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. ExxonMobil Pipeline Company Phillips Transportation Alaska, Inc. Unocal Pipeline Company Williams Alaska Pipeline Company, L.L.C.	Docket No. IS03-137-001 Docket No. IS03-141-001 Docket No. IS03-142-001 Docket No. IS03-143-001 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.

> *   *   *   *

> 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*

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[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 Platts 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

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[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

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[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

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[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.

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[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 before 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

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[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,

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[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 $\quad=\quad$ ((175-60)/(390-60)) * PIMS C_5-390 yield

175º-350ºF Naphtha yield $\quad=\quad$ ((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 $\quad=\quad$ 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 $\quad$ - $\quad$ the value produced by the regression formula he developed

West Coast VGO $\quad$ - $\quad$ OPIS West Coast price for high sulfur VGO

West Coast Distillate $\quad$ - $\quad$ 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 100°F C_5 cut point rather than the 60°F 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 1050º+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.

>   *   *   *   *

> 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

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[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.*

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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

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[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

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[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.

<p style="text-align:center">*   *   *   *</p>

[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.

*   *   *   *

[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.

*   *   *   *

[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.
>
>   *   *   *   *
>
> Even if he were to incur the costs needed to reduce the decoking cycle, he would still have a problem with vapor velocity.
>
>   *   *   *   *
>
> 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.

*   *   *   *

[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. *Id*. 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

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[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

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[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

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[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.*

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[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

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[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.

> *   *   *   *

> 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

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[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-

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[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.

D.   MARTIN TALLET

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

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[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

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[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

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[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

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[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

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[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.

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[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

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[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

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[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

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[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

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[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

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[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,

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[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,

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[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

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[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° 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

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[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

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[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.

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[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,

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[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

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[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

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[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

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[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.

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[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.

* * * *

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.

* * * *

[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.

* * * *

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

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[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.

> *   *   *   *

> 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.

> *   *   *   *

> 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

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[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

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[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

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[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 hydrockackate 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

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[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.

> *   *   *   *

> 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.

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[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]

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

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[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

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[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.

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[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

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[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.*

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[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

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[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.