this case. *Id.*

3004. The Eight Parties also argue that Exxon is wrong in its belief that it need only show that the Naphtha and VGO cut valuations are unjust and unreasonable and its right to reparations will follow as an entitlement. Eight Parties Initial Brief at p. 216. They acknowledge that Exxon can point to Commission decisions awarding reparations based on the difference between rates actually paid and the just and reasonable rates that should have been paid. *Id.* However, the Eight Parties assert, those decisions are distinguishable from the facts of this case. *Id.*

3005. The leading Commission decision awarding reparations, according to the Eight Parties, is *SFPP, L.P.*, 86 FERC ¶ 61,022 (1999), *modified*, 91 FERC ¶ 61,135 (2000), *reh'g denied*, 96 FERC ¶ 61,281 (2001). In that case, explain the Eight Parties, the Commission found that rates for SFPP's East Line were unjust and unreasonable, and that SFPP had violated the Interstate Commerce Act. *Id.* at pp. 216-17. They state that the East Line rate had not previously been reviewed and approved by the Commission, so it enjoyed no filed rate doctrine protection. *Id.* at p. 217. The Eight Parties further state that the Commission ordered SFPP to develop a cost of service for the East Line, and to pay reparations for the difference between the just and reasonable cost-based rate and the rate that had actually been paid. *Id.* Thus, assert the Eight Parties, all three elements of a reparations claim mentioned above were found to be present. *Id.*

3006. Of even greater significance, in the opinion of the Eight Parties, are the Commission's holdings in *SFPP* that a reparations claim is shipper specific and must be raised in an appropriate complaint filed by the injured shipper. *Id.* The Eight Parties explain that, in *SFPP*, the Commission found initially that only one shipper qualified for reparations because only one had filed a complaint respecting East Line rates, while the other shipper parties had filed complaints against the West Line rates.[890] *Id.* The basic rule to be gleaned from the *SFPP* case, according to the Eight Parties, is that only parties who file complaints are eligible for reparations if that rate is found unjust and unreasonable, and the complaining party has the burden of proving that the rate is unjust and unreasonable. *Id.* Further, the Eight Parties explain, in a later order in the case, the Commission rejected claims that merged entities could assert reparations claims initiated by a merged party, and ruled that each entity must file its own, specific reparations claim under Section 13(1) of the Interstate Commerce Act and Rule 206 of the Commission's

[890] According to the Eight Parties, the West Line complaints did not qualify for reparations because the West Line rates were grandfathered under the Energy Policy Act of 1992, and the complainants failed to show changed circumstances. Eight Parties Initial Brief at p. 217, n.116. The Eight Parties also cite *Big West Oil, LLC v. Alberta Energy Co., Ltd.*, 100 FERC ¶ 61,171, at p. 61,610 (2002) for the proposition that reparations complaints do not lie against rates that have been protested and suspended. *Id.*

regulations. *Id.* The Commission has also held, according to the Eight Parties, that one entity cannot piggyback on the claims filed by another entity. *Id.* at pp. 217-18.

3007. In this case, the Eight Parties argue, Exxon's reparations claim falls far short of the *SFPP* requirements. *Id.* at p. 218. Specifically, the Eight Parties point out, the complaint does not specifically challenge the rates at issue, does not mention the Naphtha and VGO cuts, and does not seek damages predicated on the use of Gulf Coast prices to value these cuts. *Id.* If there was any question, the Eight Parties explain, the Circuit Court made clear, in the *Exxon* decision, that VGO and Naphtha were not part of the remand. *Id.* Consequently, in the Eight Parties view, Exxon is relying on Tesoro's raising of the Naphtha and VGO issues in a later-filed Tesoro complaint, even though no reparations damages have been asserted by Tesoro. *Id.* They assert that *SFPP* not only precludes Exxon's attempt to piggyback on the Tesoro complaint, but also may preclude Mobil from joining Exxon on the complaint. *Id.*

3008. The Eight Parties contend that *SFPP* is instructive on other aspects of the reparations claim as well. *Id.* at p. 219. According to them, the Commission did not hold in *SFPP* that reparations are an entitlement brought to life by a showing of unjustness and unreasonableness in the rates. *Id.* To the contrary, the Eight Parties explain, the Commission observed that the reparations remedy is an equitable remedy, and the complaining shipper was denied reparations for the two-year period preceding the filing of the complaint on the grounds that the shipper and the pipeline were parties to a settlement during that time. *Id.* Therefore, state the Eight Parties, the Commission reasoned that, during the settlement period, the carrier was not on notice that its rates could be subject to challenge in a reparations complaint. *Id.* The Eight Parties assert that, in this case, Exxon is seeking reparations for a period of time during which Exxon itself, at the least, did not oppose the use of Gulf Coast pricing for the Naphtha and VGO cuts. *Id.* It would be inequitable, in the Eight Parties's view, to award reparations to Exxon for a period of time during which it did not oppose the use of Gulf Coast pricing for the two cuts at issue, and in fact affirmatively supported the use of Gulf Coast pricing, because neither the Carriers nor other shippers were on notice that Exxon would demand reparations for the cuts now at issue. *Id.* at pp. 219-20.

3009. While the Eight Parties argue that reparations are clearly inappropriate in this case, they also point out that the *SFPP* decision states how reparations should be calculated, if it were appropriate to award them. *Id.* at p. 220. They point out that the proper measure is the difference between the new lawful rate and the old rate that has been determined to be unjust and unreasonable. *Id.* The Eight Parties also point out that actual damages, such as lost customers and actual additional costs, are not relevant as damages are fixed as the difference in the rates for the amount of product affected. *Id.* Thus, they note, *SFPP* applies a standard that is more lenient than earlier case law and Interstate Commerce Commission precedent, which required proof of actual damage by the complainant, not just a difference in rates paid as compared to the just and reasonable rate. *Id.* The Eight Parties point out that Exxon did not submit any evidence of actual damage that could satisfy the burden of proof of damages from these earlier cases. *Id.*

3010. But even under the *SFPP* formula, the Eight Parties argue, serious questions arise. *Id.* at p. 221. They claim that Exxon has submitted no evidence that would prove what the just and reasonable rate in the years prior to 1999 would have been. *Id.* The *SFPP* damages formula, according to the Eight Parties, is based on a cost-of-service for a test year using the ratemaking standard of Opinion No. 154-B. *Id.* They explain that the just and reasonable rate for SFPP was developed for a 1994 test year using actual cost data from SFPP's records, and the 1994 cost of service was then indexed for years after 1994, modified with actual cost adjustments for specific cost categories. *Id.* The Eight Parties point out that the TAPS Quality Bank is not based on a carrier cost-of-service, but on evidence of costs and industry practices submitted by the parties to litigation. *Id.* Thus, note the Eight Parties, there is no agreed cost model similar to Opinion No. 154-B, and not all industry participants are parties to this case. *Id.* Consequently, the Eight Parties assert, the basis for applying the *SFPP* reparations model is not present in this case. *Id.* Furthermore, they argue, Exxon, the party with the burden of proof on reparations, has not submitted evidence of actual costs or actual price values for Naphtha and VGO on the West Coast for years prior to 1999. *Id.* Accordingly, in the view of the Eight Parties, there is no basis for calculating reparations or awarding them for the period requested by Exxon. *Id.*

3011. The Eight Parties also point out that the Interstate Commerce Act makes no provision for requiring a party other than a carrier to pay reparations, so there is no statutory basis for requiring retroactive assessments against other shippers, even if Exxon were deemed to be entitled to damages. *Id.* Moreover, according to the Eight Parties, because reparations are an equitable remedy, the Commission must weigh the impact of reparations on those who would pay. *Id.* They note that their arguments respecting these equitable considerations have been made in the section on refunds and apply here as well. *Id.* In the view of the Eight Parties, they are reinforced by the testimony of Sanderson, who stated that the refiners were never put on notice respecting reparations for Naphtha and VGO, and therefore had no opportunity to adjust their business practices. *Id.* at pp. 221-22. Accordingly, the Eight Parties conclude, any award of reparations would be unlawful and inequitable. *Id.* at p. 222.

3012. In its brief, according to the Eight Parties, Exxon raises for the first time the argument that, if a reparations award is denied, retroactive effect to a new Naphtha and VGO price should nevertheless be given in order to correct the legal error committed when the Commission denied the Tesoro complaint without a hearing. Eight Parties Reply Brief at p. 192. They state that Exxon relies on the decision in *Tesoro* which reverses the Commission for summarily dismissing the Exxon and Tesoro complaints and cites *Tennessee Valley* as authority for retroactive application of the new Naphtha and VGO valuations "to compensate for its erroneous dismissal." *Id.* (quoting *Tennessee*

Valley, 470 F.2d at p. 453).

3013. The Eight Parties state that *Tennessee Valley* is not on point. *Id.* They claim that, first, *Tesoro* did not involve a remand to the Commission with an instruction to retroactively correct a prior legal error. *Id.* Rather, explain the Eight Parties, the decision required the Commission to hold a hearing on the issues raised by the respective complaints and grant appropriate relief. *Id.* Further, the Eight Parties note that, in its complaint, Exxon did not request reparations for improper valuation of the Naphtha and VGO cuts, and they assert that Exxon cannot piggyback on the Tesoro complaint in order to obtain such relief in this proceeding. *Id.*

3014. Second, state the Eight Parties, although the *Tesoro* court did not reach the issue of whether retroactive relief would be available on remand, Exxon raised that issue on brief, and the Circuit Court intimated that relief would be prospective only. *Id.* at pp. 192-93 (citing *Tesoro*, 234 F.3d at p. 1286).

3015. Third, the Eight Parties state that *Tennessee Valley* is distinguishable on its facts from the present case. *Id.* at p. 193. They explain that this proceeding concerns a remand of Commission prescribed rates for the Naphtha and VGO cuts that were previously determined by the Commission to be just and reasonable. *Id.* In *Tennessee Valley*, note the Eight Parties, the 1969 dismissal of a complaint filed in 1966 was vacated and set for hearing in 1970. *Id.* Further, according to the Eight Parties, the utility had filed, in 1970, to change its rates, and the rates had been suspended subject to refund. *Id.* (citing *Tennessee Valley*, 470 F.2d at p. 449). The Eight Parties point out that the Circuit Court in *Tennessee Valley* ordered that the time gap between the erroneous dismissal of the complaint and the Commission's vacating and reopening order, 112 days, be used to measure the extent of retroactive relief granted in order to remedy the prior legal error. *Id.* They state that, in *Tennessee Valley*, whatever filed-rate protection existed for the preexisting rates was obviated by the gas company's filing in 1970 to change its rates. *Id.* Finally, the Eight Parties explain, the remand that required the Commission to make its determination of just and reasonable rates take effect 112 days earlier than they otherwise would have overlapped the period covered by the rate increase proceeding. *Id.* at pp. 193-94.

3016. Fourth, the Eight Parties state, the Circuit Court has described the relief approved in *Tennessee Valley* as "extraordinary" and as relief that "cuts to the heart of the concerns and values which inform 'the filed rate' doctrine." *Id.* at p. 194 (quoting *Northwest Pipeline Corp. v. F.E.R.C.*, 863 F.2d 73, 78 (D.C. Cir. 1988)). They assert that this kind of retroactive relief is equitable in nature and should not be awarded in this case, because the equities of this situation do not warrant it. *Id.* Specifically, the Eight Parties argue, a *Tennessee Valley* delay calculation of 920 days proposed by Exxon is tied to the dismissal of the Exxon and Tesoro complaints, neither of which sought the reparations for the Naphtha and VGO cuts to benefit Exxon that Exxon now demands. *Id.* The Eight

Parties position is, therefore, that legal error cannot be used as grounds for the grant of retroactive relief in this case. *Id.*

3017. Because Exxon has not filed a complaint claiming reparations for an incorrect valuation of the Naphtha and VGO cuts, the Eight Parties argue, reparations are not available and should not be awarded. Eight Parties Initial Brief at p. 222. Were the Commission, however, to conclude that reparations should be awarded, the Eight Parties note, an effective date for reparations would have to be determined. *Id.* In deciding on a reparations effective date, the Eight Parties state, the Commission would be applying an equitable remedy, as acknowledged in *SFPP*. *Id.* Notwithstanding the statute's provision for availability of reparations for two years prior to the filing of a complaint, the Eight Parties explain, *SFPP* states that the Commission must fashion an equitable remedy and cannot simply award the statutory maximum automatically. *Id.*

3018. The Eight Parties view two points as critical to the question of setting an effective date for reparations. *Id.* First, the Eight Parties assert, because no party was put on notice that reparations could be demanded for the Naphtha and VGO cuts until Tesoro filed its complaint, under *SFPP,* the date of that filing is the earliest possible date that reparations could be ordered. *Id.* They note that even Exxon suggests this date, which is August 1998, as an alternative to the 1994 date on the grounds that all parties were on notice as of the 1998 date. *Id.* at pp. 222-23.

3019. Second, the Eight Parties argue that, even if the date of the Tesoro complaint is the earliest that the potential for reparations relief for the Naphtha and VGO cuts became known, that date should not be used for Exxon's reparations. *Id.* at p. 223. Again, the Eight Parties point out, Exxon never mentioned the Naphtha and VGO cuts in its own complaint, and Tesoro did not request reparations in its complaint. *Id.* Indeed, according to the Eight Parties, no damage claims or evidence were ever submitted on behalf of Tesoro. *Id.* Instead, the Eight Parties urge the Commission to choose a date that takes into account when the parties were first put on actual notice as to Exxon's position with respect to its claim for reparations. *Id.* They assert that notice did not occur until Exxon filed its testimony in this case in February of 2002. *Id.* Hence, in keeping with the Commission's emphasis on the importance of notice, the Eight Parties believe that February 2002 would be the earliest date from which reparations could be ordered, but only if Tesoro had sought them. *Id.* According to the Eight Parties, Tesoro did not seek reparations and, therefore, Exxon cannot seek reparations from any date because it has not filed the requisite complaint. *Id.*

3020. Exxon states that the parties have stipulated to a new basis for valuing the West Coast VGO cut – namely, the OPIS West Coast High Sulfur VGO weekly price quote. Exxon Initial Brief at p. 385. If, as Exxon and Tesoro contend, the current valuation of the West Coast Naphtha cut is found to be unlawful in this proceeding, then Exxon asserts that any new lawful valuation of West Coast Naphtha should be implemented on the same date as that on which the new West Coast VGO valuation is implemented. *Id.* at pp. 385-86. Similarly, Exxon asserts that, if reparations are ordered with respect to the West Coast Naphtha valuation for any past period, then reparations should also be ordered for the same period with respect to the West Coast VGO valuation. *Id.* at p. 386.

3021. The Eight Parties, according to Exxon, raise four arguments as to why reparations should not be awarded in this case: (1) that reparations claims have not been properly raised; (2) that reparations are barred by *Arizona Grocery*; (3) that there are other legal defects in the claims for reparations; and (4) that equity should bar an award of reparations. *Id.* Exxon asserts that each of these arguments is demonstrably incorrect. *Id.*

3022. Any assertion by the Eight Parties that reparations are not an issue in this case should be dismissed, in the view of Exxon, on at least two grounds. *Id.* First, Exxon states, claims for retroactive relief were made in both the Exxon and Tesoro complaints and that this contributed to the Commission's setting these cases for hearing. Exxon Initial Brief at p. 386. Indeed, in setting the Exxon complaint for an investigation "into the lawfulness of the present quality bank methodology," Exxon states, the Commission invoked Section 13(1) of the Interstate Commerce Act,[891] which entitles a complainant to reparations (assuming it satisfies its burden of proof).[892] *Id.* at pp. 386-87. Moreover, Exxon notes that, in an order issued subsequent to its order initiating an investigation into its complaint, the Commission noted that, "If Exxon should prevail in its complaint case, then relief will be prospective from the date of the finding and reparations are available to correct any inaccuracies that have occurred." *Trans Alaska Pipeline System,* 82 FERC at p. 62,352.

3023. Similarly, states Exxon, the plain language of the Tesoro complaint flatly belies the Commission Trial Staff's contention that Tesoro's complaint did not request reparations. Exxon Reply Brief at pp. 449-50. To the contrary, Exxon asserts, Tesoro's complaint sought retroactive relief, for example, when it asked to have revised valuations of the West Coast VGO and Naphtha cuts applied retroactively to December 1, 1993. *Id.* at p. 450.

3024. Second, Exxon points out, in its November 2001 order setting several related TAPS Quality Bank matters for hearing, the Commission directed that all issues remanded by the Circuit Court in the *Exxon* and *Tesoro* decisions be taken up in this

[891] See Trans Alaska Pipeline System, 76 FERC at p. 61,621.

[892] Exxon maintains that Commission decisions confirm that reparations are part and parcel of complaints brought under Section 13(1) of the Interstate Commerce Act. Exxon Initial Brief at p. 387, n.167

hearing. Exxon Initial Brief at p. 387 (citing *Trans Alaska Pipeline System,* 97 FERC at p. 61,652). In *Tesoro,* notes Exxon, the Circuit Court declined to address the reparations issue, finding that it was premature because there was no finding that the prevailing methodology for valuing West Coast Naphtha and VGO was not just and reasonable. *Id.* The Circuit Court therefore remanded to the Commission for further consideration the claims that the West Coast Naphtha and VGO valuations are not just and reasonable, according to Exxon, and the Commission, in turn, set those issues for hearing in the instant proceeding. *Id.* at pp. 387-88. Thus, in the event the Commission concludes that the West Coast Naphtha and VGO valuations are not just and reasonable, Exxon argues it must necessarily determine, in light of the *Tesoro* remand, what reparations, if any, are appropriate. *Id.* at p. 388.

3025. Exxon argues that federal courts have long held that the act of charging an unreasonable rate is itself a violation of the Interstate Commerce Act, and that a complainant who has paid a rate afterwards declared to be unreasonable is entitled to an order for reparations in the amount by which the rate paid exceeds a just and reasonable rate, without further proof of injury.[893] *Id.* Consistent with these holdings, Exxon notes, the Commission and the Interstate Commerce Commission have ordered reparations equal to the difference between the rates complained of and the just and reasonable rate determined by the Commission in the complaint proceeding.[894] *Id.* Thus, in the instant case, Exxon asserts, reparations should be awarded for the differences between the valuations determined to be lawful for the West Coast Naphtha and VGO cuts and the valuations that were in effect for those cuts in the past. *Id.* at pp. 388-89.

3026. In its complaint filed on June 19, 1996, Exxon stated that it requested reparations for the period beginning two years prior to the filing of its complaint – that is, for the period beginning on June 19, 1994. *Id.* at p. 389. It asserts that this "reach-back" period is provided in the Interstate Commerce Act itself (49 U.S.C. App. §16 (1988)), and has been acknowledged by the Commission in numerous orders. *Id.* Accordingly, Exxon believes, the request in its complaint for reparations back to June 19, 1994, is solidly

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[893] Exxon cites two decisions in support of this argument: *I.C.C. v. United States,* 289 U.S. 385 at p. 390 (1933) and *Chicago, Milwaukee, St. Paul & Pacific R.R. Co. v. Alouette Peat Products, Ltd.*, 253 F.2d 449 at p. 455 (9th Cir. 1957). Exxon Initial Brief at p. 388, n.169.

[894] Exxon cites the following decisions in support of this statement: *SFPP, L.P.,* 80 FERC ¶ 63,014 at p. 65,202 (1997); *Thomson Phosphate Co. v. Atlantic Coast Line R. Co.,* 291 I.C.C. 1, 4 (1953); *Kerr-McGee Refining Corp. v. Williams Pipe Line Co.,* 63 FERC ¶ 61,349, at p. 63,224 (1993); *Union Oil Co. of California v. Cook Inlet Pipe Line Co.*, 71 FERC ¶ 61,300 at p. 62,184 (1995); *SFPP, L.P.,* 91 FERC ¶ 61,135 at p. 61,516 (2000). Exxon Initial Brief at p. 388, n.170.

grounded on statutory language and judicial and Commission precedent. *Id.*

3027. Exxon also believes that the record in this case clearly establishes justification for paying reparations back to June 19, 1994. *Id.* In support, Exxon cites Exhibit No. SOA-28 that it believes demonstrates that, for the period 1994-2001, the Gulf Coast Naphtha price used as the proxy price for West Coast Naphtha (denominated "Sanderson/Culberson") was, on average, 6.5¢/gallon (or about $2.73/barrel) lower than prices at which West Coast Naphtha sold under contract for the same period. *Id.* at pp. 389-90. Even if one focuses solely on the earliest years of this period, 1994-1998, Exxon notes that the Gulf Coast-based proxy price for Naphtha, on average, lagged 1.6¢/gallon (67.2¢/barrel) below the West Coast Naphtha contract prices for the same period. *Id.* at p. 390.

3028. Moreover, states Exxon, for the period 1994-2001, the Gulf Coast-based Naphtha proxy price was, on average, $3.82/barrel below the Naphtha price that most of the parties agreed to in the 1993 Settlement (which would have set the West Coast Naphtha price based on the adjusted price of West Coast conventional unleaded gasoline). *Id.* (citing Exhibit No. EMT-430 at p. 5). Further, Exxon states, Exhibit No. SOA-28 demonstrates that the Gulf Coast-based proxy price (denominated "Sanderson/Culberson" on SOA-28) falls well below every other valuation proposed in this case (i.e., below Tallett, O'Brien, Tallett Governed, O'Brien Governed, Dudley Governed and Sanderson/Culberson Governed) except the Dudley ungoverned proposal, for the entire period 1994-2001, as well as the earlier years 1994-1998.[895] *Id.*

3029. According to Exxon, even these comparisons tend to understate significantly the degree to which the Gulf Coast-based proxy price has fallen below the actual market value of West Coast Naphtha. *Id.* Exxon points out that the Quality Bank Administrator has proposed, and no party has opposed, using the Platts quote for Heavy Naphtha, rather than the Platts quote for Full Range Naphtha that has been used as the proxy price on both coasts, because the properties of the Quality Bank Naphtha cut are much closer to the Platts Heavy Naphtha specifications than to the Platts Full Range Naphtha specifications. *Id.* at pp. 390-91. The record shows, in Exxon's opinion, that the price of Heavy Naphtha has exceeded the price of Full Range Naphtha on the Gulf Coast, on average, by about 1.3¢/gallon, and on the West Coast by about 2.7¢/gallon, for the period 1994-2002.[896] *Id.* p. 391.

[895] According to Exxon, the record "clearly establishes" that, for the period 1994-2001, the Gulf Coast-based proxy price for VGO consistently has been different from the published price for West Coast VGO that the parties have now agreed should be used as the proxy price for West Coast VGO. Exxon Initial Brief at p. 390, n.173 (citation omitted).

[896] In addition, Exxon states there is at least one additional reason the current

3030. Exxon states that the Eight Parties assert that Exxon's claims do not qualify under Section 13(1) of the Interstate Commerce Act for a reparations award. Exxon Reply Brief at p. 451. Specifically, according to Exxon, the Eight Parties contend that Exxon's claim falls short of the requirements delineated in the Commission's decisions in the *SFPP* cases, namely that (1) a reparations claim must assert a claim against a specific shipper, and (2) to be eligible for reparations a complaint must be filed. *Id.* Exxon notes that the Eight Parties claim this is so because Exxon's complaint does not discuss the Naphtha and VGO cuts and these cuts are not part of the *Exxon* remand. *Id.* Finally, Exxon explains that the Eight Parties argue that Exxon must thus rely on the fact that Tesoro raised Naphtha and VGO issues in a later complaint, but that *SFPP* does not allow Exxon to use Tesoro's complaint to assert a claim for reparations in this proceeding. *Id.* at pp. 451-52.

3031. In making each of these arguments, states Exxon, the Eight Parties have grossly misrepresented the required elements of reparations claims in general, and have inaccurately described Exxon's complaint, in particular. *Id.* at p. 452. First, notes Exxon, their claim that Exxon's complaint failed to mention Naphtha and VGO is belied by the complaint, which specifies that the Commission's decision to value these cuts on the basis of Gulf Coast prices caused (along with other defects) the distillation methodology to be unjust and unreasonable. *Id.*

3032. Second, continues Exxon, the Eight Parties erroneously contend that any doubt that Exxon's complaint failed to challenge the valuation of the VGO and Naphtha cuts is removed by the *Exxon* decision which, they claim, stated that those cuts were not part of the remand. *Id.* Exxon asserts that this claim is false. *Id.* According to Exxon, the *Exxon* remand rendered no judgment whatsoever on the scope or merits of Exxon's complaint or the legality of the current valuation of the West Coast Naphtha and VGO cuts, except to note that those issues were beyond the scope of its decision. *Id.* at pp. 452-53.

3033. Third, Exxon asserts, there is no basis to the Eight Parties's contention that a party

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Naphtha proxy price further understates the actual market value of Naphtha on both coasts. Exxon Initial Brief at p. 391, n.174. It asserts that the evidence clearly establishes that the Naphtha prices published by Platts are based on an N + A of 40. *Id.* It is also undisputed, according to Exxon, that the Naphtha produced from ANS crude over the past decade has an N + A that is greater than 55. *Id.* Because Quality Bank Naphtha has an N + A content that is substantially higher than 50, Exxon states, it would receive the maximum proposed N + A adjustment of 1.5¢/gallon. *Id.* This means, explains Exxon, that the existing Naphtha proxy prices have likely understated the market value of Naphtha by an additional 1.5¢/gallon. *Id.* (citations omitted) cannot "piggyback" on the claim of another. *Id.* at p. 453 (citing Eight Parties Initial Brief at pp. 217-18). Rather, Exxon asserts, *Texaco* makes clear that this doctrine does not bar a claim by a party, like Exxon, which has "filed its own complaint and has fully participated throughout the hearings." *Id.* (quoting *Texaco Refining and Marketing, Inc.*, 99 FERC ¶ 63,009, at P 22 (2002)). More specifically, Exxon states, this doctrine applies only in narrow circumstances not present in this case, i.e., where a tardy complainant seeks to piggyback on the original complaint of another entity, after having failed to file a complaint until nearly the end of proceeding and who had remained passive throughout several years of a case. *Id.* Thus, Exxon argues that the anti-piggybacking doctrine does not apply here, because Exxon filed its own complaint in 1996 seeking damages (reparations) under Section 13(1) of the Interstate Commerce Act, has actively participated in the entirety of these proceedings, and was certainly not tardy or passive in any respect. *Id.* at pp. 453-54.

3034. Finally, Exxon suggests, the Eight Parties's assertion that Exxon's complaint fails the requirements of the *SFPP* cases is without merit as the claim rejected in *SFPP* is distinguishable from Exxon's claims in several respects. *Id.* at p. 454 (citing Eight Parties Initial Brief at p. 218). Exxon also states that the Eight Parties cannot deny that, in its complaint filed on June 19, 1996, it requested reparations for the period beginning two years prior to the filing of its complaint – that is, for the period beginning on June 19, 1994. *Id.* The Eight Parties concede (Eight Parties Initial Brief at p. 222), according to Exxon, that this "reach-back" period is provided in the Interstate Commerce Act itself (49 U.S.C. App. § 16 (1988)) and has been acknowledged by the Commission in numerous orders. Exxon Reply Brief at pp. 454-55 (citing *SFPP, L.P.*, 96 FERC at p. 62,071).

3035. Accordingly, Exxon asserts, the request in its complaint for reparations back to June 19, 1994, is solidly grounded in statutory language and judicial and Commission precedent. *Id.* at p. 455. It also argues that its request is supported by sound policy considerations as the Commission has acknowledged that a policy of not awarding reparations – as advocated by the Eight Parties here – "removes much of the incentive for [parties] to settle or to act with restraint in the litigation." *Id.* (quoting *SFPP, L.P.*, 86 FERC at p. 61,113).

3036. Moreover, Exxon argues, by 1998, it should have been perfectly clear to all parties that the West Coast valuations of Naphtha and VGO were being challenged. Exxon Initial Brief at p. 392. Specifically, Exxon notes, on August 20, 1998, Tesoro filed its complaint challenging the use of Gulf Coast prices to value the West Coast Naphtha and VGO cuts. *Id.* In particular, notes Exxon, Tesoro asked the Commission to value West Coast Naphtha based on West Coast gasoline prices, and argued that such new valuations should be made effective as of the effective date of the *OXY* remand cuts; and that a just and reasonable Quality Bank methodology must be put in place effective December 1, 1993. Exxon Reply Brief at pp. 467-68.

3037. Exxon states that case law makes clear that notice of a dispute concerning cut valuation is an important factor in guiding the Commission's discretion as to whether to award reparations. *Id.* (citing *SFPP, L.P.*, 86 FERC at p. 61,113). Additionally, notes Exxon, a comparison of Platts Gulf Coast Naphtha quotes with West Coast Naphtha contract prices demonstrates that Naphtha values on the two coasts began to diverge even more substantially in the late 1998 timeframe. *Id.* at pp. 392-93. For example, states Exxon, citing Exhibit No. SOA-28, an Alaska study shows that, for the period 1994-1998, West Coast Naphtha sold under contract at a price, on average, about 1.6¢/gallon higher than Platts Gulf Coast Naphtha price for the same period, while from 1999-2001 that differential widened to 14.2¢/gallon.[897] *Id.* at p. 393. Exxon asserts that this divergence further supports the appropriateness of awarding reparations. *Id.*

3038. Finally, Exxon asserts that it is impossible to argue that notice is even an issue following issuance of the *Tesoro* decision in December 2000. *Id.* In *Tesoro*, claims Exxon, the Circuit Court found that sufficient new evidence had been presented to establish a prima facie case that the Commission's practice of valuing West Coast Naphtha on the basis of Platts Gulf Coast Naphtha price was not just and reasonable, and that such evidence required the Commission to reexamine how West Coast Naphtha should be valued.[898] *Id.* Indeed, Exxon adds, the Circuit Court commented, in its *Tesoro* decision, that the Commission's reliance on the Gulf Coast Naphtha price to value West Coast Naphtha "is more dubious now than in 1993." *Id.* (quoting 234 F.3d at p. 1292).

3039. According to Exxon, the Eight Parties argue that, even were reparations an issue in this proceeding, reparations cannot be awarded in this case because of the principle established in *Arizona Grocery*. *Id.* at pp. 393-94. Exxon explains that *Arizona Grocery*

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[897] Exxon notes that the Alaska study is consistent with studies submitted by it and Unocal. Exxon Initial Brief at p. 393, n.177. According to Exxon, Unocal's study shows that, for the period 1993-1998, West Coast Naphtha sold under contract at a price, on average, about 1.48¢/gallon higher than Platts Gulf Coast Naphtha price for the same period, while from 1999-2001 that differential widened to 11.63¢/gallon. *Id.* (citing Exhibit No. UNO-52 at p. 5). Exxon notes that its study shows that, for the period 1994-1998, West Coast Naphtha sold under contract at a price, on average, about 2.07¢/gallon higher than Platts Gulf Coast Naphtha price for the same period, while from 1999-2001 that differential widened to 12.0¢/gallon. *Id.* (citing Exhibit No. EMT-380).

[898] In making this claim, Exxon overstates the Circuit Court's finding. Rather than holding that Tesoro established a prima facie case that it was not just and reasonable to continue valuing West Coast Naphtha on the basis of Platts Gulf Coast Naphtha assessment, the Court held that Tesoro "at the least establish[ed] a prima facie case that new evidence warrants re-examination of how West Coast Naphtha should be valued." *Tesoro*, 234 F.3d at p. 1293. That holding is significantly different than Exxon's claim.

held that, where an agency has prescribed a just and reasonable rate, it may subsequently find that rate unlawful and order it changed prospectively, but it may not award retroactive relief. *Id.* at p. 394. It argues that, contrary to the Eight Parties's contention, the principle of *Arizona Grocery* is not a bar to an award of reparations in this case, because the Commission's adoption in 1993 of Gulf Coast-based prices to value West Coast Naphtha and VGO did not amount to a prescription of those valuations. *Id.* Such is the case, states Exxon, because: (1) neither the distillation methodology as a whole, nor its West Coast Naphtha and VGO components, has ever produced a final, lawful rate; and (2) neither record evidence nor sound regulatory policy supported use of Gulf Coast prices to value West Coast cuts when those valuations were adopted in 1993. *Id.*

3040. Exxon points out that the principles for establishing a lawful Quality Bank methodology were set forth in *OXY*. *Id.* There, explains Exxon, the Circuit Court held that, in order to be lawful, a Quality Bank methodology must "assign accurate relative values to the petroleum that is delivered to TAPS," and that, "[i]n order to achieve this goal, [the Commission] must accurately value all cuts." *Id.* (quoting *OXY*, 64 F.3d at p. 693). It further explains that given the comparative nature of the distillation methodology, the valuation of any single component is integrally related to the value of all other components, and to the lawfulness of the methodology as a whole. *Id.* at pp. 394-95. Accordingly, Exxon asserts, the Commission will not have finally "prescribed" rates, within the meaning of *Arizona Grocery,* using a distillation methodology, until all of the methodology's components are accurately valued. *Id.* at p. 395.

3041. Yet, Exxon notes, the Eight Parties's brief sheds little, if any, light on this critical point because neither *Arizona Grocery* nor any other case cited by the Eight Parties addressed how a rate is prescribed in a situation similar to the one presented by the distillation methodology. Exxon Reply Brief at p. 457. Indeed, Exxon asserts, the Eight Parties's analysis of this critical issue is limited to their single statement, devoid of any analysis or supporting case law, that "[i]t is no answer that a final Quality Bank methodology with all cuts resolved and not subject to judicial review has not been attained." *Id.* (quoting Eight Parties Initial Brief at p. 216). Exxon states that this statement is no substitute for analysis of this very important and novel issue. *Id.* Instead, notes Exxon, the Eight Parties assume that the valuations of West Coast Naphtha and VGO were prescribed in the 1993-1994 timeframe notwithstanding the Commission's continued failure to accurately value all cuts as required by *OXY*. *Id.*

3042. Although the Commission has been working to prescribe a complete, accurate Quality Bank methodology since the 1993 change to a distillation methodology, Exxon asserts that it has not yet succeeded. Exxon Initial Brief at p. 395. Instead, since its initial implementation in December 1993, the distillation methodology has been the subject of three appeals in which various aspects of the methodology have been challenged, found to be deficient, and remanded to correct legal error. *Id.* Exxon argues that, because these legal errors remain unresolved, the Commission has not yet prescribed a final, lawful methodology for Quality Bank assessments using the distillation approach. *Id.* at p. 396. As a result, the principle of *Arizona Grocery* does not yet apply. *Id.*

3043. Exxon states that the parties to the 1993 settlement had proposed that West Coast Naphtha be valued on the basis of an adjustment to West Coast gasoline prices. *Id.* It explains that the Commission rejected that valuation on grounds that market prices, without adjustments, were more reliable than adjusted market prices. *Id.* For that reason, notes Exxon, the Commission used Gulf Coast prices to value Naphtha and VGO on both the West Coast and the Gulf Coast. *Id.*

3044. *Arizona Grocery* is inapplicable here for at least two other reasons, continues Exxon. Exxon Reply Brief at p. 458. First, it argues, the Commission's adoption of single coast pricing to value both West Coast and Gulf Coast components was made up of "whole cloth," because, it asserts, there was no evidentiary support whatsoever for the Commission's 1993 decision to use Gulf Coast Naphtha prices to value West Coast Naphtha. Exxon Initial Brief at p. 396. Indeed, in the five-year proceeding that led to that decision, Exxon notes, no party had even suggested – much less presented any evidence – that the price for a product on one Coast was a reasonable basis for valuing that product on the other Coast. *Id.* at pp. 396-97. Thus, concludes Exxon, the absence of any evidentiary support for the 1993 decision to use Gulf Coast prices to value West Coast Naphtha further undermines any claim that that valuation enjoys the retroactive protection of *Arizona Grocery*. *Id.* at p. 397.

3045. Exxon states that the Supreme Court explained in *Arizona Grocery*, 284 U.S. at p. 386, n.15, that the claim that a rate "has the force of a statute" and is therefore prescribed may be undermined where "the administrative agency . . . has based its order upon a finding without evidence or upon evidence which clearly fails to support it." Exxon Initial Brief at p. 397, n.179. Yet, notes Exxon, the Eight Parties assume that the Commission established the use of Gulf Coast pricing to value West Coast Naphtha and VGO based on the record, without ever specifying any evidence that supported this decision. Exxon Reply Brief at p. 459. Nor, according to Exxon, have the Eight Parties cited a single case holding that a rate is prescribed in the *Arizona Grocery* sense even where it is not supported by any record evidence. *Id.* Thus, Exxon argues, the absence of any evidentiary support for the 1993 decision to use Gulf Coast prices to value West Coast Naphtha further undermines any claim that such valuation enjoys the retroactive protection of *Arizona Grocery*. *Id.*

3046. Second, the use of Gulf Coast prices to value West Coast Naphtha was also based, in the opinion of Exxon, on an ill-founded and ultimately ill-fated regulatory policy. Exxon Initial Brief at p. 397. In *OXY*, Exxon states, the Circuit Court held that the policy on which use of Gulf Coast prices to value West Coast components was based lacked an adequate foundation and was "arbitrary and capricious."[899] *Id.* (quoting 64 F.3d at pp. 693, 695) On remand, according to Exxon, the Commission abandoned its no adjustment policy, adopting instead adjusted market prices for the remanded cuts on both Coasts. *Id.* at pp. 397-98. And in *Tesoro*, states Exxon, the Circuit Court relied in part on the Commission's abandonment of the no adjustment policy in holding that the Commission must reconsider the use of Gulf Coast pricing to value West Coast Naphtha. *Id.* at p. 398. (citing *Tesoro*, 234 F.3d at p. 1293).

3047. Exxon asserts that the Eight Parties offer no other grounds which could possibly support the Commission's use of single market pricing. Exxon Reply Brief at p. 460. Thus, Exxon argues, the only grounds that ever existed for the Commission's use of single-market prices were discredited by the Circuit Court and ultimately abandoned by the Commission. Exxon Initial Brief at p. 398. Under these circumstances, claims Exxon, the Commission's 1993 valuations of West Coast Naphtha and VGO cannot be deemed to have been prescribed within the meaning of *Arizona Grocery*. *Id.* Accordingly, Exxon concludes there is no bar to retroactive relief in the form of reparations for past valuations of the West Coast Naphtha and VGO cuts once lawful valuations for those cuts are finally established. *Id.*

3048. Exxon further states that the Eight Parties argue that "[a] reparations claim must . . . satisfy the following elements: (1) there must be an allegation that a carrier has violated the [Interstate Commerce Act]; (2) the claimant must allege it has sustained injury as a result of the violation; and (3) the relief sought must be against the carrier." *Id.* at p. 399. It also states the Eight Parties claim that none of these elements is present in this case. *Id.* Even assuming that each of these elements is, in fact, a prerequisite to a successful reparations claim, Exxon asserts, both the Exxon and Tesoro complaints clearly satisfy each element. *Id.*

3049. As to the first element, Exxon asserts, both it and Tesoro allege that the TAPS Carriers have violated § 1(5) of the Interstate Commerce Act to the extent that they have placed in effect a Quality Bank methodology, and specific elements thereof, that are not just and reasonable. *Id.* It points out that Section 1(5)(a) of the Act declares that "every unjust and unreasonable charge . . . or any part thereof is prohibited and declared to be

[899] Exxon's claim in this regard appears, at a minimum, to be overstated. In fact, the Circuit Court did not address the "policy" of valuing West Coast cuts on the basis of the value of Gulf Coast cuts. At the places cited by Exxon, it found that the Commission's justification for using the price of jet fuel to value light distillate and the price of No. 2 fuel oil to value heavy distillate to be arbitrary and capricious and the use of FO-380 as a proxy for Resid also to be arbitrary and capricious. *OXY*, 64 F3d at pp. 693, 695. Thus, Exxon's contention that the Court even addressed the question of valuing West Coast cuts on the basis of the value of Gulf Coast cuts is without merit.

unlawful." *Id.* (quoting 49 U.S.C. App. §1(5)(a)(1988)). Thus, to the extent that the Commission finds that use of Gulf Coast prices to value West Coast Naphtha and VGO is unjust and unreasonable, Exxon asserts that a violation of Section 1(5) will have been established. *Id.*

3050. With respect to the second element, Exxon points out, both the courts and the Commission have held that a complainant who has paid a rate afterwards declared to be unreasonable is entitled to an order for reparation in the amount by which the rate paid exceeds the just and reasonable rate, without other evidence of loss. *Id.* at pp. 399-400. Thus, asserts Exxon, the allegation of injury sustained not only has been made, but also will have been proven in the event the Commission concludes that use of Gulf Coast prices to value West Coast products is not just and reasonable. *Id.* at p. 400.

3051. Finally, Exxon notes that, as reflected in the caption of the complaints, both complainants seek relief against the TAPS Carriers, as they must in light of the fact that the TAPS Carriers administer the Quality Bank. *Id.* at p. 400. Because the Quality Bank is the vehicle through which debits and credits are assessed for differences in the quality of crude oil transported by the Carriers, Exxon argues that it follows that complaints lodged for the purpose of effecting changes in the Quality Bank methodology are directed to the TAPS Carriers. *Id.* Accordingly, Exxon's stipulation with the TAPS Carriers simply recognizes that the TAPS Carriers (1) implemented the valuations for the West Coast Naphtha and VGO cuts that were ordered by the Commissions, and (2) serve merely as conduits for Quality Bank payments among TAPS shippers. *Id.*

3052. The Eight Parties assertion that there is no legal basis for reparations because Exxon failed to provide evidence of a violation of any Quality Bank tariffs is, in Exxon's view, a misstatement of law. *Id.* at pp. 400-01. Exxon argues that no case has held that a tariff violation is an element of a reparations claim. *Id.* at p. 401. Rather, as both case law and the text of the Interstate Commerce Act make clear, a rate may be found unjust and unreasonable, and reparations awarded, absent a tariff violation. *Id.* It points out that its claim is predicated on §1(5) of the Interstate Commerce Act, which clearly states that charging an unjust and unreasonable rate is itself a violation of the Act. *Id.* Thus, Exxon asserts, proof of a tariff violation is not necessary to proving a violation of §1(5). *Id.* Moreover, Exxon maintains that case law[900] confirms its view that reparations may be awarded on the basis that the rate provided in a carrier's tariff is unjust and unreasonable. *Id.*

3053. Contrary to the Eight Parties's position, according to Exxon, the Commission's decisions in *Trans Alaska Pipeline System* and *Conoco* do not hold that reparations

[900] Exxon cites *Chicago*, 253 F.2d at pp. 455-56.

cannot be awarded absent proof of a tariff violation.[901] *Id.* Rather, according to Exxon, the Commission held that a tariff violation needed to be proven in those cases because relief was sought (refunds in *Trans Alaska Pipeline System* and reparations in *Conoco*) on the theory that there was a tariff violation, i.e., the carriers allegedly had violated limits in their tariffs regarding API gravity by allowing shipments of crude oil contaminated with Natural Gas Liquids. *Id.* at p. 401-02. Exxon maintains that the Commission did not announce a general rule of law to the effect that a tariff violation must be proven in all reparations cases. *Id.* at p. 402.

3054. The Eight Parties invoke what Exxon views as inapplicable Interstate Commerce Act provisions and ignore the text of other, also in Exxon's view, more pertinent provisions, when they "erroneously" suggest that the Commission lacks statutory authority to award reparations. *Id.* For example, Exxon asserts that the Eight Parties wrongly suggest that §15(1) of the Interstate Commerce Act prohibits the Commission from ordering retroactive rate changes. *Id.* The Eight Parties also note, erroneously according to Exxon, that the Commission is prohibited from ordering the payment of money under §13(2) of the Interstate Commerce Act, and also point to §15(7) of the Act, which applies to an award of refunds. *Id.* In invoking all of these statutory provisions, Exxon states, the Eight Parties fail to focus upon the statutory provisions under which reparations are sought here, including §13(1) of the Interstate Commerce Act, which expressly provides for the award of damages, and §16(3)(b) of the Act, which explicitly, according to Exxon, provides for reparations for up to two years prior to the filing of a complaint. *Id.* at pp. 402-03. The Eight Parties also ignore decades of case law construing the Commission's authority to award reparations, it claims. *Id.* at p. 403.

3055. In Exxon's view, the Eight Parties misinterpret the Commission's decisions in *Trans Alaska Pipeline System* and *Conoco* by arguing that those decisions mandate that Quality Bank changes can only be applied prospectively. *Id.* Here again, Exxon claims, the Commission did not announce such a broad rule. *Id.* Rather, explains Exxon, it announced a much narrower holding based on the facts of those cases – namely, that the gravity methodology had been prescribed by the Commission, and that its ruling that changes to that methodology could be made only prospectively had been upheld on judicial review. *Id.* It was in this context that the Commission held, notes Exxon, that, notwithstanding its determination that the gravity methodology was unjust and unreasonable, it had no authority to apply the rate retroactively because of the filed rate doctrine (and its corollary, the rule against retroactive rate-making). *Id.*

3056. In contrast, asserts Exxon, the distillation methodology has yet to be prescribed in its final form, as it remains the subject of legal errors remanded by the Circuit Court. *Id.*

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[901] Exxon cites, in support, *Trans Alaska Pipeline System*, 65 FERC at p. 62,292 and *Conoco*, 72 FERC at p. 61,013.

at p. 404. In these circumstances, Exxon maintains, the rule against retroactive ratemaking does not apply. *Id.* Moreover, in Exxon's view, there is nothing inconsistent about the Commission's prescribing a methodology to be applied prospectively from the date of its order, and, at the same time, awarding reparations for past periods. *Id.* (citing *Trans Alaska Pipeline System*, 82 FERC at p. 62,352).

3057. Exxon asserts that, after eliminating the Eight Parties's unsubstantiated arguments, the Commission clearly has both the legal authority and compelling evidence in this record to award reparations for the West Coast Naphtha and VGO cuts. *Id.* Accordingly, Exxon and Tesoro request that the Commission award reparations back to June 19, 1994, (or at least August 20, 1998, the date Tesoro's complaint was filed) for the difference between the West Coast Naphtha and VGO values that have been in effect since those dates and the values for those cuts ultimately determined to be lawful. *Id.*

3058. Moreover, Exxon argues that, even if the Commission were to decline to award reparations based on the Exxon and Tesoro complaints, retroactive application of any revised West Coast Naphtha and VGO values adopted in this proceeding would still be required for some period of time to compensate for the Commission's erroneous dismissal of those complaints in 1999. Exxon Initial Brief at p. 405. According to Exxon, this is the principle laid down in *Tennessee Valley*. *Id.* It states that the Eight Parties's brief does not even mention this important remedial consideration. Exxon Reply Brief at pp. 471-72. According to Exxon, application of this principle to the facts of this case would require the Commission to make its decision on the complaints effective as of a date 920 days prior to the conclusion of the complaint proceedings, even if the Commission were to deny the request for reparations. *Id.* at p. 472.

3059. Exxon explains that *Tennessee Valley* involved a complaint, filed pursuant to Section 5 of the Natural Gas Act, alleging that existing rates of a natural gas pipeline company were excessive. Exxon Initial Brief at p. 405. It notes that the Federal Power Commission dismissed the Section 5 proceeding, but that, on review, the Circuit Court held that dismissal of the proceeding, rather than reopening it for further hearings, constituted legal error. *Id.* In so ruling, notes Exxon, the Circuit Court observed that the policy of the Natural Gas Act could not be defeated by allowing Commission error to remain uncorrected. *Id.* Therefore, explains Exxon, the Circuit Court held that the injured party must be placed in the same position it would have occupied had the error not been made; in this case, by granting reparations for the period of time between the Commission's wrongful dismissal of the case and the time it cured that error by reopening the hearings. *Id.* at pp. 405-06.

3060. In the instant case, Exxon notes that the Commission dismissed Exxon's and Tesoro's complaints on April 30, 1999,[902] but reinstated hearings on the complaints on

[902] *Exxon Co., U.S.A. v. Amerada Hess Pipeline Corp., et al.,* 87 FERC ¶ 61,133 at

November 7, 2001,[903] after the Circuit Court held that the dismissals were arbitrary and capricious and reversed and remanded the cases for further proceedings.[904] *Id.* at p. 406. Thus, Exxon calculates, a period of 920 days elapsed between the date of the Commission's erroneous dismissal of the complaints and the date of the Commission's order on remand setting those complaints for hearing. *Id.* Accordingly, Exxon claims that, under the principle established in *Tennessee Valley,* the Commission must compensate for its erroneous dismissal of the Exxon and Tesoro complaints – even if it were to decline to award reparations based on those complaints – by making its decision on the complaints effective as of a date 920 days prior to the conclusion of the complaint proceedings. *Id.* at pp. 406-07.

3061. Exxon states that the Eight Parties contend that equity precludes granting Exxon's reparations claim because they were never put on notice, until Exxon filed testimony in February 2000, that reparations were a possibility for the Naphtha and VGO cuts. Exxon Reply Brief at p. 467. It suggests that this claim is implausible. *Id.* In 1993, Exxon states, it co-sponsored a settlement proposal valuing the Naphtha and VGO cuts on a West Coast basis and, in 1996, it filed its complaint explaining that the distillation methodology, including the use of Gulf Coast pricing to value certain West Coast products (including West Coast Naphtha), produced unjust and unreasonable results. *Id.*

3062. The Eight Parties erred, according to Exxon, when they suggested that, because Tesoro has not sought reparations for itself, it has not suffered any damages. *Id.* at p. 469. Exxon states that Tesoro has a strong interest in competing on a level playing field with other TAPS shippers, particularly other Alaskan refineries (such as those operated by Williams and Petro Star). *Id.* at pp. 469-70. It contends that the TAPS Quality Bank plays an indispensable role in ensuring that a level playing field is maintained when it values Quality Bank cuts at market values. *Id.* at p. 470. In addition, according to Exxon, the evidence in this case demonstrates that, for the last decade, Alaskan refiners have paid less than West Coast market values for their use of Naphtha from the TAPS common stream. *Id.* Exxon asserts that Tesoro plainly has been, and continues to be, damaged by its competitor's access to Naphtha at a cost below the West Coast market value for Naphtha. *Id.* In these circumstances, it argues, the appropriate remedy is for the improper financial benefits accruing to Williams and Petro Star to be disgorged and for West Coast Naphtha to be valued at the West Coast market value for Naphtha. *Id.*

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p. 61,531 (1999); *Tesoro Alaska Petroleum Co. v. Amerada Hess Pipeline Corp., et al.,* 87 FERC ¶ 61,132 at p. 61,520 (1999).

[903] *Trans Alaska Pipeline System,* 97 FERC ¶ 61,150 at p. 61,652 (2001).

[904] *Tesoro*, 234 F.3d at pp. 1294-95.

3063. Also, Exxon finds no merit to the Eight Parties's argument that it would be inequitable to award Exxon reparations for a period in which it supported – or at least did not oppose – Gulf Coast pricing for Naphtha and VGO on which its reparations claims are based. *Id.* The Eight Parties attempt to support this plea for equity, states Exxon, by noting that Exxon offered proposals in the 1997 and 2000 settlement proceedings that included Gulf Coast pricing for these cuts. *Id.* This argument is plainly wrong, maintains Exxon, as those proceedings were limited to the issues remanded in *Exxon* and *OXY,* which (as the Eight Parties concede) never reached the issue of how to value the West Coast Naphtha and VGO cuts. *Id.* As noted above, states Exxon, it joined Tesoro before the Circuit Court in advocating that retroactive relief be granted with respect to the Naphtha and VGO cuts. *Id.* at pp. 470-71.

3064. Exxon notes that the parties have stipulated that, if a revised West Coast Naphtha valuation is adopted in this proceeding, the revised West Coast VGO valuation to which the parties have stipulated should have the same effective date. Exxon Initial Brief at p. 407. When the TAPS Carriers amended their Quality Bank tariffs to change the pricing basis used to value the Naphtha cut from Platts reported Gulf Coast waterborne Naphtha price assessment to Platts newly-reported Gulf Coast waterborne Heavy Naphtha price assessment, Exxon points out, they requested special permission to allow the tariff revisions to be effective on March 1, 2003, with one day's notice. *Id.* In the Commission's March 28 Order, notes Exxon, it accepted use of the Platts Gulf Coast Heavy Naphtha price assessment to value the Naphtha component, subject to further investigation and refunds back to March 1, 2003. *Id.*

3065. In light of these orders, Exxon contends that a new West Coast Naphtha valuation should be applied by the Quality Bank effective March 1, 2003, with refunds awarded for the period between March 1, 2003, and the date of the Commission's decisions in these proceedings. *Id.* at p. 408. If refunds are awarded, Exxon urges that reparations equal to the difference between the valuations that have previously been in effect for such cuts and such new, revised valuations, be ordered for the period June 19, 1994 (or, at the latest, August 20, 1998) to March 1, 2003. *Id.*

3066. Finally, in light of the parties's stipulation in this case covering the effective dates of new valuations for the West Coast Naphtha and West Coast VGO cuts, Exxon believes that the new valuation for West Coast VGO should also be made effective March 1, 2003, with refunds ordered for the period between March 1, 2003, and the date of the Commission's decision in these proceedings, and reparations ordered for the period June 19, 1994 (or August 20, 1998) to March 1, 2003. *Id.*

3067. According to the TAPS Carriers, several parties have proposed that Quality Bank adjustments among the shippers be recalculated to take account of a new methodology for valuing one or more components of the Quality Bank streams. TAPS Carriers Initial Brief at p. 30. In some cases, note the TAPS Carriers, they have characterized these retroactive adjustments as refunds and in others as reparations. *Id.* However they are characterized, the TAPS Carriers state, the retroactive calculations that have been proposed are administratively feasible. *Id.* So long as the data are available to recalculate the value of the component in question for some past period, it is administratively feasible, explain the TAPS Carriers, for the Quality Bank Administrator to recalculate Quality Bank adjustments, send out new invoices and redistribute the funds collected (less Quality Bank expenses). *Id.* Of course, in doing so, point out the TAPS Carriers, the Quality Bank Administrator would be functioning purely as a stakeholder and would incur no liability if, for example, it proved impossible to collect amounts owed by a shipper as a result of the revised Quality Bank invoices. *Id.*

3068. The TAPS Carriers note that Mitchell qualified his opinion regarding the administrative feasibility of making retroactive adjustments to Quality Bank calculations by stating that his opinion was based on his understanding that the Quality Bank would continue to deal only with shippers of record, not others, such as royalty owners or customers of the shippers, with which a shipper might have some contractual relationship. *Id.* at p. 31. The TAPS Carriers explain that it would not be administratively feasible for the Quality Bank either to collect money from or to pay money to parties other than the shippers of record. *Id.* They note that the Quality Bank has no information on the identity of entities other than shippers of record, or of any contractual or other legal obligations that a shipper might have to such entities. *Id.* In addition, the TAPS Carriers claim that, even if the Quality Bank had information on the contractual or other arrangements between shippers and third parties, it would have no way of knowing whether the third party agreed with the shipper's interpretation of any such agreement. *Id.* Finally, they state, the Interstate Commerce Act regulates the legal relationship between a pipeline carrier and its shippers. *Id.* It is not apparent to the TAPS Carriers what legal authority they would have to compel payment from an entity that was not its shipper. *Id.*

3069. The TAPS Carriers do not see that the necessity of dealing with shippers would cause a problem for the Quality Bank. *Id.* According to them, there have been a relatively small number of shippers on TAPS and either the shippers or their corporate successors are still in existence. *Id.*

3070. Commission Staff notes that reparations in this case are not being sought from a carrier, i.e., the TAPS Carriers. Staff Initial Brief at p. 6. Rather, in conjunction with a proposal to establish new West Coast VGO and Naphtha cut valuations effective back to June 19, 1994, that, if adopted, would increase its revenue entitlement, Staff explains Exxon seeks refunds retroactively from other shippers based on the difference between the new and old valuations. *Id.* Thus, Staff argues that, because there is no claim for damages from the TAPS Carriers, the Exxon reparations claim is really a claim for refunds from other shippers that might result if the Naphtha and VGO valuation methods are retroactively changed. *Id.*

3071. The Staff's position is that Exxon's witnesses, Pavlovic and Toof, attempt to confuse reparations and refunds by: (1) repeatedly referring to the refund amounts sought as damages, (2) suggesting that the effective date of the proposed Naphtha and VGO changes should be June 19, 1994, because of the Interstate Commerce Act's limit on reparations to a two-year period prior to the date of filing of complaints, and (3) then limiting their refund calculations to that two-year period.[905] *Id.* In Staff's view, their attempt fails to overcome the fact that there is no evidence that the TAPS Carriers violated their tariffs[906] and that Joint Exhibit No. 12 states that Exxon does not seek payment from the TAPS Carriers's own funds, but only seeks a pass-through by the TAPS Carriers of any refund overpayments by other shippers. *Id.* at pp. 6-7. Inasmuch as there are no damages being sought from the TAPS Carriers and no showing of a violation of the TAPS tariffs, Staff argues there is no basis for an award of reparations. *Id.* at p. 7. Staff recommends that the claims against other shippers should be considered in connection with Issues 3 and 4 concerning the effective dates for any changes in the valuation methodologies for the Naphtha and VGO cuts and any refunds that may result, issues which Staff is not addressing. *Id.*

3072. According to Staff, neither of Exxon's arguments in support of reparations has merit. Staff Reply Brief at p. 3. First, Staff states, Exxon suggests that the issue of reparations is valid here because of the retroactive relief claims in the Exxon and Tesoro complaints, reference to section 13(1) of the Interstate Commerce Act in the Commission's 1996 hearing order on the Exxon complaint, and the statement in *Trans Alaska Pipeline System,* 82 FERC at p. 62,352, that, if Exxon's complaint is successful, "reparations are available." *Id.* (citing Exxon Initial Brief at pp. 386-87). These complaints and the Commission's responding orders referenced by Exxon, must, in Staff's view, be put in the proper context. *Id.* Staff points out that Exxon's Prayer for Relief in its 1996 complaint at page 22, paragraph (4), requests a finding that the TAPS Carriers "failed to comply with the [Quality Bank Methodology] Tariff's requirements for administering the distillation methodology and determining payment to, and receipts from, the Quality Bank in violation of Sections 6(1) and 6(7) of the [Interstate Commerce Act]." *Id.* Thus, explains Staff, an allegation of violations of the Act by the TAPS Carriers was an important element of the Exxon complaint. *Id.*

3073. Staff asserts that the Commission, in its 1996 hearing order, noted that Exxon's complaint alleged a failure to comply with the Quality Bank tariff, and that the TAPS Carriers had responded by denying the allegations. *Id.* (citing *Trans Alaska Pipeline*

[905] Staff cites the following in support of this position: Exhibit Nos. EMT-68 at pp. 7-18, l3-14, EMT-1 at pp. 28, 32-33.

[906] Staff cites Exhibit No. PAI-47 at p. 7 in support of this statement.

System, 76 FERC at p. 61,621). It explains that the subsequent order's reference to section 13(1) and statement concerning the availability of reparations reflects the Commission's recognition that Exxon's complaint had requested relief in the form of reparations and is not a pre-approval for the payment of reparations. *Id.* at pp. 3-4. Staff argues that, until execution of Joint Exhibit No. 12, which resolved any real claims against the TAPS Carriers for damages, Exxon appeared to be pressing a genuine claim against the Carriers for Interstate Commerce Act violations that would justify the Commission invoking section 13(1) and paying reparations. *Id.* at p. 4. Staff asserts that the referenced Commission orders, therefore, provide no support for finding that reparations are an issue in this proceeding subsequent to the execution of Joint Exhibit No. 12. *Id.*

3074. Exxon's second argument for recognizing reparations in this case, states Staff, is its assertion that, in *Trans Alaska Pipeline System*, 97 FERC at p. 61,652, the Commission directed that all matters remanded in *Exxon* and *Tesoro* be taken up in the present hearing, including reparations related to Naphtha and VGO valuations. *Id.* (citing Exxon Initial Brief at p. 387). However, Staff notes, the Commission's order did not discuss reparations claims and identified only the following as central issues to be resolved: (1) valuation of the Resid cut and the retroactive application of the modifications in the settlement approved by the Commission in 1997 (*Exxon* remand); (2) valuation of the Naphtha and VGO cuts and the continued just and reasonableness of the distillation methodology (*Tesoro* remand); and (3) sulfur processing adjustment (replacement product proceeding). *Id.* (citing 97 FERC at p. 61,650). Staff argues that the focus in the Commission's order on issues other than reparations (and the absence of any reference to reparations) means that that order lends no strength to Exxon's argument. *Id.* It concludes that, although Exxon's 1996 complaint passed the threshold prima facie test for raising a claim for reparations, the execution of Joint Exhibit No. 12 removed that claim. *Id.* at p. 5. There is an absence in the resulting record in this case of any basis for claiming damages under ICA section 13(1) against a carrier, Staff concludes, and it recommends that Exxon's claim for reparations be denied. *Id.*

DISCUSSION AND RULING

3075. The first question raised concerns whether reparations are an issue in these proceedings. Staff's analysis, summarized above, correctly indicates that they are not. According to Staff, Exxon "seeks retroactive Quality Bank methodology changes and refunds that may result from such changes from refiners and other shippers, not reparations from any carrier." Staff Reply Brief at p. 2. That this is an accurate statement is made clear by the Joint Stipulation of the Parties, filed October 3, 2002. Since Exxon has agreed that it is not seeking reparations from the TAPS Carriers, the Commission lacks jurisdiction to hear its complaint.

3076. In any event, even were reparations to be an issue here, I would not award reparations to Exxon. While other arguments have been made, Exxon's claim for reparations focuses on the question of what the effective date for the new West Coast Naphtha value should be.[907] For reasons stated above, I have determined that the new West Coast Naphtha value should be effective on a going-forward basis only. It follows that Exxon is, therefore, not entitled to reparations.

3077. Moreover, Exxon's argument regarding reparations fails on other grounds as well. As noted by the Eight Parties,[908] the Interstate Commerce Act, in pertinent portion, provides as follows:

> Whenever, after full hearing, upon complaint made as provided in section 13 of this Appendix, . . . the Commission shall be of [the] opinion that any individual or joint rate, fare, or charge whatsoever demanded, charged, or collected by any common carrier or carriers subject to this chapter for the transportation of persons or property, as defined in section 1 of this Appendix, or that any individual or joint classification, regulation, or practice whatsoever of such carrier or carriers subject to the provisions of this chapter, is or will be unjust or unreasonable or unduly discriminatory or unduly preferential or prejudicial, or otherwise in violation of any provisions of this chapter, the Commission is empowered to determine and prescribe what *will be* the just and reasonable individual or joint rate, fare, or charge, or rates, fares, or charges, *to be thereafter* observed in such case or the maximum or minimum, . . . *to be charged* . . . .

Title 49 App. § 15(1) (1988) (emphasis supplied). According to the Eight Parties, in this language, the Act only allows for prospective rate changes. Eight Parties Initial Brief at p. 211. Exxon did not directly reply to this argument.

3078. Exxon does argue that the Commission never has established "lawful rates through a distillation methodology" because the Circuit Court has not accepted the Commission's determination as to the value of each of the nine cuts for both the Gulf Coast and the West Coast. Exxon Reply Brief at pp. 456-57. While I suspect that it is not so, a review of the factual situation regarding Naphtha might cause one to think that Exxon made this argument tongue in cheek. In 1993, the Commission modified and adopted a contested

[907] The parties have agreed that West Coast VGO should be valued as the OPIS West Coast High Sulfur VGO weekly price and that, "if a different West Coast Naphtha valuation methodology is adopted in this proceeding, it and the new West Coast VGO value should have the same effective date." Joint Stipulation of the Parties, filed October 3, 2002, at p. 4; Exxon Initial Brief at p. 384.

[908] Eight Parties Initial Brief at p. 211.

settlement in which it determined that the gravity method should be replaced by the distillation method for calculating the Quality Bank. *Trans Alaska Pipeline System*, 65 FERC ¶ 61,277 (1993). The Commission, in that order, decided that, both the West Coast and the Gulf Coast Naphtha values should be determined using the Platts U.S. Gulf Coast spot quote for Waterborne Naphtha. *Id.* at p. 62,289. Its order was appealed to the Circuit Court which affirmed it except as regarding the Distillate and the Resid cuts. *OXY*, 64 F.3d at p. 701.

3079. It is totally clear to me that both the Commission and the Circuit Court found that it was just and reasonable for the TAPS Carriers to use Platts U.S. Gulf Coast spot quote for Waterborne Naphtha as a component of its Quality Bank formula. I see nothing in either ruling which indicates that either believed that, until the Commission and the Courts were satisfied with the valuation of each and every cut on each coast, the TAPS Carriers could not use the distillation methodology to calculate the Quality Bank. Unlike its argument regarding Resid, I conclude that Exxon's argument that there is no "lawful [rate] through a distillation methodology," therefore, has no merit.

3080. In addition, Exxon challenges the Eight Parties's reliance on *Arizona Grocery*. It states that *Arizona Grocery* is not pertinent because there was no evidentiary support for the Commission's 1993 decision regarding Naphtha and because "the use of Gulf Coast prices to value West Coast Naphtha was based solely on a 'No Adjustment Policy' that was discredited on appeal and then abandoned by the" Commission. Exxon Reply Brief at pp. 458-60. Exxon's argument, however, ignores, once again, the simple truth – the Commission's 1993 holding determining the Naphtha values set forth in its ruling to be just and reasonable was affirmed by the Circuit Court. *OXY*, 64 F.3d at p. 701. Exxon's claim here, therefore, amounts to an impermissible collateral attack on these rulings. *See Dynegy Power Marketing, Inc.,* 101 FERC ¶ 61,369 at P 18-20 (2002).

3081. The Supreme Court, in *Arizona Grocery,* considered whether the Interstate Commerce Commission properly awarded reparations "with respect to shipments which moved under rates approved or prescribed by it." *Arizona Grocery*, 284 U.S. at p. 381. It noted, when that Commission determined that a rate was just and reasonable, that it acted in its legislative capacity and that its decision had "the force of a statute." *Id.* at p. 386. The Supreme Court further noted that the Commission was forbidden, by statute, from approving a rate which was not just and reasonable and that it could not "retroactively repeal its own enactment as to the reasonableness of the rate it has prescribed." *Id.* at pp. 387, 389. The Interstate Commerce Commission, the Supreme Court added, could repeal the rate setting order, but it could only do so prospectively, and noted that its ruling only affected rates established by the Interstate Commerce Commission and not "carrier-made rates." *Id.* at pp. 389-90; *see also Aquila Energy Marketing Corp. v. Natural Gas Pipeline Co. of America*, 66 FERC ¶ 61,284 at pp. 61,810-11 (1994).

3082. In the instant case, as was discussed above, while the Commission previously determined that it was just and reasonable for both the Gulf Coast and the West Coast Naphtha values to be determined using a Gulf Coast reference price, the instant record has made it clear that the use of a Gulf Coast reference price for West Coast Naphtha no longer is just and reasonable. The proxy which I ordered to replace it only can be made effective on a prospective basis. Therefore, no party is entitled to reparations.[909]

CONCLUSION

3083. It is concluded that the rates, and the Tariff provisions affecting those rates, which are in conformance with the findings and conclusions of this Initial Decision are just and reasonable.

ORDER

3084. IT IS ORDERED, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that within thirty (30) days of the issuance of the final order of the Commission in this proceeding, the TAPS Carriers shall file revised Tariff sheets in accordance with the findings and conclusions of this Initial Decision, as adopted or modified by the Commission.

EDWARD M. SILVERSTEIN
Presiding Administrative Law Judge

[909] I feel compelled to note that, in essence, Exxon really is not seeking "reparations" which, in this case, would be damages awarded against the TAPS Carriers for violating their Tariff. As all parties have agreed that the TAPS Carriers did not violate the terms of their Tariff, that there are no damages sought from them, and that what is sought is an order requiring the Quality Bank Administrator to re-calculate the Quality Bank for a period of time, it is clear that what is sought is refunds, not reparations.