883. Exxon accuses the Eight Parties of not providing any substantial evidence in support of their proposed 100°F C_5 cut point. *Id.* at pp. 22-23. Indeed, Exxon claims, O'Brien admits that the true C_5 cut point is 60°F and that 60°F represents the best initial boiling point for C_5. *Id.* at p. 23. According to Exxon, the principal support for O'Brien's 100°F C_5 cut point contention is that it provided a closer fit to the Coker Naphtha distillation curve he presented than did the 60°F cut point proposed by Tallett. *Id.* After the conversion described above, Exxon argues, the evidence demonstrated that the 60°F C_5 cut point produced a closer fit. *Id.* at pp. 23-24.

884. As for O'Brien's reliance on a 96°F cut point provided with the PIMS model documentation to support his position, Exxon explains that the reliance was unwarranted. *Id.* at p. 24. The reference to a 96°F cut point, Exxon argues, was prepared for demonstration purposes based on generic technology and was not intended to represent a standard cut point. *Id.* Also, the documentation, Exxon contends, was based on stale data prepared before current reformulated fuels altered U.S. refiners's fractionation practices, and Aspen Technology neither sells nor stands behind the data in that documentation. *Id.* O'Brien, Exxon states, admits his inexperience with both operating PIMS as well as the documentation provided with the PIMS model. *Id.* at p. 25.

885. The Eight Parties respond by pointing out that the logical place to find an appropriate cut point is the PIMS model itself. Eight Parties Initial Brief at p. 15. According to the Eight Parties, Tallett admits that PIMS uses a C_5 cut point for Coker Naphtha of 96°F on a true boiling point basis. *Id.* Furthermore, the Eight Parties relate, Tallett confirmed that the cut point for LSR in PIMS was 96°-180°F and that ANS is one of the crudes in the PIMS model. *Id.*

886. According to the Eight Parties, the Gary & Handwerk textbook indicates that the LSR cut point for typical crude oil fractions is 90-190°F on a true boiling point basis. *Id.* at p. 16. This 90°F initial boiling point used in the textbook, the Eight Parties continue, is on both an ASTM and TBP basis. *Id.* The Eight Parties assert that Tallett testified that the lowest boiling point for C_5 is 82°F, which is the boiling point for Isopentane, the heaviest Pentane. *Id.* This boiling point, the Eight Parties note, is confirmed by Gary. *Id.*

887. On Reply, Exxon argues that the record supports a 60°F C_5 cut point. Exxon Reply Brief at p. 15. Citing the Transcript at p. 1248, it claims that O'Brien agreed to that fact. Exxon Reply Brief at p. 15. It notes, in addition, that despite the Eight Parties's claim that Gary, and his treatise, support the use of at least an 82°F Naphtha cut point, Gary testified "that the C_5 cut point for Coker material should be in the 'low 60s.'" *Id.* at p. 17.

888. Exxon argues that O'Brien's testimony supporting a 100°F cut point was based on an ASTM boiling point basis while the PIMS model and the assays used in this case are based on a true boiling point basis. *Id.* at p. 19. It asserts that a 60°F cut point most accurately reflects the point separating the C_4 material from the C_5 material and is closer to the cut point used by the Quality Bank than that proposed by the Eight Parties. *Id.* at p. 20.

889. In their Reply Brief, the Eight Parties claim that Exxon misreads O'Brien's testimony and that O'Brien clearly supports a 100°F C_5 cut point. Eight Parties Reply Brief at p. 9. According to the Eight Parties, PIMS uses a 96°F C_5 cut point and Tallett confirmed this. *Id.* They conclude that, as O'Brien's suggested C_5 cut point of 100°F is closer to the PIMS cut point of 96°F, it is more acceptable than Tallett's proposal that a 60°F cut point be used. *Id.* at p. 12.

2. Assays

890. A dispute also exists over which ANS assays should be used with PIMS, Exxon notes, to calculate the product yields resulting from running ANS Resid through a Coker, for the past period at issue in the case. Exxon Initial Brief at p. 25. Exxon argues that an average of all reliable assays should be used, while the Eight Parties believe that three of the ten assays in dispute should be used in evaluating the past period – two assays produced by Caleb Brett, one in 1996 and the other in 2001, and a 1994 Exxon assay. *Id.* at pp. 25-26.

891. As for the future period, Exxon states, all parties agree that the 2001 Caleb Brett assay should be used as a starting point and that the two new assays taken in April/May 2003 and April/May 2004 will also be used in this proceeding. *Id.* at pp. 26-27. The new assays, Exxon explains, are necessary as the qualities of the TAPS common stream have changed over time because of the new Alpine and Northstar fields and because of declines in the older fields's production.[357] *Id.* at pp. 27-28. Also for these reasons, Exxon recommends that new assays be taken on an annual basis or whenever the Quality Bank Administrator has reason to believe that there may have been changes to the common stream. *Id.* at p. 29.

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[357] Exxon explains that, if the new assays and the 2001 Caleb Brett assay are deemed by the Quality Bank Administrator to be consistent, the newest assay should be used. Exxon Initial Brief at p. 28. However, Exxon continues, if the new assays and the 2001 Caleb Brett assay are deemed by the Quality Bank Administrator to be inconsistent, the Quality Bank Administrator should attempt to determine why the assays are inconsistent, and determine which assay should be used. *Id.* Finally, Exxon states, if the Quality Bank Administrator cannot determine the cause of the differences, he should use an average of the assays. *Id.* at p. 29.

892. Exxon additionally argues that, on a going forward basis, the carbon residue content of the Resid be measured using the Microcarbon Residue ("Microcarbon") test rather than the Conradson Carbon Residue ("ConCarbon") test. *Id.* According to Exxon, the evidence demonstrates that the Microcarbon test is an improved method of measuring carbon residue equivalent to the ConCarbon test but more accurate with a higher level of repeatability and reproducibility. *Id.* at pp. 29-30. The Microcarbon test, according to Exxon, is the industry standard for testing carbon residue, especially for heavy fractions like the Resid at issue in this proceeding. *Id.* at p. 30. Answering the Eight Parties's argument that the ConCarbon test is the one related to the PIMS model, Exxon argues that the American Society for Testing and Material has found that the two methods are alike although the Microcarbon test is more precise. Exxon Reply Brief at p. 24. It further suggests that Dayton agrees that PIMS works as well with the Microcarbon test as with the ConCarbon. *Id.* at p. 25.

893. Regarding the past periods, Exxon asserts that the 10 assay average, adjusted to reflect the weight-blending approach advocated by the Eight Parties, is the most reasonable method of measuring the common stream's qualities. Exxon Initial Brief at p. 31. According to Exxon, this 10 assay average of the ANS Resid results in an average carbon residue content of 23.07%. *Id.* The Eight Parties, Exxon relates, support a three assay average resulting in an average carbon residue of 22.60%. *Id.* at p. 32. Exxon claims that the 10 assay average is strongly supported by the record because none of the assays are without flaws and the carbon residue content of 23.07% proposed by Tallett was near the lower end of the range of possible results, while Dayton's 3-assay average represented the lowest extreme of that range. *Id.* at pp. 32-33. Using all available, reliable assays, Exxon contends, "reduces the chance that a single assay, or the manner in which a single lab has produced a particular assay or performed a particular test, will unduly skew the average." *Id.* at p. 34.

894. Exxon accuses the Eight Parties of an effort to avoid the "obvious superiority" of the 10 assay average. *Id.* at p. 35. The criticisms presented by the Eight Parties, Exxon believes, are without merit. *Id.* According to Exxon, the procedures used by Haverly in making the assays are all standard industry practice. *Id.* Addressing the Eight Parties's contention that three of the ten assays should be disregarded because they had Resid volume percentages either higher or lower than the range of monthly Quality Bank assays for the year in which the sample was taken, Exxon insists that the Eight Parties are mistaken. *Id.* at p. 36. Dayton's comparison of assays, Exxon explains, was taken on a single day with a monthly average sample while the monthly Quality Bank assays were based on a continuous sample drawn over a month-long period. *Id.* Such a comparison, Exxon maintains, was "plainly an apples-to-oranges comparison." *Id.*

895. According to Exxon, the 10 assay average is the most reasonable put forth, while the 3 assay average advocated by the Eight Parties is at the extreme low end of the range of possible carbon residue values, consequently producing the highest Resid value. *Id.* at

p. 39. Additionally, Exxon notes that, when the 3 assay average is computed on the basis of the Microcarbon test rather than on the basis of the mix of methods used by Dayton, the results clearly validate the reasonableness of the values proposed by Tallett.[358] *Id.* at p. 40.

896. For prospective periods, the Eight Parties agree with Exxon that an average of the 2001 Caleb Brett assay and assay(s) taken in the future should be used. *Id.* at pp. 27-28; Eight Parties Initial Brief at p. 19. As for the retroactive period, the Eight Parties maintain that a three assay average should be used. *Id.* at p. 20. According to the Eight Parties, seven of Exxon's proposed ten assays have a serious flaw. *Id.*

897. Four Haverly/Chevron assays used by Tallett, the Eight Parties begin, have Resid ConCarbon measurements taken from cuts other than the 1050°+ cut, to wit: 1005°F, 1065°F, 1000°F, and 650°F.[359] *Id.* at pp. 20-21. The problem, the Eight Parties explain, is that, in order to use measurements taken from cuts with these cut points to determine the qualities of the Quality Bank 1050°+ Resid cut, it is necessary to extrapolate data based on a single data point, which is not possible. *Id.* at p. 21. The Eight Parties point out that Tallett agrees with their concerns regarding measuring ConCarbon at a cut differing significantly from the 1050°+. *Id.*

898. Three assays, the Eight Parties assert, reported Resid yields outside of the range of Resid volume yields in the assays taken each month of the year by the Quality Bank Administrator. *Id.* at p. 22. The Eight Parties explain that the Quality Bank Administrator's assays do not show the Resid qualities needed to be input into the PIMS model, but do show how much Resid each sample contains by volume. *Id.* at pp. 22-23. According to the Eight Parties, assays should not be used if their Resid volume yields were higher or lower than all of the monthly Resid volume percentages in the Quality Bank Administrator's assays for the year in which the assay sample was taken. *Id.* at p. 23.

899. The Williams/BP assay is the last disputed assay, according to the Eight Parties, and it is faulty, they say, because the vacuum distillation procedure used is D-2892, which, they claim, is not the appropriate method. *Id.* at p. 24. According to the Eight Parties, everyone agrees that the test referenced in the assay is the wrong test and, unless

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[358] Exxon explains that the evidence shows that the carbon residue value for the 3-assay average using the Microcarbon test is 23.29%. Exxon Initial Brief at p. 40. The carbon residue content test, Exxon insists, confirms the reasonableness of the 10-assay average. *Id.*

[359] The Eight Parties explain that the Quality Bank Resid cut is defined as the crude components that have not boiled off at 1050°F (referred to as "1050°+"). Eight Parties Initial Brief at p. 20.

it can be shown that the correct test was performed, this assay must be discarded. *Id.* at pp. 24-25. Thus, the Eight Parties maintain, Tallett's proposed 10 assay average is unsupportable because seven of the ten assays are invalid. *Id.* at p. 25.

900. As for implementing changes in assays to be used for Resid valuation, the Eight Parties advocate that once the Commission determines the appropriate assays to use as well as the C_5 cut point issue, the Quality Bank Administrator should be ordered to recalculate using yields equivalent to the most recent version of PIMS. *Id.* at p. 26.

901. On reply, Exxon declares that the assay question has two components: which assay(s) should be used on a going-forward basis (i.e. from the date of the final order in this proceeding), and which assay(s) should be used for the period from December 1, 1993, through that date. Exxon Reply Brief at p. 20. Other than suggesting that the parties do not agree on whether the Microcarbon or the ConCarbon test should be used, "the parties agree that, if the Resid valuation is to be done on the basis of the common stream, then current assay data should be used to account for recent changes in" its composition. *Id.* at pp. 20-21 (note omitted). It adds that the 2001 Caleb Brett assay is a starting point, that it would not be prudent to rely solely on it, and that it should be tested against assays the parties agree should be taken in 2003 and 2004. *Id.* at p. 21. Exxon declares that it now has no objection to use of an average of the 2001 Caleb Brett assay and the new ones if "the Quality Bank Administrator deems the results of the 2001 assay and the new assays to be consistent." *Id.* at p. 22. It also suggests that the Quality Bank Administrator should recheck common stream values on a periodic basis. *Id.*

902. Addressing the going-forward period, the Eight Parties claim that Exxon posits that the 2001 Caleb Brett "assay should not be used unless it differs significantly from the 2003 and 2004 assays."[360] Eight Parties Reply Brief at p. 13. They suggest that there are problems with the 2003 assay and that, if those problems cannot be resolved, this assay should not be used. *Id.* The Eight Parties add that the "2004 assay should only be used if all the parties agree that the [2004] assay is representative of all the input streams and free of analytical problems." *Id.* at p. 14.

903. Acknowledging that the Microcarbon test is newer, the Eight Parties do not agree that Dayton suggested it was more precise. *Id.* Rather, they state that, were the ConCarbon test preformed by an "experienced lab technician" who performs multiple tests, it is just as accurate as the Microcarbon test. *Id.* at p. 15. Further, the Eight Parties note, Mitchell testified that when both test were performed, the Microcarbon test "gave almost universally higher carbon residue results than the" ConCarbon test. *Id.* Therefore, they argue, the question is not which test is more precise, "but whether a test

[360] Exxon's position is not accurately described by the Eight Parties. See the discussion above.

should be used that reaches consistently higher carbon residue results." *Id.* The answer, according to the Eight Parties, is that the ConCarbon test should continue to be used as "it is the test that the PIMS yields were based upon." *Id.*

904. Turning to the past period, Exxon states that the parties disagree on whether a 10-assay average should be used, as suggested by Tallett, or a 3-assay average, as suggested by Dayton. Exxon Reply Brief at p. 26. In making their argument, Exxon explains, the Eight Parties ignore the impact of which carbon test results should be used. *Id.* Should the Microcarbon test results be used, Exxon asserts, "Tallett's proposed 10-assay average is far more reasonable than Ms. Dayton's proposed 3-assay average." *Id.* at p. 27.

905. Exxon also defends Tallett's use of certain assays against the Eight Parties's attack. *Id.* at pp. 28-33. It begins by acknowledging that the four Haverly/Chevron assays "employed an assay manger computer program to recut the assay data and [that they] did not always use the 1050°F cut point used by the Quality Bank." *Id.* at p. 29. However, it argues that this is not a reasonable basis for dismissing these four assays because they have a quality rating of good and accurate carbon residue numbers. *Id.* Exxon adds:

> Moreover, the evidence shows that the Haverly/Chevron assays were performed in accordance with the widely-accepted procedure of taking small incremental cuts of about 10°F, examining the qualities of each cut, and then taking the industry-standard mathematical interpolation procedures to reconcile and balance quality results and to state the qualities of cuts specifically matching the Quality Bank cuts.

Id. at pp. 29-30.

906. Next, Exxon turns to the three assays which Dayton claimed should be disregarded because the percentage of Resid was "either higher or lower than the range of monthly Quality Bank assays for the year in which the sample was taken." *Id.* at p. 30. According to Exxon, it is unfair to compare assays of samples taken on a single day with assays of samples taken over a full month. *Id.*

907. The last assay addressed by Exxon is the one performed by Caleb Brett in 1995 for BP and discovered in the files of Williams. *Id.* at pp. 31-32. Exxon argues that, although the assay reflects that the vacuum distillation method used was D-2892, which Dayton claims is not appropriate, Tallett testified that the results reported could not by reached by the D-2892 methodology and that the results only could be reached if the correct vacuum distillation method, D-5236, was used. *Id.* at p. 32.

908. According to Exxon, Tallett's 10-assay average is reasonable "when viewed against the many possible assay combinations that were presented at the hearings." *Id.* at p. 33. It states that the various combinations produce carbon residue averages ranging from a low of 22.48% to a high of 24.3%[361] and argue that Tallett's carbon residue content of 23.07% "is conservative and near the lower end of the range of possible results." *Id.* at pp. 33-34.

909. In their Reply Brief, the Eight Parties acknowledge that all parties agree that different assays should be use for the going forward period than for the retroactive period. Eight Parties Reply Brief at p. 12. Referring to the 2001 Caleb Brett assay, the Eight Parties note that Exxon did not believe it should be used "unless it differs significantly from the 2003 and 2004 assays." *Id.* at p. 13. They claim that Exxon fails to state any reason why this should be so, and argue that it should be used whether it is consistent or not. *Id.*

910. The Eight Parties next turn to the 2003 ANS Valdez assay and assert that, while they initially agreed that it should be used, they have now seen the results from it and believe that there are problems "both with respect to the testing that was performed and with the samples that were taken." *Id.* They state that the parties are discussing (as of November 2003) whether the samples can be retested and, if not, the Eight Parties submit that the 2003 ANS Valdez assay cannot be used. *Id.* With regard to the 2004 assay, the Eight Parties state: "Given the problems with the 2003 assay, [they] believe that the ANS Valdez assay to be taken as part of the agreed suite of 2004 assays should only be used if all the parties agree that the assay is representative of all the input streams and free of analytical problems." *Id.* at p. 14.

911. Turning to which assays should be used for the retroactive period, the Eight Parties begin by asserting that seven of the 10 assays in the record should not be used because they are unreliable for one or more of the following reasons: (1) the carbon residue test was based on a different cut than the 1050°F Resid cut point used by the Quality Bank; (2) "the volume of Resid included in the assay was outside the range of the Quality Bank assays for the entire year in which the assay was taken;" and (3) "the wrong test was used to determine the qualities of the Resid cut." *Id.* at p. 16. For this reason, the Eight Parties find fault with Exxon's suggestion that all 10 assays be used. *Id.* They further note that Tallett, Exxon's witness, agreed with Dayton's criticism of these seven assays. *Id.* at pp. 16-17.

912. In defense of the two Caleb Brett assays, which it claims Exxon attacked, the Eight Parties note, they were performed by the same laboratory which performs assays on

[361] According to Exxon, other combinations produce carbon residue averages of 22.60%, 23.41%, 23.51%, 23.53%, and 23.77%. Exxon Reply Brief at pp. 33-34.

behalf of the Quality Bank Administrator. *Id.* at pp. 17-18. They suggest, too, that, at the hearing, Tallett withdrew his criticism of the two assays. *Id.* at p. 18.

3. Coke Value

913. Exxon explains that the parties agree that the coke produced by the coking process should be valued on the basis of the free on board ("FOB") vessel prices for fuel grade coke published in the *PCQ*. Exxon Initial Brief at p. 40. Specifically, Exxon notes, the parties agree that the published coke prices to be used are: (1) on the West Coast, the mid-point monthly quote from *PCQ* for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke; and (2) on the Gulf Coast, the mid-point monthly quote from *PCQ* for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke. *Id.* at pp. 40-41; Joint Stipulation p. 2.

914. The only disputed issue remaining, Exxon states, is whether the FOB vessel prices must be adjusted to reflect transportation, handling, storage, and reselling costs incurred by the refiner when shipping the coke from the refinery gate to the point of sale reflected in the FOB vessel price. Exxon Initial Brief at p. 41. The Eight Parties's failure to make such an adjustment, Exxon argues, results in an overstatement of approximately 65¢/barrel in the before-cost value of the coke produced from the ANS Resid over the period from 1992 through 2001. *Id.*

915. In Exxon's view, to properly reflect Coke's value to the refiner, the FOB vessel price must be adjusted. *Id.* Exxon explains:

> Both of the stipulated *PCQ* Coke prices are export prices quoted on an FOB vessel basis, and it is well established that an FOB vessel price means that the product (*i.e.*, Coke) is to be delivered and loaded by the seller at no expense to the buyer. This means that in order to realize the FOB vessel price, the refiner must incur all of the costs required to get the Coke from the refinery to the dock and onto the vessel, the point of sale reflected in the FOB vessel price. Accordingly, in order to reflect the value of the Coke to the refiner, the FOB vessel price must be adjusted to account for the substantial costs incurred by the refiner to move the Coke from the refinery to the vessel.

Id. at pp. 41-42 (emphasis in original; citations omitted).

916. While the published *PCQ* FOB vessel prices for coke are the appropriate starting point for determining the value of coke to the refiner, Exxon insists, those prices do not represent the value of the coke to the refiner. *Id.* at p. 42. To realize the FOB vessel price, Exxon explains, the refiner must move the coke from the refinery to the vessel and, the costs associated with transporting, handling, storing, and loading the coke constitute a

substantial percentage (about 61% on average on the West Coast) of the reported price for Coke. *Id.*

917. Consequently, Exxon argues, the value of the coke to the refiner on the West Coast is, on average, only 39% of the quoted FOB vessel price. *Id.* Furthermore, according to Exxon, the costs of moving coke from the refinery to the vessel are sometimes so high that the coke is sold at a net loss by the refiner because coke cannot be practicably stored for any length of time by the refinery while continuing refinery operations. *Id.* Coke produced from ANS Resid, Exxon believes, will be radically overvalued unless the FOB vessel price is adjusted to account for the costs that must be incurred by the refiner to get the coke to the point of sale reflected in the FOB vessel price. *Id.* at pp. 42-43.

918. Exxon notes that the estimated cost of shipping coke from the refinery gate to the point of sale is at least $6.00/short ton on the Gulf Coast and at least $10.75/short ton on the West Coast, and claims that these cost estimates are undisputed. *Id.* at p. 43. Additionally, Exxon states, the Eight Parties agree that coke's value to the refiner is determined by the "net-back" value a refiner can earn from coke produced in the coking process, and that this net-back value is the *PCQ* FOB vessel price less the costs of moving the coke from the refinery to the vessel. *Id.* Consequently, Exxon argues, without adjusting the quoted FOB vessel price for costs of moving coke from the refinery to the vessel, "the FOB vessel price will substantially overstate the value of the coke to the refiner." *Id.* The Eight Parties admit, Exxon asserts, that, without Bartholomew's adjustment, the Resid cut would be overvalued by approximately $10.82 million for every 100 million barrels of ANS crude passing through TAPS. *Id.* at pp. 43-44.

919. As for the Eight Parties's objections to Exxon's coke value adjustment proposal, Exxon asserts that they are without merit. *Id.* at p. 44. Their argument that the adjustment is inconsistent with using unadjusted waterborne prices for other liquid Quality Bank cuts, Exxon insists, is baseless. *Id.* To begin, Exxon explains, coke is the only solid among the Quality Bank products. *Id.* Consequently, Exxon states, the magnitude of the costs of transporting, handling, storing, and reselling the coke are far higher than the corresponding costs for other Quality Bank products and these costs are of a different order of magnitude than the transportation and handling costs associated with the other Coker products. *Id.* The result, Exxon argues, is that the shipping and handling costs for coke represent, on average, more than 60% of its value, while corresponding costs for other Coker products represent only about 2% to 8% of their value. *Id.* at p. 44-45.

920. According to Exxon, although coke accounts for only 4% of the ANS common stream, coke bears over 17% of the total logistics costs (an overly disproportionate amount) for all Quality Bank products while VGO, which accounts for 36% of the ANS common stream, bears only 31% of the total logistics costs. *Id.* at p. 45.

921. The only logical place for valuing coke, Exxon believes, is the refinery gate. *Id.* All parties stipulated to valuing Fuel Gas at the refinery gate, Exxon notes, because there is no Quality Bank reference price for Fuel Gas. *Id.* Consequently, Exxon explains, the parties agreed that Fuel Gas will be valued at the *Natural Gas Week* monthly average California South (Los Angeles) delivered-to-pipeline natural gas spot price, plus a 15¢/MMBtu transportation charge, which represents the cost of transporting the gas from the pipeline at the Arizona-California border to the refinery gate of a refinery in the Los Angeles basin. *Id.* at pp. 45-46. The 15¢ transportation charge is added to the pipeline spot price, Exxon asserts, because Fuel Gas produced in the coking process at the refinery is used by the refinery to avoid purchasing Fuel Gas that the refinery would otherwise have to purchase from the pipeline at the Arizona-California border and pay to have delivered to the refinery gate in Los Angeles. *Id.* at p. 46. The same reasoning, Exxon argues, applies to coke valuation as it is the only other Coker product for which there is no Quality Bank reference price. *Id.* at pp. 46-47.

922. Exxon also objects to the Eight Parties's attempt to introduce the value of calcined coke as an issue at the hearing for the first time. *Id.* at p. 47. According to Exxon, calcined coke is a higher quality coke made by processing of higher grades of unprocessed or "green" Coke. *Id.* Exxon notes that the parties have stipulated that coke should be valued on the basis of the *PCQ* quoted prices for fuel grade or green coke for the purposes of this case. *Id.* Coke made from 1050+°F Resid, Exxon relates, is a poor quality coke unsuitable for calcination due to its concentration of metals, carbon residue, and sulfur. *Id.* Consequently, Exxon states, the Eight Parties argued, in an earlier phase of the proceeding, that a cut point of 1050°+F for the Resid cut, as opposed to 1000°F, was justified because the coke was to be valued on the basis of a coke price equal to that of the lower valued fuel coke, *not* that of coke used for calcinating. *Id.* at pp. 47-48. As a result, Exxon argues, the Eight Parties are estopped from claiming they are entitled to a higher Resid value based on the higher price of calcined coke. *Id.* at p. 48. This is so, Exxon believes, because were the *PCQ* quoted price for calcined coke used instead, the cut point for the Resid cut would have been lower (1000°F), and the VGO yields would be smaller. *Id.*

923. Additionally, Exxon insists, it is much more expensive to produce calcined coke because there are significant additional costs that must be incurred to process green coke into calcined coke. *Id.* Therefore, Exxon explains, "[i]f the higher price of calcined Coke were used to value the Coke in this proceeding, the proxy price for Coke would have to be adjusted to account for the significantly higher costs of producing calcined Coke." *Id.* at p. 48.

924. Most important, Exxon asserts, is that the Eight Parties have not produced any evidence as to how the price of calcined coke would be adjusted to reflect additional processing costs, and there is no evidence in the record to support the Eight Parties's

attempt to introduce the value of calcined coke into this proceeding. *Id.* at pp. 48-49. Finally, Exxon notes that, because the *PCQ* quoted price for calcined coke is also an FOB vessel price, further adjustments reflecting costs incurred by the refiner to ship calcined coke on a vessel would be necessary. *Id.* at p. 49. Exxon concludes:

> [T]he evidence is overwhelming that in order fairly to value the Coke produced by a refiner in the coking process, the FOB vessel prices for Coke must be adjusted to account for the disproportionately high additional costs that the refiner must incur in order to move the Coke from the refinery to the vessel in order to obtain the FOB vessel Coke price to which the parties have stipulated. For this purpose, the Commission[] should use $10.75 per short ton cost for the West Coast, and $6.00 per short ton cost for the Gulf Coast.

Id.

925. The Eight Parties view is that consistent valuation of Quality Bank cuts is essential in order to achieve just and reasonable valuations, and adopting Exxon's proposal would create "an unacceptable and unnecessary inconsistency" in Resid valuation. Eight Parties Initial Brief at p. 27. According to the Eight Parties, Resid is the heaviest of the five liquid Quality Bank cuts and, once generated from the distillation tower, it is processed in a Coker, creating Coker products. *Id.* Coke, the Eight Parties continue, is one of the eight salable Coker products resulting from the Resid coking process. *Id.* at p. 28. Although all parties agree that the base coke price on the West and Gulf Coasts will be derived from waterborne quotes in the *PCQ*, the Eight Parties state, they disagree whether those price quotes should be adjusted. *Id.* at pp. 27-28.

926. Exxon's proposal to value coke at the refinery gate, the Eight Parties argue, is inconsistent with the current and proposed prices for other liquid products as the coke prices are already on a waterborne basis. *Id.* Additionally, the Eight Parties maintain, valuing coke at an unidentified refinery gate, while other products are valued elsewhere, will create inconsistencies between the coke values and other product values. *Id.* at p. 28. The Eight Parties insist that waterborne prices are the most appropriate basis for valuing liquid products because they represent cargoes of products at their source or destination harbor and are the largest available parcels and include the lowest marketing margins. *Id.* In the case of coke, the Eight Parties contend, the waterborne prices are published by *PCQ* and should be adopted. *Id.*

927. According to the Eight Parties, consistency is sought by all parties in the proceeding as well as the Commission. *Id.* Bartholomew states, the Eight Parties note, that the *PCQ* prices coke at a waterborne location as it is a consistent location. *Id.* at p. 29. Further, the Eight Parties claim that they rely on the Circuit Court's opinion in *OXY* in which it stated that "the [Commission] must accurately value all cuts - - not merely

some or most of them - - or it must overvalue or undervalue all cuts to approximately the same degree." *Id.* (quoting *OXY*, 64 F.3d at p. 693).

928. The Eight Parties argue that Exxon's arguments about the importance of a transportation and handling adjustment are untenable. *Id.* Exxon's position that there currently is no consistency in valuing various Quality Bank cuts, the Eight Parties assert, is wrong because the four gas plant products are consistently valued at the largest quantity available for the products (pipeline basis on the Gulf Coast and truck/rail basis on the West Coast) while the liquid products for the Gulf Coast are consistently valued on a waterborne basis. *Id.* at pp. 29-30. As for West Coast Naphtha, Light Distillate, and VGO, the Eight Parties contend, these are also valued consistently on a waterborne basis. *Id.* at p. 30. The remaining two West Coast liquid cuts (Heavy Distillate and Resid), the Eight Parties believe, should also be valued on a waterborne basis. *Id.* Should the Commission adopt the Eight Parties's proposal, they argue, all liquid products on both coasts will be valued on a consistent waterborne basis. *Id.*

929. Exxon's argument that the coke transportation and handling adjustment is a substantial portion of coke's value, but only a minor portion of other products values, the Eight Parties contend, is flawed. *Id.* Exxon does not acknowledge, the Eight Parties argue, that "on a whole barrel of ANS crude basis, the impact of the [Coke adjustment] . . . on the value of Resid . . . is actually less than the impact a similar, consistent adjustment would have if it were made to VGO and Heavy Distillate." *Id.* Furthermore, the Eight Parties maintain, a comparable Naphtha adjustment would have a similar impact as the proposed coke adjustment. *Id.* at pp. 30-31. Such a result exists, the Eight Parties explain, because the yield of coke from the Coker is small, and, when multiplied by the yield of Resid in ANS, the disproportionate effect does not exist. *Id.* at p. 31. Consequently, the Eight Parties argue, no reason exists to treat coke differently from other liquid products. *Id.*

930. Additionally, the Eight Parties contend that, were the Commission to value coke at the refinery gate, then similar adjustments would be necessary to value every other Quality Bank product, but, the Eight Parties maintain, there is no evidentiary basis to make such adjustments. *Id.* Also, the Eight Parties question which refinery gate would be used for any adjustments. *Id.* at p. 32. Any determination, the Eight Parties assert, would require further litigation, prolonging the ultimate resolution of this case. *Id.*

931. The Eight Parties also believe that Exxon's support for a transportation adjustment only for coke is inconsistent and supported only because it benefits Exxon's economic position. *Id.* According to the Eight Parties, Pavlovic admits that, if all of the transportation cost adjustment he developed were applied to the other products, Exxon's total refund claim would be decreased by 4 or 5%. *Id.*

932. Finally, the Eight Parties argue that Exxon's proposed adjustment of $10.75/ton is merely a guess and is not rooted in any systemic study. *Id.* They point out that Bartholomew did not perform a study of coke transportation rates, nor did he produce any documents related to his analysis. *Id.* Instead, the Eight Parties relate, he testified that his $10.75 was comprised of $2.00 for transportation, $6.75 for handling, and $2.00 for sellers's commissions; without any variation over time. *Id.* at pp. 32-33.

933. On reply, Exxon argues, the "facts" requiring an adjustment to the FOB vessel price of coke are "undisputed." Exxon Reply Brief at p. 35. It then argues that coke, being a coal-like solid,[362] must be transported from the refinery to the vessel and that, as a result of the cost of doing that, the value of coke to a refiner is only 39% of its FOB vessel price. *Id.* It further asserts that, upon occasion, the cost of transportation has been so high that coke had a negative value to the refiner. *Id.*

934. Answering the Eight Parties claim that coke should be valued on a waterborne basis for consistency, Exxon points out that the parties have agreed that Fuel Gas is to be valued on a landborne basis and declares that, therefore, there is no inconsistency in valuing coke on the same basis. *Id.* at p. 39. It also notes that, contrary to the Eight Parties's claim that Fuel Gas is not a "salable product," the Fuel Gas price is based on a published market price. *Id.* at pp. 39-40. Exxon further declares that coke, though only 4% of the common stream, "bears over 17% of the total logistics costs for all Quality Bank products." *Id.* at p. 41.

935. The Eight Parties's challenge to its suggestion that the cost of transporting, handling and selling coke is $10.75, Exxon claims, is without merit. *Id.* at p. 42. It notes that the Eight Parties offered no evidence to counter the testimony of its witness that this was the cost, and that Ross, the Eight Parties's witness, admitted that he had no basis on which to challenge Exxon's evidence. *Id.* As to the Eight Parties's challenge of its witness's calculations, Exxon notes that its witness "described in detail how he did his calculations, which were based on many years of course-of-business dealings with refineries, transportation and storage companies and Coke traders, as well as cost studies done for clients in 1991-92 and 1995." *Id.* at p. 43.

936. In their Reply Brief, the Eight Parties indicate their disagreement with Exxon's contention that the matter in dispute is whether and how the reported coke price should be adjusted. Eight Parties Reply Brief at p. 21. Rather, according to them, the issue is "whether it is appropriate to value one of the eight saleable coker products on a refinery gate basis, as [Exxon] suggests, when none of the other saleable coker products or any of the Quality Bank cuts are valued on that basis." *Id.* The Eight Parties say no. *Id.*

[362] Exxon declares that it disputes the Eight Parties assertion that coke is a liquid product. Exxon Reply Brief at p. 39.

937. Claiming that there is no need to adjust the coke waterborne price, the Eight Parties declare that doing so would create an inconsistency in the Quality Bank valuation. *Id.* at pp. 21-22. They point out that Exxon's own witnesses testified in support of consistency in the valuation of all of the ANS cuts. *Id.* at p. 22.

938. Responding to Exxon's claim that coke is physically different from other products and accordingly should be treated differently, the Eight Parties, while acknowledging the physical difference, state that, as the amount of coke produced from a barrel of ANS is small in comparison with other products produced from the barrel, "the impact of the proposed adjustment . . . is actually less than the impact a similar, consistent adjustment would have if it were made to VGO or Heavy Distillate." *Id.* at pp. 22-23.

939. Regarding Exxon's assertion that setting the price of coke at the refinery gate would be consistent with the manner in which Fuel Gas is treated, the Eight Parties state that Fuel Gas is used internally by a refinery, and therefore is not a marketed product. *Id.* at p. 23. According to the Eight Parties, because it is used internally by the refinery, its value is the same as the refinery's avoided cost of purchasing natural gas. *Id.*

940. The Eight Parties also assert that, while Ross, their witness, did not directly dispute Exxon's witnesses testimony regarding the cost of moving the coke from the refinery to a ship, he "did not agree or even opine as to their accuracy." *Id.* at p. 24. In addition, the Eight Parties state that Ross did not estimate that, unless the coke price was adjusted as Exxon requested, "the Resid cut would be overvalued by approximately $10.82 million for every 100 million barrels of ANS crude." *Id.*

D. COKER COSTS

1. Overall Approach

941. The parties disagree, Exxon explains, over the cost of coking the Resid cut. Exxon Initial Brief at p. 49. Such costs, Exxon notes, are incurred to refine Coker products into products meeting specifications used by the Quality Bank to value the other ANS cuts. *Id.* Exxon presents a cost study demonstrating that the coking cost for ANS Resid is $5.75/barrel on the Gulf Coast and $6.97/barrel on the West Coast in Year 2000 dollars; while the Eight Parties present cost curves to estimate a cost of $4.60/barrel in Year 2000 dollars ($4.30/barrel in Year 1996 dollars) to coke the ANS Resid on both Coasts. *Id.* at pp. 49-50.

942. According to Exxon, Jenkins submitted a line item cost study identifying direct or inside battery limits ("ISBL") costs for all the major equipment required for the Coker and the related downstream refinery units necessary to process Coker products and bring them up to the quality specifications of the Quality Bank reference products. *Id.* at p. 50.

Jenkins next, Exxon states, adds offsite or outside battery limits ("OSBL") Coker costs, fixed and variable operating costs, and related financing costs. *Id.* Finally, Exxon notes, in order to convert his capital cost estimates from Gulf Coast costs to West Coast costs, Jenkins used West Coast location factors. *Id.* Following the cost estimation procedures recommended in the Gary & Handwerk treatise, Exxon relates, Jenkins itemized storage facilities, steam systems, and cooling water systems costs and then provided for the remaining OSBL costs by using a factor of 25% of the ISBL cost of the Coker and related processing units. *Id.* at p. 51.

943. Exxon points out that Jenkins's overall capital cost estimates compared favorably with Coker cost estimates provided in several treatises, as well as with actual costs for several recent Coker construction projects. *Id.* at p. 52. In contrast, the Eight Parties, Exxon states, presented a conceptual cost estimate based on proprietary conceptual cost curves without any supporting documentation. *Id.* at p. 54. Furthermore, Exxon contends, the Eight Parties did not include a West Coast location factor, although they did admit that capital costs are higher on the West Coast than the Gulf Coast. *Id.* According to Exxon, O'Brien essentially concedes that his conceptual approach is subjective and that he could get any result he wanted from the cost curves by adjusting certain constants in the underlying cost curve equations. *Id.* at pp. 54-55. Exxon asserts that the Eight Parties's approach is a "black box," making the evaluation of coker costs "exceedingly difficult, if not impossible." *Id.* at p. 55.

944. Additionally, Exxon contends that cost curves are an unreliable way of calculating Coker costs. *Id.* at p. 56. According to Exxon, the Meyers Handbook states that using cost curves for Delayed Cokers is not practicable because of the differences in the quality of feedstock and the differences in facilities required. *Id.* Also, Exxon states, Gary testified that he was surprised cost curves were being used to estimate Coker costs. *Id.*

945. According to Exxon, cost curves are, at best accurate only to about ±25 to ±30%. *Id.* Even O'Brien's consulting firm, Baker and O'Brien, Exxon relates, recommend an allowance of at least 20% to cost curves in order to capture unidentified but real costs. *Id.* at p. 57. O'Brien, Exxon notes, does not include any contingency allowance for his cost curves. *Id.*

946. Exxon insists that O'Brien's approach to estimating downstream processing units costs was defective. *Id* at pp. 57-58. O'Brien assumes that processing can be done in larger units serving the entire refinery, Exxon states, and, consequently, assigns only incremental costs of such costs to the Coker. *Id.* at p. 58. He also, Exxon contends, ignores the Coker gas plant costs and makes no attempt to separate the costs for storage, steam systems, or cooling water systems from his overall OSBL cost estimate. *Id.* The ultimate result, Exxon argues, is that O'Brien's estimates for OSBL and downstream processing units costs are black boxes that "[can] not be analyzed or validated." *Id.* Finally, O'Brien's Coker cost estimate, Exxon asserts, is below Coker cost estimates

found in the most widely accepted petroleum engineering texts. *Id.*

947. The Eight Parties state that the Coker cost issue is about defining the costs of operating a Delayed Coker at the "Quality Bank Refinery" in order to complete the formula to calculate the Quality Bank Resid component on the Gulf and West Coasts. Eight Parties Initial Brief at p. 33. O'Brien's West Coast cost figure, the Eight Parties relate, is $4.30/barrel in Year 1996 dollars and $4.62/barrel in Year 2000 dollars; while Exxon's figure for the West Coast is $6.97/barrel in Year 2000 dollars and $5.75/barrel on the Gulf Coast. *Id.* at pp. 33-34.

948. The difference between the parties, the Eight Parties claim, results from the different approaches adopted as well as Exxon's inconsistent approach designed to allow the cost curves in valuing certain components to be higher or lower as needed to skew the valuation, thus benefiting Exxon's interests. *Id.* at p. 34. O'Brien's approach, the Eight Parties explain, assumes a typical large West Coast coking refinery with an assumed coking capacity of 40,000 barrels/day because Resid processing costs vary from refinery to refinery. *Id.* Furthermore, the Eight Parties note, O'Brien not only determines the processing costs at a typical coking refinery to coke Resid, but also determines the costs of processing the Coker product cuts into Quality Bank quality products so they could be valued consistently using Quality Bank reference prices. *Id.* at pp. 34-35. O'Brien, the Eight Parties explain, divides his processing cost calculations into three categories: (1) capital costs; (2) fixed costs; and (3) variable costs. *Id.* at p. 36.

949. According to the Eight Parties, Exxon's approach is an attempt to determine the costs of adding a Coker to an existing refinery utilizing efficient units and focuses on design rather than actual operations. *Id.* at pp. 36-37. They claim it represents the results of a "skewed engineering exercise" that fails to answer the fundamental question of what costs do West Coast refiners incur in processing Resid in a Delayed Coker. *Id.* at p. 37. In the Eight Parties's view, Jenkins does not adhere to standard industry practice because he does not use cost curves to develop estimates of capital costs, but, instead, creates a detailed capital cost estimate for an unknown site, using the Los Angeles area as a proxy. *Id.*

950. Such an approach, the Eight Parties believe, allows Exxon to craft its desired result – an entirely subjective, high cost estimate driving down Resid's value.[363] *Id.* at p.

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[363] According to the Eight Parties, Exxon's approach has numerous flaws:

> Jenkins' faulty detailed cost estimate approach . . . make[s] highly subjective factored estimates from phantom vendor quotes. These already high costs were then subjected to an endless series of subjective multiplication factors. Mr. Jenkins then added additional high capital costs for steam generation, unnecessary new tankage . . . , plus the high-end

38. In comparing Exxon's distillate hydrotreater and Delayed Coker capital cost bases, the Eight Parties note, many inconsistencies exist that would result in inconsistent valuations for heavy distillate and Resid. *Id.* at p. 39. According to the Eight Parties, these inconsistencies include the following:

> [B]ecause Exxon desires a lower capital cost for the Distillate hydroheater in order to have a higher Heavy Distillate value, Mr. Jenkins in this instance elected to use his company Jacobs' cost curve instead of using the detailed estimate approach used for the delayed coker cost. Or stated another way, Mr. Jenkins elected not to use the Jacobs' cost curve for developing his delayed coker costs. Similarly, for the Distillate hydroheater, the factor Mr. Jenkins applies to ISBL costs to determine OSBL costs was 20%, compared to the 25% that he used for the delayed coker. He similarly applied owner's costs of only 6% for the Distillate hydrotreater versus 10% for the delayed coker.

Id. at pp. 39-40 (internal citations and notes omitted). The result, the Eight Parties assert, of the inconsistent valuation is that Exxon has developed two dissimilar methodologies allowing them to skew the Heavy Distillate value higher. *Id.* at p. 40.

951. On reply, Exxon reiterates that the parties differ on the amount of the costs involved in coking ANS Resid and refining the Coker products into products which meet Quality Bank specifications. Exxon Reply Brief at p. 44. Exxon adds that its "overall capital cost estimates compared favorably with the coker cost estimates provided by several well known independent industry benchmarks, including the Gary & Handwerk treatise and the Myers text, as well as with the actual costs reported for several recent coker construction projects." *Id.* at p. 47.

952. Exxon also attacks the Eight Parties's "depiction" of their "cost curve approach as a straight-forward objective application of a 'standard industry' approach to calculating the costs of a 'typical' West Coast refinery." *Id.* at p. 48. It claims that cost curves "are

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> range of a factor for other "offsites." . . . Mr. Jenkins continued the multiplication factor frenzy by multiplying the costs by a location factor of approximately 130%, then by a further 110% for "owners costs," and finally, assuming the worst case scenario of borrowing funds for construction rather than using equity funds to finance construction, he justified a multiplier of 104.3% on top of all of the others. Thus, there is no wonder that [Exxon]'s cost estimate is about 50% higher than the Eight Parties' estimate.

Eight Parties Initial Brief at p. 38.

not a reliable way of calculating coker costs" and, in support, cites to the Meyers textbook and Gary's testimony. *Id.* Exxon also criticizes the Eight Parties for failing to use a West Coast location factor when, it claims, it is undisputed that West Coast construction costs are higher than those on the Gulf Coast. *Id.* at p. 49.

953. Lastly, Exxon attacks the Eight Parties's approach as "subjective." *Id.* at p. 50. In support, it points to their own witness's testimony and, in particular, Exxon quotes O'Brien as stating that his cost curve approach was "'conceptual' or a 'hypothetical construct,' . . . conced[ing] that [his approach is] 'subjective to the extent that it's conceptual' . . . [and] acknowleg[ing] that all changes to his conceptual cost curves . . . were 'subjective.'" *Id.* Exxon also accuses O'Brien of admitting that he could, by "adjusting the value of certain constants in the equations underlying his cost curves" get any result he wanted. *Id.*

954. The Eight Parties begin the discussion of this issue in their Reply Brief by noting that the parties have not altered their positions: they still support O'Brien's cost curve approach for determining the ISBL cost of major equipment for both the Delayed Coker and any related downstream refinery units, while Exxon continues to support Jenkins's line item analysis. Eight Parties Reply Brief at p. 26. They claim that the result is that O'Brien estimated a cost, in Year 1996 dollars, of $4.30/barrel and that Jenkins estimated, in Year 2000 dollars, a cost of $5.75/barrel on the Gulf Coast and $6.97/barrel on the West Coast. *Id.*

955. Answering Exxon's complaint that O'Brien's $107.4 million Coker cost estimate was significantly below the $175 million estimate in the Gary & Handwerk Treatise, the Eight Parties note that, in 2000, Jenkins, using his company's cost curve, estimated the cost of a Coker to be $111 million, which they allege is near O'Brien's estimate. *Id.* at p. 27.

2. Capital Costs

956. According to Exxon, the parties agree that the capital costs of the Coker consist of:

> (1) the direct, or Inside Battery Limits ("ISBL"), costs of the coker itself and the related downstream refinery units (*e.g.*, hydrotreaters, sulfur plant) that are required to process the coker products to bring them up to the quality specifications of the Quality Bank reference price; (2) the costs of the other facilities (referred to as "Outside Battery Limits," or "OSBL," facilities) that are required to support the major refinery processing units, such as storage facilities, steam generation systems, electric power distribution facilities, fuel oil and fuel gas facilities, cooling water systems, and waste water treatment and disposal facilities; and (3) various financing costs, such as capital recovery costs, owner's costs, and interest during

construction.

Exxon Initial Brief at pp. 59-60; Eight Parties Reply Brief at p. 28. After adjusting the capital costs by an appropriate location factor, Exxon explains, the costs are combined with fixed and variable operating costs producing a total cost for coking ANS Resid. Exxon Initial Brief at p. 60.

a. ISBL Coker Costs[364]

i. Approach

957. Exxon explains that Jenkins's cost study assumed that a Coker would be added to an existing refinery, that it would have a 40,000 barrels/stream day of ANS Resid capacity, and an 87% annual utilization rate. *Id.* Additionally, Exxon notes, Jenkins concluded that four drums would be necessary, as well as automatic deheading equipment, a modern coke handling system, and a Coker gas plant.[365] *Id.* at pp. 60-61.

958. To derive total installed ISBL costs, Exxon states, Jenkins next applied installation factors based on the particular classes of equipment, which included individual factors for all of the major installation cost components. *Id.* at p. 62. These installation factors, Exxon asserts, were derived by Jacobs Consultancy from a book written by Kenneth Guthrie, and were modified over the years by Jacobs Consultancy, and were reviewed for reasonableness by personnel at Jacobs Engineering. *Id.* Finally, according to Exxon, Jenkins used a West Coast location factor of 1.26 to end up with $173 million in Year 2000 dollars on the West Coast for the ISBL capital cost. *Id.* at pp. 62-63.

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[364] ISBL costs, Exxon states, are the direct costs for acquiring and installing the equipment required by the particular refinery processing unit. Exxon Initial Brief at p. 60.

[365] To develop the costs for each item, Exxon explains, Jenkins used cost estimation formulæ developed by his employer, Pace/Jacobs Consultancy, and its parent company, Jacobs Engineering, from public data and vendor quotations. Exxon Initial Brief at p. 61. For specialty equipment, for which no general cost formulæ were available or appropriate, Exxon states, Jenkins used vendor quotes from other projects that Jacobs Consultancy had worked on or quotes obtained specifically for this project from vendors. *Id.* Next, Exxon continues, the bare costs were reviewed for reasonableness by employees of Jacobs Engineering, and where cost estimation formulæ were used, Jenkins confirmed the reasonableness of his estimates against the lowest acceptable actual vendor quotes for equipment of the particular type or size using vendor quotes from other projects that his firm had worked on, or quotes specifically obtained for this cost study. *Id.*

959. According to Exxon, Jenkins's estimate for the ISBL costs of the Coker is more reasonable than O'Brien's estimates:

> [T]he evidence shows that Mr. Jenkins' assumption that a 4-drum coker would be used to coke 40,000 barrels/day of ANS Resid is more reasonable than Mr. O'Brien's assumption that a 2-drum coker would be used, and that Mr. Jenkins's assumption that the coker would have automatic deheading equipment, a modern coke handling system, and a gas plant are far more reasonable than Mr. O'Brien's assumption that the coker would have none of these features (or in the case of the gas plant, that the costs would be covered by his OSBL factor).

Id. at p. 65. In comparing Jenkins's and O'Brien's cost estimates, Exxon contends, for the items both included in their estimates, Jenkins's cost estimates are lower. *Id.* The result, Exxon argue, is that when the equipment O'Brien concluded are inappropriate or unnecessary are removed from Jenkins's estimate so that the two Coker cost estimates include only the same equipment, Jenkins's Coker cost estimate is $12 million lower than O'Brien's estimate. *Id.* at p. 66.

960. Beginning, the Eight Parties state that O'Brien's assumptions include: (1) a 2-drum Coker sufficient to coke 40,000 barrels/day of ANS Resid, (2) manual deheading, (3) standard coke handling equipment, and (4) including the Coker gas plant in OSBL costs. Eight Parties Initial Brief at p. 41. Furthermore, the Eight Parties note, O'Brien checked his cost curve results against estimates using data in publicly available textbooks – Gary & Handwerk, Meyers, and Maples. *Id.*

961. The Eight Parties explain that, although he found significant variation, when making adjustments, the result was that O'Brien's own cost estimate of $145.0 million fell between the low end, represented by Maples at $111.2 million, and the high end, represented by Meyers at $256.8 million. *Id.* According to the Eight Parties, Jenkins also prepared a cost curve valuation, using his firm's cost curves, which were close to O'Brien's estimate ($111 million in 1997 dollars as compared to $107 million in 1996 dollars). *Id.* at p. 43. In the Eight Parties view, the sole reason for not using Jenkins's cost curve approach is that Exxon would benefit from a low Resid value. *Id.* at pp. 43-44.

962. Additionally, the Eight Parties argue, Jenkins does not have particular technical expertise with Delayed Cokers sufficient to create a detailed cost estimate for these Cokers and he has never previously prepared a detailed cost estimate for Delayed Cokers. *Id.* at p. 45. According to the Eight Parties, Jenkins and Dickman did not spend the time necessary to develop a detailed cost estimate. *Id.* at p. 46. They note that Gary had stated that a lot of engineering manpower is necessary in order to get a detailed Delayed Coker

cost estimate, requiring that equipment is specified in sufficient detail that adequate costs can be found. *Id.* Jenkins and Dickman, the Eight Parties point out, spent approximately three weeks doing this work. *Id.* Also, the Eight Parties assert that Jenkins did not follow the steps[366] Gary said were necessary for a detailed estimate even though Jenkins repeatedly used the Gary & Handwerk textbook to support his detailed estimate and resulting Delayed Coker capital cost. *Id.*

963. Another criticism, the Eight Parties relate, is that Exxon ignored the PIMS operating parameters in its design of the Delayed Coker while at the same time retaining the PIMS yields even though the two are directly linked. *Id.* at p. 48. The Eight Parties contrast Exxon's actions with O'Brien's decision, correct in their view, to retain the PIMS operating parameters in his Delayed Coker design. *Id.* According to the Eight Parties, Exxon's explanation for this is that the PIMS operating parameters were not tied to yields. *Id.* However, the Eight Parties explain, the operating parameters cells in PIMS are dead cells or place holders, but the operating parameters given are comments corresponding to the yields the parties agreed to use. *Id.* Exxon's position, the Eight Parties assert, is necessary to justify its need for a higher cost four-drum Coker rather than a two-drum Coker to process 40,000 barrels/day of ANS Resid. *Id.* at p. 49.

964. On reply, Exxon notes that the difference in Coker ISBL estimates between it and the Eight Parties is around $20 million in Year 1996 dollars.[367] Exxon Reply Brief at p. 51. It claims, however, that the Eight Parties failed to include, in their $107.4 million estimate, the costs of "automatic deheading equipment, certain coke handling facilities necessary to meet West Coast environmental regulations, and a coker gas plant." *Id.* at p. 52. Exxon adds that the Eight Parties's estimate only includes the cost of a 2-drum Coker when a 4-drum Coker is required. *Id.*

965. Moreover, Exxon asserts that the Eight Parties's cost curve is not supported by documentation and that O'Brien could not identify one project underlying his cost curves. *Id.* at p. 55. Nor could he detail what specific equipment is included. *Id.* Exxon adds that O'Brien "admitted that there is simply no way for anyone else to validate his cost curves." *Id.* at p. 56.

966. Answering the Eight Parties's charge that Jenkins, Exxon's witness, failed to

[366] These failings, the Eight Parties explain, include not getting any vendor quotes or getting quotes for an insufficiently detailed Delayed Coker. Eight Parties Initial Brief at p. 46. Another failed step, the Eight Parties relate, is not performing any heat and material balance. *Id.* at p. 47.

[367] Exxon's estimate is about $127 million and the Eight Parties's estimate is about $107.4 million, according to Exxon. Exxon Reply Brief at p. 51.

follow the common industry practice of using cost curves to estimate project costs, Exxon asserts that, while cost curves may be used to estimate the cost of "simple types of processing units . . . where there are no significant variations in equipment design or cost," using a "general cost curve for a delayed coker is not a reliable approach." *Id.* at p. 57. It also notes that O'Brien's estimate of $107.4 million is "below the Gary & Handwerk estimate ($175.0 million) and below the entire broad range of estimates set forth in the Myers text (ranging from $109.5 million to 219.1 million)." *Id.* at p. 58. Exxon adds that, O'Brien, faced with that evidence, deducted certain costs from them which he claimed were not included in his estimate, but still wound up with a Gary & Handwerk estimate of $137.5 million, well above his $107.4 million estimate, and a Myers text range of $99.5 million to $205.5 million, whose midpoint ($150 million) is well above his estimate. *Id.* at p. 59.

967. On reply, the Eight Parties assert that Jenkins's "line item estimate is fatally flawed." Eight Parties Reply Brief at p. 28. Claiming that Jenkins failed "to adhere to strict detailed design requirements," they elucidate as follows: "[Jenkins's cost estimates] are totally lacking in foundation, particularly for a refinery adding a delayed coker to run ANS crude oil. Moreover, the factors Mr. Jenkins used were old and error-prone." *Id.* at pp. 28-29.

968. The Eight Parties accuse Jenkins of running up the costs in his 2002 line item estimate, and in support they note that his 2000 estimate, based on a cost curve, was lower. *Id.* at p. 29. They note further that his 2002 line item approach is inconsistent with the cost curve approach he used to estimate the capital cost for the Heavy Distillate cut. *Id.*

969. Detailing some specific errors they allege are contained in Jenkins's line item estimate, the Eight parties note the following: (1) Jenkins applied installation factors, but could not state whether they had anything to do with a Delayed Coker; (2) referring to Exhibit No. WAP-81, Jenkins admitted that all of the numbers in the "total column on the installation factors" were incorrect;" (3) Jenkins could not "state with certainty where the factors he used originated;" and (4) the installation factors which Jenkins used were old, i.e., they were based on a 1970s era textbook and Jenkins had no idea as to whether they had been updated. Eight Parties Reply Brief at pp. 30-34. The Eight Parties also assert that Jenkins failed to "do the work necessary to size the equipment to obtain vendor quotes for his detailed cost estimate for the delayed coker." *Id.* at pp. 34-35.

970. Continuing to attack Jenkins's cost estimate, the Eight Parties claim that the vendor quotes Jenkins used were not related to a 40,000 barrels/day Delayed Coker, as envisioned in this proceeding. *Id.* at p. 35. Moreover, they allege that neither Jenkins nor Dickman, who aided Jenkins on this project, were able to present vendor quotes to support their testimony. *Id.* at pp. 36-39.

971. The bottom line, according to the Eight Parties, contrary to Exxon's assertion that none of Jenkins's line item estimate was challenged, is that they challenged it in its entirety and it was "shown to be lacking." *Id.* at p. 39. In comparison with Jenkins's faulty line item estimate, the Eight Parties claim that O'Brien's cost curve approach is sound and based upon a database which has been "compiled, correlated, and updated . . . for over twenty years." *Id.* at p. 41. Finishing this portion of their argument, the Eight Parties state as follows:

> [B]oth Baker & O'Brien and Jacobs [Jenkins's employer] have cost curves for delayed cokers. Both have developed the data from various sources over the years. Both do not maintain the underlying supporting documentation and data. Both Mr. O'Brien and Mr. Jacobs could not identify any particular coker project data included in their respective cost curve data. Most importantly, both Mr. O'Brien and Mr. Jenkins used their respective delayed coker cost curves in 2000 and calculated a cost that was within a couple of million dollars of each other's calculations. The only difference now is that Mr. O'Brien followed the typical industry practice and used a cost curve to calculate his delayed coker cost while Mr. Jenkins did not. As a result of this variance in approach, Mr. Jenkins has increased significantly the ISBL cost difference from a couple of million dollars to $66 million ($173 million, less $107 million).

Id. at p. 43.

ii. Two Drum or Four Drum Coker

972. Exxon insists that a 4-drum Coker is necessary to process 40,000 barrels/day of ANS Resid, while contending that O'Brien's 2-drum Coker, operating in a 14 hour cycle time, is unsupportable and unreasonable. Exxon Initial Brief at p. 66. According to Exxon, O'Brien admitted that 4-drum Cokers could be used for lower feed rates. *Id.* at p. 67. Also, Exxon states, O'Brien acknowledged that he did not know how many 2-drum Cokers were used in his firm's 2-drum cost curve; nor did he know the coke drum sizes used in deriving the 2-drum cost curve. *Id.* Exxon asserts that O'Brien's assumptions do not fare well when compared with real world Coker capacity and that his assumption that a refiner would construct a 2-drum Coker to process 40,000 barrels/day is unreasonable. *Id.*

973. According to Exxon, the evidence demonstrates that a Coker processing 40,000 barrels/day of ANS Resid will have four drums and that the crossover point between a 2-drum and a 4-drum Coker is within the 25,000 to 35,000 barrels/stream day.[368] *Id.* at

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[368] O'Brien defined "stream day" as follows:

> Stream day is the amount that a refinery can run in one 24-hour

pp. 67-68. Furthermore, Exxon relates, 4-drum Cokers within the United States are used to process amounts as low as 17,500 barrels/stream day. *Id.* at p. 68. Only one existing 2-drum Coker, Exxon states, was found to have the capacity for processing 40,000 barrels/day of Resid and that that Coker, the CITGO Petroleum Coker in Corpus Christi, Texas, exists on the Gulf Coast and produces shot coke.[369] *Id.* Exxon adds that this Coker was originally built in 1982 to process 22,500 barrels/day, and, since then, significant enhancements have been added to increase the Coker's capacity. *Id.* at p. 69. Such enhancements, Exxon contends, are not included in O'Brien's Coker cost calculations. *Id.* The newest and largest 2-drum Coker on the West Coast, Exxon relates, has only a 26,000 barrels/stream day capacity and no other existing 2-drum Coker, beside the CITGO Corpus Christi Coker, processes more than 35,500 barrels/stream day. *Id.* Finally, Exxon argues, two of the four 4-drum West Coast Cokers process merely 28,000 barrels/stream day (Valero/Ultramar's Wilmington refinery) and 22,000 barrels/stream day (Phillips/Tosco's Rodeo refinery), respectively. *Id.*

974. Consequently, Exxon concludes, O'Brien's assumption that a 2-drum Coker can process 40,000 barrels/day is not reasonable. *Id.* According to Exxon, O'Brien did not estimate a typical Coker's cost. *Id.* at pp. 69-70. Instead, Exxon insists, he assumed that a Coker could push its maximum possible capacity at optimal operating conditions in order to achieve the assumed results. *Id.* at p. 70. O'Brien additionally admits, Exxon notes, that his proposed 2-drum Coker would be unable to process 40,000 barrels/day of a crude producing heavier coke than that produced by ANS Resid, such as the coke produced by California crude. *Id.*

975. Exxon argues that O'Brien's drum size assumptions are inconsistent, unclear, and unreasonable. *Id.* at pp. 70-72. In order to process 40,000 barrels/day of ANS Resid, Exxon states, O'Brien asserts that the largest size drums manufactured today must be used. *Id.* at pp. 70-71. Exxon notes that O'Brien changed his position several times regarding the actual specifications for the proposed drum size. *Id.* at p. 71. At various points in his testimony, Exxon states, O'Brien proposed the following measurements for his drums: (1) drums with a 29 foot diameter and an overall length of 120 feet, (2) drums that were 28.5 feet in diameter and 120 feet in height, and (3) that his conceptual cost

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> period when it's operating under optimal conditions. Calendar day is when it can run under a period of a year or more on a continuous basis. It has to shut down periodically for maintenance and other unexpected problems.

Transcript at p. 852.

[369] Shot coke, Exxon notes, is easier to remove from coke drums as compared to the sponge coke produced by ANS Resid, and also employs automatic deheading equipment to reduce cycle time. Exxon Initial Brief at p. 68.

curve makes no drum size assumption. *Id.* at pp. 71-72.

976. According to Exxon, the evidence demonstrates that O'Brien's coke drums would not be able to process 40,000 barrels/day of ANS Resid based on reasonable operating assumptions. *Id.* at p. 71. Exxon insists that a coke drum processing 40,000 barrels/day of ANS Resid in a 2-drum Coker with the drum diameter initially assumed by O'Brien -- 27.5 feet -- and reasonable assumptions regarding cycle time would be 148 feet, which is far larger than any coke drum manufactured today. *Id.*

977. Additionally, Exxon notes that, even if O'Brien's coke drums had 29- or 30-foot diameters, the resulting vapor velocity would exceed acceptable limits. *Id.* at p. 72. Finally, Exxon contends that O'Brien's 2-drum Coker design has no spare capacity and, consequently, no operating flexibility. *Id.*

978. Exxon contends that O'Brien's cycle time assumptions are not reasonable because his assumed 2-drum Coker would require a 14 hour cycle time. *Id.* O'Brien, Exxon notes, admits that his cost curve does not contain cycle time information and that the 14 hour cycle time is not typical for a 2-drum Coker. *Id.* at p. 73. Upon investigating the Solomon Associates data used by O'Brien in assuming a 14 hour cycle time, Exxon states it discovered that the data was based on erroneously reported cycle times and the correct data had a corrected average cycle time of approximately 16 hours. *Id.* O'Brien, Exxon relates, admits that he did not verify the accuracy of the Solomon Associates data and that a 16 hour cycle time would mean that his proposed 2-drum Coker would have insufficient capacity to process 40,000 barrels/day of ANS Resid. *Id.*

979. Solomon Associates reported operating cycle times, Exxon explains, rather than design cycle times. *Id.* According to Exxon, the witnesses agreed that when estimating Coker construction costs, one should use design rather than operating cycle time. *Id.* Virtually all new Delayed Cokers, Exxon states, are designed for cycle times between 16 and 24 hours and no Coker operating today was designed to operate in less than 16 hours cycle time. *Id.* at pp. 73-74. Although Coker operating cycle times can be reduced beneath the design cycle time, Exxon insists such reductions involve extra expenses for "modifications, revamping, and debottlenecking;" none of which are included in O'Brien's cost estimates. *Id.* at p. 74. O'Brien fails, Exxon relates, to include modern coke handling systems such as automatic deheading equipment and automatic chutes necessary to achieve short cycle times.[370] *Id.* Finally, Exxon insists, a 14-hour cycle time

[370] Another problem, Exxon explains, is that O'Brien's large diameter coke drums are difficult and time-consuming to decoke because, as drum diameter increases, the water pressure in the stream of water used to decoke coke drums drops as the distance from the central cutting head increases. Exxon Initial Brief at pp. 74-75. When the coke is shot coke, Exxon notes, this is not a problem as it falls in balls out of the bottom of the Coker drum. *Id.* However, Exxon relates, it is a problem when the coke is sponge coke,

would materially shorten the life of the coke drum because of additional drum stresses due to rapid temperature cycles and this fact is ignored by O'Brien. *Id.* at p. 75.

980. According to Exxon, another problem with O'Brien's 2-drum Coker is that it would have excessive vapor velocity that would carry over coke particles ("coke fines") into the fractionator, causing poor operation and, ultimately, unit shut down. *Id.* at p. 76. In Exxon's view, vapor velocity is the design limiting factor for a Coker using Resid feed with a ConCarbon of 23 and operating at 15 psig and the problem can be avoided by either reducing the Coker fresh feed rate below the 40,000 barrels/day or by moving to a 4-drum coker. *Id.*

981. To avoid this problem, Exxon notes, O'Brien proposed that his Coker would operate with zero recycle[371] thus avoiding the vapor velocity problem. *Id.* Even though O'Brien claimed that his Coker would be assumed to operate with zero recycle because the PIMS model assumed zero recycle, Exxon explains that zero recycle has varied meanings and can refer to recycle varying from zero up to 5 percent. *Id.* at pp. 76-77. Additionally, Exxon contends, the PIMS model is inconsistent with true zero recycle because it does not produce extra heavy Coker gas oil, which would be produced under conditions of true zero recycle. *Id.* Another problem, Exxon states, is that O'Brien's Coker did not factor in the costs of operating with true zero recycle and if they had, the capital costs would be at least one million dollars greater. *Id.*

982. Exxon argues, in contrast to O'Brien's unreasonable assumptions, Jenkins's 4-drum Coker is reasonable. *Id.* Four-drum Cokers, Exxon explains, are used to process anywhere from 17,000 to 80,000 barrels/day of Resid and virtually all Cokers processing 40,000 barrels/day have four drums. *Id.* at pp. 77-78. Additionally, Exxon contends, assuming a 16-hour design cycle time is reasonable, and Jenkins's design did not have vapor velocity problems. *Id.* at p. 78. Although Jenkins's assumptions regarding outage -- the distance between the top of the coke in the coke drum and the top of the drum -- were challenged on the ground that some Cokers have been operated with smaller outages, Exxon states, Jenkins's Coker cost estimates were appropriately based on a reasonable outage for which a Coker would be designed. *Id.* Exxon insists that Jenkins properly designed a contingency thus allowing the operator flexibility should problems

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like that produced from ANS crude. *Id.*

[371] As to zero recycle, O'Brien states as follows: "Zero recycle means effectively, [that] all the material coming into the coker, the coking drum – only goes through the coking drum once and there's no material being brought back and sent through the drum twice." Transcript at p. 1019. He adds: "If you have recycle in the drums, then that material is being coked twice and it will reduce the yields of the liquid products and increase the yields of the coke." *Id.* at p. 1020.

arise when decoking the other drum. *Id.* at p. 79. These design contingencies, Exxon notes, are often used in designing refineries. *Id.*

983. As to the question of two or four drums, the Eight Parties believe that only a 2-drum Coker is necessary and the difference between the two proposals is approximately $13 million in ISBL costs. Eight Parties Initial Brief at pp. 49-50. According to the Eight Parties, Jenkins, calculating the difference solely on the cost of coke drum sizes, concluded that the difference in ISBL costs between two drums and four drums is approximately $25 million on a Gulf Coast basis and $32 million on a California basis. *Id.* at p. 50.

984. O'Brien explains, the Eight Parties state, that his firm uses three different cost curves for developing estimates of Coker costs, depending on whether the Coker is 2-drum, 4-drum, or a 6-drum Coker, and the break even point between using two drums or four drums for a Coker is very near, but slightly above, where 40,000 barrels/day of ANS Resid falls. *Id.* at pp. 50-51. Despite Exxon's contention that a 2-drum Coker would be inadequate, the Eight Parties insist that there are 2-drum Cokers in the United States capable of processing 40,000 barrels/day of ANS Resid. *Id.* at p. 51. The Eight Parties note that three such refineries exist: the Citgo Corpus Christi refinery, the Flint Hills/Koch Saint Paul/Rosemont refinery, and the Marathon Garyville refinery. *Id.* at pp. 52-53. Additionally, the Eight Parties state, the 4-drum Orion Good Hope/Norco refinery has an 80,000 barrels/stream day or 75,000 barrels/calendar day capacity. *Id.*

985. Discussing Dickman's contention that the 2-drum Corpus Christi refinery should be disregarded because it produces shot coke instead of sponge coke that is easier to remove which shortens cycle time, the Eight Parties's argue that a coke drum containing shot coke is subject to hot spots making it *more*, not less, difficult to cut the shot coke out of the drum, thus increasing cycle times. *Id.* at p. 54. As for Dickman's testimony that 24 hour cycle times are typical, the Eight Parties disagree, arguing that Cokers operate on 14-16 hour cycles because the economics of coking encourages operating at maximum capacity and shorter cycle times. *Id.* at pp. 54-55.

986. The Eight Parties point out that Dickman's testimony about 24 hour cycle times is inconsistent with Jenkins's proposed 16 hour cycle time used in Exxon's Coker design cost estimate. *Id.* at p. 55. Furthermore, the Eight Parties state, cycle times below 16 hours are supported by numerous industry articles regarding cycle times, and the Meyers textbook states at page 10 that that cycles of 14 to 16 hours are typical. *Id.*

987. Regarding the vapor velocity issue, the Eight Parties note that there is no absolute vapor velocity limit recognized in the industry; but, instead, the limit used by a refinery depends on the refinery's tolerance with respect to the amount of coke fines that carry over into the fractionator, which has to be traded off against the greater capacity achievable with higher vapor velocity. *Id.* at pp. 55-56. The Eight Parties explain that

O'Brien did not assume any particular vapor velocity for his conceptual design, but did calculate a vapor velocity of 0.72 feet/second for his design, which is within limits acceptable to most refiners. *Id.* at p. 56. Dickman's assertion that the vapor velocity limit applicable to a Coker processing ANS is 0.625 feet/second, the Eight Parties insist, is incorrect. *Id.* No industry standard, the Eight Parties relate, exists on the subject and refineries do operate with vapor velocities higher than what Exxon suggests. *Id.* at p. 57.

988. As for Dickman's spreadsheet Coker drum calculations, the Eight Parties argue it does not support Exxon's assertions. *Id.* The Eight Parties explain that Dickman developed the spreadsheet allowing different parameters to be input into the spreadsheet, allowing the inputs to calculate the height of the Coker drum or vapor velocity. *Id.* It was used, the Eight Parties continue, to calculate other operating parameters of a Coker, such as tons of coke processed per day. *Id.* The Eight Parties contend that,

> In presenting various scenarios modeled by his spreadsheet, Mr. Dickman varied the spreadsheet's base assumptions to favor the result that he wanted to achieve for that particular application, rather than using uniform assumptions across the different scenarios that he considered. What is more, Mr. Dickman did not mention these variations in his testimony, instead leaving it to others to uncover how the scenarios differed and how those differences affected the results.

Id. at pp. 57-58.

989. The Eight Parties also question Dickman's conclusions regarding his calculations for tons of coke processed. *Id.* at p. 58. Dickman's testimony, the Eight Parties relate, asserts that O'Brien's approach would not allow a 2-drum Coker to process the necessary 2,400 tons/day of coke required to process 40,000 barrels/day of ANS Resid based on Dickman's calculations. *Id.* However, the Eight Parties point out, Dickman admits that he changed O'Brien's exact assumptions. *Id.* Dickman in his coke tons calculations, the Eight Parties relate, assumed a 16 hour cycle time rather than O'Brien's 14 hour cycle time, assumed a 30-foot outage instead of a 25-foot outage, and assumed a drum outlet temperature of 850°F instead of the 805°F shown on PIMS and a drum pressure of 25 psig instead of the 15 psig shown on PIMS. *Id.* at p. 58-59.

990. Consequently, the Eight Parties contend, as O'Brien's key assumptions were altered, Dickman's spreadsheet underestimates the amount of capacity available in the coker drums. *Id.* at p. 59. A similar altering of assumptions, the Eight Parties continue, impacted Dickman's vapor velocity calculations because he changed the assumptions in the spreadsheet from those he used in the coke tons calculations, increasing the calculated vapor velocity above what it would have been under the assumptions in the coke tons calculations. *Id.*

991. The Eight Parties also claim that Dickman, after using Jenkins's assumed 25 psig drum pressure in his coke tons calculations, "switched to the 15 psig found in PIMS and assumed by Mr. O'Brien in the Vapor Velocity Calculations." *Id.* at p. 60. They further state that Dickman agrees that switching from 25 psig to 15 psig "increases the resulting calculated vapor velocity and makes it harder for the design to stay within maximum limits." *Id.* The Eight Parties add:

> Ironically, Mr. Dickman defended his decision to use 15 psig in the Vapor Velocity Calculations instead of 25 psig that he used in the coke Tons Calculations on the grounds that increasing the pressure changes the coker yields from what was shown in PIMS. That argument is inconsistent with [Exxon's] argument . . . that it was appropriate for Mr. Jenkins to use the PIMS yields notwithstanding that Mr. Jenkins assumed a Drum Pressure of 25 psig.

Id. at p. 60 (internal citations omitted).

992. Another change, the Eight Parties note, between the coke tons calculations and the vapor velocity calculations was in the natural recycle assumption. *Id.* Dickman employed the 0% recycle assumption appearing in PIMS in his coke tons calculations while using a 5% recycle in his vapor velocity calculations, thus causing the calculated vapor velocity to increase. *Id.*

993. To demonstrate the results under O'Brien's assumptions, the Eight Parties state, Phillips modeled several scenarios using Dickman's spreadsheet and concluded that O'Brien's model can handle the 2,400 tons/day of coke required to process 40,000 barrels/day of ANS Resid.[372] *Id.* at p. 61. According to the Eight Parties, Dickman

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[372] The Eight Parties explain how, under O'Brien's assumptions, his 2-drum coker can handle the required amount of coke:

> [Exhibit No. PAI-141] shows that, under these assumptions, the two-drum coker can handle 2,403 tons/day of Coke . . . which means that it can handle the necessary 2,400 tons/day of Coke required to process 40,000 barrels/day of ANS Resid. The vapor velocity shown is 0.71 feet/ second.
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> * * * *
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> [Exhibit No.] PAI-142 shows what happens if all of the assumptions in [Exhibit No.] PAI-141 are held constant, except that Mr. Jenkins's assumed operating pressure of 25 psig were [sic] used. This exhibit shows that, under this assumption, the two-drum coker could process 2,403 tons/day of Coke with a lower vapor velocity of 0.53 feet/ second.

agreed that their calculations accurately reflected the results of putting O'Brien's assumptions into his spreadsheet and agreed that those results indicated that the 2-drum Coker could process 40,000 barrels/day of ANS Resid. *Id.* at p. 62.

994. The Eight Parties argue that Jenkins made two errors in calculating drum size with the result that his 4-drum Coker can process far more than 40,000 barrels/day of ANS Resid. *Id.* at p. 63. Jenkins testified, the Eight Parties relate, that his Coker drum cost estimate was based on two inputs: the drum's diameter and the drum's height. *Id.* According to the Eight Parties, he used a drum diameter of 27 feet and then performed a calculation based on the 60,034 cubic feet of coke produced by 40,000 barrels/day of ANS Resid to determine the necessary drum height. *Id.* The Eight Parties state that Jenkins calculated 60,034 cubic feet of coke would fill a 27-foot diameter drum up to 51 feet and he added 25 feet to account for outage. *Id.* at p. 64. Summing these numbers, the Eight Parties continue, results in a calculated drum height of 76 feet, which was the height Jenkins used to get a price quote for the cost of the drum. *Id.*

995. The two mistakes, the Eight Parties point out, include first his underestimation of the amount of coke going into the cone and bottom head extension at the bottom of his coke drum -- instead of 1,801 cubic feet assumed by Jenkins, he should have used 9,335 cubic feet. *Id.* Second, the Eight Parties claim, he misapplied his calculation of the 25-foot outage by failing to calculate the outage from the top of the flange as is industry practice and by improperly calculating the outage from the top of the tangent. *Id.* Jenkins admits, the Eight Parties assert, that he was effectively using a 35-foot outage instead of a 25-foot outage and that he only needed to add 15 feet to the tangent length to account for a 25-foot outage. *Id.*

996. These two mistakes, the Eight Parties contend result in an overly high price quote for the Coker drums. *Id.* According to the Eight Parties, Jenkins design only requires Coker drums with only 59 feet of tangent length, which is the sum of the 44 feet taken by the coke, plus 15 feet necessary to account for the outage. *Id.* at p. 65. Jenkins, the Eight Parties state, admitted to this error at hearing. *Id.*

997. According to the Eight Parties, they've devised a method to quantify the cost impact of Jenkins's errors. *Id.* at p. 66. Beginning with Dickman's admission that the 4-drum Coker can process 50,000 barrels/day of ANS Resid instead of the 40,000 barrels/day it was designed for, the Eight Parties state, the cost impact can be quantified by allocating Jenkins's total capital costs to the 50,000 barrels/day of ANS Resid that it can actually process instead of the 40,000 barrels/day used in Jenkins's calculations. *Id.*

Eight Parties Initial Brief at pp. 61-62.

998. Dividing the total costs, the Eight Parties explain, by 50,000 barrels instead of 40,000 results in cost per barrel of capacity of $7,692 instead of $9,616, which translates into net capital recovery cost per barrel/day of $3.62 on a West Coast basis. *Id.* at p. 67. Such costs, the Eight Parties point out, are over $1/barrel lower than the equivalent net capital recovery cost per barrel/day of $4.64 when assuming 40,000 barrels/day of capacity. *Id.*

999. On reply, Exxon reiterates its position that a 2-drum Coker is not feasible where it was necessary to process 40,000 barrels/day of ANS Resid. Exxon Reply Brief at p. 61. Regarding the Eight Parties suggestion that a 2-drum Coker was sufficient, Exxon finds a disparity between their position that their cost curves represent a typical Coker and what Exxon claims is a lack of evidence that a 40,000 barrel/day 2-drum Coker is typical. *Id.* at p. 62. To the contrary, according to Exxon, the record does not indicate that there are any 2-drum Cokers on the West Coast with a capacity exceeding 26,000 barrels/day and that there is only one 2-drum Coker in all the United States with a 40,000 barrels/stream day capacity.[373] *Id.* Moreover, Exxon asserts that "O'Brien's coker" pushed the maximum limits of a 2-drum Coker operated under optimal conditions and could not, therefore, be determined to be typical. *Id.* at pp. 62-63.

1000. In contrast with its assertions regarding O'Brien's 2-drum proposal, Exxon declares that a 40,000 barrel/day Coker almost always has four drums. *Id.* at p. 63. It adds that "the cross-over between a 2-drum coker and a 4-drum coker is in the range of 25,000 to 35,000 barrels per stream day." *Id.*

1001. In their Reply Brief, the Eight Parties allege that a Coker for a 40,000 barrel/day refinery processing ANS is on the boundary between being able to use a 2-drum Coker and requiring a 4-drum Coker. Eight Parties Reply Brief at p. 43. They claim that O'Brien determined that it was "possible" for a 2-drum Coker to process this amount of ANS. *Id.* In support, the Eight Parties claim that the record reflects that at least four existing 2-drum Cokers are capable of so performing, that the drum sizes imagined by O'Brien are well within the sizes available to the industry, that the less than 16-hour cycle times imagined by O'Brien "are commonly achieved by many refineries," that it is not relevant that sponge coke, not shot coke, is produced by ANS Resid, and that the vapor velocity imagined by O'Brien is within industry standards. *Id.* at pp. 44-45.

1002. Claiming that Exxon suggests that many of its proposals are based on design criteria even when refineries can be operated at more efficient levels, the Eight Parties

[373] According to Exxon, the 2-drum Coker is operated by CITGO in Corpus Christi, Texas, and uses automatic deheading equipment to lower the cycle time. Exxon Reply Brief at p. 64. It further notes that the Eight Parties's proposal does not include use of such equipment. *Id.*

argue that the issue is not how much it would cost to install a new Coker in a refinery, but "how much it costs to process Resid into the various products for which there are published prices that are used to establish the value of Resid." *Id.* at pp. 45-46.

iii. Automatic Deheading

1003. According to Exxon, automatic deheading equipment should be included in the Coker's cost because it is used to improve safety and reduce Coker cycle time. Exxon Initial Brief at p. 80. All the Cokers built within the past ten years, Exxon notes, have automatic deheaders. *Id.* Jenkins's model, Exxon states, includes automatic deheading and the ISBL cost of automatic deheading equipment on the West Coast would be about $12.7 million – a number unchallenged by O'Brien. *Id.* at p. 81. Instead, Exxon states, O'Brien assumed that manual deheading could be used to save costs and the automatic deheading equipment costs would be avoided. *Id.* Using automatic deheading equipment, Exxon asserts, shortens cycle times by from 35 minutes to an hour. *Id.* at p. 82.

1004. Exxon notes that O'Brien admits that automatic deheaders improve cycle time, that his firm has never recommended that a Coker be built without automatic deheading equipment, and that building a Coker without automatic deheading would endanger worker safety. *Id.* Regarding the cost of automatic deheading equipment, Exxon explains that Jenkins relied on a Year 2000 vendor quote installed at a CITGO refinery in Lake Charles, Louisiana. *Id.* at p. 83. On the other hand, Exxon asserts, the Eight Parties did not present direct testimony on this issue. *Id.*

1005. As to the question of automatic deheading equipment, the Eight Parties insist that such equipment is not necessary. Eight Parties Initial Brief at p. 69. O'Brien testified, the Eight Parties state, that this equipment is sometimes added to Cokers to improve safety, especially when producing shot coke. *Id.* He also testified, the Eight Parties note, that ANS produces sponge coke, that automatic deheading equipment is not used in all modern Cokers, and, while automatic deheading is an available safety feature for shot coke, the safety issue is lessened for sponge coke. *Id.* at p. 70.

1006. Even if automatic deheading is included, the Eight Parties argue, Jenkins's estimates included flawed and inflated assumptions. *Id.* According to the Eight Parties, Exxon did not produce a single vendor quote in support of Jenkins's testimony regarding automatic deheading and instead presents an estimate for an automatic deheading device.[374] *Id.* Additionally, the Eight Parties contend, Jenkins's estimate includes a

[374] The Eight Parties further question Jenkins's assumptions, noting that the estimate was derived from a summary sheet obtained by Dickman from Citgo's Lake Charles Refinery but never physically provided to Mr. Jenkins. Eight Parties Initial Brief at p. 70. According to the Eight Parties, Dickman testified that this estimate was based

number of escalators or multipliers to his bare cost estimate of $5,800,000 to account for higher West Coast coasts resulting in a $12,716,575 total cost; but nowhere does Exxon substantiate why automatic deheading equipment would cost more on the West Coast. *Id.* at p. 71. The Eight Parties assert that the only record evidence for a vendor quote for a West Coast automatic deheading system is the Hahn & Clay system at the BP Carson Refinery in California. *Id.* at p. 72. Jenkins's estimate, the Eight Parties point out, exceeded the Hahn & Clay cost by more than $10,000,000 ($12,716,575 - $2,616,810) [Hahn & Clay estimate scaled to a four-drum coker in Year 2000 dollars.][375] *Id.*

1007. On reply, Exxon notes that its estimate assumes that automatic deheading equipment would be used, while the Eight Parties's assumed that it would not. Exxon Reply Brief at p. 77. According to Exxon, contrary to the Eight Parties's assertion, automatic deheading equipment is used "not only for safety reasons (including to enhance safety in the production of sponge coke), but also to improve efficiency and reduce cycle times in the production of all kinds of Coke." *Id.* at pp. 77-78. It notes that, over the last 10 years, all Cokers built have included automatic deheaders. *Id.* at p. 78. Moreover, Exxon claims, that to reach the short cycle times assumed by both its and the Eight Parties's witnesses, automatic deheading equipment would have to be used. *Id.*

1008. According to the Eight Parties, in their Reply Brief, it was not necessary for O'Brien to discuss automatic deheading equipment because he used "conceptual cost curves to model a typical, economic and efficient refinery." Eight Parties Reply Brief at p. 49. They further note that such curves are "supported by a number of projects, which include varying pieces of equipment." *Id.* at p. 50. Declaring that there is no evidence in the record supporting Exxon's assertion that, for the last 10 years, all Cokers built have had automatic deheading equipment, the Eight Parties assert that, even were it true, it would mean nothing because the record is not clear as to the type of automatic deheader to which Jenkins referred in his testimony. *Id.* at pp. 51-52.

The Eight Parties submit that, even were automatic deheaders required, they would only be needed on the bottom heads. *Id.* at p. 52. Therefore, they claim, Jenkins estimate for

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upon a vendor quote, which was not competitively bid. *Id.* The Eight Parties note the estimate was for a more expensive retrofit of an existing drum rather than the less expensive building of new drums. *Id.* Jenkins, the Eight Parties continue, also assumed top and bottom automatic deheading, but admits that the preponderance of automatic deheading systems are bottom systems and not top systems. *Id.* at pp. 70-71.

[375] Furthermore, the Eight Parties reiterate, Jenkins's estimate included both top and bottom deheading and, even if the top deheading is removed from the calculation, Jenkins's estimate exceeds the Hahn & Clay estimate by approximately $6,400,000 [Hahn & Clay estimate scaled to a 4-drum Coker in Year 2000 dollars]. Eight Parties Initial Brief at p. 72.

the cost of automatic deheading equipment was excessive inasmuch as he included automatic deheading on both the top and bottom heads. *Id.*

iv. Coke Handling Equipment

1009. In Exxon's view, Coker costs should include the cost of appropriate coke handling facilities meeting West Coast environmental requirements. Exxon Initial Brief at p. 84. These facilities include, Exxon relates, the coke pit and crane, chutes and conveyor system, and covered storage used to move and store coke and to meet environmental requirements. *Id.* Although Jenkins includes these costs in his ISBL coker costs, Exxon notes, O'Brien asserts that these costs are not necessary and that all that is necessary is a coke pad and front end loader. *Id.* at p. 85. West Coast environmental standards, Exxon states, can only be met with a coke pit and crane, chutes and conveyor system, and covered storage. *Id.* Exxon explains:

> Coke is a very dirty, dusty product analogous to coal. Environmental requirements designed to prevent the release of coke dust into the atmosphere are stringent . . . . To meet these requirements, the Coke is cut into a coke pit, and a clamshell crane is then used to pick it up and put it into a hopper where it is crushed and screened. The Coke is then conveyed to a storage barn, from which it is later loaded into trucks using a smaller conveyor system. For environmental reasons, all of these operations must be enclosed to minimize the release of coke dust into the atmosphere. Indeed, even the loaded trucks must be washed down to minimize the release of dust before they leave the refinery.

Id. According to it, O'Brien's suggested alternative – the coke pad and front end loader – would not be acceptable under West Coast environmental requirements. *Id.* Because of these requirements, Exxon contends, no West Coast refinery uses a coke pad and front end loader to handle coke. *Id.*

1010. Addressing the coke handling issue, the Eight Parties state that it is handled in varied ways and that coke handling costs will be covered in the various costs curves that companies have developed over the years for Delayed Cokers. Eight Parties Initial Brief at p. 73. The Eight Parties note that O'Brien's cost curves include coke handling as part of the ISBL costs for Delayed Cokers and any other equipment taking coke outside of the battery limits is included in O'Brien's OSBL number. *Id.* According to the Eight Parties, because O'Brien's cost curve is underpinned by numerous projects with varied equipment and at various locations, the curve provides an objective method to cost coke handling. *Id.* at p. 74.

1011. Jenkins's cost approach, the Eight Parties insist, involves a state of the art, and highly expensive, coke handling system which is "neither consistent with nor typical of the West Coast refining industry." *Id.* The Eight Parties believe that Exxon improperly compares the Shell Martinez system to a typical West Coast refinery. *Id.* at p. 75. This refinery, the Eight Parties assert, is world class. *Id.* According to the Eight Parties, Jenkins admits that of the West Coast refineries of which he is aware, not one of the refineries installed all of the coke handling equipment his detailed cost estimate includes. *Id.* Additionally, the Eight Parties relate, Exxon did not produce a single vendor quote or other evidence supporting Jenkins's cost for coke handling.[376] *Id.* at p. 76. The Eight Parties note that Jenkins escalates his bare cost for coke handling from $2.7 million to $5,919,785 through a number of multipliers but failed to establish that Jenkins's estimate is typical of the West Coast coking industry. *Id.* at pp. 76-77.

1012. According to Exxon, the Eight Parties wrongly defend O'Brien's failure to include storage costs in his ISBL calculations by suggesting that O'Brien included the costs in his OSBL calculations. Exxon Reply Brief at p. 85. In response, Exxon notes that O'Brien agreed that his OSBL estimate did not include the costs of storage. *Id.*

1013. The Eight Parties, in response to Exxon's assertion that O'Brien conceptualized a simple coke pad and front end loader to handle the coke, argue that, relying on "conceptual cost curves" O'Brien calculated "costs for a typical, economic and efficient delayed coker at a refinery" which may have, to handle coke, pits and cranes or pads. Eight Parties Reply Brief at pp. 56-57. Further, the Eight Parties attack Exxon's evidence regarding the need for coke handling equipment beyond a coke pit and front end loader in order to meet West Coast environmental standards, noting that Exxon failed to place evidence that such standards exist into the record. *Id.* at pp. 57-58.

1014. According to the Eight Parties, O'Brien included the costs of coke handling equipment in both his ISBL and OSBL cost estimates. *Id.* at pp. 58-59. They claim that Exxon wrongly suggested, in its Initial Brief, that coke handling must be in the Coker's ISBL costs, and that Exxon wrongly relies on the Gary & Handwerk textbook for that claim. *Id.* at p. 59. Moreover, the Eight Parties suggest that Exxon's coke handling proposal is "world class" rather than typical and that Jenkins's proposed costs for it are therefore excessive. *Id.* at pp. 60-61.

v. Coker Gas Plant

1015. According to Exxon, Coker ISBL costs should include the cost of a Coker gas plant, which is used to process gases produced in coking Resid. Exxon Initial Brief at p. 87. Exxon explains that Jenkins includes the cost of the Coker gas plant in these costs,

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[376] The Eight Parties characterize Dickman's research into conveyor systems as "a discussion with a vendor that was not reduced to a quote, estimate or even a note or memorandum." Eight Parties Initial Brief at p. 76.

while O'Brien does not, even though he admits that allowances for processing Coker gas should be made. *Id.* at p. 88. O'Brien's claim that the Coker gas plant should be included in the OSBL costs, Exxon insists, must be rejected. *Id.* He admits, Exxon points out, that the Gary & Handwerk text costs out the Coker gas plant as part of ISBL costs. *Id.*

1016. Additionally, Exxon contends, O'Brien's OSBL cost was not large enough to include the Coker gas plant in addition to all the other costs included in his OSBL factor. *Id.* According to Exxon, the Coker gas plant cost alone would consume almost 40% of O'Brien's OSBL allowance. *Id.* at pp. 88-89. Furthermore, Exxon states, O'Brien's claim that the Coker gas plant should be included in the OSBL costs is inconsistent with other O'Brien positions. *Id.* at p. 89. O'Brien's positions for downstream hydrotreater units and the Coker sulfur plant, Exxon claims, are costed out separately on an ISBL plus OSBL cost basis. *Id.* In addition, Exxon argues, O'Brien's approach for the Naphtha gas plant differs as well because he includes ISBL costs for the hydrotreater, catalytic reformer, and the gas plant. *Id.*

1017. Alternatively, Exxon asserts, Jenkins's estimate for the Coker gas plant cost was reasonable because he estimated cost as a function of the horsepower requirement, which, in turn, was determined by the volume and composition of the gas stream coming off the Coker. *Id.* Exxon explains that, for the purposes of determining the split of the gases coming off the Coker, Jenkins used information from the Gary & Handwerk treatise. *Id.* An alternative was suggested at hearing, Exxon notes, but it insists it would have increased the gas plant cost:

> Jenkins could instead have used the PIMS model to derive the gas yields at the battery limits of the coker and worked backward to determine the gas yields at the off-gas compressor, [but] this approach would have *increased* the cost of the gas plant. Specifically, the evidence showed that if Mr. Jenkins had so used the PIMS yields, the cost of the gas compressor would have *increased* by nearly a million dollars and the total cost of the project would have *increased* by nearly four million dollars, because the amount and composition of the gas stream produced by the PIMS model would have required the use of a compressor with substantially greater horsepower.

Id. at pp. 89-90 (emphasis in original).

1018. In addressing the Coker gas plant, the Eight Parties assert, O'Brien does not consider the gas plant to be part of ISBL Coker equipment, and instead considers the gas plant as part of his OSBL factor of 35% of ISBL costs. Eight Parties Initial Brief at p. 77. Jenkins, the Eight Parties state, includes a gas plant in his ISBL calculation designed to process only Coker gases.[377] *Id.* O'Brien explains, according to the Eight Parties, that it is inappropriate to include the Coker gas plant as part of the ISBL costs because the gas plant is not part of the Coker, but is a separate unit entirely, and thus is not inside the battery limits of the Coker. *Id.* at p. 78. Also, the Eight Parties point out, the gas plant is shared among several units in the refinery, primarily the cat cracker and the Coker, and, consequently, it is inappropriate to assign its entire cost to the Coker as an ISBL cost. *Id.*

1019. In its Reply Brief, Exxon states that the "coker gas plant is used to process the gases produced in the coking of the Resid." Exxon Reply Brief at p. 86. According to it, O'Brien failed to include its cost in his ISBL estimate, but claimed that it was included in his OSBL estimate. *Id.* Exxon, challenging the Eight Parties's defense of O'Brien's failure to include such costs in his ISBL estimate because they claimed that the gas plant would serve both the Coker and the cat cracker unit, declares that O'Brien admitted that, if the refinery did not have the latter unit, it would still have to build a gas plant. *Id.* at pp. 86-87. Acknowledging the Eight Parties claim that a gas plant would not be inside the battery, Exxon asserts that Coker gas plants are located as close as possible to the Coker fractionator because the heat from the latter is used in the gas plant to minimize costs. *Id.* at pp. 87-88. Exxon also rejects the Eight Parties's claim that the Gary & Handwerk textbook supported placing the Coker gas plant costs in the OSBL as totally unsupported: "Gary directly addressed this argument and flatly rejected it." *Id*. at p. 89. Lastly, Exxon posits that O'Brien's OSBL costs were insufficient to have included the costs of a Coker gas plant in addition to the other costs which O'Brien claims he included there. *Id.* at p. 90.

1020. In their Reply Brief, the Eight Parties begin by declaring that Exxon is wrong in suggesting that the Gary & Handwerk textbook agrees with Jenkins that the Coker gas plant should be costed out as part of the ISBL. Eight Parties Reply Brief at p. 61. They note that Jenkins testified to this and that the text does not list it as part of the Coker gas plant. *Id.* The Eight Parties also assert that the Gary & Handwork textbook indicates that a refinery "will have a single gas plant that supports a number of processes, including the coker, the cat cracker, the hydrocracker and the reformer." *Id.* According to them, also, O'Brien assumed that a portion of the costs of a gas plant were included in the Coker's OSBL costs and Jenkins erred in assigning 100% of its cost to the coking unit. *Id.* at p. 62.

[377] The Eight Parties explain that Jenkins did not provide a West Coast cost for this gas plant, but used his Gulf Coast cost estimate of $14 million, then applied a 30% West Coast location factor resulting in a West Coast ISBL cost of $18.2 million. Eight Parties Initial Brief at p. 77. After the OSBL, the Eight Parties continue, interest during construction, and owner's cost adders, the total Coker gas plant cost is approximately $26 million. *Id.*

1021. Next, the Eight Parties argue that Exxon erred in suggesting that O'Brien was being inconsistent in developing ISBL and OSBL cost estimates for the hydrotreaters, but only treating the gas plant as part of the OSBL costs.[378] *Id.* According to them, the Gary & Handwerk textbook treats the gas plant as a process which is indirectly involved, i.e., supports, but isn't directly engaged in, the production of hydrocarbon fuels. *Id.*

1022. Acknowledging Exxon's attack on O'Brien's testimony that a refinery would not build an "inefficiently-sized gas plant just for its Coker, but instead would integrate its gas plant into the refinery and use it to process gases produced from a number of process units," the Eight Parties claim that it is without merit. *Id.* at p. 63. They state that O'Brien's testimony is supported by Gary & Handwerk. *Id.* According to the Eight Parties, Exxon's further claim that O'Brien testified that the gas plant would be integrated with the gas plant used by the catalytic cracking unit is without merit. *Id.* at pp. 63-64. Rather, they say, he testified "that he assumed 'an integrated efficient refinery for all of [his] calculations.'" *Id.* at p. 64. In other words, the Eight Parties claim, O'Brien assumes "that the gas plant would be shared by the several processes, including the coker, added to the base refinery in a typical West Coast refinery." *Id.* at p. 65.

1023. Lastly, the Eight Parties find fault with Exxon's claim that the gas plant must be located close to fractionator of the Coker. *Id.* They say the gas plant's location is irrelevant. *Id.* at pp. 66-67.

b. OSBL Coker Costs

i. Approach

1024. According to Exxon, all the parties agree that the OSBL facilities include electric power distribution systems, fuel oil and fuel gas facilities, water supply systems, waste water treatment and disposal systems, plant air systems, fire protection systems, flare, drain and waste containment systems, plant communications systems, roads and walks, railroad facilities, fences, buildings, vehicles, product and additives blending facilities, and product loading facilities. Exxon Initial Brief at p. 92. However, Exxon states, the parties disagree over whether the Coker gas plant should be treated as part of the OSBL costs or separately costed out as an ISBL unit, and how certain OSBL facilities - storage facilities, cooling water systems, and steam generation systems - should be costed out for purposes of estimating the cost of the Coker. *Id.*

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[378] The Eight Parties also state that it wasn't inconsistent for O'Brien to cost out a gas plant in the Naphtha reforming process because that was a saturated gas plant as compared with the *unsaturated* gas plant associated with a coker. Eight Parties Reply Brief at pp. 62-63.

1025. Exxon explains that only Jenkins presented a reasonable estimate of OSBL Coker costs in accordance with the procedures described in the Gary & Handwerk text, concluding with total OSBL costs for the Coker and related processing units of $118.3 million in Year 2000 dollars on the West Coast and $91 million in Year 2000 dollars on the Gulf Coast.[379] *Id.* at pp. 93-94. O'Brien's estimate, Exxon contends, "unreasonably low, incomplete, and impossible to verify" because he failed to quantify any specific costs in his OSBL cost estimate and, instead, merely applied a single OSBL factor of 35% to the ISBL costs of the coker, for a total OSBL cost of $37.6 million. *Id.* at p. 95.

1026. According to Exxon, O'Brien's factor was a black box "whose lack of transparency severely limited any meaningful analysis of his OSBL cost estimate." *Id.* at pp. 95-96. This estimate, Exxon notes, is based on O'Brien and his staff's experience and judgment, with no documentation supporting any part of the estimate. *Id.* at p. 96. Additionally, Exxon points out, O'Brien could not explain why he included no OSBL costs with respect to the downstream hydrotreaters estimate, or why he used a different OSBL factor for the sulfur plant cost estimate. *Id.*

1027. Addressing OSBL Coker costs, the Eight Parties explain that they used the typical industry practice in expressing OSBL costs as a percentage of ISBL costs and used 35% of the ISBL costs because O'Brien includes steam and cooling water facilities as OSBL costs. Eight Parties Initial Brief at p. 80. Jenkins, the Eight Parties note, agrees that the Eight Parties's approach is typical in the industry. *Id.* However, the Eight Parties relate, Jenkins adopts the Gary & Handwerk textbook approach, thus increasing capital costs $57 million for steam generation, cooling water, and storage.[380] *Id.* at p. 81. The Eight Parties characterize Jenkins's approach as an "inconsistent patchwork" resulting in a higher OSBL cost. *Id.* at pp. 81-82.

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[379] Exxon relates that Gary explained the appropriate procedures for estimating refinery costs. Exxon Initial Brief at pp. 92-93. According to Exxon, Gary recommends estimating the costs of the major processing facilities to be built or added in addition to costs of major supporting facilities, such as related storage facilities and any related steam generation facilities and cooling water systems. *Id.* Next, Exxon states, the cost estimator applies a percentage factor to cover the other OSBL support facilities costs and adds this to the costs of the process units, storage facilities, steam systems, and cooling water systems. *Id.* at p. 93.

[380] According to the Eight Parties, this amount includes $26.8 million in costs for Jenkins's economies of scale on a West Coast basis and $20.5 million in costs after economies of scale on a Gulf Coast basis. Eight Parties Initial Brief at p. 81. If Jenkins followed typical industry practice, the Eight Parties insist, any cost for storage tanks would have been included in the offsite factor. *Id.*

1028. In addition, Exxon claims that the Eight Parties's OSBL estimate of $37.6 million is too low. *Id.* Exxon breaks out the "undisputed" cost of a Coker gas plant, which O'Brien claims to have included, of $14 million and declares that the $23.6 million remainder[381] would have to cover all the other costs. *Id.* at p. 94-95. It also noted that O'Brien included no monies for storage costs. *Id.* at p. 95. Further, according to Exxon, O'Brien failed to separate out the cost of the steam and cooling water facilities, a minimum of $13.5 million according to it, which further diminishes the $23.6 million remainder. *Id.* Exxon concludes that O'Brien's $37.6 million OSBL estimate is wholly inadequate. *Id.*

1029. In their Reply Brief, the Eight Parties declare that O'Brien's cost curve methodology followed standard industry practice, while Jenkins's itemized approach strays from it and allows Exxon "to accumulate unrealistically high OSBL costs." Eight Parties Reply Brief at p. 66. They add that, contrary to Exxon's claim, Jenkins did not follow the Gary & Handwerk procedure in making his estimations of the cost of the Coker and the related downstream equipment. *Id.* Rather, the Eight Parties state that Jenkins used a "Jacobs . . . based detailed line item cost estimate." *Id.* at p. 67. The Eight Parties further charge that "Jenkins engaged in a selective patchwork approach that enabled him to increase substantially the costs he calculated." *Id.* at pp. 66-67.

ii. Coker Gas Plant

1030. Exxon believes that the Coker gas plant costs should be included as part of the ISBL costs for the Coker because the Coker gas plant is an integral part of the processing units for the Coker and, consequently, should be costed out in the Coker's ISBL costs. Exxon Initial Brief at p. 97. O'Brien concedes, according to Exxon, that the Gary & Handwerk text suggests that Coker gas plant costs should be separately costed out in the ISBL costs. *Id.* Additionally, Exxon insists, economic reasons exist for locating the gas plant within the battery limits of the Coker, putting it in close proximity to the Coker fractionator. *Id.* at p. 98.

1031. O'Brien's credibility regarding his claim that the gas plant costs were included in his OSBL cost estimates for the Coker, Exxon states, is undermined because O'Brien was unable, in discovery, to identify the gas plant when listing the equipment included in his OSBL costs. *Id.* Additionally, Exxon asserts, by failing to include Coker gas plant costs in ISBL costs, O'Brien fails to include a corresponding share of OSBL costs for the gas plant. *Id.* at p. 99. Such an amount, Exxon insists, is not trivial. *Id.*

1032. Noting that the Gary & Handwerk text "explains that the gas plant supports *all* of

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[381] Exxon erroneously states the remainder as $23 million. *See* Exxon Reply Brief at p. 95.

the refineries processing units," the Eight Parties suggest that Exxon's gas plant estimate needs to be "allocated among *all* the refinery's processing units and not just the coker." Eight Parties Initial Brief at p. 83 (emphasis in original). They add that, once that is done, Exxon has no support for claiming that O'Brien's $37.6 million estimate is insufficient. *Id.*

1033. In its Reply Brief, Exxon reiterates that "the coker gas plant is an integral part of the coker and should be separately costed out as a part of the coker's ISBL costs, not merely lumped into the coker's OSBL costs." Exxon Reply Brief at p. 96. It further claims that the record is "undisputed" that the Gulf Coast cost of a gas plant, in Year 1996 dollars, is at least $14 million. *Id.* According to Exxon, the Gary & Handwerk textbook places Coker gas plant costs in ISBL costs. *Id.*

1034. Addressing the Eight Parties's argument that the gas plant services processing units other than the Coker, principally a cat cracker, and that only a portion of the $14 million should be placed in OSBL costs, Exxon declares that O'Brien testified that the Quality Bank refinery he had in mind did not have a cat cracker. *Id.*

1035. Exxon also states that the Eight Parties ignored Gary's testimony in making their claim. *Id.* In connection with this assertion, Exxon declares that O'Brien admitted that he misread the Gary & Handwerk textbook and, therefore, mistakenly included the Coker gas plant in OSBL costs. *Id.* It further states that the Gary & Handwerk textbook "indicates that the coker gas plant should be separately costed out as an ISBL cost," as Exxon's witness did. *Id.* at pp. 96-97.

1036. Lastly, Exxon challenges the Eight Parties's claim that O'Brien included the cost of a Coker gas plant in his OSBL estimate. *Id.* at p. 98. It asserts that, deducting the $14 million cost of the gas plant from his OSBL estimate would leave "the amount remaining for all other OSBL costs [as] no more than $23 million, or about 21% of ISBL costs, an amount that is plainly not sufficient." *Id.* Exxon also claims that the Eight Parties's failure to include the Coker gas plant in its ISBL cost leads to a "double undercount" because they also have "failed to include a corresponding share of OSBL costs for the gas plant." *Id.* The result, Exxon asserts, is that the Eight Parties underestimated the cost of the Coker by "$14 million for the ISBL cost, plus $3.5 million for the OSBL cost." *Id.*

1037. In their Reply Brief, the Eight Parties assert that the gas plant is a support facility which should not be included in the Coker ISBL costs. Eight Parties Reply Brief at p. 70. They say that the Coker gas plant is properly accounted for in the OSBL costs as it is a shared facility and only a portion of the costs should be attributed to the Coker. *Id.*

iii. Storage Costs

1038. According to Exxon, OSBL costs must also include appropriate storage costs for storing the Resid as a Coker feedstock and for the storage associated with downstream units. *Id.* at pp. 99-100. Jenkins, Exxon states, includes additional tank costs in his OSBL costs, but O'Brien does not include any storage costs. *Id.* at p. 100. Instead, Exxon contends, O'Brien argues that the Coker could merely use existing storage tanks that are already part of an assumed Quality Bank base refinery. *Id.* Exxon insists that such an assumption is clearly wrong and notes that O'Brien concedes that "if the addition of a coker to a refinery required additional storage, the costs of adding that additional storage should be treated as a cost of the coker." *Id.* at pp. 100-01.

1039. Additionally, Exxon asserts, O'Brien's claim that Coker storage costs are recovered through the prices of other Quality Bank cuts is incorrect because a refinery without a Coker blends Resid directly into fuel oil, which has very different storage requirements. *Id.* at p. 101. Consequently, Exxon explains, no intermediate storage would be necessary. *Id.* However, Exxon states, in a refinery with a Coker, intermediate storage would be needed both for the Resid and for the Coker products to protect the Coker from having to shut down due to a shutdown of a downstream processing unit, and to protect the downstream processing units by making product available in the event of a shutdown of the Coker. *Id.*

1040. O'Brien's contention, according to Exxon, that existing storage tanks can be used to store Resid is incorrect because Resid storage tanks must be heated to around 500ºF and insulated in order to keep the material in a liquid state. *Id.* at p. 102. Crude oil and other refinery product storage tanks, Exxon notes, must be maintained at temperatures below 212ºF. *Id.* Also, Exxon points out, the Coker storage tank's heating process uses open flames and, consequently, these tanks are segregated in a separate area of the refinery away from the tank farm used for other refinery products. *Id.* Concluding, Exxon maintains that even if no additional storage was required to be built, the Coker should still bear a share of costs for the existing storage facilities it uses because the costs of common facilities used to support a group of refinery products should be attributed to all those products. *Id.* at pp. 102-03.

1041. According to Exxon, Jenkins's estimate of the magnitude of the storage costs is reasonable. *Id.* Jenkins testified that Coker feed tanks would require 15 days of storage capacity. *Id.*; Exhibit Nos. EMT-37 at p. 48, EMT-56, EMT-289. This estimate, Exxon explains, was based on Dickman's knowledge that an average Coker experiences downtime of about 45 to 48 days every year, including downtime of about 7 days to decoke the Coker heaters, as well as downtime associated with power failures, foam-overs, and other equipment failures.[382] Exxon Initial Brief at p. 103. Dickman, Exxon

[382] Exxon further explains that, based upon Dickman's determination that the Coker feed tank would normally be filled to approximately 50% of capacity in order to provide protection against both a shutdown of the upstream vacuum unit and a shutdown of the downstream Coker, he next determined that about 13.5 days of usable storage

contends, confirmed the reasonableness of his estimates by comparing them to storage capacity installed at existing refineries. *Id.* at p. 104.

1042. Exxon points out that Jenkins's Coker feed tank cost estimates - $24.1/barrel on the Gulf Coast and $31.5/barrel on the West Coast, - are below the $60 to $80/barrel benchmark set forth in the Gary & Handwerk treatise. *Id.* Additionally, Exxon insists, Jenkins's estimates for propane and butane storage tanks are reasonable as they are based on recommended per barrel costs presented in the Gary & Handwerk textbook, and the tanks are properly sized for the Coker gas plant. *Id.* Similarly, Exxon contends, Jenkins's hydrotreater storage tanks are properly sized given the Coker yields. *Id.* at pp. 104-05. Concluding, Exxon states that Jenkins's cost estimates for the storage facilities required by the Coker are reasonable and appropriate. *Id.* at p. 105.

1043. Regarding storage, the Eight Parties argue that its costs are captured in the Quality Bank reference price. Eight Parties Initial Brief at p. 83. Consequently, the Eight Parties contend, it is improper to charge Resid a storage cost as storage is not a processing cost. *Id.* The Eight Parties explain, however, that Jenkins does charge the Quality Bank Resid component with a storage cost. *Id.* Moreover, the Eight Parties relate, the number of tanks Jenkins includes in his cost estimate is unrealistic, resulting in excessive costs. *Id.* According to the Eight Parties, even if storage were a factor in determining the processing costs of Resid, it is unnecessary to add new tanks simply because a Delayed Coker is added to the base refinery. *Id.* at p. 84. The Eight Parties point out that an integrated refinery producing fuel oil would have vacuum Resid tanks necessary to operate the Coker as well as product storage tanks. *Id.* Further, the Eight Parties relate, such a refinery does not have dedicated Coker intermediate product storage. *Id.*

1044. Exxon's argument that it is not proper cost allocation to use existing tankage because the cost is not charged back to the Resid cut, the Eight Parties contend, is correct on a total refinery accounting basis, but is incorrect for the purposes of this case. *Id.* Here, the Eight Parties explain, the exercise is to define the costs of processing Resid and not to perform a refinery cost allocation analysis. *Id.* Jenkins, the Eight Parties argue, failed to investigate whether refineries added new tankage as part of their Coker construction projects or utilized existing storage. *Id.* at p. 85. According to the Eight Parties, he admitted that a number of refineries either did not add storage tanks or modified existing tanks.[383] *Id.* Despite his admissions, the Eight Parties state, Jenkins

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would be required. Exxon Initial Brief at pp. 103-04. He further determined that in order to provide 13.5 days of usable storage, the Coker feed tank should be sized to provide 15 days of storage, Exxon relates, because three feet of "heel" at the bottom of the tank would be unusable and an additional foot of "free board" at the top of the tank would be unusable except to protect against overflow. *Id.* at p. 104.

[383] The Eight Parties further explain that,

uses costs related to new tanks "regardless of whether the tanks are new, existing or modified." *Id.* at pp. 86-87.

1045. Another problem with Jenkins's approach, the Eight Parties assert, is that he oversized his storage tanks, thus increasing their cost. *Id.* at p. 87. Assuming that the addition of new tanks is appropriate, the Eight Parties believe, Exxon failed to support Jenkins's cost estimate. *Id.* According to the Eight Parties, Jenkins's tank calculations are highly subjective and excessive. *Id.* at p. 88. No single source, the Eight Parties argue, defines Jenkins's days of inventory for his various tanks. *Id.*

1046. For the Coker feed tank, the Eight Parties explain, Jenkins estimate is based upon a conversation Dickman had with a contact at a refinery indicating a Coker feed tank volume corresponding to 15 days of coker throughput. *Id.* Furthermore, the Eight Parties continue, Jenkins based his Coker feed tank costs on costs derived from a conversation Dickman had with a tank vendor, basing the entire cost estimate on this one conversation without further investigation. *Id.* They point out that the industry average for Coker feed tank volumes is 5.5 days of storage, rather than the 15 days of storage assumed by Jenkins. *Id.* at pp. 88-89.

1047. The Naphtha, Distillate, and Gasoil intermediate tank costs, the Eight Parties explain, were developed based upon a spreadsheet Jenkins created for this litigation, which is based on approximately twenty data points of tank information in Jacobs Consultancy's files. *Id.* at p. 89. They point out that Jenkins based his intermediate storage numbers on 15 days of inventory for the Coker feed tank before making additional subjective adjustments. *Id.* According to them, Jenkins admits that refiners generally run their Coker Naphtha, Distillate, and Gasoil directly to the processing units without passing through intermediate storage. *Id.* The Eight Parties argue that Jenkins failed to present any support for the need to add intermediate product storage. *Id.* at p. 90.

> Jenkins admitted that with regard to the Shell Deer Park Refinery, both Maya 1 and Maya 2 projects, that no new tanks were added nor were modifications made to the existing tanks . . . Mr. Jenkins agreed that the Phillips Sweeney Refinery used existing tanks with some possibly being modified . . . Similarly, Mr. Jenkins agreed that at the Valero Texas City coker project, a refinery with which Mr. Jenkins was familiar existing tanks were used and refurbished . . . Finally, Mr. Jenkins acknowledged that at the PACC Port Arthur Refinery[,] tanks 108 and 109 referred to as "new crude storage tanks" were on a drawing dated 4-18-74.

Eight Parties Initial Brief at pp. 85-86 (citations omitted).

1048. In its Reply Brief, Exxon begins by noting that, while it included the total costs of storage in its OSBL estimates,[384] the Eight Parties failed to include any storage costs at all. Exxon Reply Brief at p. 99. It notes that O'Brien claimed that the Coker could use existing storage. *Id.*

1049. Claiming it to be "absurd on its face," Exxon notes that one argument made by the Eight Parties is "that coker storage costs are covered by the Quality Bank reference prices." *Id.* at p. 100. First stating that the parties agreed that "in order to calculate the value of Resid, coker costs must be calculated, including coker OSBL costs," Exxon then itemized the other costs the parties agreed should be included in OSBL costs. *Id.* Declaring that all Quality Bank cuts incur these OSBL costs and that no one has suggested that these costs could be ignored, Exxon exclaims that, for the same reason, storage costs should not be ignored in determining the cost of a Coker. *Id.* at pp. 100-01.

1050. Exxon adds that it is unreasonable to assume that the storage requirements of a refinery with a Coker would be the same as that of a refinery without a Coker. *Id.* at p. 101. According to it, without a Coker, a refinery would blend the Resid with Fuel Oil eliminating the need for an intermediate storage. *Id.* Exxon then states:

> By contrast, in a refinery with a coker, intermediate storage would be needed both for the Resid and for the coker products to protect the coker from having to shut down due to a shutdown of a downstream processing unit, and to protect the downstream processing units by making product available in the event of a shutdown of the coker.

Id. at pp. 101-02. Moreover, Exxon says, storage for the Resid is necessary so that the crude unit would not have to shut down in the event of a Coker shutdown. *Id.* at p. 102.

1051. Exxon, noting the possibility that Coker products could be run straight into a hydrotreater, indicated that intermediate storage would still be necessary to protect the Coker from having to shut down as a result of the shutdown of a downstream processor. *Id.* Further, disputing the Eight Parties's claim that Coker products could be held in the virgin product tanks, Exxon states that, to avoid contamination, refiners do not like to intermingle lower quality products, such as those produced by a Coker, and higher quality virgin products. *Id.*

1052. In their Reply Brief, the Eight Parties declare that, under the Quality Bank methodology, no single product is charged for storage. Eight Parties Reply Brief at pp.

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[384] Exxon states that the total for storage in Year 2000 dollars, was $34.1 million on the West Coast and $26.2 million on the Gulf Coast. Exxon Reply Brief at p. 99.

70-71. Rather, according to them, "any cost of storage is captured in the Quality Bank reference price." *Id.* p. 71. They note that O'Brien testified that, with regard to Resid, the only processing costs involved are those which are required to turn it into Quality Bank quality. *Id.* The Eight Parties further claim that, were storage costs considered for coker products, "an inconsistency will be introduced into the Quality Bank methodology." *Id.*

1053. Acknowledging Exxon's attack on O'Brien's suggestion that, were a Coker added to an existing refinery, a refiner would use existing storage, the Eight Parties assert that even Jenkins testified to facts which support that claim.[385] *Id.* at p. 73. They submit, further, that even were new tanks needed, Jenkins's estimate does "not even come close to replicating a typical West Coast refinery." *Id.* at p. 74. The Eight Parties assert that there is no "objective or verifiable" evidence supporting Jenkins's "wildly inflated estimate that refiners install fifteen days of vacuum Resid inventory when adding a delayed coker to an existing refinery." *Id.* Instead, they submit, "the average storage is 5.5 days" which is "much closer to the 6.8 days . . . Jenkins gave as a corrected answer on re-direct than the completely unsubstantiated 15 days that he actually used." *Id.* at pp. 75-76 (footnote omitted).

1054. Attacking Exxon's claim that Jenkins's $31.50/barrel West Coast estimate for storage was conservative because the Gary & Handwerk estimate ranged from $60/barrel to $80/barrel, the Eight Parties assert that the Gary & Handwerk estimate related to "an entire tank farm not a single feed tank." *Id.* at p. 76. They add that, from their perspective, Exxon offered nothing to support Jenkins's estimate. *Id.* at p. 77. Contrariwise, they claim that Boltz obtained quotes from two vendors for an 80,000 barrel storage tank and that those estimates were $12.35/barrel and $9.70/barrel. *Id.*

1055. Further, the Eight Parties note that Exxon cites to a report by the California Energy Commission that includes a $31.00/barrel estimate for storage tanks, but claim that its confidence that the report support Jenkins's estimate is misplaced. *Id.* at pp. 77-78. According to the Eight Parties, the California Energy Commission's quote

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[385] The Eight Parties state:

> The fallacy of this argument is shown in Exhibit WAP-94, the tank study of West Coast refineries which added a coker, which clearly demonstrated that refineries adding a delayed coker do not add new tanks but rather utilized existing tankage. Mr. Jenkins admitted and agreed that this was true with respect to six of the refineries that *he* had included in his Exhibit EMT-63.

Eight Parties Reply Brief at p. 73 (emphasis in original; note and citation omitted).

represents an amount necessary for the site acquisition and the necessary connections to product pipelines as well as the cost of constructing the storage tanks. *Id.* at p. 78. They further note that the California Energy Commission report reflects that, were the storage tank constructed as part of the expansion of an already existing facility, the cost would be "in the $15 - $16 per barrel range." *Id.* at pp. 78-79.

1056. In closing, the Eight Parties declare that, "in the real world, refiners who operate integrated, economic and efficient refineries take advantage of existing facilities within the refinery which can be converted when changes in the process flow of the refinery occur." *Id.* at p. 79.

iv. Steam Generation and Cooling Water Facilities

1057. As for the steam generation and cooling water facilities cost estimates, Exxon asserts, Jenkins estimates are reasonable. Exxon Initial Brief at p. 105. His costs, Exxon notes, are consistent with the OSBL costing procedure in the Gary & Handwerk textbook and include itemized estimates based on recommendations within the Gary & Handwerk text. *Id.* Following that approach, Exxon states, Jenkins estimated that additional steam generation systems would cost approximately $20.1 million in Year 2000 dollars, and additional cooling water systems would cost approximately $2.6 million in Year 2000 dollars. *Id.* at p. 106. These estimates, Exxon points out, were not disputed by any witness or party. *Id.*

1058. O'Brien, on the other hand, Exxon states, did not itemize an estimate for the steam generation systems or cooling water systems, but, instead provided only a lump sum OSBL cost estimate of $37.6 million in Year 1996 dollars. *Id.* at p. 106. Exxon notes that, although O'Brien did not separately identify the portion of his overall OSBL cost that related to the cost of additional steam generation and cooling water systems, he did admit that "a substantial part" of the difference between his 35% OSBL factor and the 20 to 25% OSBL factor recommended by the Gary & Handwerk textbook was due to the fact that he did not separately cost out an allowance for any steam or cooling water facilities.[386] *Id.* In its Reply Brief, Exxon notes that its estimate of the cost of steam

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[386] Exxon is critical of O'Brien's method:

> Assuming that the full amount of that difference ($13.48 million) was attributable to steam and water cooling facilities, Mr. O'Brien's estimate was grossly inadequate, particularly when applied to the West Coast. At a minimum, the amount should be increased by a location factor of 1.3 to reflect the higher costs found on the West Coast. Even then, however, the resulting amount ($17.5 million) is still well below Mr. Jenkins's itemized estimate of $22.7 million based on the Gary & Handwerk treatise.

generation and cooling water facilities was not disputed by any witness or by the Eight Parties in their Initial Brief. Exxon Reply Brief at p. 107.

1059. The Eight Parties, in their Reply Brief, assert that they have not accepted Jenkins's estimate for the cost of steam generation and cooling water facilities. Eight Parties Reply Brief at p. 80. According to them, "O'Brien included these costs in his OSBL costs, which in part was why [he] used a thirty-five percent OSBL factor instead of the twenty-five percent recommended by Gary & Handwerk." *Id.* Moreover, they assert that O'Brien did not agree with Exxon counsel that even $13.5 million was a reasonable cost for steam and cooling water. *Id.*

1060. The Eight Parties also claim that Exxon's approach is based on a "'grass roots' refinery in that it assumes no steam generation or cooling water was required for any other refinery processes and therefore was non-existent prior to the addition of the delayed coker." *Id.* at p. 81. Thus, according to them, Jenkins's testimony has no credibility. *Id.*

v. Remaining OSBL Costs

1061. Finally, Exxon contends that O'Brien's cost estimate for the remaining OSBL costs is not sufficient.[387] Exxon Initial Brief at p. 107. To the standard list of facilities, Exxon states, O'Brien wished to add the Coker gas plant costs as well as unspecified coke handling costs. *Id.* However, Exxon insists, O'Brien's OSBL cost estimate of $37.6 million is clearly insufficient to cover all the costs:

> [I]f one simply subtracts the ISBL costs of the coker gas plant (at least $14 million) and the cost of the steam generation and cooling water facilities (at least $13.5 million) from Mr. O'Brien's total OSBL estimate of $37.6 million, the resulting amount (at most $10 million) is plainly not sufficient to cover the remaining OSBL costs. Further, Mr. O'Brien's OSBL cost estimate wholly fails to take into account higher West Coast costs.

Exxon Initial Brief at pp. 106-07.

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[387] The standard, agreed upon OSBL costs, Exxon relates, include the cost of electric power distribution systems, fuel oil and fuel gas facilities, waste water treatment and disposal systems, plant air systems, fire protection systems, flare, drain and waste containment systems, plant communications systems, roads and walks, railroad facilities, fences, buildings, vehicles, product and additives blending facilities, and product loading facilities. Exxon Initial Brief at p. 107.

Id.

1062. In its Reply Brief, after itemizing what it claims are other OSBL costs, Exxon argues that the Eight Parties's $37.6 million OSBL estimate is not sufficient to cover them. Exxon Reply Brief at p. 108.

1063. The Eight Parties, in their Reply Brief, attack Exxon's reliance on a "laundry list" of needed "off-site" items to establish OSBL costs. Eight Parties Reply Brief at p. 81. They assert that the items contained in Exxon's list reflect the needs of "a start-up grass roots refinery, not an existing refinery to which a delayed coker is being added." *Id.* at p. 82. Noting that even Exxon concedes that the needs would differ between different refineries, the Eight Parties indicate that because of those differences "the typical industry practice is to use the percentage of the ISBL approach to develop and estimate, and not a detailed cost estimate which in effect is refinery specific." *Id.*

c. Other Capital Costs

i. Sulfur Recovery Costs

1064. Exxon explains that the parties agreed that a sulfur plant would be necessary to convert hydrogen sulfide and other sulfur compounds coming out of the Coker and downstream hydrotreaters into elemental sulfur and also agreed that back up capacity was necessary for the sulfur plant. Exxon Initial Brief at p. 108. However, Exxon notes, the parties disagreed over the necessary amount of back-up sulfur plant capacity. *Id.* Exxon's witnesses argued for a 100% back up capacity while O'Brien argued for a 30% back up capacity. *Id.* at pp. 108-09.

1065. In order to meet West Coast environmental requirements, Exxon insists, and as a matter of good engineering and business practice, 100% sulfur processing back up capacity is required. *Id.* at p. 109. Sulfur plant average utilization rates for the West Coast, Exxon relates, are approximately 50%, indicating that refiners employ 100% backup capacity. *Id.* at p. 110. Exxon points out that this added capacity can be installed at a low cost compared to the potential costs and liabilities of operating without the added capacity. *Id.* According to Exxon, 100% backup capacity means only that a plant would have sufficient capacity to operate 100% of the time, which could be achieved "by building three units each capable of providing 50% of the total capacity required, such that if one unit goes down, another unit would be available to maintain a 100% level of operation even though the amount of spare capacity was only 50%." *Id.*

1066. Exxon maintains that O'Brien's 30% sulfur plant backup capacity is clearly inadequate to deal with the potential costs to the refiner should a unit go down. *Id.* at pp. 110-11. O'Brien admits, Exxon points out, that sulfur capacity must always be available when a Coker is operating. *Id.* at p. 111. Additionally, Exxon states, O'Brien's evidence justifying the 30% back up capacity assumption - a comparison of the difference between the amount of sulfur contained in the crude oil coming into West Coast refineries and the amount of sulfur in the products produced by those refineries - is "fundamentally flawed and produced illogical results." *Id.* Exxon asserts that O'Brien admitted that he understated the sulfur amount in coke produced from coking ANS Resid by almost 50 % and ignored sulfur removed during the refining process by means other than the sulfur plant. *Id.*

1067. O'Brien's analysis, Exxon argues, suggested that certain West Coast refineries had no spare capacity or insufficient capacity to remove the sulfur produced in their facilities. *Id.* Exxon believes that such an analysis is unsupportable because Dickman's analysis of West Coast sulfur refining capacity demonstrated that West Coast refineries had an average of about 54% excess or spare capacity in their sulfur plants. *Id.*

1068. Additionally, Exxon points out, O'Brien assumed a single sulfur plant with 130% of the required capacity, which would not provide backup if the unit failed. *Id.* at p. 112. Finally, Exxon insists, no justification exists for O'Brien's approach of estimating the cost of building a larger sulfur recovery plant with substantial scale economies, but then simply taking a pro rata share of those costs as the estimated cost of a much smaller plant. *Id.*

1069. According to Exxon, Jenkins's sulfur plant cost estimate is reasonable while O'Brien's is unsupportable. *Id.* at pp. 112, 114. Jenkins, Exxon explains, applies the sulfur recovery facility cost curve provided in the Gary & Handwerk text, determining that the ISBL capital costs of the sulfur recovery facilities for the Coker in Year 2000 dollars would be $24.7 million on the West Coast and $19.0 million on the Gulf Coast. *Id.* at pp. 112-13. Next, Exxon relates, Jenkins adds OSBL costs and deducts an allowance for economies of scale, resulting in a capital cost for the sulfur plant of $20 million on the West Coast and $15.4 million on the Gulf Coast in Year 2000 dollars. *Id.* at p. 113.

1070. O'Brien's cost estimate, Exxon notes, was merely $8.7 million on both coasts in Year 2000 dollars. *Id.* This estimate, Exxon explains, lacked both a West Coast location factor and 100% back up capacity. *Id.* Additionally, Exxon states, O'Brien admits that his estimate is based on an outdated version of the cost curve in the Gary & Handwerk text.[388] *Id.*

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[388] Exxon editorializes that:

> It is also revealing that, although Mr. O'Brien used a Gary & Handwerk cost curve to estimate the capital costs of the sulfur plant, he elected not to use the Gary & Handwerk cost curves in estimating the cost

1071. The Eight Parties characterize the sulfur recovery question differently than does Exxon:

> [D]o you assign the costs from the capacity plus a reserve from an existing efficiently sized sulfur recovery plant at the refinery as Mr. O'Brien proposes on behalf of the Eight Parties, or do you build a redundant (*i.e.* second full sized) sulfur recovery plant because you are adding a delayed coker as Mr. Jenkins proposes on behalf of [Exxon]?

Eight Parties Initial Brief at p. 91. According to the Eight Parties, O'Brien assumes an existing sulfur recovery plant capable of processing 200 long tons per day for all processing units at an existing refinery generating H_2S that has to be recovered in order not to violate environmental emission standards. *Id.* When he applies all costs, the Eight Parties continue, O'Brien's total capital cost allocated to the Coker for H_2S processing is $9.95 million, or $14.2¢/barrel. *Id.*

1072. Exxon's proposal, the Eight Parties accuse, is subjective and based upon erroneous assumptions. *Id.* at p. 92. According to the Eight Parties, Exxon proposed two identical, redundant, full-sized sulfur recovery plants. *Id.* Furthermore, the Eight Parties argue, Jenkins inconsistently derived his cost estimate for the redundant sulfur recovery plant using Gary & Handwerk text cost curve, even though Jacobs Consultancy has a cost curve for sulfur recovery plants. *Id.* at p. 93. Jenkins's assumptions, the Eight Parties contend, are flawed. *Id.* at p. 94. Despite his assertions, the Eight Parties relate, California does not require redundant sulfur recovery plants. *Id.* They point out that the South Coast Air Quality Management District under California's Best Available Control Technology Statute does not specify a redundant sulfur recovery plant. *Id.* at p. 95. Furthermore, the Eight Parties relate, the California Shell Martinez Refinery Coker project has only one installed sulfur plant. *Id.*

1073. On Reply, Exxon notes that, while the parties agree that a sulfur plant is necessary as well as back-up capacity for that plant, they disagree as to how the back-up capacity is to be supplied, the amount of the back-up capacity necessary, and the unit cost of the sulfur recovery unit. Exxon Reply Brief at p. 109. As to how the back-up capacity is to be supplied, Exxon declares, the Eight parties are simply wrong in suggesting that it can be supplied in the same unit as the original capacity: "If all of the sulfur recovery capacity is contained in a single unit, no matter how large, and that unit goes out of

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> for either the coker or the distillate hydrotreater. In those instances, he instead chose to use his own firm's cost curves, which resulted in outcomes more favorable to the position of his clients.

Exxon Initial Brief at pp. 113-14.

service, the refinery must either shut down or run the risk of substantial fines associated with violation of applicable environmental regulations." *Id.* Consequently, Exxon argues, O'Brien's proposal of a sulfur plant able to process 130% of the needed amount is simply unsound and that true back-up capacity can only come in multiple units. *Id.* at pp. 110-12.

1074. Turning to the amount of back-up capacity, Exxon argues that O'Brien, in suggesting that 30% is sufficient, errs. *Id.* at p. 112. It claims that the record indicates that, at the hearing, O'Brien "admitted . . . that he had understated the amount of sulfur in the Coke produced from coking the ANS Resid by almost 50%," and failed to take into consideration the sulfur which would be removed by other means than the sulfur plant. *Id.* at p. 113. According to Exxon, the average sulfur plant back-up capacity of West Coast refineries is 54%. *Id.*

1075. According to Exxon, its witness, Jenkins, estimated the cost, Year 2000 dollars, of sulfur recovery facilities to be $24.7 million on the West Coast and $19 million on the Gulf Coast. *Id.* at p. 114. It asserts that Jenkins's estimate is based on the cost curve from the Gary & Handwerk text. *Id.* Answering the Eight Parties's criticism of Jenkins's use of this cost curve, Exxon notes that O'Brien also used a Gary & Handwerk cost curve for his estimate of these costs and admitted that his estimate was based on "an outdated version of the cost curve." *Id.*

1076. On reply, the Eight Parties, first noting that O'Brien's estimate that only 30% of redundant capacity is needed was based on a study he had conducted of West Coast refineries not all of which had Delayed Cokers, attack Exxon's proposal that 100% excess capacity is required. Eight Parties Reply Brief at pp. 83-85. They argue that, despite the testimony of Exxon's witnesses, no evidence in the record established that there are any environmental requirement that there be such excess capacity, nor, they say, is there "any evidence proving that the Claus sulfur recovery plants used by the industry are hard to operate and prone to frequent breakdowns." *Id.* at p. 85. Acknowledging that Jenkins used the high range of the Gary & Handwerk OSBL factor (20-25%), the Eight Parties note that O'Brien testified that his standard practice is to use a 15% factor for an ISBL sulfur plant. *Id.* at p. 86.

ii. Downstream Hydrotreater

1077. Exxon explains that all parties agreed that the Coker requires downstream hydrotreaters to reduce the amount of sulfur and other impurities in the Coker Naphtha, Coker Distillate and Coker VGO products in order to bring those products up to the quality of the proxy products used by the Quality Bank to value "virgin" or Quality Bank Naphtha, Distillate and VGO. Exxon Initial Brief at pp. 114-15. Jenkins, Exxon notes, provided cost calculations for each of the hydrotreaters and, where the products were superior to the Quality Bank proxy products, he reduced the costs by a credit. *Id.* Also, Exxon relates, Jenkins credited the hydrotreaters with any economies of scale that a refinery might enjoy by building a larger hydrotreater integrated with other refinery operations. *Id.*

1078. In contrast, Exxon states, O'Brien assumed that a single distillate hydrotreater could be used to process the Coker Distillate and the "virgin" or "Quality Bank" Distillate, that another hydrotreater would be used to process the Coker VGO and "virgin" or "Quality Bank" VGO, and that a Naphtha hydrotreater would be used to process the combined Coker LSR, Coker Naphtha, and "virgin" or "Quality Bank" Naphtha streams. *Id.* at pp. 115-16. Furthermore, Exxon states, O'Brien assumed that his VGO and Naphtha hydrotreaters would be "hybrid" hydrotreaters operating at an intermediate pressure in view of the fact that Coker VGO and Coker Naphtha would require high pressure hydrotreating, while virgin VGO and virgin Naphtha could be hydrotreated using a less-costly medium-pressure hydrotreater. *Id.* at p. 116. O'Brien, Exxon explains, then calculates the incremental processing cost attributable to hydrotreating Coker products in order to bring them up to Quality Bank specifications.[389] *Id.* However, Exxon asserts, O'Brien's did not provide any factual support for his approach in estimating hydrotreating costs. *Id.*

1079. Exxon insists that O'Brien's approach to the costing of the Naphtha and VGO hydrotreaters was also inconsistent. *Id.* at p. 117. For pricing virgin Naphtha, Exxon explains, he assumed that the Naphtha hydrotreater would be a medium-pressure hydrotreater. *Id.* However, Exxon continues, his pricing assumed that the Coker Naphtha hydrotreater would be a hybrid intermediate-pressure hydrotreater with a pressure somewhere between high and medium. *Id.* He admitted, Exxon relates, that the medium-pressure hydrotreater used by a refinery to process virgin Naphtha would not be able to process the Coker Naphtha. *Id.*

1080. Additionally, Exxon notes, O'Brien admitted that the medium-pressure hydrotreater that a refinery without a Coker would build to process virgin VGO would be unable to process the VGO produced by the Coker, and that a higher pressure hydrotreater would be required to process Coker VGO. *Id.* Another flaw, according to Exxon, was that he was unable to explain how the medium-pressure hydrotreaters could be transformed into larger, higher pressure hydrotreaters when the Coker was added to the refinery, nor did he attempt to estimate the costs of doing so. *Id.* Exxon states that

[389] According to Exxon, O'Brien concedes that a refinery without a Coker would install economically sized hydrotreaters sufficient to process the Quality Bank products, and that, were a Coker subsequently added to the refinery, the refinery would add hydrotreating capacity to process the Coker products. Exxon Initial Brief at p. 116. Additionally, Exxon relates, he admits that the Quality Bank prices for Quality Bank VGO, Quality Bank Naphtha, and Quality Bank LSR do not capture any of the costs associated with hydrotreating the products of the Coker. *Id.*

Jenkins estimate on the Gulf Coast was \$19.4 million in Year 2000 dollars, while O'Brien estimated that the Gulf Coast cost would be \$14.6 million in Year 2000 dollars. *Id.* at p. 118.

1081. The Eight Parties argue that O'Brien followed standard industry practice by assuming that process units that are efficiently sized as they exist in an efficient West Coast coking refinery. Eight Parties Initial Brief at p. 96. Refinery processing units, the Eight Parties relate, are sized to process all of the material that comes from distillation, cracking and coking units, rather than from just one of them, which allows refiners to achieve economies of scale and reduce the cost per barrel of hydrotreating. *Id.*.

1082. According to the Eight Parties, Jenkins fails to follow standard industry practice in his Coker product treatment costs. *Id.* at p. 97. In creating his line item estimate, the Eight Parties assert, he does not follow actual refinery practice because he downsizes his hydrotreaters, treating only the respective product coming from the 40,000 barrels/day Delayed Coker. *Id.* Consequently, the Eight Parties explain, this results in factored costs for a 12,000 barrel/stream day Coker VGO hydrotreater, a 6,500 barrel/stream day Coker Naphtha hydrotreater, and an 8,300 barrel/stream day Coker Distillate hydrotreater. *Id.* No refiner, the Eight Parties insist, would build units this small, especially in a 200,000 barrels/day refinery. *Id.* As a result of choosing hydrotreating equipment and operating conditions producing products exceeding the applicable proxy product specifications, the Eight Parties maintain, Jenkins makes a series of subjective adjustments to the hydrotreating costs of the Coker VGO and Coker Distillate streams to compensate. *Id.*

1083. While admitting that the parties agree that downstream hydrotreaters will be necessary to reduce the amount of sulfur and other impurities in Coker Naphtha, Distillate and VGO products, in its Reply Brief Exxon notes that, although the parties followed different approaches to reach an estimate of their cost, the end results were close. Exxon Reply Brief at pp. 115-16. Nevertheless, Exxon explains that Jenkins used a "reasonable approach" to estimate the cost "with every aspect of his estimate transparent and subject to audit," while O'Brien "relied on impossible-to-audit cost curves." *Id.* at p. 116.

1084. According to Exxon, "Jenkins provided detailed cost calculations for each of the necessary hydrotreaters, and designed hydrotreaters of a size and type which would be found in actual refineries." *Id.* at p. 117. He also credited the hydrotreaters with the appropriate economies of scale. *Id.* Taking issue with the Eight Parties's claim that Jenkins's estimates were "subjective," Exxon declares this assertion to be without merit and states that the Eight Parties "had a full and fair opportunity to take issue" with them. *Id.* at pp. 117-18.

1085. Responding to the Eight Parties's claim that the approach O'Brien used to make his estimate followed an approach which was standard in the industry, Exxon asserts that they failed to identify any evidence to support it. *Id.* at p. 118. It adds that, at the hearing, "O'Brien conceded that a refinery without a coker would be expected to install economically sized hydrotreaters sufficient only to process the Quality Bank products, and that if a coker were subsequently added to the refinery, the refinery would have to add additional hydrotreating capacity to process the coker products." *Id.* at p. 119. Moreover, Exxon argues, on cross-examination, O'Brien admitted that the same hydrotreaters which were capable of treating virgin Naphtha or virgin VGO, which need only be medium-pressure hydrotreaters, would not be capable of treating Coker Naphtha, or Coker VGO. *Id.* at p. 120. It declares that his "approach required a complex and *highly subjective* cost allocation procedure." *Id.* (emphasis added). In closing, Exxon highlights its claim that the difference between the parties's estimates is less than $5 million.[390] *Id.* at p. 121.

1086. In their Reply Brief, the Eight Parties declare that "O'Brien followed standard industry practice with respect to the efficient sizing of process units which enables a refiner to achieve economics [sic] of scale that reduce the cost per barrel of hydrotreating." Eight Parties Reply Brief at p. 87. Thus, they say, using the Baker & O'Brien cost curves to determine the overall cost for an appropriate hydrotreater, O'Brien then assigned a portion of that cost to treating products from the Coker. *Id.* In comparison, wrongly they argue, Jenkins used hydrotreaters which he downsized solely to treat the Coker products.[391] *Id.* at p. 89. According to the Eight parties, no refiner would do what Jenkins did, instead they "build larger units that enjoy economies of scale." *Id.*

iii. Finance Costs

1087. Jenkins, Exxon begins, combined three different cost factors to produce a 19.5% total capital cost factor for computing the capital costs of the Coker and related downstream units.[392] Exxon Initial Brief at pp. 118-19. In contrast, Exxon relates,

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[390] Exxon states that its estimate, taking economies of scale into account, in Year 2000 dollars, is $19.4 million while the Eight Parties's is $14.6 million. Exxon Reply Brief at p. 121.

[391] According to the Eight Parties, Jenkins's approach results in "an almost doubling of the cost on a unit of throughput basis for his three hydrotreaters compared to Mr. O'Brien's efficiently sized hydrotreaters." Eight Parties Reply Brief at pp. 89-90.

[392] Exxon explains that, first, Jenkins used a 17% capital recovery factor, derived by Toof, based on an expected 25-year useful life and a resulting 4% depreciation rate, a capital structure of 35% debt/65% equity, a 7.85% cost of debt, and a 15.78% pre-tax cost of equity. Exxon Initial Brief at p. 118. Second, Exxon continues, Jenkins used an "owner's cost" of 10%. *Id.* Third, it states, Jenkins used an interest during construction

O'Brien assumes a five year payback for the Coker investment, equivalent to a 20% capital cost factor. *Id.* at p. 119. Exxon contends that O'Brien's approach oversimplifies, excluding relevant costs, but not by much. *Id.* Exxon contends that the error here from O'Brien's 20% capital recovery factor is relatively small and, as Jenkins's combined capital cost recovery factor is 19.5%, the outcome is essentially the same. *Id.* at pp. 119-20.

1088. The Eight Parties explain that O'Brien uses a capital recovery factor of 20%. Eight Parties Initial Brief at p. 100. According to the Eight Parties, a 20% annual capital recovery factor used in calculation costs for the adjustment to the Heavy Distillate price was found to be reasonable in the Certification of Contested Settlement and Ruling on Motion to Omit the Initial Decision, *Trans Alaska Pipeline System*, 80 FERC ¶ 63,105 at p. 65,235 (1997). *Id.* at p. 102.

1089. Exxon's approach, the Eight Parties contend, is subjective as it is nothing more than a snapshot for a one year period. *Id.* at pp. 103-04. Toof, the Eight parties state, testifies that the capital recovery factors cost can change from year-to-year and, therefore, he recommends an annual update. *Id.* at p. 104. The Eight Parties disagree with Exxon's approach to interest during construction, since they assume that the project is built with equity, thus avoiding the question of interest during construction. *Id.* However, like Exxon, the Eight Parties note that whichever approach is adopted the outcome is essentially the same. *Id.* at p. 105.

1090. In its Reply Brief, Exxon states that, to compute the finance costs of capitalizing the Coker and related downstream processing units, Jenkins used three multipliers: (1) a 17% capital recovery factor derived by Toof "from standard industry and financial indices, based on an expected 25-year useful life and a resulting 4% rate of depreciation, a capital structure of 35% debt and 65% equity, a 7.85% cost of debt, and a 15.78% pre-tax cost of equity;" (2) an owner's cost of 10% which it claims was "at the low end of the range of owner's cost as a percentage of total construction costs for a number of refinery construction projects;" and (3) "an 'interest during construction' ('IDC') factor of 4.3% based on a three-year construction schedule, a debt ratio of 35%, and an interest rate of 7.85%." Exxon Reply Brief at p. 122. It states that combining these factors resulted in a 19.5% total capital cost factor. *Id.* In contrast, Exxon states, O'Brien merely assumed a five-year payback on the Coker investment which resulted in a 20% capital cost factor. *Id.* at pp. 122-23.

1091. While admitting that O'Brien's approach often is used to make preliminary cost estimates, Exxon declares that it is inadequate to make final estimates because it can leave out relevant costs. Exxon Reply Brief at p. 123. Exxon notes that its witness,

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factor of 4.3% based on a three-year construction schedule, a debt ratio of 35%, and an interest rate of 7.85%. *Id.* at p. 119.

Baumol, testified that O'Brien's approach was simply wrong. *Id.*

1092. In their Reply Brief, the Eight Parties conclude as follows:[393] "O'Brien's twenty percent capital factor should be adopted because it doesn't have to be adjusted annually. Moreover, it is the same capital factor used for other Quality Bank components when a finished product has to be adjusted to reflect an intermediate feedstock value." Eight Parties Reply Brief at p. 93. In comparison, they argue that Toof agreed that his capital cost number would have be adjusted annually by the Nelson Farrar index. *Id.* at p. 92. According to them, once the project would be finished, "the costs would not be changed each future year." *Id.* at pp. 92-93.

3. Location Factor

1093. Exxon states that a major area of disagreement between the parties relates to using a location factor for the West Coast. Exxon Initial Brief at p. 121. All parties assumed the Coker would be built on the West Coast, Exxon begins, and Jenkins calculated construction and operating costs on the Gulf Coast, adding a location factor to reflect the West Coast's higher costs. *Id.* O'Brien, Exxon relates, makes no such adjustment. *Id.* It insists that this failure is a clear and indefensible error, departing from standard industry practice as well as the principal industry cost treatises and resulting in almost 50% of the $2.40/barrel difference between the parties regarding the West Coast Resid value. *Id.* at pp. 121-22.

1094. Exxon explains that using a location factor with cost studies is "an appropriate and well-established industry practice." *Id.* at p. 123. As an example, Exxon points to the Gary & Handwerk treatise, which uses a factor of 1.0 for the Gulf Coast and gives a location adjustment of 1.4 for Los Angeles and 1.2 for Portland and Seattle. *Id.* at p. 124. Also, Exxon notes that a National Petroleum Council-commissioned study by Bechtel estimated that, taking into account differences in construction costs, building codes, environmental rules, and other design parameters, the cost to build a unit would be 40% higher in California and 20% higher on the rest of the West Coast than on the Gulf Coast. *Id.* Finally, Exxon states that O'Brien's own firm uses location factors in preparing cost estimates. *Id.*

1095. Pointing out that the parties agreed to value West Coast Resid on the basis of West Coast prices and not on Gulf Coast prices, Exxon suggests that West Coast costs rather than Gulf Coast costs must be used for valuation. *Id.* at p. 122. It accuses the Eight

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[393] It must be noted that the Eight Parties cite to no record evidence to support their claim that the 20% return "is the same capital factor used for other Quality Bank components when a finished product has to be adjusted to reflect an intermediate feedstock value."

Parties of undervaluing West Coast Resid by not accounting for the West Coast's higher costs. *Id.* According to Exxon, no one disputes that construction costs, labor costs, and permitting costs are significantly higher on the West Coast than on the Gulf Coast. *Id.* at p. 123. O'Brien concedes, Exxon relates, that no authority supports his position that a location factor should not be used in preparing cost estimates. *Id.* at p. 125. Exxon argues that O'Brien's explanation, that it is too early in the cost estimating process to use such a factor, is not credible. *Id.* Any credible analyst, Exxon insists, would use a location factor, even when starting from a cost curve. *Id.* Additionally, Exxon notes, the parties have assumed West Coast prices for other aspects of the case. *Id.*

1096. According to Exxon, O'Brien's attempt to confuse West Coast location factor with site preparation costs[394] has no valid basis. *Id.* Jenkins, Exxon explains, did not use any site preparation costs because he assumed that the Coker was to be added to an existing refinery without a Coker and the refinery site would already have been prepared. *Id.* at p. 126.

1097. Jenkins, Exxon points out, uses a West Coast location factor of 1.26 for the Coker and location factors ranging from 1.26 to 1.3 for other process units such as the hydrotreaters and the sulfur plant. *Id.* at p. 127. The varying West Coast location factors, Exxon explains, result from variations in the mix of equipment, structures, and other costs required for each type of processing unit. *Id.* These factors, Exxon believes, are reasonable for the West Coast, but are conservative for the Los Angeles area, noting that the Gary & Handwerk textbook uses 1.4 for the Los Angeles location adjustment. *Id.*

1098. The West Coast location factor, Exxon notes, is supported by more general construction and building authorities for different geographic regions:

> The September 11, 2000 edition of *Engineering News Record* ("*ENR*") provides relative cost indices applicable to all types of construction and buildings for U.S. cities, including New Orleans where numerous Gulf Coast refineries are located. These data show that West Coast construction costs are from 139% to 222% higher than Gulf Coast construction costs. A similar R.S. Means study of general construction cost location factors also showed a Los Angeles location factor of approximately 1.3, and an overall West Coast location factor of between 1.25 and 1.29, when the location factor for Gulf Coast cities that have refining capacity was set at 1.0.

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[394] Exxon explains that site preparation costs are costs associated with getting a site prepared to be built upon and that site preparation costs are specific to particular sites, involving costs distinct from location costs addressed by geographic location factors. Exxon Initial Brief at p. 126.

Id. at pp. 128-29 (internal citations omitted).

1099. According to the Eight Parties, no location factor is necessary in this case because the Delayed Coker is not for a specific project defined in sufficient detail and pinned down to a specific location. Eight Parties Initial Brief at pp. 105-06. They maintain that cost curves are the most appropriate basis for such a project.[395] *Id.* at pp. 106-09. Location factors, the Eight Parties assert, are highly subjective and differ by whoever does them. *Id.* at p. 109. Such subjectivity is demonstrated, the Eight Parties explain, in examining the *Engineering News Record,* which applies to all types of construction and which Jenkins relies on to demonstrate the higher West Coast costs. *Id.* at pp. 111-12.

1100. According to the Eight Parties, the *Engineering News Record* confirms their opinion of the subjectivity of location factors:

> A more detailed review of [the *Engineering News Record*] than the cursory reliance by Mr. Jenkins on the difference in the hourly rate for common labor also reveals the subjectivity of location factors or comparison of costs

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[395] The Eight Parties compare two refineries -- the Shell Deer Park Refinery on the Gulf Coast and Shell's Martinez Refinery on the West Coast – to demonstrate that California projects may, indeed, be cheaper than Gulf Coast projects:

> [T]he cost of the Deer Park Refinery coker project is $13,636 per barrels/day while the cost of the Martinez Refinery coker project is $10,331 per barrels/day. Thus, based on actual cost data for the two refineries owned by the same company, Shell, on an equivalent cost in dollars per barrels/day basis, the cost of the coker project on the West Coast is *lower* than the cost on the Gulf Coast.
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> * * * *
>
> [T]he only factual evidence of comparable cost data for a coker project on the West Coast and the Gulf Coast shows that the cost expressed in barrels/day in order to put the costs on the same basis, was *lower* not higher on the West Coast. This empirical data supports Mr. O'Brien's expressed concern that until you had a specific project it was appropriate to use only a generic cost curve and not apply a location factor because the cost might be lower. More significantly for this proceeding, the only record evidence does not support the use of any location factor in determining the delayed coker costs to be used in the Resid valuation formula.

Eight Parties Initial Brief at pp. 108-09 (emphasis in original; internal citations omitted).

> between the Gulf Coast and the West Coast. First, in the October 2, 2000 edition of [the *Engineering News Record*], the costs for common labor, skilled labor and materials are *lower* in St. Louis compared to Los Angeles, which is the exact opposite of what the Gary & Handwerk textbook shows for location factors for the two cities, 1.6 and 1.4, respectively. . . . The comparison of costs and location factors for a Chicago and Los Angeles refinery used in [the *Engineering News Record*] and Gary & Handwerk has the same dichotomy in results. In [the *Engineering News Record*], Chicago has higher common labor, skilled labor and materials costs than Los Angeles, while the Gary & Handwerk textbook location factor for Chicago is less than Los Angeles.

Id. at p. 112.

1101. Another approach to West Coast location factors, the Eight Parties assert, is to average several different locations. *Id.* at p. 114. Using PRISM, the Eight Parties state, the number would be 1.08 for Portland, 1.20 for Seattle and 1.35 for California (Los Angeles and the San Francisco Bay area). *Id.* Although Jenkins calculated the average of these three numbers to be 1.21, the Eight Parties note, if he had included the inland California refineries in the California number, changing the 1.35 to 1.28 rounded (1.35 + 1.20 divided by 2), the resulting average is 1.19. *Id.* All this demonstrates, the Eight Parties contend, the immense subjectivity involved in using location factors and "how they are affected by simply changing one number." *Id.* at p. 115.

1102. Acknowledging that the use of a location factor is a major difference between it and the Eight Parties, on reply, Exxon points out that, despite his failure to use a location factor to increase West Coast costs, O'Brien acknowledged that West Coast costs were higher than those on the Gulf Coast. Exxon Reply Brief at pp. 125-26. In contrast, Exxon claims that Jenkins, its witness, after determining construction and operating costs on the Gulf Coast applied "appropriate location factors to reflect" the higher West Coast costs. *Id.* at p. 126. As to O'Brien's failure to use a location factor, Exxon states:

> This failure by Mr. O'Brien to adjust his Gulf Coast cost estimate to reflect the higher West Coast costs is a clear error and an indefensible departure from both standard industry practice (including his own firm's practice) and all of the principal cost treatises that are used in the industry.

Id.

1103. Exxon challenges the Eight Parties's claim that there is no need to use a location factor because no specific project is being planned stating that, as all of the information for planning the project is available, it would be "plainly wrong" not to use a location factor to reflect the higher West Coast costs and that no "credible analyst" would fail to do so. *Id.* at p. 128. It adds that even using a cost curve requires the use of a location factor. *Id.* at p. 129.

1104. Responding to the Eight Parties's claim that its use of a 1.26 location factor is too subjective, Exxon claims that its use was not based solely on its data, but that its use is consistent with "the Gary & Handwerk treatise, the 1993 NPC commissioned study, and the 200 API study by Mr. O'Brien's firm, as well as the more general cost indices in *ENR* and R.S. Means." *Id.* at pp. 135-36.

1105. In its Reply Brief, the Eight Parties again defend O'Brien's refusal to adjust his cost curve to reflect the higher costs on the West Coast in comparison with those on the Gulf Coast indicating that he refused to do so because there was no "specific location" identified for the Coker. Eight Parties Reply Brief at pp. 93-95. They continue to attack Exxon for locating its hypothetical Coker in the Los Angeles area stating that there is no basis for doing so. *Id.* at pp. 95-96. In any event, the Eight Parties maintain that location factors are "highly subjective." *Id.* at pp. 98-99.

4. Operating Costs

a. Fixed Operating Costs

1106. The fixed operating costs, Exxon explains, include the labor required to operate the Coker and related downstream units, maintenance expense, plant supplies, administrative and technical management, taxes and insurance. Exxon Initial Brief at p. 129. Jenkins, Exxon states, provided a list of fixed operating costs necessary for the Coker, related downstream units, and offsite facilities. *Id.* at pp. 129-30. These costs, Exxon relates came to $1.19/barrel on the Gulf Coast and $1.43/barrel on the West Coast in Year 2000 dollars; while O'Brien's comparable estimate came to 96¢/barrel in Year 2000 dollars for both coasts. *Id.* at p. 130.

1107. According to Exxon, much of the difference between the two estimates results from the fact that a number of the fixed operating costs are computed as a percentage of either the ISBL costs or the total capital costs. *Id.* As the parties's capital cost estimates differ, Exxon states, the resulting fixed operating cost estimates differ. *Id.* Jenkins, Exxon notes, concludes that this factor accounts for nearly all the difference between the parties's estimates. *Id.* Another factor accounting for the difference, Exxon relates, is differing labor cost estimates. *Id.* Jenkins, Exxon explains, details the various parts of his labor cost estimate; while O'Brien puts forth labor cost estimates, adding a contingency allowance for miscellaneous fixed operating costs, which he calculated as a percentage of his ISBL capital cost estimate. *Id.* at pp. 130-31.

1108. Exxon contends that O'Brien's approach is a non-transparent black box and that Jenkins's approach is more reasonable. *Id.* at p. 131. Furthermore, Exxon claims, O'Brien's criticisms of Jenkins's labor cost assumptions are without merit. *Id.* In contrast, Exxon asserts, O'Brien's fixed operating cost estimate includes a number of unrealistic and uncorrected assumptions.[396] *Id.* at pp. 131-32.

1109. The Eight Parties explain that O'Brien and Jenkins presented fixed cost estimates that are 22¢/barrel apart for the Gulf Coast and 47¢/barrel different for the West Coast, on a Year 2000 basis. Eight Parties Initial Brief at pp. 115-16. Several elements of the fixed cost calculations, the Eight Parties note, are based on a percentage of capital costs and, therefore, some of the difference between the two fixed cost estimates is explained by the difference in the calculation of capital costs. *Id.* at p. 116. Three differences, the Eight Parties state, stem from differences that are not explained by different capital cost calculations, and these include: (1) the number of operators; (2) inclusion of a foreman; and (3) the labor multipliers used in estimating labor costs. *Id.*

1110. O'Brien assumes six operators per shift (25 in total), the Eight Parties state, while Jenkins assumes nine operators per shift (38 in total). *Id.* Part of the difference in number of operators, the Eight Parties relate, results from the difference between the 2-drum and 4-drum Coker assumptions. *Id.* Another difference, the Eight Parties contend, stems from Jenkins failure to account, in his staffing requirement, for the automatic deheading equipment, automatic chutes, and a sophisticated coke handling system used in reducing cycle time. *Id.* at p. 117.

1111. Jenkins also assumes a foreman to supervise the operations of the Coker, the Eight Parties note, while O'Brien does not. *Id.* Because there would not be a foreman assigned solely to the Coker in an integrated refinery, the Eight Parties insist, the refinery would not incur the incremental cost of a foreman to process Resid. *Id.*

1112. Regarding labor multipliers, the Eight Parties argue, Jenkins multiplies his direct labor values twice for benefits, overtime, and other labor related costs. *Id.* at p. 122. Such an approach is inappropriate, the Eight Parties believe, stating that it is appropriate to use a multiplier only once to reflect benefits and costs. *Id.* A proper multiplier in this situation, the Eight Parties assert, is 45%. *Id.*

1113. In its Reply Brief, Exxon notes, the parties agree that the "remaining differences in fixed operating costs are largely explained by differences relating to labor costs." Exxon Reply Brief at p. 140. According to Exxon, O'Brien based his operating costs on a six-operator per shift crew, while Jenkins based his on a nine-operator per shift crew. *Id.* at

[396] These assumptions, Exxon states, include O'Brien's contention that a 40,000 barrels/day Coker and required downstream processing units could be operated on a 14-hour cycle with only a 6-man crew. Exxon Initial Brief at p. 132. Also, Exxon points out, O'Brien's proposed work force could not operate the Coker 24 hours per day for seven days a week, and he did not include costs for the operators of hydrotreaters. *Id.*

p. 141. Exxon declares that the record reflects that a six-man crew would be inadequate to operate a Coker on a 24/7 basis and that a nine-man crew is required. *Id.* at pp. 141-42. Furthermore, explaining that O'Brien did not believe that the addition of a Coker to a refinery would not require any further supervision, Exxon asserts that Jenkins disagreed and testified that "it is simply not reasonable to assume" that this was possible. *Id.* at p. 142.

1114. Turning to labor multipliers, Exxon explains, O'Brien used a single multiplier of 45% to estimate the costs of overtime and benefits while Jenkins used three separate multipliers: (1) 45% for overhead; (2) 15% for offsite labor; and (3) 20% for administrative labor. *Id.* at p. 143. It declares that Jenkins multipliers are open and aboveboard with no hidden components and that the three multipliers he used are based "on the Pace Refinery model (Exhibit No. WAP-78), which is used in the normal course of business." *Id.* at pp. 143-44.

1115. In their Reply Brief, the Eight Parties agree with Exxon "that the major source of the difference in fixed operating cost estimates is that the estimates are based on a percentage of capital costs." Eight Parties Reply Brief at p. 100. They also indicate that another source of the difference relates to labor costs. *Id.* With regard to staffing, the Eight Parties maintain that a six-man crew is sufficient to operate the Delayed Coker. *Id.* at pp. 100-01. When asked, they note, whether he assumed only 18 workers (three shifts of six staffers), that O'Brien indicated that "he assumed 25.2 workers." *Id.* at pp. 101-02.

b. Variable Operating Costs

1116. As for the variable operating costs, Exxon relates, these include the costs of the fuel, electricity, steam, water, hydrogen, catalysts and chemicals used in processing coke and treating Resid to meet the quality standards of the Quality Bank proxy products. Exxon Initial Brief at p. 132. Jenkins, Exxon begins, details the variable operating costs a Coker and related downstream units require, but O'Brien offers an estimate of variable operating costs. *Id.* at p. 133. According to Exxon, Jenkins's estimate results in 92¢/barrel on the Gulf Coast and 90¢/barrel on the West Coast in Year 2000 dollars while O'Brien's results in operating costs of 79¢/barrel in Year 2000 dollars for both coasts. *Id.* Exxon believes that the difference between the estimates result from (1) O'Brien's failure to include variable operating costs for the Coker gas plant, (2) his failure to include energy for the amine unit, a part of the sulfur recovery system, and (3) his failure to include any allowance for antifoaming and other chemicals in his Coker estimate. *Id.*

1117. As for variable operating costs, the Eight Parties note, Jenkins calculated an 11¢/barrel difference between O'Brien's variable cost calculation (79¢/barrel) and his West Coast variable cost calculation (90¢/barrel), based on Year 2000 costs. Eight Parties Initial Brief at p. 123. However, the Eight Parties argue, Jenkins neglected to increase O'Brien's calculation, which had been performed on a Year 1996 basis, to account for increases in operating costs between Years 1996 and 2000. *Id.* When O'Brien's costs are increased to a 2000 basis, the Eight Parties explain, they come out to 85¢/barrel, which is only 5¢/barrel below Jenkins's West Coast cost calculation. *Id.*

5. Base Year

1118. The correct base year used to determine the cost of coking ANS Resid, Exxon states, is also in dispute. Exxon Initial Brief at p. 134. Exxon explains that Jenkins's cost analysis uses Year 2000 as the base year while O'Brien's cost curve approach uses Year 1996 as the base year. *Id.* at p. 134. A problem arises, Exxon notes, as there are two Nelson Farrar indices applicable to different types of costs, which produce different results depending on how they are applied and which base year is used: (1) the Nelson Farrar Refinery Construction Cost Index (sometimes referred to as the Nelson Farrar capital cost index), and (2) the Nelson Farrar Refinery Operating Cost Index. *Id.*

1119. According to Exxon, when adjusting Resid coking costs to the respective base years, both parties adjusted their estimates of the capital costs of the Coker and related downstream processing units by using the Nelson Farrar construction cost index, and both parties used the Nelson Farrar operating cost index to adjust their operating cost estimates. *Id.* at p. 135. The parties agree, Exxon relates, that it is appropriate to use the Nelson Farrar construction cost index to adjust the capital costs to the base year and that it would not be appropriate to use the Nelson Farrar operating cost index to adjust capital costs to the base year. *Id.*

1120. However, Exxon continues, once Coker costs have been adjusted to the base year, the Eight Parties insist that all Coker costs, including the capital costs, should be adjusted thereafter solely by the Nelson Farrar operating cost index. *Id.* This position, Exxon states, is based on the fact that the parties previously stipulated to the use of that index for adjustments to the value of the Quality Bank cuts. *Id.* at pp. 135-36. As applied to the capital costs of the Coker, Exxon relates, this proposal would distort Coker costs in all years other than the base year because the two Nelson Farrar indices do not track one another. *Id.* Exxon points out that, unlike the Nelson Farrar construction cost index, which has risen relatively steadily over time, the Nelson Farrar operating cost index has gone up and down from year to year. *Id.* Consequently, Exxon insists, future year costs will be different if the Nelson Farrar operating cost index is used to adjust the capital costs of the Coker relative to the base year instead of the Nelson Farrar construction cost index, and the selection of the base year will have an impact on the capital cost figure for all prior years as well. *Id.* To avoid this problem Exxon proposes two alternatives:

> One solution - the analytically correct solution - would be simply to direct that capital costs should be adjusted from the base year by the Nelson Farrar construction cost index rather than by the Nelson Farrar operating cost index. It makes no sense for capital costs to be adjusted *to* the base

> year by the use of the Nelson Farrar construction cost index - as all parties agree is the only appropriate approach - and then to adjust those same capital costs *from* the base year to other prior and subsequent years using the Nelson Farrar operating cost index. Using the Nelson Farrar construction cost index to adjust the base year capital costs for other years will eliminate this peculiar anomaly.
>
> Alternatively, the impact of the problem for future years can be limited by selecting the most current base year - namely, the base year 2000 proposed by [Exxon] rather than the base year 1996 proposed by the Eight Parties. While the selection of 2000 as the base year would not eliminate the anomaly of using an operating cost index to adjust capital costs, it would at least reduce the impact of that approach by bringing all of the capital costs forward to 2000 by using the correct Nelson Farrar construction cost index.

Id. at pp. 136-37 (emphasis in original).

1121. The Eight Parties believe that the differences in base years should not have any material impact on the outcome of this proceeding. Eight Parties Initial Brief at p. 124. The annual adjustments, the Eight Parties explain, apply to both proposals and adequately account for inflation. *Id.* Further, the Eight Parties contend, the Commission should resolve any disputes over equipment on the merits without regard to the base year assumed by the witness. *Id.* Once the merits of the dispute are resolved, the Eight Parties insist, the costs of that equipment can be determined for the appropriate base year and the resulting total costs adjusted to current levels according to the Nelson Farrar Operating Cost Index. *Id.*

1122. In its Reply Brief, Exxon acknowledges that the parties disagree as to whether the appropriate base year to use should be 2000, as it suggests, or 1996, as is suggested by the Eight Parties. Exxon Reply Brief at p. 146. Stating that, in theory, it shouldn't matter, Exxon states that the real problem is which Nelson Farrar index to use. *Id.* According to Exxon, both O'Brien and Jenkins support use of the Nelson Farrar Refinery Construction Index to adjust capital costs and that its use is therefore appropriate. *Id.* at p. 147. It also suggests use of the Nelson Farrar Operating Cost Index to adjust Coker operating costs. *Id.* Exxon implies that, were this done, the identity of the base year would not matter, but that, were the Nelson Farrar Operating Index used to adjust both the capital and the operating costs, 2000 should be used as the base year because "use of a 1996 value plus the Nelson Farrar Operating Cost Index will result in an underestimation of costs for all subsequent years." *Id.* at p. 148.

1123. In their Reply Brief, the Eight Parties agree with Exxon that the choice of the base year should not impact the results as, by use of the Nelson Farrar index, the cost could be inflated or deflated accordingly. Eight Parties Reply Brief at p. 104. They oppose, however, the suggestion in Exxon's Initial Brief, that "the capital costs should be adjusted by the Nelson Farrar Capital Cost Index, while other costs are adjusted by the Nelson Farrar Operating Cost Index." *Id.* The Eight Parties claim that this would "add a new level of complexity to the Quality Bank" which, currently, only uses the Nelson Farrar Operating Cost Index. *Id.* at p. 105. They add that, were this done, not only would the coker costs need to be broken down between capital and operating costs, but that the same thing would have to be done for the Heavy Distillate and Light Distillate cuts as well. *Id.* According to the Eight Parties, the "difference between changes in capital and operating cost methodologies are not significant" and, therefore, adding the additional level of complexity is unnecessary. *Id.* at pp. 105-06.

E. ADMINISTRATIVE FEASIBILITY

1124. According to Exxon, the Quality Bank Administrator, Mitchell, stated that both Exxon's and the Eight Parties's Resid valuation methodologies are administratively feasible. Exxon Initial Brief at p. 137. In both cases, Exxon states, the first step calculates the value of the products produced by processing the Resid through a Coker, while the second step deducts from that value the costs of coking the Resid and bringing the resulting Coker products up to the quality of the Quality Bank proxy products. *Id.* Mitchell, Exxon notes, has confirmed that its approach is feasible on both a prospective and a retroactive basis. *Id.* at pp. 137-38. Furthermore, Exxon relates, Mitchell has testified that both proposals would cost the same to administer and all the price data required to apply the Exxon Resid valuation methodology retroactively is available. *Id.* at p. 138.

1125. On a going forward basis, Exxon believes, the Commission should order the Quality Bank Administrator to retest the common stream properties whenever the Administrator believes significant change may have occurred. *Id.* at p. 139. Also, Exxon contends, the Administrator should be permitted to use samples taken at the Petro Star Valdez refinery of the passing stream and the return stream whenever he thinks a change in the common stream may have occurred. *Id.* Finally, Exxon advocates a periodic re-sampling every year at the Petro Star Valdez refinery connection to ensure the properties of the common stream are constant and the cost estimates based on those common stream properties remain valid. *Id.*

1126. Exxon advocates that the Quality Bank Administrator be instructed to use the Microcarbon test in the future instead of the ConCarbon test in order to measure the carbon residue content for Resid. *Id.* at p. 140. According to Exxon, the Microcarbon test is a newer method of measuring carbon residue equivalent to the ConCarbon test but more accurate, with a higher level of repeatability and reproducibility. *Id.* Also, Exxon notes, this test is now the industry standard, especially when testing heavy fractions such as the 1050°+F plus Resid. *Id.*

1127. All parties agree that, in order to avoid the expense of purchasing the PIMS model, the Quality Bank Administrator should be authorized to use the PIMS correlations found in various exhibits, which would be turned into an electronic spreadsheet used to calculate yields. *Id.* at p. 141.

1128. Also, Exxon believes that once the PIMS yields have been established, the Administrator should use 60°F as the C_5 cut point, which will be reflected in the electronic spreadsheet to be provided by the parties. *Id.* According to Exxon, neither the adjustment nor the determination of the coke price used in valuing Resid poses any administrative feasibility issue. *Id.*

1129. Finally, Exxon relates that the parties stipulated that coke will be valued based on the West Coast at the mid-point monthly quote from *PCQ* for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke, and on the Gulf Coast at the mid-point monthly quote from *PCQ* for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke. *Id.* Exxon advocates that in order to value coke to the refiner, these published FOB vessel prices should be adjusted downwards to reflect costs incurred when coke is moved from a refinery to the point of sale. *Id.* at pp. 141-42. This issue, Exxon states, will be resolved in this proceeding and, thus, does not present any administrative feasibility issue. *Id.* at p. 142.

1130. According to the Eight Parties, both their and the Exxon proposals are administratively feasible. Eight Parties Initial Brief at p. 125. As for the issues raised by the Quality Bank Administrator, the Eight Parties state that the Resid value should initially be based on an average of the 2001 Caleb Brett assay and the assay sample taken this year as part of the stipulation on the intra-cut issues. *Id.* at p. 127. The Quality Bank Administrator, the Eight Parties continue, should be granted discretion to take additional future samples if he determines they are necessary due to a change in circumstances. *Id.*

1131. The ConCarbon test, the Eight Parties state, should be used instead of the Microcarbon test because the PIMS model was based on a correlation with the ConCarbon test. *Id.* at p. 128. As for the PIMS model, the Eight Parties assert that the Quality Bank Administration, in implementing any changes associated with a new ANS Resid sample, should be required to use yields that are equivalent to the yields that would result from the most current version of PIMS. *Id.* at pp. 128-29. Further, the Eight Parties state that he should get the yields from the parties. *Id*. Also, the Eight Parties believe that shippers, Alaska, and any non-shipper parties should be notified before the Quality Bank Administrator implements any change in the Resid valuation formula and explains why the change was proposed. *Id.* at p. 129.

1132. In its Reply Brief, Exxon reiterates its assertion that the parties agree that, on a going forward basis, the Quality Bank Administrator should retest the common stream whenever the Administrator "has reason to believe that any significant change may have occurred." Exxon Reply Brief at p. 149. It further notes that the parties agree that the new samples should be taken "following the same procedures that have applied to the taking of the ANS samples in 2003 and 2004." *Id.* at 150. Exxon submits that it and the Eight Parties disagree on whether annual retesting should be done. *Id.*

1133. In their Reply Brief, the Eight Parties state the following: (1) they now agree with Exxon that "continuous monthly samples of the Petro Star Valdez passing and return streams taken for preparing the monthly Quality Bank assays are more likely to be representative;" (2) however, they do not agree, because of the costs involved, that it is necessary to resample the ANS stream each year unless the Quality Bank Administrator believes that there was "a material change in the qualities of the ANS Resid;" and (3) the Quality Bank Administrator should not have to spend the money to acquire the PIMS model, but ought to be able to get the PIMS Coker yields from the parties and ought "to use yields consistent with the most recent version of PIMS when performing yield calculations in the future." Eight Parties Reply Brief at pp. 107-08.

ISSUE 1 – DISCUSSION AND RULING

1134. In the distillation process,[397] when all else has boiled out, the remainder is Resid. *Exxon,* 182 F.3d at pp. 35-36. Under the Quality Bank,[398] Resid is any material which does not boil out until the temperature reaches or exceeds 1050°F. *Id.* at pp. 36-37; *OXY,* 64 F.3d at p. 688.

[397] O'Brien describes the distillation process as follows: "[I]n distillation, the crude oil is heated until it starts to boil, and the different cuts boil out of the crude at different temperatures. The cuts produced in the distillation process are defined by the temperatures at which the cut is produced." Exhibit No. PAI-1 at p. 4.

[398] O'Brien states that the Quality Bank

> takes 9 basic cuts commonly produced by refiners in the distillation process, and determines how much of each of these cuts is contained in each of the crude streams transported by TAPS. The methodology then develops a price for each cut, multiplies that price by the percentage of the cut that is contained in the crude stream, and sums the resulting prices to develop a total crude stream value. These values are then used to determine Quality bank payments.

Exhibit No. PAI-1 at p. 5.

1135. The parties have stipulated that Resid should be valued as a Coker feedstock using the following formula: "Resid = Before-Cost Value of Coker Products – (Coking Costs * Nelson Farrar Index)." "Joint Stipulation of the Parties," filed October 3, 2002, at p. 1. The Stipulation provides that the Before-Cost Value is to be calculated using a 3-step process: (1) the product (Fuel Gas, Propane, Isobutane, Normal Butane, LSR, Naphtha, Heavy Distillate, VGO, and coke) yields are to be determined through the use of PIMS; (2) Values are to be determined for each;[399] and (3) the product yields are to be multiplied by the product prices and the resulting values are added together. *Id.* at pp. 1-2. Moreover, the parties agreed that coking costs are to be given a "single value," but failed to agree on what that value should be. *Id.* at p. 3. While not agreeing as to the "base year"[400] the parties agreed that the Nelson Farrar Index to be used is a ratio of the Nelson Farrar Index (Operating Indexes Refinery) for the year in which the value is sought and the Nelson Farrar Index (Operating Indexes Refinery) for the base year. *Id.*

1136. By the time at which the record closed in this matter, as indicated above, the parties had reduced their disputes to a number of very specific items. Each of the issues briefed by the parties requiring a ruling will be addressed below.[401]

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[399] Except for Fuel Gas and coke, the Quality Bank value for each product is to be used. As to Fuel Gas, on the West Coast, the monthly California Natural Gas spot quote from *Natural Gas Week* (South, delivered to pipeline) plus 15¢/MMBtu for transportation from the Arizona-California Border shall be used; and on the Gulf Coast, the monthly Gulf Coast (Henry Hub, Louisiana) Natural Gas spot price quote from *Natural Gas Week* should be used. As to coke, on the West Coast, the mid-point monthly quote from *PCQ* for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke should be used; and, on the Gulf Coast, the mid-point monthly quote from *PCQ* for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke should be used. However, then the parties disagreed that an additional adjustment should be made to the coke price. "Joint Stipulation of the Parties," filed October 3, 2002, at p. 2.

[400] As noted above, the Eight Parties have suggested that the base year should be 1996 and Exxon has suggested that it be 2000.

[401] At various places on brief, one party or the other has argued that the other has made a proposal which is in its economic interest. Of course, it is a given that a party is not going to assert a position in litigation which is not in its self-interest and it is also a given that a proclamation of this by an opposing party is not evidence that the position is not otherwise supported by evidence. In general, therefore, I reject all such arguments and will not further comment on them.

A. BEFORE-COST ISSUES

1. C_5 Cut Point

1137. The Quality Bank, as is pertinent to this discussion, uses the following cut points: C_5 - 175°F (Light Straight Run), 175°- 350°F (Naphtha), 350° - 390°+F (Distillate).[402] Exhibit Nos. PAI-58 at p. 5; EMT-84 at p. 46. In order to determine the volume of each cut as a percentage of the whole, the C_5 cut point must, therefore, be identified.

1138. O'Brien, the Eight Parties's witness, in his direct testimony, stated that he used the PIMS Coker yields. Exhibit No. PAI-1 at pp. 11-12. Nowhere in that testimony does he refer to a specific C_5 cut point. According to Tallett, Exxon's witness, in his answering testimony, O'Brien erroneously had used a 100°F C_5 cut point when the "standard figure accepted by the petroleum industry for this cut point is 60°F." Exhibit No. EMT-84 at p. 46. In his reply testimony, O'Brien agreed that he used a 100°F C_5 cut point and defended it as giving "the most accurate allocation" using "linear interpolation."[403] Exhibit No. PAI-58 at pp. 5-6. Moreover, acknowledging and not denying Tallett's assertion that 60°F is "commonly accepted . . . [as] the best boiling point for C_5s," O'Brien states:

> The question is *not* what is the most representative initial boiling point for C_5s. The question is what boiling point should be used in the linear interpolation in order to get the best estimate of how the C_5-390°F coker fraction should be divided into the LSR, Naphtha and Heavy Distillate Quality Bank cuts. The answer to this question must take into account the fact that the distillation curve for a typical C_5-390°F coker fraction is actually curved and not a straight line.

Id. at pp. 6-7 (emphasis in original).

1139. In the C_5 argument in their Initial Brief, which ironically contains no valid cite to O'Brien's testimony regarding his C_5 cut point proposal,[404] the Eight Parties suggest that

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[402] The temperature range for VGO is 650° - 1050°F and Resid is anything exceeding 1050°F. Exhibit Nos. PAI-1 at p. 6; EMT-84 at p. 46.

[403] According to O'Brien: "In linear interpolation, one assumes that the liquids are distributed linearly (evenly) over the entire boiling range." Exhibit No. PAI-58 at p. 6.

[404] In the only cite to O'Brien's testimony in the argument in their Initial Brief on C_5, Eight Parties Initial Brief at p. 15, the Transcript page to which the Eight Parties cite in support, 247, contains nothing whatsoever to do with the C_5 cut point. The Eight parties, in the same location in their brief, cite to Exhibit No. WAP-61 at p. 2 in support

the record has little evidence as to whether 60°F or 100°F is the most appropriate C_5 cut point because such data is proprietary and the companies possessing the data were unwilling to reveal it. Eight Parties Initial Brief at p. 14. Moreover, it appears that, on brief, the Eight Parties are abandoning O'Brien's 100°F cut point in favor of the 96°F on a True Boiling Point basis cut point which they claim is used in the PIMS model,[405] a 90°F cut point which they claim is used in the Gary & Handwerk textbook, and an 82°F cut point which they suggest Tallett admitted is the lowest C_5 boiling point and which testimony, they claim, was supported by Gary. *Id.* at pp. 15-16.

1140. Exxon explains that the PIMS model divides the total Coker yield into three boiling ranges on a True Boiling Point basis[406] while the Quality Bank divides the yield into the four boiling ranges indicated above. Exxon Initial Brief at pp. 18-19. It notes that the PIMS yields are apportioned, using "linear interpolation," among the Quality Bank cuts. *Id.* at p.19. Exxon strongly urges its continued support for Tallett's testimony that the appropriate C_5 cut point is 60°F. *Id.* at p. 20. It points out that his testimony was supported by Gary. *Id.*

1141. Tallett testified that the C_5 cut point "accepted by the petroleum industry" is 60°F.[407] Exhibit EMT-84 at p. 46. He also notes that, while the lowest boiling point of

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of a claim that the PIMS model uses a 96°F C_5 cut point. While the Eight Parties correctly indicate that the document indicates that the PIMS model uses a 96°F cut point for LSR, it was introduced during Tallett's cross-examination and not while O'Brien was on the stand. Moreover, it is only when the appropriate transcript pages, Transcript at pp. 2346-47, to which the Eight Parties did not cite, are read in conjunction with the exhibit, that the exhibit has any meaning.

[405] Incredibly, the Eight Parties, on at least one occasion argue in favor of the 100°F cut point, not because they offered evidence to support it, but because 96°F, the C_5 cut point used in the PIMS model, "is much closer to 100° than to 60°." Eight Parties Reply Brief at p. 10. Then they suggest abandoning O'Brien's proposal that 100°F cut point be used in favor of a 96°F cut point. *Id.*

[406] Naphtha (C_5 - 390°F), Distillate (390° - 650°F) and Gas Oil (650°+F). Exxon Initial Brief at pp. 18-19.

[407] Exxon notes that O'Brien, during a deposition, testified that the Quality Bank C_5 cut point is 60°F. Exhibit No. EMT-97 at p. 10. At the hearing, O'Brien also stated as follows: "What does C_5 mean in terms of temperature? I think we kind of agreed that is about 60." Transcript at p. 1248. In fairness, it must be noted that, after making that statement, O'Brien also said: "We're trying to get the best split there, the most accurate split. Our view is 100 degrees gives you a more accurate split for the C_5." *Id.*

isopentane, the lowest boiling virgin C_5 is 82.1°F; the Coker, which is a cracking unit, produces pentenes as well as pentanes. *Id.* at p. 47. Tallett adds that the lowest boiling point of pentenes is 68°F. *Id.* At the hearing, Tallett's testimony was consistent. *See, e.g.,* Transcript at pp. 2270-74, 2363-68.

1142. Gary, acknowledging that his textbook, as the Eight Parties pointed out, used a 90°F temperature for LSR, added that it might have been better to use 80°F because in "straight run naphtha, the lowest boiling point for the C_5 fraction is isopentane, and its boiling point is around 82 degrees Fahrenheit." Transcript at pp. 2652-53. He also said that Coker LSR would have a lower temperature because it not only has isopentane, it also has isopentene which has a 68°F boiling point. *Id.* at pp. 2653-54. Gary also made the following statement:

> If we're talking about the boiling range for the light coker naphtha, the initial temperature should be less than 68.
>
> Now, it can be anywhere between, 31 which is a boiling point of normal butane, which is the heaviest component in the C_4 and lighter gases, or the highest boiling component in the C_4 and lighter [gases] and between the 68 for the isopentane. It can be any temperature in there in that range, and wouldn't affect the amount of the light coker naphtha because there's nothing in between 31 and 68 to boil.
>
> It could be any number there. If I had to pick a number, I would pick a number that I could put a little bit of justification on, and that may be around 60. It's below 68, and whether it's 60 or 65 wouldn't make any difference as to the quantity of the light coker naphtha because there's nothing that boils between 60 and 68.

Id. at p. 2654. According to Gary, there is no justification for setting the C_5 cut point any higher than 68, and he does not understand how anyone could say that it should be in the 90° - 100°F range. *Id.*

1143. Based on Tallett's and Gary's testimony I am satisfied that the C_5 cut point should be set at 68°F on a True Boiling Point basis. They both testified that this would be the lowest boiling point for the isopentene created in the Coker, the lowest C_5 boiling point. O'Brien's testimony in support of a 100°F cut point is weak, as evidenced by the Eight Parties failure to cite to it on this point, and equivocal. I, therefore, hold that the C_5 cut point should be 68°F on a True Boiling Point basis.

2. Assays

1144. The parties's dispute regarding which assays should be used with the PIMS model to calculate the product yields from running ANS through a Coker is bifurcated: (1) which should be used on a going forward basis, i.e., from the effective date of the final decision in this matter forward; and (2) which should be used for the past period, i.e., from December 1, 1993, through the effective date of the final decision in this matter. Exxon Initial Brief at p. 25. "The assays are used to determine the API gravity, sulfur content and concarbon content of the Resid."[408] Eight Parties Initial Brief at p. 17 (note added).

(a) Going Forward Basis

(1) Assay

1145. In its Initial Brief, while Exxon supported using the 2001 Caleb Brett assay[409] as "a reasonable starting point," it states that, because of the possibility of changes in the ANS stream, "it would not be prudent to rely solely on that one assay." Exxon Initial Brief at pp. 27-28. Accordingly, it suggests comparing the 2001 assay against an assay run in 2003 and one which will be run in 2004. *Id.* at p. 28. Exxon adds that, if the new assays are consistent with the 2001 Caleb Brett assay, then the newest assay should be used; but if they are inconsistent, the Quality Bank Administrator should determine why they were inconsistent and should "determine which assay should be used." *Id.*

1146. The Eight Parties, in their Initial Brief, acknowledging that, at the hearing, they did not take a position on how to treat the new assays, now state that they should be averaged with the 2001 Caleb Brett assay. Eight Parties Initial Brief at p. 19. However, in their Reply Brief, the Eight Parties assert that there are problems with the 2003 assays, both with regard to the sampling and the testing and that, therefore, they should not be used. Eight Parties Reply Brief at p. 13. Exxon's position, in its Reply Brief, remained the same with regard to the assays. Exxon Reply Brief at pp. 22-23.

1147. There really is no dispute and little factual evidence in the record supporting any ruling on this question. However, both parties agree that the 2001 Caleb Brett assay is a starting point for use on a going forward basis; both parties also agree that the Quality Bank Administrator ought to have the discretion to re-test the common stream whenever

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[408] The API gravity, sulfur content and ConCarbon content are then input into the PIMS yield spreadsheet, which was made part of the record as Exhibit No. EMT-237, and the Coker yields are derived from it. Eight Parties Initial Brief at p. 17.

[409] Entered into the record as Exhibit No. EMT-96 pp. 1-11.

he has reason to believe that a significant change may have occurred in the Quality Bank stream.[410] Eight Parties Initial Brief at p. 127; Exxon Reply Brief at p. 22. The Quality Bank Administrator testified that, while he should not have to re-test frequently, the re-testing should be done, at least, annually. Exhibit No. TC-1 at p. 15.

1148. In view of the above, I hold that, until such time as the Quality Bank Administrator is satisfied that a new sample is properly taken and tested, the 2001 Caleb Brett assay shall be used to determine the API gravity, sulfur content and carbon residue content of the Resid. I further hold that the Quality Bank Administrator shall have the discretion to re-test whenever he believes that there may be a change in the common stream which will affect the Quality Bank and that, if he is satisfied that the new sample was properly taken and tested, the new assay should replace that previously used to determine the API gravity, sulfur content and carbon residue content of the Resid.

(2) Carbon Residue Test

1149. In its Initial Brief, Exxon "recommended" that, on a going forward basis, the carbon residue content of Resid be measured by the Microcarbon test rather than the ConCarbon test. Exxon Initial Brief at p. 29. It claims that the former test "is a newer, improved method of measuring carbon residue that is 'equivalent to ConCarbon but more accurate' with a higher level of 'repeatability' and 'reproducibility.'" *Id.* at pp. 29-30. As support for this claim, in part, it cites to the hearing testimony of Tallett who stated:

> The microcarbon test was developed through a large effort by an ASTM committee back in the 1980s. The reason for developing it was to arrive at a test of carbon residue that was equivalent to ConCarbon but more accurate. You can see this in the stated repeatabilities and reproducibilities that are in the ASTM standards. They show, on repeatability, microcarbon has a third of the variance of ConCarbon and it's also lower on reproducibility.
>
> In addition to this, not only does microcarbon exist as a test, but it's really become the norm. It's become pretty much the industry standard test today for testing carbon residue, especially on heavy fractions like 1050 plus resid.

Transcript at p. 2282. Exxon also relies on the testimony of Mitchell, the Quality Bank Administrator, who agreed that the "repeatability and reproducibility" of the Microcarbon tests were "probably tighter than the ConCarbon test." *Id.* at pp. 13137-38. It notes, further, that Mitchell recommended using the Microcarbon test, stating that it "has largely

[410] As does the Quality Bank Administrator. Exhibit No. TC-1 at p. 15.

supplanted the Conradson carbon residue test as standard industry practice." Exhibit No. TC-1 at p. 13.

1150. According to Exxon, Dayton, the Eight Parties's witness, agreed that the Microcarbon test is "less subjective" and had "better repeatability." Transcript at pp. 1623-24, 3672. This claim is somewhat misleading. In fact, while she did agree that the Microcarbon test "has been determined to be less subjective," *id.* at p. 1624, Dayton defended the use of the ConCarbon test stating that whether the Microcarbon test was more accurate depended "upon who's doing the analysis" and that, if a "single analyst" did both tests correctly, "then in the ideal world you would not necessarily get different results." *Id.* at pp. 1623-24. Later, under further cross-examination, Dayton stated that the PIMS model could be used "equally well" with the ConCarbon test and the Microcarbon test, but that it was developed using the former. *Id.* at pp. 3672-73. She also denied that the results from the Microcarbon test were "any better" than those from the ConCarbon test. *Id.* at p. 3673.

1151. In their Initial Brief, the Eight Parties, while not acknowledging that Mitchell recommended the use of the Microcarbon test, cited his testimony[411] in support of their claim that the ConCarbon test, and not the Microcarbon test should be used. Eight Parties Initial Brief at p. 128. In their Reply Brief, the Eight Parties, again citing Mitchell's testimony, noted that the Microcarbon tests "gave almost universally higher carbon residue results than the" ConCarbon test. Eight Parties Reply Brief at p. 15. They add that the choice between the two tests "is not just a question of which is the more accurate test, but whether a test should be used that reaches consistently higher carbon results." *Id.*

1152. I disagree with the Eight Parties's claim that the choice is not between which test is more accurate. That is exactly the choice I need to make, and it is perfectly clear that everyone agrees that the Microcarbon test is more accurate. Mitchell, the Quality Bank Administrator, recommends it and states that it has supplanted the ConCarbon test as the

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[411] After reviewing the assays in the record here, Mitchell stated:

> [A]lmost universally the microcarbon method gives you a higher residue number than the ConCarbon. I've not investigated why that would be the case, but that obviously means since some people have an interest in a higher one than the lower like everything else in this proceeding, that could be a point of controversy, and I just want to make sure any settlement agreement or order of the Commissions specifically sets out which test I should use.

Transcript at p. 13110.

industry standard, and Tallett testified that it is more accurate. The Eight Parties plaint that it results in a higher carbon content being reported is not evidence that supports the continued use of the ConCarbon test.

1153. Accordingly, I hold that, on a going forward basis, the Microcarbon test should be used to determine the carbon residue content of Resid.

(b) Past Period

(1) Assay

1154. In its Initial Brief, Exxon describes all of the various assay combinations discussed at the hearing and argues in favor of Tallett's 10-assay proposal.[412] Exxon Initial Brief at pp. 31-40. The Eight Parties, without citing to her testimony, reflect that they support Dayton's 3-assay proposal.[413] Eight Parties Initial Brief at pp. 20-27. As no one disagrees as to whether those three assays should be used, there is no need to discuss them. Consequently, the discussion will be focused on Dayton's objections to the use of the remaining seven assays.

1155. Referring to Exhibit No. PAI-122, but not her testimony, the Eight Parties explain that the problem with the four Haverly/Chevron assays is that the carbon residue testing was not performed on the 1050°F cut, but on one made at another temperature.[414] *Id.* at p. 21. According to Dayton, the correct data cannot be extracted from that single data point. Transcript at p. 3636; *see also id.* at p. 3638. The Eight Parties also note the following discussion between Exxon counsel and Tallett:

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[412] The 10 assays are: (1) the February 1994 Haverly/Chevron, (2) the August 1994 Exxon, (3) the 1995 Haverly/Chevron, (4) the January 1995 Williams/BP (Caleb Brett), (5) the 1996 Haverly/Chevron, (6) the April 1996 Exxon, (7) the October 1996 ARCO (Caleb Brett), (8) the 1998 Haverly/Chevron, (9) the January 2000 Exxon, and (10) the December 2001 Phillips (Caleb Brett) assay. Exhibit No. EMT-277. Exxon declares that, as "none of the assays was perfect," a need to use all of them is highlighted. Exxon Initial Brief at p. 33.

[413] The three assays she recommended being used were: (1) the August 1994 Exxon assay, (2) the October 1996 ARCO (Caleb Brett) assay, and (3) the December 2001 Phillips (Caleb Brett) assay. Eight Parties Initial Brief at p. 20; Exhibit No. PAI-122.

[414] It is reflected, on Exhibit No. PAI-122, that the temperature of the cuts was as follows: (1) February 1994 - 1005°F, (2) 1995 - 1065°F, (3) 1996 - 1000°F, and (4) 1998 - 650°F. In other testimony, Dayton described how she calculated the temperature of the cuts tested. *See* Transcript at pp. 3630-47.

> Q When she was here on Monday, I think Ms. Dayton indicated she would be particularly concerned if you were taking something like a 1023 cut-point for the resid and trying to extrapolate out. What's our reaction to that concern?
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> A I would agree with that. If your last cut-point was 1023 and you were trying to get to 1050, you could make that extrapolation because the crude assay management systems all have curves built into them because properties tend to behave in similar ways, but that's a fairly long way to go in a vacuum resid.

Transcript at p. 2305.

1156. The Eight Parties also referred to Dayton's testimony regarding the 1994 and 2000 Exxon assays stating that she noted that testing was done at different temperature ranges and that, while the carbon residue reported at 650°F was the same on both, when the testing was done on the 1049°F cut, there was a difference of 1.75 wt%. *Id.* at pp. 3636-38. Of this variance, Dayton stated: "So they have distinctly different trends based on the measured data. So the trend is specific to the sample that you've taken, and if you haven't measured the data and established what the specific trends are, you have no basis to do an extrapolation of the data." *Id.* at p. 3638.

1157. In its Initial Brief, Exxon argues that there is no reason for excluding the Haverly/Chevron assays because they used "an assay manager computer program to recut the assay data and did not always use the 1050°F cut point used by the Quality Bank." Exxon Initial Brief at p. 35. They claim further that Dayton testified the quality rating of the assays was good and that there was no qualification as to their accuracy, but that claim is misleading as Dayton was asked what the assay reported as to its quality and she answered "good," and whether there was qualifications as to its Microcarbon numbers and she answered "no." Transcript at pp. 3661-68. That hardly reflects her opinion. All it does is represent her ability to read what is reported on the document which *may* contain self-serving information.

1158. Exxon also seeks support from Tallett's testimony. However, the testimony to which it cites,[415] in part, refers to the Caleb Brett assays, not the Haverly Chevron assays. While the remainder of the testimony to which it cites refers to the Haverly/Chevron assays,[416] it does not reflect that Tallett had substantial knowledge on which to base his testimony. For example, at Transcript p. 2301, he testified as to his *understanding* of

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[415] Transcript at pp. 2401-03.

[416] Transcript at pp. 2300-04, 2404-08.

how Haverly Systems used the Chevron database, stating that he didn't "know specifically how many cuts Chevron will cut the resid or typically the 650 plus material up into." He also testified that, based on his claim that "Haverly Systems is the leading supplier of crude assay management and recutting software," the number of its clients, and that it "wouldn't exist if oil companies were not satisfied with [its] ability to recut assays using software," that "the assay results were within certain tolerances of accuracy." *Id.* at pp. 2303-04. Tallett also admitted that the carbon residue test performed by Haverly was the Ramsbottom test, rather than either the ConCarbon or the Microcarbon tests, that these were the results he used, and that he never saw the "Chevron assays that underlie the Haverly data." *Id.* at pp. 2403-04, 2406.

1159. According to the Eight Parties, Dayton also criticizes three other assays because the "reported Resid yields . . . are outside of the range of Resid volume yields in the assays taken each month of the year by the" Quality Bank Administrator. Eight Parties Initial Brief at p. 22. Included in this group is the April 1996 Exxon assay which displays a Resid content of 18.36% in comparison with the highest percentage reported by the Quality Bank Administrator of 18.1%, the 1998 Haverly/Chevron assay, previously discussed, and the 2000 Exxon assay, both of which, the Eight Parties claim, reported Resid percentages "well below the minimum [Quality Bank Administrator's] Resid yields for 1998 and 2000 respectively." *Id.* at pp. 22-23. The Eight Parties also suggest that Tallett agreed, on cross-examination, that these assays are questionable.[417] *Id.* at pp. 23-24.

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[417] The testimony to which the Eight Parties refer is as follows:

Q And Ms. Dayton has indicated that the three assays, the Exxon '96 assay, the Haverly '98 assay and the Exxon 2000 assay, ought to be eliminated because their [Resid] volume percentages fall outside of the range of volume percentages reported by the Quality Bank - the Caleb Brett assays that are done for the Quality Bank administrator on a regular basis. Are you familiar with that criticism?

A Yes, I am.

Q What's your reaction to that criticism?

A Well, if you go back to my prior testimony, I think that when an assay flags a value that is outside a range, there is some basis to question it. I think you could argue it either way, but the conservative approach, which is what Ms. Dayton followed, would be to reject those assays because they're outside the range of the averages.

Transcript at pp. 2311-12.

1160. Exxon, in its Initial Brief, accuses Dayton of making an "apples-to-oranges" comparison with regard to those three assays; i.e., it asserts that Dayton is comparing assays taken on a single day to the Quality Bank monthly sample average. Exxon Initial Brief at p. 36. It adds that it should be expected that a sample taken on any given day might be above or below a range of monthly samples, and further note that, in the past, Dayton stated that only yields *significantly* outside the monthly average should be questioned. *Id.* at p. 37; Exhibit No. EMT-135 at p. 2, n. 1.

1161. The last assay which the Eight Parties criticize is the 1995 Williams/BP (Caleb Brett) assay. Eight Parties Initial Brief at p. 24. They state that, according to Dayton, method D-2892 was the vacuum distillation procedure used and that such use was inappropriate.[418] *Id.* Moreover, while they claim that Tallett agreed with her, that assertion is not entirely correct. Tallett testified that, while it was correct of Dayton to "raise the flag," he thought the test actually was performed using the correct procedure (either D-2892 or D-5236) and was trying to confirm his analysis and verify which test was used. Transcript at pp. 2295-97. He added that while he "would still raise somewhat of a flag over that assay, . . . [he was] not convinced there's grounds for just rejecting it out of hand." *Id.* at p. 2297. The Eight Parties note that, they assume, Tallett was never able to confirm his analysis as Exxon never offered further evidence as to the procedure used. Eight Parties Initial Brief at p. 24. In its Reply Brief, Exxon uses Tallett's testimony to support inclusion of this assay, but fails to acknowledge that Tallett could not verify his analysis. Exxon Reply Brief at pp. 31-33.

1162. Based on Dayton's testimony and the documents associated with it, I am satisfied that the Haverly/Chevron assays should not be used. The evidence reflects that the carbon residue tests were not performed at the 1050°F temperature of the Quality Bank Resid cut. Moreover, Tallett's testimony regarding his discussions with Haverly personnel did not convince me that these assays were as reliable as the three upon which the parties agree. Consequently, I find the February 1994, 1995, 1996 and 1998 Haverly/Chevron assays should not be used.

1163. With regard to the April 1996 Exxon and January 2000 Exxon assays, I am not satisfied that Dayton has established that they should not be considered.[419] I agree with Exxon that the small deviation of a daily sample from a monthly average should not be cause for excluding them. Moreover, the Eight Parties have not proved, or even suggested, that there was anything incorrect in the manner in which these assays were performed. Consequently, I find that the April 1996 and January 2000 Exxon assays should be used.

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[418] Dayton's testimony appears at Transcript pp. 1448-49.

[419] I already have ruled that the 1998 Haverly/Chevron assay also included in this category should not be considered.

1164. It appears that the January1995 Williams/BP (Caleb Brett) assay may not have been performed using the appropriate procedure. Both Dayton and Tallett agree that, under those circumstances, it should not be used. While Tallett testified that, while he *believed* that the proper procedure was used, he "would still like to be able to confirm that positively." Transcript at p. 2297. Apparently, he was not able to do so as Exxon offered no further evidence on this point. Therefore, as I cannot be certain that the proper procedure was used to perform this assay, I must hold that it cannot be used.

1165. In view of the above, I hold that the following assays should be used for the past period: (1) August 1994 Exxon; (2) October 1996 Arco (Caleb Brett); (3) December 2001 Phillips (Caleb Brett); (4) April 1996 Exxon; and (5) January 2000 Exxon.

(2) Carbon Residue Test

1166. Exxon's argument in favor of the Microcarbon test, rather than the ConCarbon test, is the same for the past period as it was for the going forward period. Exxon Reply Brief at p. 26. However, while I held, above, that the evidence supported a conclusion that the Microcarbon test should be used in the going forward period, the record does not indicate at what point in time that test "supplanted" the ConCarbon test.[420] Additionally, I note that Mitchell testified that, if he were using any assay which only had a ConCarbon test result, he would only be able to use that test, Transcript at p. 13139, and I note that the 1994 Exxon assay[421] does not contain any Microcarbon test results.

1167. In view of the above, I cannot find that the Microcarbon test was acceptable for use during the whole period in question or that all of the assays which are to be used contained Microcarbon test results. Accordingly, I find that, for the past period, the ConCarbon test should be used to determine the carbon residue content of the Resid.

3. Coke Value

1168. As noted above, the parties have agreed that coke is to be valued at the FOB vessel prices for fuel grade coke published in the *PCQ*. Exxon Initial Brief at p. 40; Eight Parties Initial Brief at pp. 27-28. "More specifically, the parties have agreed that the published Coke prices to be used are: (1) on the West Coast, the mid-point monthly quote from *PC*Q for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke; and (2) on the Gulf Coast, the mid-point monthly quote from *PC*Q for Gulf Coast High Sulfur

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[420] As noted above. Mitchell recommended that the Microcarbon test be used in the going forward period because it "largely supplanted the Conradson carbon residue test as standard industry practice." Exhibit No. TC-1 at p. 13.

[421] Exhibit No. WAP-68.

(Above 50 HGI) Petroleum Coke." Exxon Initial Brief at pp. 40-41. However, the parties have not agreed as to whether those prices should be adjusted to account for the cost of shipping the coke from the refinery gate to the point of sale reflected in the FOB vessel price. *Id.* at p. 41.

1169. Exxon argues that the FOB vessel price does not accurately reflect the value of coke to the refiner because it must incur the cost of moving the coke from the refinery gate to the point of sale.[422] *Id.* at p. 42. Its evidence on this point, not unexpectedly, establishes that refiners incur these costs which, I think, is a given and, therefore, find no need to discuss. From this, Exxon argues that pricing coke at the refinery gate overvalues it. *Id*. at pp. 42-43.

1170. According to Exxon, the deduction which should be made to the West Coast price is $10.75/short ton and $6.00/short ton on the Gulf Coast. *Id.* at p. 49. Its proposal is based on Bartholemew's testimony who, after detailing how he made estimates of the costs of transportation, handling and reselling, came to the conclusion which Exxon supports.[423] Exhibit No. EMT-31 at pp. 14-19.

1171. Addressing what it claims is the Eight Parties only objection to its coke value proposal – "it is allegedly 'inconsistent' with the use of unadjusted waterborne prices for 'other liquid Quality Bank cuts'" – Exxon suggests that the opposition is without support

[422] Exxon submits that those costs include "transportation, handling, storage and reselling costs." Exxon Initial Brief at p. 41.

[423] Exxon claims that Ross, the Eight Parties's witness, did not dispute that these costs estimates are conservative, but this claim is not accurate. While Ross agreed that those types of cost are incurred, he specifically stated that he had not studied them and expressed "no opinion" as to the accuracy of Bartholemew's estimates. Transcript at pp. 1648-49. In point of fact, he asserted that they were "not relevant." *Id.* Exxon also refers to Ross's testimony at Transcript pp. 1650-51, 1799-1800, 1809-10, in support of its assertion that the "Eight Parties also agree that the value of Coke to the refiner is determined by the 'net-back' value that the refiner can earn from Coke produced in the coking process, and that this net-back value is the *PCQ* FOB vessel price less the costs of moving the Coke from the refinery to the vessel." Exxon Initial Brief at p. 43. Unfortunately for Exxon, however, in the first instance, Ross was answering questions, based on Exhibit No. EMT-35, as to what his understanding was of what Bartholomew did, and in the second and third instances, he was answering questions about Exhibit No. BPX-17, an Exhibit he prepared to demonstrate his claim that Bartholomew misinterpreted Exhibit Nos. EMT-34 and 35. Suggesting from this that the Eight Parties agreed with Exxon that the value of coke was its FOB price less the expenses of moving it from the refinery to the FOB point of sale is too much of a stretch for anyone to accept.

because coke is not a liquid product. Exxon Initial Brief at p. 44. It also suggests that, when compared with its "very low market value," the costs of transporting, handling, storing and reselling coke are "of a wholly different order of magnitude than the transportation and handling costs associated with the other coker products." *Id.* In support it points to Ross's testimony, particularly Exhibit No. BPX-17 and Transcript at pp. 1795-97, which, Exxon correctly claims, reflects that, while it makes up only 4% of the common stream is responsible for 17.31% of the "total logistics costs for all Quality Bank products." Exxon Initial Brief at p. 45. Exxon also correctly notes that the parties have agreed to value Fuel Gas at the refinery gate. *Id.* at pp. 45-46.

1172. The Eight Parties claim that coke already is valued on waterborne basis. Eight Parties Initial Brief at p. 28. As such, it argues, coke is treated like all other Coker products as the Circuit Court required in *OXY,* 64 F.3d at p. 693. Eight Parties Initial Brief at pp. 29-30.

1173. Coke is what remains after Resid is processed through the Coker. It is unique in that, whether it is shot coke or sponge coke, it is a solid, not a liquid or a gas as are all of the other products produced from crude oil, and "can be moved only by truck, rail, or solid bulk vessel." Exhibit No. EMT-31 at pp. 10-11. While there is an FOB vessel price for coke, the price is sometimes so low that coke is sold at a deficit when the cost of moving it to the vessel is considered. *Id.* at pp. 11-12; Transcript at pp. 2181, 2203. Nevertheless, according to Bartholomew, and undisputed by the Eight Parties, it must be removed from the refinery, even at a loss, "because the refinery cannot store it and still continue its refining operation." Exhibit No. EMT-31 at p. 12.

1174. I am unconvinced by the Eight Parties's argument that the cost of moving coke from the refinery to the vessel should not be considered when determining what its value is. In this exercise, if I am truly to determine the *value* of coke, it is clear to me that I must consider certain refinery cost factors, but perhaps not all that Exxon espouses, and not just the market price at a delivered location. The Eight Parties next argue that, were this done, cost factors related to other products also would have to be considered. However, its argument errs in two regards: (1) the *OXY* court did not require that, were a proposal made regarding one of the nine Quality Bank cuts, the Commission must consider, at the same exact time, that same proposal as it relates to the remaining eight; and (2) it is clear that I may consider only those proposals which are actually made and referred to me by the Commission.[424]

1175. Based on the record, I am satisfied that Exxon has established that coke is a product which is unique enough to warrant being treated differently than the other Coker products. Moreover, I am convinced by Bartholemew's testimony, as well as the

[424] *Sierra Pacific Power Co.*, 104 FERC ¶ 61,223 at P 36 (2003).

evidence attached thereto, that refiners must incur costs related to their sale of coke inordinate to their costs for sales of other products related to the Quality Bank process. Bartholomew testified that, based on his investigation and the experience of his Jacobs Consultancy, the company for which he works, on the West Coast, refiners incurred an average transportation cost of $2.00/short ton and an average storage and handling charge of $6.75/short ton, and that, on the Gulf Coast, refiners incurred an average transportation cost of $2.50/short ton and an average storage and handling charge of $2.50/short ton. Exhibit No. EMT-31 at pp. 9-19. The Eight Parties failed to present any evidence contradicting this testimony.

1176. Bartholomew also testified that sellers on both coasts also incurred "reselling fees or commissions." *Id.* at pp. 15-16, 18. However, in contrast with the evidence regarding transportation and handling fees, nowhere in the record did Exxon establish that incurring such costs was unique to coke either in magnitude or discrete association with any other Quality Bank product.

1177. In view of the above, I hold that, on the West Coast, the mid-point monthly quote from the *PC*Q for West Coast Low Sulfur (Above 2% Sulfur) Petroleum Coke should be adjusted by $2.00/short ton for transportation and by $6.75/short ton for handling. I further hold that, on the Gulf Coast, the mid-point monthly quote from the *PC*Q for Gulf Coast High Sulfur (Above 50 HGI) Petroleum Coke should be adjusted by $2.50/short ton for transportation and by $2.50/short ton for handling.

B. COKER COST ISSUES

1. Overall Approach

1178. A major area of dispute between Exxon and the Eight Parties involves how to determine how much it costs to coke Resid. The two presented diametrically opposite proposals for reaching the ultimate conclusion. In sum, Exxon presented what it describes as a "detailed cost study" revolving around Jenkins's

> detailed "line item" cost study that identifies the direct or "inside battery limits" . . . cost of all the major equipment required for both the coker itself and the related downstream refinery units that would be needed to process the coker products to bring them up to the quality specifications of the Quality Bank reference products.

Exxon Initial Brief at p. 50. Exxon added that Jenkins used "appropriate West Coast location factors" to adjust Gulf Coast costs. *Id.* According to Exxon, the costs Jenkins calculated "compared favorably with the coker cost estimates provided in several well known treatises, including the Gary & Handwerk treatise and the Meyers text." *Id.* at p. 52.

1179. Not disagreeing with Exxon as to the ultimate goal, the Eight Parties still have difficulty in agreeing with Exxon's approach. Eight Parties Initial Brief at pp. 33-34. They begin their criticism of Exxon's approach by stating: "Instead of trying to divine the processing costs of a delayed coker in a typical refinery, [Exxon's] approach is to determine the costs of adding a coker to an existing refinery utilizing efficient units and focusing on design rather than actual operations." *Id.* at pp. 36-37. The Eight Parties add that, despite the fact that Jenkins previously had used cost curves to estimate capital costs,[425] this time he used "a detailed capital cost estimate" to construct a hypothetical Delayed Coker in a hypothetical refinery located somewhere in the Los Angeles area. *Id.* at p. 37. According to them, this approach allowed Exxon to reach an "excessively high detailed cost estimate" which it then "subjected to an endless series of subjective multiplication factors." *Id.* at p. 38.

1180. Exxon claims that the "picture painted by the Eight Parties is demonstrably false." Exxon Reply Brief at p. 45. It claims that all of Jenkins's estimates are "transparent and . . . subject to audit." *Id.* According to it, Jenkins "identified the bare costs for each and every piece of equipment required for a 40,000 barrels/day coker (EMT-46) and the factors he used for each category of equipment to estimate the installed costs of the coker (EMT-47)." *Id.* To prove its point, Exxon claims that, were the costs of the equipment which O'Brien failed to include in his estimate deducted from Jenkins's estimate, Jenkins's estimate would be lower than O'Brien's. *Id.* at p. 46.

1181. Exxon attacks what it refers to as O'Brien's "'conceptual' cost estimate [which it asserts] O'Brien based entirely on his firm's proprietary 'conceptual cost curves' for a supposedly 'typical' coker for which there is no supporting documentation whatsoever." Exxon Initial Brief at p. 54. It also notes that O'Brien failed to adjust his estimate for its West Coast location though he admitted that West Coast capital costs were higher than those on the Gulf Coast,[426] and that his approach was not so well defined as to allow for a determination as to exactly what equipment were included.[427] *Id.* at pp. 54-55.

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[425] The Eight Parties note that, in 2000, Jenkins used his company's cost curve for a Delayed Coker whose cost he estimated to be $111 million, much closer to O'Brien's estimate of $107 million, than his detailed-cost estimate. Eight Parties Reply Brief at p. 27.

[426] On cross-examination, O'Brien admitted that, while West Coast construction costs may not always be higher than those on the Gulf Coast, "they will tend to be higher." Transcript at p. 231.

[427] On cross-examination, O'Brien stated that, as he was not actually building a Coker, "what's actually in the coker is not – cannot be that well-defined." Transcript at pp. 323-24.

1182. According to Exxon, the accuracy of cost curves to estimate Coker costs, in general, is questionable.[428] *Id.* at p. 56. In support, it cites the "Meyers Handbook," and its witness, Gary, who agreed that a "cost curve estimate is only going to be plus or minus 25 percent accurate" if you use a location differential.[429] Transcript at p. 2660. Asked, if that were so, how could the Commission rely on a cost curve to estimate the cost of a delayed coker, Gary stated:

> Well, Glenn Handwerk [his co-author] and I talked about this, and we're very surprised that cost curves are being used – even though we have a lot of confidence in our cost curves – in general, that cost curves are being used because they are so inaccurate.
>
> With the amount of money that we think is involved, which I don't know, but we're talking about millions of dollars, I understand – with the amount of money that's involved, it seems to be much better to do a detailed estimate where even though it's going to cost $2 or $3 million to get it, rather than something you can get out of a book like ours, to me, it doesn't make sense and neither did it to Glenn Handwerk.

Transcript at p. 2661. But Gary later explained the reason why a cost curve is ± 25% accurate and why a detailed estimate would be so expensive:

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

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[428] Jenkins states:

> [the company for which he works] capital cost data base uses one parameter - - unit capacity. A Delayed Coker is one of the refinery units in which a number of technical factors other than capacity influence cost. These factors include coke make, feedstock sulfur, coke handling system and other technical factors.

Exhibit No. EMT-146 at p. 16.

[429] According to Gary, without using a location factor, a cost curve only is ± 50% accurate. Transcript at p. 2660.

Transcript at pp. 2665-66.

1183. Exxon also criticizes O'Brien's methodology for assuming that certain processing would be done by large units in the refinery and only assigning the incremental costs of those units to the Delayed Coker. Exxon Initial Brief at p. 58. Also, according to Exxon, O'Brien failed to include the cost of the Coker gas plant. *Id.* Moreover, Exxon declares that O'Brien's estimate to be "well below" the estimates in "petroleum engineering texts."[430] *Id.*

1184. In truth, neither Exxon's nor the Eight Parties's "overall approach" is satisfactory. I am troubled with the complexity and subjectivity of Jenkins's itemized list of components. Also, I question whether Jenkins expended the effort necessary, described by Gary, to actually do a detailed estimate which I could accept as accurate.[431] While I am troubled by O'Brien's lack of detail, in the final analysis, as will be seen below, I can adjust O'Brien's estimate in ways which satisfy me that the end result is as close a cost estimate as possible given the limitations of what can be accomplished in the hypothetical world in which we are trying to determine the cost of a Delayed Coker. I can find no way of modifying Jenkins's estimate to satisfy me that the end result is accurate and fair to all parties. In sum, there is nothing in Jenkins's testimony or Exxon's arguments that convinces me that Jenkins's itemized cost approach is objective or accurate enough to satisfy the needs of using it as part of the formula which will result in a determination of the value of Resid. Therefore I hold that, as modified below, O'Brien's cost curve should be used.

2. Capital Costs

1185. The parties agree that the Coker capital costs consist of the direct costs, referred to as "Inside Battery Limits" or "ISBL," which include the costs of the Coker itself and related downstream refinery units, the indirect costs, referred to as "Outside Battery Limits" or "OSBL," which include facilities necessary to support refinery processing units such as storage facilities, steam generation systems, etc., and finance costs. Exxon Initial Brief at pp. 59-60; Eight Parties Initial Brief at p. 28.

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[430] According to Exxon, while O'Brien's estimates was $107.4 million, Gary & Handwerk's estimate is $175 million and the Meyers Handbook estimates range from $109.5 million to $219.1 million. Exxon Initial Brief at p. 58.

[431] Jenkins admits that he and Dickman only spent three man weeks on "engineering" the project. Transcript at pp. 2762, 2770. However, he further stated that, to do a detailed estimate to the level of which Gary spoke, i.e., 30% engineering, would take "four to six months." *Id.* at p. 2770.

a. ISBL Coker Costs

(1) Approach

1186. For the most part, except as their discussions related to subissues ii – iv, which will be addressed at the appropriate time, the parties repeated their arguments regarding whether Jenkins's itemized approach or O'Brien's cost curve based approach should be followed. Inasmuch as I have decided that O'Brien's cost curve approach, as modified below, is preferable to Jenkins's itemized cost approach, there is no need to address the parties's arguments regarding this particular subissue again. It is only necessary for me to reject O'Brien's plaint, Transcript at pp. 321-22, for the reasons stated above, that "it would be adverse to [his] methodology" to adjust his cost curves.

(2) 2 Drums v. 4 Drums

1187. O'Brien's cost estimates are based, in part, on the assumption that a 2-drum Coker would be used, while Jenkins assumed a 4-drum Coker. Eight Parties Initial Brief at p. 49; Exxon Initial Brief at p. 66. According to O'Brien's testimony, Exhibit No. PAI-58 at pp. 13-15, the cost curve used by Baker & O'Brien indicates that a 4-drum Coker is not required until one is needed to process somewhat more than 40,000 barrels/day. He further indicated that 40,000 barrels/day was not even in the transition zone between the need for a 2-drum Coker and a 4-drum Coker. *Id.* The Eight Parties further note, Eight Parties Initial Brief at p. 52, that O'Brien testified that the Coker to which he referred was a 40,000 barrel/stream day Coker by which he meant "the amount that a refinery can run in one 24-hour period when it's operating under optimal conditions." Transcript at p. 852. O'Brien further testified that, assuming a typical utilization rate of 87%, it could be assumed that a Coker capable of processing 40,000 barrels/stream day of ANS would actually average 34,800 barrels/day. Transcript at pp. 852-53. From this testimony, the Eight Parties argue that "any two drum cokers with a barrels per calendar day capacity of 34,800 would be equivalent to the 40,000 barrels per stream day capacity" which O'Brien assumed. Eight Parties Initial Brief at p. 52. The Eight parties add, citing to Exhibit No. EMT-187, that there are three such refineries. Eight Parties Initial Brief at pp. 52-53.

1188. Exxon asserts that evidence which it submitted through Dickman established the actual capacities of all of the 2-drum and 4-drum Cokers in the United States,[432] and that this evidence "shows that a coker processing 40,000 bbl/d of ANS Resid would be expected to have four drums." Exxon Initial Brief at pp. 67-68. It further states that only one 2-drum Coker has the ability to process 40,000 barrels/day of Resid and that that coker produces shot coke which it claims "is much easier to remove from the coke drums

[432] Exxon cites Exhibit Nos. EMT-167 at pp. 21-22, EMT-187, and EMT-188. Exxon Initial Brief at p. 68.

than the sponge coke produced by ANS Resid, and employs automatic deheading equipment[433] to reduce cycle time." *Id.* at pp. 68-69 (note added). On Reply, Exxon states that O'Brien's 2-drum Coker is "not from an operational standpoint a 'typical' coker but rather [was] a coker 'pushing the maximum' possible capacity of a 2-drum coker at 'optimal operating conditions.'" Exxon Reply Brief at p. 62.

1189. The question which needs to be answered is whether the "typical" Coker needed to process 40,000 barrels/stream day of ANS Resid would need two drums or four. This dispute, peculiarly enough, is one created by the parties, who, themselves, decided early in this litigation that the "typical" Coker would process 40,000 barrels/stream day of Resid.[434] Had they chosen 35,000 barrels/day, they could agree that it would only require a 2-drum Coker; had they chosen 45,000 barrels/stream day, they could agree that the Coker would require four drums.[435] But, they chose 40,000 barrels/stream day.

1190. To begin, I find that the Eight Parties's attempt to argue, Eight Parties Initial Brief at p. 52, that the parties were really focusing on a Coker capable of processing, on the average, no more than 34,800 barrels/calendar day to be disingenuous. It is clear that the parties were contemplating a Coker designed to process 40,000 barrels of ANS Resid per stream day. That such a Coker, if actually built, would process less or, as more likely, more is irrelevant. The essence of what is being addressed here is the cost of building a Coker able to process 40,000 barrels of ANS Resid per stream day. O'Brien has not convinced me that 2-drum Cokers already existing in the United States which process 34,800 barrels of Resid/calendar day are sufficient proxies for the hypothetical Coker we deal with here.

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[433] O'Brien chose not to include automatic deheading equipment in his hypothetical coker. This is discussed below.

[434] Jenkins testified that O'Brien proposed a 40,000 barrels/day Coker, and that he thought it was a "reasonable size." Transcript at p. 3893. He later described the parties's dispute:

> Well, I think the two-drum, four-drum discussion really evolved. It occurred after the initial 40 was stated, and I put out my numbers and showed a four-drum. And then Mr. O'Brien said no, you can do that in two, so it wasn't the going-in premise to be in this range or recognized that we had this issue when we went into it.

Id. at p. 3894.

[435] Transcript at pp. 3893-94, 4554-55.

1191. Moreover, I am not convinced by O'Brien that the 2-drum Coker he conceptualized is one which can, in fact, be constructed. As Exxon notes, O'Brien could not indicate what size the drums of his Coker would be: (1) 27.5 feet in diameter and 110 feet tall as he indicated in his deposition;[436] (2) 29 feet in diameter and 120 feet tall as was indicated in an email sent after his deposition;[437] or (3) 28.5 feet in diameter and 120 feet tall as he indicated in his Rebuttal Testimony.[438] On the other hand, at the hearing, he testified that he had no drum size in mind.[439] In view of previous statements made by O'Brien, I find it difficult to accept that he had no particular drum size in mind when he made his ISBL estimate. And, if in fact he did not, he should have. While one does not expect a cost curve to have the precision of a truly itemized cost estimate, nevertheless, I believe, one needs to know what components are included and, at least, a range of, or an average of, the sizes of those components. Without these in mind, it is difficult to determine whether the conceptual Coker even could be built, much less whether it is *typical.*

1192. Furthermore, serious concerns regarding ongoing Coker operations are eliminated through adopting the 4-drum design scenario. When considering a Coker capable of processing 40,000 barrels/stream day of Resid, appropriate drum size and the associated vapor velocity[440] limits are not reasonably achieved using a 2-drum design assumption. Indeed, as noted above, the record indicates that in order to process the 40,000 barrels/stream day level a 2-drum Coker would need the largest drums that have been manufactured to date. Moreover, this 2-drum Coker would need to operate at a true zero recycle[441] to prevent excessive vapor velocity during the coking process. Excess vapor

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[436] "In order to process this amount of coke with two drums, the drums would need to be pretty much the largest size drums that are fabricated today, and they'd be about – the largest standard drums today are about 27.5 feet in diameter and about 110 feet tall." Exhibit No. EMT-176 at p. 2.

[437] "Mr. O'Brien. . . . should have stated that the largest standard coker drums currently being fabricated are 30 feet in diameter and 120 feet tall. In his coker calculations, Mr. O'Brien assumed drums with a 29 foot diameter and an overall length (i.e., from the bottom flange to the top flange) of 120 feet." Exhibit No. EMT-177.

[438] Exhibit Nos. PAI-58 at p. 10; PAI-62.

[439] "There was no drum size assumption. The conceptual cost curve makes no drum size assumption." Transcript at p. 502.

[440] Vapor Velocity refers to the speed at which vapor flows in the coke drum. Exhibit No. EMT-167 at p. 15, Transcript at p. 530.

[441] O'Brien defined "zero recycle" as meaning that all of the material coming into

velocity creates an undesirable condition which can force small coke particles, referred to as "coke fines", to carry over into the fractionator causing plant complications such as pipeline plugging, reduced processing capacity, and potentially a complete shutdown. Exhibit Nos. EMT-167 at pp. 15-18, EMT-180.[442] This situation is complicated because O'Brien's 2-drum Coker design has absolutely no spare design contingency capacity and thus no operating flexibility to deal with either these complications or the commensurate coke handling challenges during normal operations.[443] Moreover, O'Brien's claim that his Coker was intended to operate at a true zero recycle consistent with the PIMS model does not withstand evidence to the contrary[444] and would require a greater capital investment than originally included in his proposal. Transcript at p. 3419.

1193. Furthermore, I am not satisfied that O'Brien's assumption of a 14-hour cycle time is reasonable as there appears to be no evidence which supports it. The only evidence cited by the Eight Parties in support of this claim is O'Brien's declaration that "many cokers [] operate on 14-16 hour cycles" and that he is "aware. . . of one coker that

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the coke drum goes through the coking process only once, and that no material is brought back through the coke drum a second time. Transcript at p. 1019.

[442] Indeed the evidence used by the Eight Parties to refute Dickman's maximum vapor velocity recommendation does not serve the purpose the Eight Parties intended. In fact, although the Eight Parties have shown 40,000 barrels of ANS Resid *could* theoretically be processed by a 2-drum Coker, the article upon which they rely states that refiners which operate with a vapor velocity at the level they assume, however, do so at the risk of foam over during attempts to maximize throughput. These operational conditions have not been shown to be a typical scenario for coking of ANS Resid. What is further clear is that the article also states that the typical range for vapor velocity is 0.5 fps to 0.6 fps – well below the 0.71 fps calculated by the Eight Parties for the 2-drum design. Exhibit Nos. PAI-141, EMT-234 at p. 9. In my opinion, these facts demonstrate another stretch in the Eight Parties attempt to convince me that a 2-drum Coker can readily process 40,000 barrels/stream day of ANS Resid. Consequently, I am not persuaded either by these arguments or by any of their evidence that this is a reasonable scenario.

[443] The record shows that certain design contingencies permit Coker operators greater flexibility and are commonly used in refinery design. Transcript at pp. 3430, 4118-21, 4742-44, Exhibit Nos. EMT-321, EMT-167 at pp. 13-14, EMT-146 at pp. 28-29.

[444] Transcript at pp. 3405, 2756-57, 3408, 3700-01, 3878, 3890-91, 3417-18, 4611, 4615.

operates on an 11 hour cycle."[445] This bald assertion is insufficient to overcome O'Brien's admission that his cost curve does not assume a cycle time.[446] It also appears that the document on which he based his 14-hour cycle time was erroneous and actually should have reflected a 16-hour cycle time.[447] Moreover, I am satisfied that the cycle time for which Delayed Cokers are being designed is not less than 16 hours.[448] Further, O'Brien himself testified that, in estimating the construction costs of a Coker, one should use a longer design cycle time, rather than a shorter operating cycle time that a refiner *might* be able to achieve by making additional investments – those not included within the original design of the Coker and thus not reflected at all in O'Brien's proposal. Transcript at pp. 553, 3173-74, 3434-36, 4352, 654-55, 4364, 4371, 4546.

1194. Therefore, based on all of the evidence in the record, I am convinced that the typical Coker constructed to process 40,000 barrels/day of ANS Resid would have four drums. There is nothing in O'Brien's testimony which would lead me to be convinced that a *typical* 2-drum Coker would be sufficiently sized so as to be able to process 40,000 barrels/stream day of ANS Resid. I am not suggesting, however, that one could not design a 2–drum Coker to do just that. Rather I am only stating that such a Coker would not be *typical*[449] and that, here, we are trying to conceptualize a *typical* Coker capable of processing 40,000 barrels/stream day of ANS Resid. Consequently, I hold that the cost of the Coker should be based on a 4-drum, not a 2-drum, Coker.

(3) Automatic Deheading

1195. "Automatic deheading equipment is the equipment that is used to open up the coke drum to permit removal of the Coke. [It] is used both to improve worker safety and to reduce coker cycle time." Exxon Initial Brief at p. 80. O'Brien admits that his typical Coker would not include any automatic deheading equipment. Transcript at p. 373.

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[445] Eight Parties Initial Brief at pp. 54-55; Eight Parties Reply Brief at p. 44.

[446] Transcript at pp. 728-29.

[447] Transcript at pp. 570-75, 2846-50; Exhibit Nos. EMT-228, EMT-229, EMT-284.

[448] Transcript at pp. 3158-59, 3438-47, 4336, 4353-54, 4361-62, 4573; Exhibit Nos. EMT-171 at p. 10, EMT-234 at pp. 5-6.

[449] Considering all the aforementioned challenges associated with the 2-drum design when trying to process 40,000 barrels/stream day of ANS Resid, it is simply more logical and prudent to base a design on a reasonable 4-drum Coker configuration than to push a 2-drum plant to its assumed maximum operational abilities under optimal conditions. Transcript at pp. 474-75, 489-90, 3707, 3890, Exhibit No. PAI-58 at p. 9.

However, he could not identify any Cokers operating with large drums and very short cycle times without such equipment. *Id.* at p. 374. Nor could he identify any Coker that has been installed since 1996 which did not have automatic deheading equipment. *Id.* O'Brien admitted that automatic deheading equipment serves to make operating the Coker safer and speeds up the cycle time. *Id.* at pp. 374-75. When asked whether, under these circumstances, a "prudent refiner" would install a Coker without such equipment, O'Brien could only respond that it wasn't against the law to do so. *Id.* at pp. 375-76. He also admitted that his firm has never recommended that a refiner install a Coker without such equipment, though he cited cost as a reason why a refiner would not. *Id.* at p. 376.

1196. According to O'Brien, "the generic or normal typical coker would not necessarily include automatic deheading" equipment. Transcript at p. 373. He added: "As long as there are many cokers out there that do not have automatic deheaders, which there are, then the coker or the automatic deheader is not the one that's setting the marketplace." *Id.* at pp. 373-74.

1197. Jenkins testified that most, if not all, Cokers built in the last 10 years had automatic deheading equipment. *Id.* at p. 3894. His comment is supported by documentary evidence in the record such as a report presented at the 1992 National Petroleum Refiners Association meeting in which it was reported that, as of November 1991, refiners were beginning to install bottom head, but not top head, automatic deheading equipment. Exhibit No. EMT-211 at p. 11. In a report presented at the 1994 meeting of the same organization, it was indicated that "[m]odern cokers include remote, automatically operated unheading systems which enhance operator safety and save time." Exhibit No. EMT-217 at p. 11. While the report does not mention sponge coke, it indicates that automatic deheading equipment makes handling shot coke easier. *Id.* At the 1996 meeting of the same Association, it was indicated that all new Cokers would have automatic deheading equipment and that refiners were considering installing them on existing coke drums. Exhibit No. EMT-234 at p. 3.

1198. According to Exxon, Jenkins assumed the use of automatic deheading. Exxon Initial Brief at p. 81. Without citing to any evidence in the record, the Eight Parties declare that, as sponge coke, rather than shot coke, is produced from ANS Resid, "the safety issue is lessened . . . [and] a coker running ANS does not necessarily require automatic deheading." Eight Parties Initial Brief at p. 70. They further note that Jenkins admitted[450] that automatic deheading equipment is predominantly used on the bottom heads, rather than both the bottom and the top heads. *Id.* at p. 71. However, Jenkins also stated that, he believed, a refiner would install both bottom and top head automatic deheading equipment because, on a new project, the incremental cost was low. Transcript at p. 3991.

[450] Jenkins stated: "There are more systems of this type, automatic deheading equipment of systems [sic] on bottom heads than top heads." Transcript at p. 3990.

1199. The evidence indicates that O'Brien errs in suggesting that the *typical* Coker built today would not have any automatic deheading equipment. Based on this record, it is clear to me that the better view is that, if a refinery were adding a Coker, in order to make its operation more safe and to speed up the cycle time, it would include such equipment. I also agree with Exxon that, were the refinery building a Coker from scratch, it probably would include automatic deheading equipment for both the top and the bottom heads.

(4) Coke Handling Equipment

1200. Jenkins included the cost of coke handling equipment, i.e., the "coke pit and crane, chutes and conveyor system, and covered storage," in his ISBL estimate.[451] Exxon Initial Brief at p. 84. On the other hand, the Eight Parties claim, Eight Parties Initial Brief at p. 73, O'Brien limited his ISBL coke handling cost and, for example, treated storage as an OSBL cost.[452] According to the Eight Parties, "O'Brien's cost curve encompasses various projects with different types of Coke handling systems and thus, represents the typical, economic and efficient refinery." *Id.* at pp. 73-74. In point of fact, when asked what kind of coke handling equipment was included in his company's cost curve, O'Brien stated:

> It is a mixture of different projects, some of which may have pits and cranes, some of which may have pads. What would be typical. In other words, this curve is supposed to show what's typical. We would not consider this enhanced dewatering and crushing and separation to be typical of your normal coker.

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[451] Describing what is pictured on Exhibit No. EMT-159, Jenkins described the "coke handling system that would typically be used on the West Coast" as follows:

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

Exhibit No. EMT-146 at pp. 33-34.

[452] In fact, the Eight Parties err in their claim regarding storage. At the hearing, O'Brien was asked whether he included the costs of storage in his ISBL or OSBL estimates and responded that he included it in neither. Transcript at p. 624.

Transcript at p. 280. This claim appears to conflict with the following assertion which he made in his rebuttal testimony: "I believe that the use of front-end loaders for coke handling is reasonable, common and supported by the facts." Exhibit No. PAI-58 at p. 15. Moreover, O'Brien claimed that he "didn't do any investigation of coke handling on the West Coast." Transcript at p. 335.

1201. On the other hand, when asked whether coke handling equipment was included in his OSBL estimate, O'Brien stated: "If you consider the pad or the crane and pit and things of that nature, if you consider those to be coke handling, those we include normally in ISBL. Anything else that takes it from the battery limits is OSBL." *Id.* at p. 441. However, this does not explain why O'Brien deducted the "extra cost for coke pit and crane" from the Meyer's estimate in an exhibit attached to his direct testimony. See Exhibit No. PAI-10. It is further noted that O'Brien also would exclude from his ISBL estimate "the coke crushing/screening equipment" and "enhanced dewatering and water purification," which Gary & Handwerk would include. Transcript at p. 441; Exhibit No. PAI-10.

1202. The Eight Parties, without citing to any evidence in the record, declare Jenkins's coke handling proposal to be a "world class," "state of the art," system for handling coke which included the "most expensive Coke handling system" available. Eight Parties Initial Brief at p. 74. They note that Jenkins admitted that not one of the refineries listed on Exhibit No. WAP-86, a summary of his answer to interrogatories, had all of the following: pit and crane, crusher, screening, and storage. *Id.* at p. 75. The Eight Parties argue, therefore, that Exxon has "failed to present evidence that a typical West Coast refinery includes all of the equipment Mr. Jenkins detailed." *Id.* at p. 76.

1203. Exxon argues that the "coke pad and front-end loader suggested by" O'Brien "would not be acceptable under current West Coast environmental requirements." Exxon Initial Brief at p. 85. Indeed, O'Brien admitted that, though a coke pad and front-end loader might have been acceptable in 1996, he did not "think it would be today." Transcript at pp. 331-32. He further admitted that he could not identify one Coker currently operating on the West Coast with just a coke pad and front-end loader. *Id.* at pp. 334-35. Moreover, in a report presented at the 1992 meeting of the National Petroleum Refiners Association, the following was stated regarding a coke pad:

> Most environmental problems are experienced at refineries with a so called "coke pad" handling scheme. Therefore this scheme, as a general rule, is not recommended.[453]

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[453] Asked whether he agreed with this statement, O'Brien said it would not be acceptable today, but it would have been acceptable in 1996. Transcript at pp. 331-32. When questioned about whether the coke pad handling system was acceptable in 1992, O'Brien did not answer either yes or no, but stated that, despite the statement in the

> In this scheme, coke from the drums is discharged onto a concrete pad. The pad is surrounded by a concrete wall on two sides leaving the third side open for a front loader
>
> A fines settling basin is adjacent to the coker pad. The basin is shallow and open on one side, so it can be accessed and cleaned by the front loader.
>
> A common problem with this scheme is that a large flow of coke slurry discharged from the coke drums into the fines settling basin will plug the screen separating the basin from the basin sump pump. This results in flooding of the area through the front end loader access.
>
> The front end loader operation prevents enclosing the coke discharge area completely, and leads to spreading coke over the adjacent area and, in general, making the are affected by the coke spillage larger than with other alternatives. The problems become more serious if a large coke storage surge capacity is required.
>
> Coke in the storage area is ground and compacted by the wheels of the front end loader and then dries. This becomes a source of dust and contamination of the storm water.

Exhibit No. EMT-211 at p. 15 (note added).

1204. I am not satisfied that O'Brien's ISBL estimate, based on his company's cost curve, adequately provides for coke handling equipment. The evidence clearly indicates that much more than a coke pad and front end loader is required,[454] particularly on the West Coast. It is clear to me that, in the 21st century, all of the equipment discussed by Jenkins would be required were a Coker added to an existing refinery. Therefore, I hold that O'Brien's ISBL estimate should be supplemented with the cost of this equipment.

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report, "there are still many cokers that operate with a simple pad." *Id.* at p. 332. Upon further questioning, he stated he had not done a study on this question and could not name a Coker on the Wet Coast that used a coke pad handling system. *Id.* at pp. 332-33.

[454] There is some confusion as to whether this was all of the equipment to which O'Brien referred. However, he did testify that he believed "that the use of front-end loaders for coke handling is reasonable, common and supported by the facts." Exhibit No. PAI-58 at p. 15. Based in part on this comment, as well as other statements which he made, I find that O'Brien, in fact, unreasonably was limiting the cost of the coke handling equipment by focusing on the least expensive equipment which might possibly be used.

(5) Coker Gas Plant

1205. According to Exxon, the "coker gas plant is used to process the gases produced in the coking of Resid." Exxon Initial Brief at p. 87. Jenkins included its cost in his ISBL estimate. *Id.* The Eight Parties claim that O'Brien included it in his OSBL cost estimate.[455] Eight Parties Initial Brief at p. 77. Exxon argues, however, that, even were it correctly placed in OSBL, "O'Brien's OSBL cost [estimate] was simply not large enough to include the coker gas plant plus all of the other costs allegedly included."[456] Exxon Initial Brief at p. 88. It also notes that O'Brien included the costs of hydrotreaters and sulfur plants, which Exxon claims serves a similar function, in ISBL, while not including the gas plant. *Id.* at p. 89. Exxon, finally, argues that O'Brien fails to take into account the location of the gas plant which, it claims, would "normally [be] located as close as possible to the fractionator of the coker because the heat from the fractionator is used in the gas plant." *Id.* at p. 91.[457]

1206. The Eight Parties argue that "the gas plant is shared among several units in the refinery, primarily the cat cracker and the coker." Eight Parties Initial Brief at p. 78 (note added). In making this argument they ignore that O'Brien testified that his conceptualized refinery does not have a cat cracker, and that the Coker would still need a gas plant. Transcript at pp. 288, 421. To add further confusion, O'Brien, after denying that his concept used the base refinery's gas plant to process the Coker gases, was asked whether he "assumed that the coker would borrow some of the gas plant from the catalytic converter," and he answered:

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[455] However, this claim may not be accurate. When given an opportunity to list the equipment covered by his OSBL estimate, O'Brien stated: "The specific equipment . . . includes, but is not necessarily limited to, electrical power distribution, boiler feed water, process and cooling water facilities, fuel gas facilities, steam systems, plant and instrument air systems, fire protection systems, and flare system and system tie-ins." Exhibit No. EMT-220 at pp. 2-3. I believe that O'Brien's failure to include a gas plant in this list was no mere oversight. It is too significant an item to not include in response to the question posed and, like Dickman, *see* Exhibit No. EMT-167 at p. 26, "I am skeptical of Mr. O'Brien's assertion that [the coker gas plant] is part of his OSBL estimate."

[456] In their Reply Brief, the Eight Parties suggest that this is beside the point because O'Brien assumes "that the gas plant would be shared by the several processes, including the coker, added to the base refinery in a typical West Coast refinery." Eight Parties Reply Brief at p. 65.

[457] Exxon cites the following portions of the record in support: Exhibit Nos. EMT-146 at pp. 36-37, EMT-167 at pp. 24-26, EMT-191 at pp. 5-6; Transcript at pp. 1327-28, 3493, 4084, 4093.

> I said in estimating the processing costs, that would be appropriate and reasonable to apply in this case. I would not build a small inefficient gas plant to process just the coker gases, which is what Mr. Jenkins did. What I said was you would integrate that processing with the existing processing in an integrated refinery on the West Coast, and so you would not spend this money to build a separate plant. You would integrate it with the refinery. That's, in fact, the way cokers are built and operated on the West Coast.

Id. at p. 289.

1207. In its Reply Brief, arguing that the Eight Parties are wrong to assert that the gas plant is not an ISBL item, Exxon cites,[458] to the following statement from Gary: "Because these facilities are part of the gas processing unit, they are 'inside' the battery limits of the refinery – and properly treated as ISBL costs – rather than OSBL costs." Exhibit No. EMT-191 at p. 4. Gary added that, though the gas plant's costs were not included in the Delayed Coker cost curve, a separate cost curve was supplied in his textbook. *Id.* at pp. 4-5. Despite Gary's comment, the Eight Parties cite Jenkins's testimony in Exhibit No. EMT-146 at p. 37 and declare that Gary & Handwerk did not include the gas plant as an ISBL cost. Eight Parties Reply Brief at p. 61. Their comment in this regard clearly is disingenuous as, while Jenkins did say that the gas plant was not included in the C*oker's ISBL cost*, he also said that the costs "are not treated as offsites," and that a separate cost curve was used on which its cost could "be estimated based on gas throughput and liquid recovery load." Exhibit No. EMT-146 at p. 37.

1208. The evidence submitted by the Eight Parties does not clearly establish how they proposed to treat the costs of the Coker gas plant,[459] or what the cost would be;[460] while the testimony of Jenkins and Gary, as well as the exhibits attached to them, satisfy me that the costs of the gas plant ought to be considered an ISBL cost. Moreover, by Exxon's admission on brief and O'Brien's testimony, I am further satisfied that the cost

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[458] Exxon Reply Brief at p. 89.

[459] As noted above, while the Eight Parties claim that it is included in the OSBL estimate, O'Brien failed to clearly identify it as such and, because of its significance, I do not think that he would have done so had he actually included it within his $37 million OSBL estimate. Moreover, I agree with Exxon that, were the gas plant included in O'Brien's OSBL cost estimate, his estimate would not be adequate to cover all costs.

[460] O'Brien indicates that there would be a "substantial" saving were the Coker gas plant integrated with the cat cracker gas plant, Transcript at p. 428, but not what the cost, integrated or not, would be.

of the Coker gas plant would be, about, $14 million.[461] Consequently, O'Brien's cost curve based ISBL estimate needs to be increased by this amount to account for the cost of the gas plant.

b. OSBL Coker Costs

1209. The Eight Parties, citing O'Brien's testimony, have suggested that the typical industry approach is to express OSBL as a percentage of ISBL costs. Eight Parties Initial Brief at p. 80. As to this matter, O'Brien stated:

> In addition to ISBL costs, when estimating the total costs of coking it is necessary to include "offsite" costs or what are also referred to as the Outside Battery Limits ("OSBL") costs. These costs represent refinery infrastructure that is necessary to support the operation of the project. OSBL costs typically are expressed as a percentage of the ISBL costs. I have used an average estimate for OSBL costs equal to 35% of the ISBL costs. This is higher than the Gary & Handwerk textbook estimate of 20 to 25%. However, a substantial part of the difference is because the Gary & Handwerk text does not include an allowance for any steam and cooling water facilities, which I included [in] my OSBL costs. Also, as noted previously, the Gary & Handwerk text includes in its ISBL estimates some facilities that I consider to be included in OSBL costs.

Exhibit No. PAI-1 at p. 24.

1210. According to Exxon, Jenkins followed the approach suggested in the Gary & Handwerk textbook. Exxon Initial Brief at p. 93. It states that, after he estimated the costs of the major process units needed to add a Coker to an existing refinery,[462] Jenkins "separately estimated the costs of the additional storage facilities, steam generation systems, and cooling water systems that would be required to support the coker," and then "applied a factor of 25% of the costs of the ISBL processing units to cover other OSBL costs." *Id.* at pp. 93-94. The Eight Parties note that even Jenkins admits, Transcript at p. 2719, that O'Brien's approach is more typical than the approach he followed.[463] Eight Parties Initial Brief at p. 81.

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[461] Exxon Initial Brief at p. 98; Transcript at pp. 422-23.

[462] "[T]he coker itself, the coker gas plant, the downstream hydroheaters, and the sulfur recovery plant." Exxon Initial Brief at p. 93.

[463] In his direct testimony, Jenkins states that "it is typical to estimate offsite costs as a percentage of the cost of the major refinery unit(s) being added." Exhibit No. EMT-37 at p. 47.

1211. Exxon argues that O'Brien's OSBL estimate is too low, but agrees that the percentage of ISBL costs he used (35%) was higher than that suggested in the Gary & Handwerk textbook (20-25%). Exxon Initial Brief at p. 95. In this regard, it should be noted that, as O'Brien's ISBL estimate has been increased as a result of the rulings I made on the ISBL issues, if no change is made in the manner in which he calculated the OSBL costs, his OSBL estimate will have a concomitant increase. This is especially true as I have held that the Coker gas plant costs should be treated as an ISBL cost and not included in the OSBL estimate.

1212. As both Jenkins and O'Brien agree that the typical approach to be followed in calculating OSBL costs is to use a percentage of ISBL costs, I find that O'Brien's approach of using 35% of the ISBL estimate should be followed.

1213. The parties, more or less, repeated the arguments that they made regarding the Coker gas plant issue in the ISBL portion of this issue discussed above. As I have held that the Coker gas plant ought to be considered an ISBL item, there is no need for me to rule again on this matter.

1214. Regarding the remaining OSBL matters specifically addressed by the parties, storage costs, steam generation and cooling water facilities, and miscellaneous items, I find that O'Brien's suggestion that they be calculated by taking 35% of ISBL costs to be adequate when the modifications which I have made in his ISBL estimate are taken into consideration.

c. Other Capital Costs

(i) Sulfur Recovery Costs

1215. The Eight Parties state the issue as follows:

> The issue related to sulfur recovery costs boils down to one single difference: do you assign the costs from the capacity plus a reserve from an existing efficiently sized sulfur recovery plant at the refinery as Mr. O'Brien proposes on behalf of the Eight Parties, or do you build a redundant (*i.e.*, second full sized) sulfur recovery plant because you are adding a delayed coker as Mr. Jenkins proposes on behalf of [Exxon]?

Eight Parties Initial Brief at p. 91. Basically agreeing, Exxon states that, as both parties agree that some backup capacity is required, the issue is how much is needed. Exxon Initial Brief at p. 108.

1216. On brief, the Eight Parties seem to indicate that one larger sulfur plant with excess capacity would provide the needed capacity as well as the necessary backup capacity.

Eight Parties Initial Brief at p. 93. However, a review of the record indicated that their witness, O'Brien, did not necessarily conceive that *only* one plant would exist. According to his testimony, he believed that only a 30% backup capacity was necessary, but he made no firm statement as to the appropriate configuration. Transcript at p. 1227. When he was asked about a three sulfur plant configuration with each capable of processing 50% of what was needed, O'Brien indicated that, while that would provide "more flexibility," he "looked at what people actually had, or tried to look at what people typically had." *Id.* at pp. 1227-28. Questioned about whether his concept involved two units each having 65% of the needed capacity, O'Brien answered that he "didn't try to estimate it that way." *Id.* at p. 1228. O'Brien also suggested that perhaps a configuration of "two 50-ton plants and one 30-ton" would work, but would only allow the Coker to operate at 80% of needed capacity if one of the 50-ton units went down. *Id.* He also stated that the three units would cost more than one 130-ton unit, but that he didn't know how many units were involved in his proposal. *Id.* at pp. 1228, 1348

1217. When asked about how he calculated his cost estimate for the sulfur plant, O'Brien testified as follows:

> [W]e used the same procedure we used on all the other units. We assumed a large plant. In fact, we assumed a 200-ton-per-day plant and we said what does that cost? We said how much total capacity do we need, and we just took it as a ratio of what a 200 ton per day plant would cost.
>
> To make it very simple, if we assumed the cost of a 200 ton a day plant, if we needed 50 tons, we said the cost would be 50 over 200. So we said it would be 25 percent, in effect, of the cost of a 200 ton a day plant and capital, a capital charge.

Id. at p. 1229. Given an opportunity to explain why, taking economies of scale into consideration, a 50-ton per day sulfur plant would not cost more to construct than 25% of the cost of constructing a 200-ton per day sulfur plant, O'Brien failed. *Id.* at pp. 1229-35.

1218. Exxon suggests that 100% backup capacity is required. Exxon Initial Brief at p. 109. However, it submitted evidence that the "average utilization [percentage] for [sulfur plants on the West Coast is] approximately 50%," Exhibit No. EMT-37 at p. 44, which indicates that, on the average, the needed backup capacity is about 50%.[464] Moreover, Dickman, Exxon's witness, testified that, if you were operating a two unit sulfur plant, you would want each capable of processing the full load, but that, most appropriately, a refinery would have a three unit sulfur plant with each unit capable of processing 50% of

[464] *See also* Exhibit No. EMT-325 which reflects that, in the refineries operating in Washington State and California, the excess capacity is 54%.

the load. Transcript at pp. 4741-42. However, when asked about this configuration, Jenkins testified as follows:

> That's the way in practice most people do handle the particular problem. The data says that there is this 100 percent capacity, but if you were charged with the task of determining how am I going to handle my sulfur plants, you would go more likely for three 50s, *but three 50s cost more than two 100s.*

Id. at p. 3913 (emphasis supplied).

1219. The record clearly reflects that the backup sulfur processing capacity needed must be sufficient to allow the refinery and the Coker to keep operating should the primary sulfur plant have a malfunction. Were the backup capacity contained in the same unit as the primary capacity, and were that unit to fail, the refinery and the Coker both would have to shut down or operate subject to penalties. Exhibit No. EMT-116 at p. 15; Transcript at p. 1347. O'Brien could not state how many units were contained in his proposal and, yet, he testified that his proposal was based on a ratio of the cost of a 200-ton per day plant, and the tons per day which were needed to process the sulfur plant influent resulting from his conceptualized Coker design. This, despite the fact that he admitted that multiple units would cost more than one large unit and that smaller units would cost more than the ratio he proposes be used to estimate the cost of such a plant. In view of this, I must conclude that O'Brien's proposal for the cost of the sulfur processing facility needed by the Coker is not only impractical, but lacks verisimilitude.

1220. Exxon has proposed using two units, each capable of processing 100% of the influent. At first blush, I was ready to reject it in favor of using three units, each having the ability to process 50% of the influent. However, it appears undisputed that those three units would cost more than two units, each capable of processing 100% of the influent, as Jenkins proposed. I, therefore, hold that the cost of Exxon's proposal for two sulfur processing units be used.

(2) Downstream Hydrotreater

1221. Exxon states that the parties agree that a downstream hydrotreater for the Coker was needed to "reduce the amount of sulfur and other impurities in the coker Naphtha, coker Distillate and coker VGO products in order to bring [them] up to the quality of the proxy products used by the Quality Bank." Exxon Initial Brief at pp. 114-15. To those three products, the Eight Parties add coker LSR. Eight Parties Initial Brief at pp. 95-96.

1222. According to Exxon, Jenkins "provided detailed cost calculations for each of the necessary hydrotreaters, . . . reduced those costs by appropriate 'quality credit[s],' . . . [and] credited the hydrotreaters with any economies of scale that a refinery might be expected to enjoy by building a larger hydrotreater integrated with other refinery operations." Exxon Initial Brief at p. 115. The Eight Parties state that O'Brien followed "standard industry practice," assuming efficiently sized process units which "would commonly be found in an existing and efficient West Coast coking refinery." Eight Parties Initial Brief at p. 96. They add that O'Brien then "assigned to the coking process" that portion of the costs of those units "attributable to treating" Coker products. *Id.*

1223. The Eight Parties find fault with Jenkins's methodology and with his estimate. They claim that no refiner would build the small units which are included in his estimate, citing O'Brien's Reply Testimony.[465] *Id.* at p. 97. Moreover, they claim that the operating conditions which Jenkins chose "produce products *that exceed* the applicable proxy product specifications." *Id.* (emphasis in original). The Eight Parties explain:

> In other words, Mr. Jenkins develops costs for producing *finished products* and not the Quality Bank intermediate products. Therefore, he has to "apply a 'credit' against the costs to reflect the fact that some of the Coker products are higher in quality than the virgin ANS cuts that are being valued in this estimate."

Id. at pp. 47-98 (emphasis in original).

1224. Exxon finds fault with O'Brien's approach which it claims has "no factual support." Exxon Initial Brief at p. 116. It argues that O'Brien conceded that, without a Coker, a refinery would have installed hydrotreaters which were sized only to treat Quality Bank products and that, if a Coker were later added, "the refinery would have to add additional hydrotreating capacity to process the coker products." *Id.* In support, Exxon cites to O'Brien's testimony during his cross-examination. There, O'Brien, though agreeing with Exxon's supposition, added:

> That would be true if we were building and constructing a refinery in our analysis. What we're looking at is what are the economic sized units

[465] O'Brien states:

> [Jenkins] assumes a distillate hydrotreater with a capacity of 8,300 barrels/day, compared to the 50,000 barrels/day that I assumes. This is an unrealistic assumption, and at his deposition, Mr. Jenkins was unable to identify any refiner that has ever constructed a hydrotreater limited to the size necessary to treat the coker products. Refiners instead typically build larger units that enjoy economies of scale.

Exhibit No. PAI-42 at p. 25.

> that refiners run their materials through because those are the units that establish the product prices in the marketplace, so your analysis is not what ends up flowing through and establishing the product prices. What established those product prices is what are the economically sized units that are available at refineries.

Transcript at p. 430. Further, O'Brien denies that he was "building a coker and adding it to a refinery and expanding all the downstream units." *Id.* at p. 432. Instead, he claimed that he was "using . . . the construction of an addition of a coker to a refinery to try to get a reasonable estimate of what the costs would be," but added that he was not "going through a complete material balance on the refinery." *Id.* According to O'Brien, the hydrotreater he conceived sets the marketplace value of the product irrespective of whether Coker or virgin product were run through it. *Id.*

1225. Despite the differences in the methodology followed by Jenkins and O'Brien, Exxon submits that the dollar difference between their results is "pretty close," less than $5 million. Exxon Initial Brief at pp. 117-18. The Eight Parties, on the other hand, suggest that the difference between the two estimates is closer to $27 million. Eight Parties Initial Brief at pp. 98-99. Exxon claims that the Eight Parties err in this regard because they omitted "Jenkins' economies of scale adjustments and the product credits." Exxon Reply Brief at p. 121. It adds that "much of the remaining difference is explained by Mr. O'Brien's failure to account for higher costs on the West Coast." *Id.*

1226. Once again, I am forced to choose between Jenkins's itemized estimate and O'Brien's cost curve based estimate. And once again, I am going to choose O'Brien's approach. I believe, based on a review of the record, that O'Brien's approach is reasonable, establishes a sufficient value for the hydrotreaters taking into consideration what is being attempted here, and is more simple to apply.

1227. I am not satisfied that Jenkins's approach is sufficiently objective to provide us with the appropriate result. Moreover, it is clear that Jenkins's proposal would, as the Eight Parties note, Eight Parties Initial Brief at p. 97 (emphasis in original), "produce products *that exceed* the applicable proxy product specifications," and I am not satisfied that the final result he reached accurately takes this anomaly into consideration. Furthermore, though I might agree with Exxon that Jenkins's estimate and O'Brien estimate are "pretty close," I cannot find that Jenkins's estimate is more reasonable than O'Brien's.

(3) Finance Cost

1228. O'Brien's approach was, as noted by the Eight Parties, "simple." Eight Parties Initial Brief at p. 100. He assumed a "simple five-year payback following commencement of operations, which is equivalent to a 20% capital recovery factor."

Exhibit No. PAI-1 at p. 24. O'Brien added that his "experience indicates that this is the type of financial return that refiners will typically require for projects of this kind, and that it is a reasonable approach for use in the Resid coker feedstock valuation calculation." *Id.*

1229. Under cross-examination, Exxon witness Baumol testified that a 20% payback was "simple and wrong." Transcript at p. 3620. While he refused to say he wouldn't use it, he did add that he wouldn't use it without knowing that he was "using a convention like straight line depreciation, which is a lie but may be a very acceptable lie." *Id.*

1230. Jenkins, based on advice from Toof,[466] used a 17% capital recovery factor. Exxon Initial Brief at p. 118; Exhibit No. EMT-37 at p. 22. He also used an "owner's cost" of 10%.[467] Exxon Initial Brief at p. 118; Exhibit No. EMT-37 at p. 52. Lastly, according to Exxon, Jenkins used "an 'interest during construction' ('IDC') factor of 4.3% based on a three-year construction schedule, a debt ratio of 35%, and an interest rate of 7.85%." Exxon Initial Brief at p. 119; Exhibit No. EMT-37 at p. 53. Exxon notes that, all of these calculations, however, results in a capital recovery factor of 19.5%, only slightly lower than O'Brien's 20%. Exxon Initial Brief at p. 120.

1231. Inasmuch as, based on the evidence and Exxon's admissions, the difference between the two proposals is de minimus and because O'Brien's 20% payback factor is simple and straight forward with no chance for subjective manipulation, I conclude that it should be applied.

3. Location Factor

1232. Exxon characterizes its use of a West Coast location factor and the Eight Parties non-use as a "major difference" between them. Exxon Initial Brief at p. 121. According to Exxon, its witness, Jenkins, calculated the cost of constructing and operating a Gulf Coast Coker and "then used appropriate location factors to reflect the higher costs that

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[466] Toof's testimony, Exhibit No. EMT-1 at pp. 18-19, in this regard is summarized by Exxon as follows: "This 17% return was derived by Dr. Toof based on an expected 25-year useful life and a resulting 4% rate of depreciation, a capital structure of 35% debt and 65% equity, a 7.85% cost of debt, and a 15.78% pre-tax cost of equity." Exxon Initial Brief at p. 118.

[467] Jenkins testified that, based on documents, *see* Exhibit No. EMT-58, he determined that the range of owner's costs were from 9%-17%, but that based on discussions with refiners, he believed that "recent projects that were financed with general corporate funds incurred owner's costs in the range of 10%." Exhibit No. EMT-37 at p. 52.

would be incurred in constructing and operating such" a Coker on the West Coast. *Id.* It notes, too, that the parties have agreed that West Coast Resid should be valued on the basis of West Coast prices. *Id.* at p. 122. Exxon also claims that O'Brien agrees that the Coker's location can influence its construction and operating costs.[468] *Id.* It submits that, because of this, a West Coast location factor must be used to estimate West Coast costs. *Id.* Moreover, Exxon claims that there is no dispute that West Coast costs are higher than those on the Gulf Coast,[469] and that use of a location factor is "an appropriate and well-established industry practice." *Id.* at p. 123.

1233. The Eight Parties define a location factor as

> an adjustment . . . used to translate a construction cost estimate developed for a specific project in a specific location (usually the U.S. Gulf Coast) to obtain a cost estimate for the same project in different parts of the county under the assumption that the cost to build a similar facility will vary depending on where it is located.

Eight Parties Initial Brief at p. 105. They support O'Brien's assertion that it is inappropriate to use a location factor when the specific location is unknown.[470] *Id.* at pp. 105-6. The Eight Parties further argue that location factors are "highly subjective," and that they differ depending on who does them. *Id.* at p. 109. They further suggest that, should a location factor be used, it should be no higher than 1.16. *Id.* at pp. 113-15.

1234. The parties appear to agree that West Coast Resid should be valued on a West Coast basis. The evidence clearly establishes, and the parties also seem to agree, that prices on the West Coast, generally, tend to be higher than those on the Gulf Coast. Yet, despite the evidence and these agreements, the Eight Parties and their witness, O'Brien,

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[468] During cross-examination, O'Brien stated that he "would say that [plant location] can have a significant influence" on plant cost. Transcript at p. 243.

[469] O'Brien, under cross-examination, when asked whether West Coast prices are higher than those on the Gulf Coast, testified that, while it isn't universally true, "generally, they will tend to be higher." Transcript at pp. 231, 1241.

[470] O'Brien stated that "[u]ntil a specific refinery project is completely defined, there are too many factors that can impact the ultimate costs – up or down." Exhibit No. PAI-1 at p. 22. He also stated that, though he acknowledged that West Coast costs can be higher, he still believed that use of his generic cost curve is appropriate without using a West Coast adjustment. Exhibit No. PAI-58 at p. 29. However, O'Brien did agree that were the Coker built in Los Angeles, it was going to cost more, although he wasn't sure how much more. Transcript at pp. 1243-44.

assert that the cost of this facility should be determined on the basis of his generic cost curve without taking into consideration the higher West Coast costs because O'Brien's conceptualized refinery with the added Coker has not been located at a specific geographical location. I cannot accept their reasoning which I find to be illogical. Once you accept the fact that West Coast costs are generally higher than those on the Gulf Coast, it follows that, at least, a generic West Coast location factor should be used.

1235. I do agree with the Eight Parties that the location factor used should not be based on the cost of building and operating a Los Angeles refinery/Coker. Since the refinery/Coker is located on the West Coast without being focused on a specific geographical site, the location factor should be generic to that Coast.

1236. Jenkins testified that he applied a range of location factors (from 1.26 to 1.3) to various components in his itemized cost estimate. Exhibit No. EMT-37 at p. 27.[471] However, since his methodology has been rejected in favor of O'Brien's cost curve based approach there is no need to consider the entirety of his testimony in this regard. In its Reply Brief, Exxon indicates it would use 1.3 as the "generic" location factor. Exxon Reply Brief at pp. 137-39.

1237. The Eight Parties challenged Exxon's proposed 1.3 location factor as excessive. Eight Parties Initial Brief at p. 113. It suggests that the location factor should be no more than 1.16. *Id.* at p. 115. Exxon admits that the 1.3 location factor represents that at a California refinery. On brief it suggests that the parties "assumed that the refinery would be located in the Los Angeles area." Exxon Initial Brief at p. 125. However, its contention is not supported by the record cites it provides. There is nothing in the October 3, 2002, "Joint Stipulation of the Parties," or in the cited portion of O'Brien's testimony[472] which would lead to such a conclusion. Indeed, the record as a whole clearly indicates that the refinery was to be located "somewhere" on the West Coast without reference to Los Angeles or any other specific portion thereof.

1238. Exhibit No. EMT-208 contains a list of location factors for many refineries including the 27 on the West Coast.[473] The average location factor for these 27 refineries

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[471] *See also* Transcript at pp. 3924-25.

[472] Exxon references the Transcript at pp. 206 and 753. Exxon Initial Brief at p. 125.

[473] BP Amoco (Carson City, CA), Chevron (El Segundo, CA), Chevron (Richmond, CA), Edgington (Long Beach, CA), Equilon (Martinez, CA), Equilon (Wilmington, CA), ExxonMobil (Torrance, CA), Greka (Santa Maria, CA), Lundy (South Gate, CA), Paramount (Downy, CA), Phillips (St. Maria/San Francisco, CA), Phillips (Wilmington, CA), Ten By (Oxnard, CA), UDS (Martinez, CA), UDS (Wilmington, CA),

is about 1.27. Were one to just focus on the 3 different location factors,[474] the average would be 1.21. And were one to give equal weight to the average of the three states (California, Washington and Oregon), the average would be 1.24.

1239. Gary testified that Los Angeles had a location factor of 1.4 and that Portland and Seattle had location factors of 1.2. Exhibit Nos. EMT-116 at p. 7, EMT-169 at p. 6. The simple average of these three locations is about 1.27. For the same three locations, R.S. Means provides location factors of 1.24 (Los Angeles, 1.22 (Portland) and 1.19 (Seattle) for a simple average of about 1.22. Exhibit No. WAP-80 at p. 1. The PRISM simple average for these same three locations (Los Angeles-1.35, Portland-1.08, and Seattle-1.08) is 1.17. *Id.*

1240. Of all of the various mathematical suppositions put forth by the parties, the most logical one is an average of the location factors at all 27 refineries located on the West Coast. Therefore, I conclude that the appropriate location factor is 1.27.

4. Operating Costs

a. Fixed Operating Costs

1241. According to the Eight Parties, O'Brien's and Jenkins's estimates for fixed operating costs vary on the Gulf Coast by 22¢/barrel and on the West Coast by 47¢/barrel, all in Year 2000 dollars.[475] Eight Parties Initial Brief at p. 115. While the parties agree that much of the difference is caused by the difference in their capital costs since most of the fixed cost estimates are a percentage of the ISBL costs or total capital costs.[476] *Id.* at p. 116; Exxon Initial Brief at p. 130; Exxon Reply Brief at p. 140. Since

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Valero (Benecia, CA), Valero/Huntway (Wilmington, CA), Equilon (Bakersfield, CA), Kern (Bakersfield, CA), San Joaquin (Bakersfield, CA), Tricor Refining (Oildale, CA), BPAmoco (Cherry Point, WA), Chevron (Portland, OR), Equilon (Anacortes, WA), Phillips (Ferndale, WA), Tesoro (Anacortes, WA), and U.S. Oil (Tacoma, WA).

[474] 13 of the California refineries had a location factor of 1.35, the remaining four had a location factor of 1.20, and the refineries in Oregon and Washington had a location factor of 1.08.

[475] Exxon states that Jenkins estimated fixed costs of $1.18/barrel on the Gulf Coast (erroneously stated as $1.19 in Exxon's brief) and $1.43/barrel on the West Coast, while O'Brien estimated the fixed costs to be 96¢/barrel on each coast. Exxon Initial Brief at pp. 129-30.

[476] *See* Exhibit Nos. EMT-37, EMT-64, PAI-11, PAI-42

the parties have not placed these percentages into dispute, there is no need to discuss them.

1242. The parties have raised four matters for discussion: the number of operators, the inclusion of a foreman, the labor multipliers used in estimating labor costs, and the operators for downstream hydrotreating units. Eight Parties Initial Brief at p. 116; Eight Parties Reply Brief at pp. 100-01; Exxon Initial Brief at p. 132.

(1) Number of Operators

1243. O'Brien assumed that the Coker could be operated with six operators per shift (25.2 in total),[477] while Jenkins assumed that nine operators per shift would be required (38 in total).[478] Eight Parties Initial Brief at p. 116; Eight Parties Reply Brief at pp. 101-02. The Eight Parties concede that some of the difference is related to the number of drums assumed in the parties's proposals, and that a four-drum Coker would require more personnel than a two-drum Coker. Eight Parties Initial Brief at p. 116. As I have already decided that a four-drum Coker is required, it is clear that even the Eight Parties would agree that more than six operators per shift would be required. The Eight Parties, however, did not indicate how many more than six operators would be required under a four-drum scenario. I am compelled, therefore, to accept Jenkins's estimate of nine

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[477] At the hearing, under cross-examination, O'Brien had great difficulty in testifying as to the number of operators he proposed using. *See* Transcript at pp. 1336-42. When asked how many operators he included, O'Brien first said "18," and then "20." While the Eight Parties failed to refer to his later clarification in their Initial Brief, on reply, they noted that O'Brien stated:

> Where I was going wrong in my calculation of that is we covered the clock completely. Seven days a week, we included all the hours seven days a week, 52 weeks a year, the whole 365 days. In any one week, you have 24 hours in a day, 7 days in a week. You have to cover 168 hours. Any worker only works 40 hours of that, so if we divide 40 into that, that's the 4.2.
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> In effect, you can say that's the number of shifts, not the three shifts that I testified to. It's actually 4.2 shifts. . . . I was not calculating the number correctly when I was talking about it.

Id. at p. 1354. He then indicated that the number of operators required was 4.2 times six, or 25.2. *Id.*

[478] *See* Exhibit No. PAI-42 at p. 28.

operators per shift, which I find to be supported by substantial record evidence.[479]

(2) Inclusion of a Foreman

1244. Exxon submits that, to coke 40,000 barrels/day of ANS Resid, a refinery adding a Coker also would have to add, besides the Coker, three downstream hydrotreaters, a sulfur plant and an unsaturated gas plant.[480] Exxon Reply Brief at p. 142. Jenkins assumed that, were a refinery to add all of this equipment, an additional foreman would be required to supervise its operation.[481] *Id.* O'Brien assumed that the already existing supervisory staff is all that would be necessary.[482] Eight Parties Initial Brief at p. 117.

1245. The evidence here represents the differing opinions of experts. After listening to the witnesses and examining the documentary evidence, I am satisfied that Jenkins's view is the better one. Therefore, I hold that the fixed cost estimate should include the cost of an additional supervisor.

(3) Labor Multipliers

1246. According to the Eight Parties, O'Brien "used a 45% labor multiplier to increase the direct cost of the coker operators to account for benefits, overtime and other labor related costs."[483] Eight Parties Initial Brief at p. 118. Exxon states that Jenkins used "three labor multipliers: a 45% multiplier to cover 'Operating Overhead;' a 15% multiplier to cover 'Offsite Labor;' and a 20% multiplier to cover 'Administrative Labor.'"[484] Exxon Reply Brief at p. 143. It adds that his calculations are based on the

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[479] *See, e.g.*, Exhibit Nos. EMT-146 at pp. 47-48, EMT-167 at p. 19.

[480] *See* Exhibit No. EMT-62.

[481] Jenkins stated: "It is simply not reasonable to assume that the management team needed to operate Mr. O'Brien's Base Refinery would be the same as the management team that would be needed to run a more complex refinery that includes a Coker and the associated downstream processing units." Exhibit No. EMT-146 at pp. 47-48.

[482] O'Brien stated: "A refinery would not assign a foreman to oversee the operations of just the coking facilities, but instead would use a foreman with responsibilities over other parts of the refinery as well." Exhibit No. PAI-42 at p. 28.

[483] *See* Exhibit No. PAI-11.

[484] *See* Exhibit Nos. EMT-64, EMT-292.

"Pace Refinery Cost Model."[485] *Id.*

1247. I find that Jenkins's proposal is not supported by evidence in the record. Moreover, I find it to be overly complicated for the purposes for which it is being used and that it may include, as the Eight Parties suggest,[486] a "hidden multiplier." In view of this, I adopt O'Brien's 45% labor multiplier which I find to be supported by the record, and reasonable for the purposes for which it is used.

(4) Downstream Hydrotreating Units

1248. Exxon alleges that O'Brien failed to include, in his fixed cost estimate, the cost of operators for the downstream hydrotreaters. Exxon Initial Brief at p. 132. The Eight Parties, in reply, claim that O'Brien did include those costs.[487] Eight Parties Reply Brief at p. 101. They add, citing Exhibit No. EMT-231, that he "did not allocate any of the labor costs for these units to Resid because there would be the same number of operators for the hydrotreaters whether or not the hydrotreaters processed products from the coking process." Eight Parties Reply Brief at p. 101. A review of the exhibits to which the Eight Parties cite in support of their claim that O'Brien included the labor costs related to the hydrotreaters reflects that the hydrotreaters to which he referred were those in the refinery before the addition of the Coker. Therefore, I conclude that O'Brien did not include any *extra labor costs* for the operators required to operate the three additional hydrotreaters which will be necessary to support the added Coker.[488] Moreover, Jenkins clearly stated in his testimony that "hydrotreaters . . . are operator driven" and that he could not find any place where O'Brien included an "allocation or cost for operators in the hydrotreaters." Transcript at p. 3697.

1249. At a minimum, even if he included the full costs of all of the hydrotreaters which a refinery would need were a Coker added to it in his Coker cost estimate, O'Brien should have included the pro-rated costs of the operators of the hydrotreaters to account for the Resid being processed. But he did not. In any event, as noted above, I cannot conclude that he included any costs related to these hydrotreaters. Consequently, I hold, based on the evidence in the record, that Jenkins's proposal to add additional costs for these operators should be included in the project's fixed costs.

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[485] *See* Exhibit No. WAP-78.

[486] Eight Parties Initial Brief at pp. 119-20.

[487] The Eight Parties cite Exhibit Nos. PAI-1 at p. 25, PAI-14, PAI-15, and PAI-16.

[488] *See* Exhibit No. EMT-62.

b. Variable Operating Costs

1250. Exxon defines the Coker's variable operating costs as "the costs of fuel, electricity, steam, water, hydrogen catalysts and chemicals that are used in the process of coking and treating the Resid to meet the quality standards of the Quality Bank proxy products."[489] Exxon Initial Brief at p. 132. Jenkins once again presented an itemized list of estimated costs for the Coker and related downstream processing units.[490] *Id.* at p. 133. According to Jenkins, his estimate is that the variable costs are 92¢/barrel on the Gulf Coast and 90¢/barrel on the West Coast in Year 2000 dollars. Exhibit No. EMT-146 at p. 7. In comparison, O'Brien estimates the cost as being 85¢/barrel in Year 2000 dollars. Exhibit No. PAI-96 at p. 2.

1251. O'Brien testified that his estimates are based, in part, on the PIMS model and the Baker & O'Brien database. Transcript at pp. 658-60. When asked why, he replied:

> Because the PIMS model is used to establish the yields, and the PIMS model also provides operating costs for these units, for the coker unit, and we looked at them and they seemed to be reasonable, not much different from what we would use typically, so we decided to stick with the PIMS.

Id. at p. 658. O'Brien indicated further that the PIMS model did not have fixed operating costs, nor did it have capital costs. *Id.* at pp. 658-59. He also testified that the unit values he used for the Coker were based on the Jacobs Consultancy database while PIMS was used for the downstream units. *Id.* at pp. 660-61.

1252. Jenkins's estimates are based on the Jacobs Consulting database.[491] Exhibit No. EMT-37 at p. 61. Exxon argues that the difference between his estimates and that of O'Brien results from O'Brien's failure to include variable operating costs for the Coker gas plant, his failure to include energy costs for the amine unit "a key part of the sulfur recovery system," and his failure to include the costs of chemicals used in processing the Resid.[492] Exxon Initial Brief at p. 133. The Eight Parties submit, on the other hand, that

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[489] *See* Exhibit Nos. EMT-65, EMT-293.

[490] *See* Exhibit Nos. EMT-37 at p. 61, EMT-65, EMT-293.

[491] Exxon claims, Exxon Reply Brief at pp. 144-45, that Jenkins's variable cost estimate were not challenged by any party, but that claim is a non sequitur. It is clear that the Eight Parties do not agree with Jenkins or Exxon as to his variable cost estimate.

[492] Exxon cites Exhibit No. EMT-146 at p. 49 and Transcript at pp. 450-51, 3697-98, in support. Exxon Initial Brief at pp. 133-34.

the difference between the Jenkins estimate and that of O'Brien "result[s] from differences in how the capital cost calculation are performed." Eight Parties Reply Brief at p. 103.

1253. Irrespective of how the differences between Jenkins and O'Brien resulted, it is clear to me that the difference is not significant, only 5-7¢/barrel. Moreover, I am satisfied with neither approach. Jenkins's methodology is too complicated and too subjective, and I am not satisfied that there was any good reason for O'Brien to use the PIMS model for a portion of the variable costs and the Jacobs Consultancy database for others.[493] The PIMS model is a third party database which is not subject to any party's subjectivity or manipulation. Therefore, I hold that, based on the evidence in the record, the PIMS model should be used for all of the variable costs in order to provide a just and reasonable result for all parties.

5. Base Year

1254. O'Brien calculated his costs on the basis of Year 1996 dollars.[494] Eight Parties Initial Brief at p. 123. Jenkins calculated his costs on the basis of Year 2000 dollars.[495] Exxon Initial Brief at p. 134. At first blush, considering that, whichever year is used, adjustments can be made using the Nelson Farrar indices, it shouldn't matter which base year is used.[496] The Eight Parties note that a possible problem with that theory is that certain equipment may be used in Year 2000 which wasn't available in Year 1996. Eight Parties Initial Brief at p. 124. They suggest ignoring this question in order to simplify matters. *Id.*

1255. Exxon raises another matter:

> [A] problem arises because there are two Nelson Farrar indices applicable to different types of costs – (1) the Nelson Farrar Refinery Construction Cost Index (sometimes referred to as the Nelson Farrar capital cost index),

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[493] While O'Brien explained why he used the PIMS model for some of his variable cost estimates, he never explained why he used the Baker & O'Brien database for the others. Transcript at pp. 660-61. Indeed, he stated that he "felt it was appropriate to stay with PIMS because they have operating costs that say for that yield, use these operating costs." *Id.* at p. 661.

[494] *See* Exhibit No. PAI-1 at pp. 19-20.

[495] *See, e.g.,* Exhibit No. EMT-37 at pp. 24-25, 33, 40, 46, 52, 54.

[496] Exxon Initial Brief at p. 134.

> and (2) the Nelson Farrar Refinery Operating Cost Index – which produce different results depending on how they are applied and which base year is used.

Exxon Initial Brief at p. 134. Stated differently, Exxon, citing Bartholomew's testimony,[497] claims the problem is that the Nelson Farrar Construction Cost Index "has risen relatively steadily over time, [while] the Nelson Farrar operating cost index has gone up and down from year to year." *Id.* at p. 136.

1256. Despite Exxon's assertion, in the cited transcript page, Bartholemew was not asked, nor did he testify, about the Nelson Farrar Construction Cost Index. Rather, he was asked about the Nelson Farrar Operating Cost Index for the period January 1992 through December 2001, and stated: "It actually shows a perfectly flat number. It shows some costs going up – the index goes up during some periods and goes back down. If you were to take a look at 1992 versus 2000, I think the indices are almost identical." Transcript at p. 2252. As Exxon's assertion on brief is solely supported by testimony, which is limited in time and limited to the Nelson Farrar Operating Cost Index, I find that its assertion is not supported by any record evidence. Thus, I find that only the Nelson Farrar Operating Cost Index should be used.

1257. Alternatively, Exxon suggests that Year 2000 should be established as the base year as "it would at least reduce the impact . . . by bringing all of the capital costs forward to 2000 by using the correct Nelson Farrar construction cost index." Exxon Initial Brief at p. 137.

1258. Based on the record, and taking the parties's arguments on brief into consideration, I find that the base year should be Year 2000 and that the existence or non-existence of certain equipment should not be considered in making any calculations.

ISSUE NO. 2: WHAT IS THE LEVEL OF ADJUSTMENT NECESSARY TO BRING THE HEAVY DISTILLATE CUT INTO LINE WITH THE SPECIFICATIONS FOR PLATT'S WEST COAST LA PIPELINE LOW SULFUR NO. 2? WHAT SHOULD BE THE EFFECTIVE DATE OF THE CHANGE IN THE HEAVY CUT DISTILLATE CUT PRICE

A. LEGAL STANDARDS AND BURDENS OF PROOF

1259. According to the Eight Parties, the issue related to the Heavy Distillate cut arises as a result of a November 24, 1999, Quality Bank Administrator Notice that explained

[497] Transcript at p. 2252.

that there had been a change in the Platts reporting of the reference price that was used to value the Heavy Distillate cut.[498] Eight Parties Initial Brief at p. 131. Previously, according to the Eight Parties, the Quality Bank used Platts West Coast High Sulfur (0.5%) Waterborne Gasoil assessment.[499] *Id.* Platt's discontinued that assessment, the Eight Parties state, and began a new assessment for West Coast Los Angeles Waterborne Low Sulfur No. 2, which has a sulfur content of 0.05%.[500] *Id.* The Quality Bank Administrator requested guidance from the Commission on what should be the appropriate replacement reference price.[501] *Id.*

1260. All parties agreed, according to the Eight Parties, that the correct Heavy Distillate price should be based on the Platts West Coast Los Angeles Pipeline Low Sulfur No. 2 reference price, but the parties disagreed over the proper adjustments needed to make that price appropriate for use in the TAPS Quality Bank. *Id.* at pp. 131-32. Furthermore, the Eight Parties contend that, because the dispute results from a notice of the Quality Bank Administrator related to the discontinuation of a reference price and the appropriate replacement reference price, and not from a protest or complaint, the burden of proof lies equally with the Eight Parties and Exxon to demonstrate that their proposed adjustments to the West Coast Los Angeles Pipeline No. 2 price are needed to make the use of that reference price and adjustments a just and reasonable approach for valuing West Coast Heavy Distillate. *Id.* at p. 132.

1261. The Eight Parties also note that all parties stipulate that the effective date for the change in the West Coast Heavy Distillate cut price should be February 1, 2000.[502] *Id.* at pp. 132-33. They view the disagreement as primarily one over the cost of desulfurization and the appropriate methodology to employ for identifying those costs. *Id.* at p. 133. In addition, the Eight Parties assert, the parties disagree over whether a logistics adjustment is necessary to put the West Coast Los Angeles Pipeline No. 2 price onto a waterborne basis consistent with other similar Quality Bank reference prices. *Id.*

1262. In Exxon's view, the sole valuation question presented by Issue No. 2 is "the level

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[498] *Trans Alaska Pipeline System*, 90 FERC ¶ 61,123, at p. 61,370 (2000).

[499] *Id.*

[500] *Id.*

[501] *Id.* at p. 61,371.

[502] The Eight Parties explain that this date is the date the change would have taken place under the Quality Bank tariff had a new price been implemented in accordance with the terms of the tariff. Eight Parties Initial Brief at p. 133.

of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the [new West Coast reference] price," which all parties have agreed will be the Platts West Coast Los Angeles Pipeline Low Sulfur (0.05 wt%) No. 2 Fuel Oil price. Exxon Initial Brief at p. 143**.**

1263. The "logistics adjustment" proposed by the Eight Parties is opposed by Exxon because, Exxon claims, it (1) is not a "sulfur processing adjustment" within the scope of the Commission's order setting the West Coast Heavy Distillate valuation for hearing, and is thus outside the scope of this proceeding, and (2) has not been justified, is not supported by substantial evidence, and is premised on numerous false assumptions. *Id.* at pp. 143-44.

1264. This issue arises, according to Exxon, because Platts, effective November 1, 1999, discontinued reporting prices for West Coast High Sulfur (0.5 wt%) Waterborne Gasoil. *Id.* at p. 144. Exxon states that the Commission had previously designated that product as the West Coast reference price for the Quality Bank Heavy Distillate cut, subject to a reduction of 1¢/gallon to reflect the cost of reducing the sulfur level of the Quality Bank Heavy Distillate cut (which has a sulfur content of 0.57 wt%) to the lower sulfur level (0.50 wt%) on which the reference price was based. *Id.* The only disagreement, according to it, related to "the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the [new proxy] price." *Id.* In particular, it states, the Eight Parties initially proposed that the sulfur processing adjustment to the new proxy price should be 6¢/gallon, while Exxon proposed that the sulfur processing adjustment should be 3.5¢/gallon. *Id* at pp. 144-45.

1265. In response to these conflicting proposals regarding the magnitude of the costs required to desulfurize the Quality Bank Heavy Distillate cut from 0.57 wt% sulfur down to the much lower 0.05 wt% sulfur content of the new West Coast reference products, Exxon points out that the Commission issued an order on February 9, 2000, in which it "accept[ed]" the Platts Los Angeles Pipeline Low Sulfur No. 2 Oil price as the new West Coast reference price for the Heavy Distillate cut and referred the issue of the "appropriate [sulfur] processing cost adjustment" to a settlement judge.[503] *Id.* at p. 145. Similarly, in its subsequent order establishing this consolidated hearing, Exxon's position is that the Commission set for hearing and resolution only the issue of "the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the [new proxy] price."[504] *Id.*

1266. Until such time as the new sulfur processing cost adjustment is finally resolved,

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[503] *Trans Alaska Pipeline System*, 90 FERC at pp. 61,370, 61,372.

[504] *Trans Alaska Pipeline System*, 97 FERC ¶ 61,150, at pp. 61,650, 61,652 (2001).

Exxon contends, the Commission, in accordance with Section III.G.5 of the TAPS tariff, ordered the Quality Bank Administrator to continue to determine the West Coast value of the Heavy Distillate cut on the basis of the frozen October 1999 Platts West Coast High Sulfur (0.5 wt%) Waterborne Gasoil price reduced by 1¢/gallon. *Id.* at p. 146. However, Exxon also points out that the Commission observed, in the same order, that the TAPS tariff provision requiring continuation of the prior price "obviously contemplated only a short period when that price would remain in effect," because the Commission was required to act within 60 days of the notice by the Quality Bank Administrator.[505] *Id.* Further, Exxon notes that, because the final decision on the new West Coast sulfur processing cost adjustment was not likely to be issued until a longer period of time had elapsed, the Commission further directed that the issue of whether the new price "should be applied on a retroactive basis" should also be addressed in the consolidated proceedings.[506] *Id.*

1267. In resolving the dispute between the parties over the valuation of the Heavy Distillate cut on the West Coast, Exxon maintains, the Commission has an obligation to reach a just and reasonable resolution of the issues on the basis of all the evidence in the record. *Id.* While it agrees that the Commission may take into consideration its resolution of similar issues pertaining to other Quality Bank cuts, Exxon interprets the Commission's decision as meaning that the Commission cannot base its decision simply on some global view of what might be a reasonable overall result. *Id.* at p. 147. Exxon also argues that there is case law that should be interpreted to mean the Commission should not be influenced either by the fact that a position presented by a group of parties may be supported by a larger number of parties or by the fact that a position presented by a group of parties may itself be the product of a compromise among those parties. *Id.*

1268. As to the sulfur processing cost adjustment, Exxon's position is that each party has the burden of supporting its own position. *Id.* Exxon cites 5 U.S.C. § 556(d) as support for this position. *Id.* The additional "logistics adjustment" proposed by the Eight Parties is not, in Exxon's view, a "sulfur processing adjustment" within the scope of the Commission's order setting the West Coast Heavy Distillate valuation for hearing, and is thus outside the scope of this proceeding. *Id.* at pp. 147-48. However, to the extent that the Commission nevertheless considers that the adjustment proposed by the Eight Parties is appropriate, Exxon maintains, the Eight Parties clearly have the burden of proving not only that this proposed additional adjustment is within the scope of the issues set for hearing in this proceeding, but also that the "logistical adjustment" they propose is necessary to achieve a just and reasonable valuation of West Coast Heavy Distillate for Quality Bank purposes and that the specific magnitude of the proposed adjustment is just

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[505] *Trans Alaska Pipeline System*, 90 FERC at p. 61,372.

[506] *Trans Alaska Pipeline System,* 90 FERC at p. 61,372.

and reasonable. *Id.* at p. 148.

B. STIPULATED MATTERS AND AREAS OF DISPUTE

1269. The parties have reached two stipulations related to the valuation of West Coast Heavy Distillate. Eight Parties Initial Brief at p. 132; Exxon Initial Brief at p. 151. First, they have agreed that the West Coast Heavy Distillate cut should be valued using the reported price for Platts West Coast Los Angeles Pipeline No. 2, minus certain deductions that are disputed. Eight Parties Initial Brief at p. 132. Second, they have agreed that the effective date for the implementation of the change in the West Coast Heavy Distillate cut price should be February 1, 2000, which is the date that the change would have taken place under the Quality Bank tariff had a new price been implemented in accordance with the tariff's terms. *Id.* at pp. 132-33.

1270. Both parties also agree that the deductions should include the cost of desulfurizing the ANS Heavy Distillate (which has a sulfur content of 0.57%) to meet the much lower 0.05% sulfur specification of the agreed-upon reference price. *Id.* at p. 133; Exxon Initial Brief at pp. 148-49. However, although the parties agree that there should be some deduction, they disagree about the cost of desulfurization and the appropriate methodology to employ for identifying those costs.[507] Eight Parties Initial Brief at p. 133; Exxon Initial Brief at p. 149.

1271. Additionally, Exxon states that the parties disagree on whether there should be an additional logistics adjustment to put the West Coast Los Angeles Pipeline No. 2 price onto a waterborne basis consistent with other similar Quality Bank reference prices. Exxon Initial Brief at p. 150; Eight Parties Initial Brief at p. 133. The Eight Parties believe that a logistics adjustment is needed; Exxon does not. Eight Parties Initial Brief at p. 133. In addition, the parties disagree about the base year that should be used for computing the various adjustments. *Id.* The Eight Parties use a 1996 base year; while Exxon uses a 2000 base year. Eight Parties Initial Brief at p. 133; Exxon Initial Brief at p. 151. They do not believe that the base year issue should have any impact on the outcome of the Heavy Distillate issue. Eight Parties Initial Brief at p. 133.

1272. The proposed "logistics adjustment" (to be imposed in addition to the sulfur processing cost adjustment) is, in Exxon's view, ostensibly designed to place the agreed-upon Los Angeles pipeline reference price for Heavy Distillate on a West Coast waterborne basis. Exxon Initial Brief at p. 150. Exxon opposes this logistics adjustment on the grounds that it is outside the scope of this proceeding, not justified as being necessary to achieve consistency, not supported by substantial evidence, and not based on valid assumptions. *Id.* at pp. 150-51.

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[507] *See* Joint Stipulation, filed October 3, 2002, at p. 3.

1273. Exxon contends that the amount of the sulfur processing cost adjustment should be $1.821/barrel, or 4.3¢/gallon, stated in Year 2000 dollars. Exxon Initial Brief at p. 149. Exxon contrasts this with the Eight Parties's proposed sulfur processing cost adjustment of $1.717/barrel, or 4.1¢/gallon, stated in 1996 dollars. *Id.* When the Eight Parties's sulfur processing costs are stated on a Year 2000 dollar basis using the appropriate Nelson Farrar indices, Exxon points out, it is very similar to its estimated cost. *Id.*

1274. Although similar in overall result, Exxon goes on to explain the two sulfur processing cost estimates differ because the Eight Parties used four "flawed" assumptions. *Id.* at p. 150. First, Exxon claims that the Eight Parties assumed that a more expensive, high-pressure hydrotreater would be required; whereas Exxon's cost figure assumed a medium-pressure hydrotreater. *Id.* Second, Exxon asserts, the Eight Parties did not include any allowance for the costs of storage associated with the processing of the ANS Heavy Distillate, which it argues is required. *Id.* Third, Exxon declares, the Eight Parties failed to use a West Coast location factor to account for the substantially higher West Coast capital and fixed operating costs, again, which it argues is required. *Id.* Fourth, Exxon argues, the Eight Parties overestimated the amount of hydrogen that would be consumed by the distillate hydrotreater in the desulfurization process. *Id.*

C. SULFUR PROCESSING COST ADJUSTMENTS

1. Capital Costs

1275. The Eight Parties claim that Exxon tries to mask its inconsistent approach between its Resid cost determination approach and its Heavy Distillate desulfurization approach by stating that "[O'Brien's] estimate is very similar to Jenkins's calculation," $1.821/barrel for Jenkins, and $1.80/barrel for O'Brien.[508] Eight Parties Reply Brief at p. 110 (quoting Exxon Initial Brief at p. 149). While the results may be similar, the Eight Parties note that O'Brien developed his ISBL costs in accordance with "typical" industry practice and consistent with his Resid cost calculations. *Id.* at pp. 110-11. The Eight Parties assert that the same cannot be said for Jenkins. *Id.* at p. 111.

[508] The Eight Parties suggest that O'Brien's proposed sulfur processing cost adjustment is actually $1.717/barrel, or 4.1¢/gallon in 1996 dollars. Eight Parties Reply Brief at p. 110, n.50. Further, state the Eight Parties, Jenkins's proposed cost is 4.3¢/gallon. *Id.* (citing Exxon Initial Brief at p. 149). The Eight Parties assert that their adjustment is greater than 4.1¢ and 4.3¢ because it includes a logistics adjustment. *Id.*

a. Inside Battery Limits Costs

1276. For the Heavy Distillate component of the Quality Bank, according to the Eight Parties, "significant treatment cost must be incurred for hydrotreating of the Heavy Distillate cut to reduce the sulfur content from approximately 0.52% sulfur to the specified 0.05% sulfur" level of the product being used.[509] Eight Parties Initial Brief at p. 134. The Eight Parties argue that the difference of 0.2¢/gallon between the Exxon and Eight Parties's processing cost numbers is largely attributable to the difference in cost data that Exxon used to calculate its cost numbers. *Id.* They argue that if Exxon had used the same approach as it did when doing the Resid calculations its cost estimate for Heavy Distillate would have been considerably higher.[510] *Id.* In contrast with Exxon's approach, the Eight Parties maintain that their expert, O'Brien, used an approach to calculate costs that is consistent with the approach used in his Resid delayed coker and coker product hydrotreating processing. *Id.* The Eight Parties claim that he used what they characterize as the appropriate Baker & O'Brien cost curve to estimate the processing costs. *Id.*

1277. The Eight Parties assumed a 50,000 barrels/day high-pressure hydrotreater at an existing refinery as the basis for "estimating a reasonable allowance for recovery of capital investment." *Id.* at p. 135. O'Brien chose this size hydrotreater, according to the Eight Parties, because he believed it to be an economically sized unit that would be commonly installed at a large existing refinery. *Id.* The Eight Parties estimated the reasonable ISBL cost to be $49.5 million. *Id.* Exxon, through Jenkins, takes exception with O'Brien's use of a high-pressure distillate hydrotreater, asserting that a lower cost medium-pressure hydrotreater, which Jenkins uses, would be more appropriate. *Id.* That position does not represent what a typical refinery likely would do in this age of ever tightening sulfur limitations in diesel fuels, according to the Eight Parties.[511] *Id.* Jenkins

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509 *See* Exhibit No. PAI-1 at p. 41.

510 To bolster this argument, the Eight Parties submit that, had Exxon used the applicable cost curve from the Gary & Handwerk textbook as it did to calculate the sulfur recovery plant in the Resid cost estimate, the cost would have been $66 million, or 50% more than the $44.4 million cost that was used. Eight Parties Initial Brief at p. 134, n.78. This would have translated, according to the Eight Parties, into 5.55¢/gallon in Year 2000 dollars rather than the 4.34¢/gallon Exxon used. *Id.* The Eight Parties claim that Exxon's expert, Jenkins, acknowledged that Exxon would benefit from a lower processing cost for the Heavy Distillate component. *Id.*

511 The Eight Parties support this assertion by citing Exhibit No. WAP-102 at p. 2, "An Assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel," prepared by employees of the Charles River Associates, Inc., and Baker and O'Brien, Inc.:

acknowledged that "high pressure" in terms of a distillate hydrotreater includes 800 psi. *Id.*

1278. The Eight Parties view Jenkins's, Exxon's expert, use of the Jacobs Consultancy cost curve when determining the capital costs for the distillate hydrotreater for this valuation as an unwarranted inconsistency. *Id.* When asked why he used a cost curve, the Eight Parties state Jenkins answered that "it basically met the test" and that after reviewing the data "and rules of thumb in terms of dollars per barrel . . . [I] felt like it was quite reasonable." *Id.* at pp. 135-36.

1279. For this valuation, the Eight Parties point out that Exxon used the same size distillate hydrotreater as the Eight Parties. *Id.* at p. 136. This 50,000 barrels/day distillate hydrotreater designed to desulfurize the Heavy Distillate cut is larger, according to the Eight Parties, than the amount of Heavy Distillate that would be processed in a 200,000 barrels/day refinery running ANS crude oil. *Id.* ANS crude oil, according to the Eight Parties, contains only 18.45% of Heavy Distillate, or 36,900 barrels/day. *Id.* Thus, in this instance, the Eight Parties note, Exxon follows typical industry practice to construct efficient sized hydrotreaters and take advantage of the lower cost per unit of throughput. *Id.* By contrast, the Eight Parties note that, in valuing Resid, Exxon's Coker distillate hydrotreater was scaled down to handle only the Coker distillate output, resulting in approximately double the cost of a 50,000 barrels/day hydrotreater similar to that which O'Brien used. *Id.* Thus, in this instance, the Eight Parties point out, Jenkins managed to have his base hydrotreater cost less than O'Brien's, $44.4 million on the Gulf Coast in Year 2000 dollars,[512] compared to O'Brien's $49.5 million in Year 1996 dollars.[513] *Id.*

1280. The Eight Parties assert that Jenkins also used an entirely different approach to

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> We have assumed that all new grass roots units constructed since 1992, in response to the EPA's 500 ppm diesel regulation, employ pressures in the higher range. Many refiners determined that the incremental cost to build at least an 800 psi unit versus a lower pressure unit was small, and an 800 psi unit protected their investment in the event diesel regulations lowered sulfur in the future.

Eight Parties Initial Brief at p. 135. They go on to note that, since this study was published, the EPA has promulgated ultra low sulfur specifications for diesel that take effect in 2006. *See* 40 C.F.R. § 80.500, *et seq*. (2004).

[512] *See* Exhibit No. EMT-37 at p. 14.

[513] The Eight Parties note that Jenkins increases this base figure to a West Coast figure of $57.7 million by using a 1.3 location factor. Exhibit No. EMT-37 at p. 14.

develop his ISBL costs for calculating the adjustment to Platts Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil Price. Eight Parties Reply Brief at p. 111. They maintain that Jenkins's inconsistency conveniently squares with Exxon's economic interests and results in a low cost adjustment for the West Coast Heavy Distillate component and a high cost adjustment for the Resid component. *Id.*

1281. Exxon summarizes Jenkins's rationale for using a cost curve for the distillate hydrotreater, the Eight Parties note, by stating: "general cost curve data are reliable for relatively simple types of equipment, such as a distillate hydrotreater, for which the other available data are consistent and produce little variance or 'scatter.'" *Id.* (quoting Exxon Initial Brief at p. 153). According to the Eight Parties, it is not surprising that Exxon's only support for this proposition is what the Eight Parties characterize as Jenkins's self-serving testimony. *Id.* The Eight Parties assert that the record does not support Jenkins's characterization of a hydrotreater as simple. *Id.* They point out that the only evidence introduced into the record on that subject was a complexity table developed by Maples, and argue that a hydrotreater is more complex (2.19, according to the Maples scale) than a delayed coker (1.52) which Jenkins characterizes as "complex." *Id.* at pp. 111-12.

1282. According to the Eight Parties, even Jenkins's choice of cost curve is inconsistent when compared to the sulfur recovery plant in his Resid calculations. *Id.* at p. 112. They note that Jenkins elected to use the cost curve in the Gary & Handwerk textbook rather than his own company's cost curve for the Resid calculations, and that, by contrast, he elected to use his company's cost curve rather than the Gary & Handwerk cost curve for the Heavy Distillate calculations. *Id.* The result, according to the Eight Parties, is a distillate hydrotreater cost that is 50% higher (using Gary & Handwerk) than it would be if the Jacobs cost curves were used. *Id.* They note that this would have resulted in a cost adjustment larger than what the Eight Parties are recommending, including the necessary logistics adjustment.[514] *Id.*

1283. More significantly, in the Eight Parties's view, if Jenkins had derived his cost for the delayed coker using a method consistent with his approach for the distillate hydrotreater, using the Jacobs Consultancy's cost curve, his Delayed Coker ISBL cost would have been virtually the same as O'Brien's. *Id.* Instead of varying his approaches to calculating ISBL costs for different process units, as Jenkins did, the Eight Parties state that O'Brien used the same approach, the Baker & O'Brien cost curves, for calculating both the delayed coker and distillate hydrotreater ISBL costs. *Id.* at p. 113 (citing Exhibit No. PAI-1 at p. 42).

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[514] The Eight Parties assert that the Exxon cost adjustment would have been even larger had Jenkins used the proper high-pressure hydrotreater. Eight Parties Reply Brief at p. 112, n.51.

1284. The Eight Parties assert that the only similarity between Jenkins's and O'Brien's approaches is their use of the same efficiently sized (50,000 barrels/day) distillate hydrotreater. *Id.* They point out that Jenkins downsized the Coker distillate hydrotreater to 8,300 barrels/stream day, and explain that this almost doubled the processing cost per barrel of throughput for Jenkins's distillate hydrotreater costs related to the Resid component compared to the distillate hydrotreating costs related to the Heavy Distillate component. *Id.* at pp. 113-14. In contrast, state the Eight Parties, O'Brien used a 50,000 barrels/day distillate hydrotreater in both instances. *Id.* at p. 114.

1285. Neither Jenkins nor Dickman, the Eight Parties argue, provide any support for their use of a less costly medium-pressure hydrotreater to desulfurize Heavy Distillate. *Id.* They point out, however, that in Jenkins's pre-filed testimony he stated that "because the Coker products contain significantly more contaminants than the virgin ANS cuts, it might be necessary to install higher-pressure units to process both the virgin material and the coker products, which in turn would result in higher capital costs for those units." *Id.* (citing Exhibit No. EMT-37 at p. 55.)

1286. Exxon frames the dispute between the parties over the ISBL capital costs as relating to whether a high-pressure distillate hydrotreater would be required or whether a lower cost, medium-pressure hydrotreater would be sufficient to reduce the sulfur level of the ANS Heavy Distillate from 0.57 wt% to the much lower 0.05 wt% sulfur level on which the agreed-upon Platts Los Angeles Pipeline Low Sulfur No. 2 Fuel Oil reference price is based. Exxon Initial Brief at p. 151.

1287. In its cost study for the distillate hydrotreater, Exxon concluded that a medium-pressure hydrotreater would be sufficient to reduce the sulfur content of the ANS Heavy Distillate. *Id.* at p. 152. Based on this conclusion, Jenkins used the cost curve data maintained by his firm, Jacobs Consultancy, to determine the capital costs for a medium-pressure distillate hydrotreater and related fixed and variable costs. *Id.*

1288. Although the Eight Parties maintain that a more expensive high-pressure hydrotreater would be employed, according to Exxon, they offered no evidence that a medium-pressure unit would not be sufficient. *Id.* Moreover, Exxon points out, the Eight Parties initial explanation that a high-pressure unit would be required due to the high nitrogen content of the ANS Heavy Distillate was shown to be irrelevant and was abandoned, because there is no nitrogen specification for the reference product. *Id.* Exxon also notes that O'Brien has never, unlike Jenkins, designed a hydrotreater, and was unable to state whether the hydrotreater at the Phillips refinery in Ferndale, Washington, on which he relied, was operated at high pressure for the purpose of sulfur processing, or for some other purpose such as aromatics reduction. *Id.*

1289. Further, Exxon argues that the Eight Parties's criticism of the use of the cost curve by Jenkins for this issue is devoid of merit. *Id.* at pp. 152-53. Exxon asserts that the evidence is clear that general cost curve data are reliable for relatively simple types of equipment, such as a distillate hydrotreater, for which the other available cost data are consistent and produce little variance or scatter. *Id.* at p. 153. Consistent with this approach, Exxon believes Jenkins's review of the "fair amount of [cost] data available about distillate hydrotreaters" and determination that they were consistent, made it reasonable to use cost curve data to estimate the ISBL costs of a virgin distillate hydrotreater.[515] *Id.* Exxon also takes issue with the Eight Parties's argument that Jenkins should not have used cost curves for the hydrotreater calculations, because he did not use them for the Delayed Coker calculations. Exxon Reply Brief at pp. 158-59. Its decision, Exxon notes, not to use cost curves for the Resid issue is justified by O'Brien's widely variable coker cost estimates. *Id.* Because this variability in cost estimates does not exist for distillate hydrotreaters, Exxon maintains, it is appropriate to use the cost curves for the heavy distillate calculations. *Id.*

1290. Exxon states that the lone argument offered by the Eight Parties that refineries today would install high-pressure hydrotreaters is based on an assumption, contained in a study by Baker & O'Brien, that hydrodesulfurization units installed after 1992 would use pressures in the higher range. Exxon Reply Brief at p. 158, n.83 (citing Exhibit No. EMT-294). According to Exxon, the study did not define what that higher range would be, nor did it define the terms high and medium pressure as they relate to hydrotreaters. *Id.* It maintains that the Eight Parties assertion that high-pressure hydrotreaters would be installed is, therefore, not supported. *Id.*

1291. There was no basis, Exxon also asserts, for the Eight Parties's criticism of Jenkins's sulfur processing cost adjustment on the ground that it was designed to produce a higher value for the Heavy Distillate cut, which the Eight Parties alleged is in Exxon's economic interest. Exxon Initial Brief at p. 153. In fact, Exxon states, Jenkins's sulfur processing cost estimate is marginally higher than the Eight Parties's, and thus results in a slightly lower value for the West Coast Heavy Distillate cut, contrary to the Eight Parties's view of Exxon's economic interest. *Id.* at pp. 153-54. Further, Exxon asserts, the Eight Parties's argument concerning Exxon's economic interest is undercut because its witness, O'Brien, used cost curve data appropriate for a medium-pressure hydrotreater even though he was purportedly estimating the cost for a high-pressure unit. Exxon Reply Brief at p. 160, n.85.

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[515] Exxon also noted that Jenkins decided not to use cost curve data to determine the cost of a Delayed Coker (*see* discussion of the value of Resid) because of the complexity of the equipment and because the high level of variance or scatter among the available cost curves demonstrated that the data were not reliable. Exxon Initial Brief at p. 153, n.66.

b. Outside Battery Limits Costs

1292. The Eight Parties assert that their approach to offsite costs is consistent. Eight Parties Initial Brief at p. 136. They added $14.36 million for necessary ancillary equipment to their ISBL cost of $49.5 million, giving them a total capital cost of $63.86 million in 1996 dollars. *Id.* According to them, O'Brien then points out that the OSBL cost estimate (29% of ISBL) is equivalent to approximately 22.5% of the total capital cost and is, according to the Gary & Handwerk textbook, within the expected range for capital additions to existing refineries. *Id.* at p. 137.

1293. The approach of Jenkins, according to the Eight Parties, is inconsistent when compared to his Resid valuation resulting in lower OSBL costs for the distillate hydrotreater and, therefore, a lower cost deduction from the product price used to value the Heavy Distillate component of the Quality Bank. *Id.* For instance, in this valuation, Jenkins uses the low end of 20% of the ISBL costs from the Gary & Handwerk textbook factor range of 20-25%, compared with the 25% he used in the Resid valuation. *Id.* According to the Eight Parties, Jenkins justifies this lower percentage by stating that the distillate hydrotreater is less complex. *Id.* However, the Eight Parties point out, the Maples textbook has a higher complexity factor (Nelson Farrar Index) for a hydrotreater than for a delayed coker. *Id.*

1294. While Exxon adds two intermediate product tanks in this cost study, the Eight Parties note, it properly added no additional feed tanks, unlike its method in the Resid study. *Id.* However, the Eight Parties characterize this as an inconsistency, because it does not comport with either the Gary & Handwerk textbook or Exxon's methodology in its Resid cost study. *Id.* The result of all of these inconsistencies, according to the Eight Parties, is that Exxon's effective OSBL costs for the distillate hydrotreater are 38% of the ISBL estimate for the distillate hydrotreater compared to 48% of the ISBL estimate for the delayed coker. *Id.* at pp. 137-38. In addition, the Eight Parties claim, while "Jenkins still follows the Gary & Handwerk non-typical industry approach of adding separately the dollar costs for steam generation, cooling water system and tanks, for the Distillate hydrotreater, the add on is *only* $10.5 million for two intermediate storage tanks versus the $57 million in add-ons before adjustments for the delayed coker."[516] *Id.* at p. 138 (emphasis in original).

1295. In their Reply Brief, the Eight Parties assert that there is no reason to include storage tank costs, because no new tanks have to be constructed and there is no evidence that any existing storage tanks for the distillate hydrotreater would have to be revamped at a Quality Bank refinery. Eight Parties Reply Brief at pp. 115-16. The Eight Parties

[516] The Eight Parties cite to Exhibit No. EMT-37 at p. 18. Eight Parties Initial Brief at p. 138.

point out that the Heavy Distillate cut already has its sulfur level reduced to meet the specification of the finished product used by the Quality Bank. *Id.* at p. 116. They note that Jenkins agreed that the existing refinery must have a distillate hydrotreater to meet the Quality Bank cut specification for Heavy Distillate, but that he stated that he did not use the Quality Bank refinery when making his assumption of what tanks existed. *Id.* Rather, explain the Eight Parties, he used a refinery with no distillate hydrotreater and then calculated the cost of adding one. *Id.* Thus, according to them, reducing the sulfur further does not change the use or size of existing intermediate product storage tanks, thereby negating any additional cost whatsoever for tanks. *Id.* Moreover, the Eight Parties argue, adding storage tank costs would be inconsistent with the cost adjustment that it is replacing. *Id.* They note that there were no storage tank costs included in the 1¢ adjustment to the old Gasoil product price. *Id.*

1296. Exxon argues that the Eight Parties err in failing to include the cost of storage in their estimate of the OSBL cost of the distillate hydrotreater. Exxon Initial Brief at p. 154. In its view, the evidence strongly supports Jenkins's position on storage costs. *Id.* Jenkins, according to Exxon, included a separate cost estimate of the storage tanks that would be required to support the distillate hydrotreater, because that is the approach recommended in the Gary & Handwerk textbook for calculating OSBL costs. *Id.* Exxon believes this is a reasonable approach because, it claims, the distillate hydrotreater would require the use of intermediate storage tanks to store the Heavy Distillate product prior to processing, and the costs of those storage tanks should be allocated to the distillate hydrotreater whether the tanks are newly built to serve the distillate hydrotreater or borrowed from storage tankage that already exists in the refinery. *Id.* at pp. 154-55. Further, it views both the storage capacity used (50,000 barrels/day capacity hydrotreater, total cost of $10.5 million, and 2 tanks with a combined capacity of 15 days's output) and the cost per barrel as reasonable in light of the Second Stillwater Report, prepared for the California Energy Commission.[517] *Id.* at p. 155.

1297. The Eight Parties, Exxon claims, did not challenge the storage cost figures; instead they omitted storage costs entirely from their calculations.[518] *Id.* Exxon contends that

[517] Exxon states that the Stillwater report used a storage cost of $31/barrel. Exxon Initial Brief at p. 155.

[518] Exxon claims that, although Boltz later disputed Jenkins's cost estimate for the storage tanks that would be required for the Delayed Coker, he did not address the reasonableness of Exxon's cost estimate for the storage tanks that would be required for the desulfurization of the Heavy Distillate. *Id.* at p. 155, n.68. In any event, Exxon notes that Boltz's testimony was based on cost estimates that did not include most of the instrumentation, piping, pumps, containment dikes, site preparation, permits, utilities, fire protection and other safety equipment that would be required for the storage tanks. *Id.*

O'Brien's failure to include any allowance for storage costs in his calculation of the OSBL costs for the Heavy Distillate hydrotreater was clearly erroneous in view of the fact that O'Brien did not dispute that the distillate hydrotreater would require the use of intermediate storage tanks to store the Heavy Distillate that comes off the distillation tower before it goes into the hydrotreater. *Id.* at pp. 155-56.

1298. Exxon also asserts that the fact that there may already be storage tanks at the refinery which could be used with the distillate hydrotreater does not justify omitting the storage costs. *Id.* at p. 156. It explains that the distillate hydrotreater would plainly require the use of storage tanks, and the costs of those storage tanks should be included in the costs allocated to that hydrotreater even if the tanks are already in existence because those tanks would have alternative uses if they were not used by the distillate hydrotreater. *Id.* Exxon points out that the costs of common facilities that are used to support a group of refinery products should be attributed to all of those products for valuation purposes. *Id.*

1299. In its Reply Brief, Exxon claims that the Eight Parties's allegations of inconsistencies in its OSBL calculations are unfounded. Exxon Reply Brief at p. 161. First, Exxon notes, the Eight Parties criticize Jenkins's decision to use an OSBL factor of 20%, rather than 25%, of ISBL costs even though that decision was justified by the fact that a hydrotreater is not as complex a unit as a Coker—a conclusion that draws support, according to Exxon, from the fact that O'Brien's firm's OSBL factor for a Coker (35%) exceeds his firm's OSBL factor for a distillate hydrotreater (29%). *Id.*

1300. Second, Exxon finds no merit to the claim that Jenkins's decision not to make any specific allowance for steam generation and/or cooling water facilities in connection with his distillate hydrotreater OSBL estimate was somehow inconsistent. *Id.* Exxon points out that this is completely justified by the fact that a distillate hydrotreater does not consume large amounts of power, cooling water, or other utilities and, therefore, a separate adjustment is not necessary. *Id.* It asserts that this observation clearly is not applicable to a Coker. *Id.* at p. 162.

1301. Third, Exxon claims that the Eight Parties's assertion that Jenkins's $10.5 million estimate of Heavy Distillate storage costs is inconsistent with Jenkins's $57 million estimate of "add-ons before adjustments for the delayed coker" is wholly disingenuous. *Id.* at n.86 (quoting Eight Parties Initial Brief at p. 138). The Eight Parties should realize, notes Exxon, that the Coker estimate included storage costs for five of the Coker distillate products (Naphtha, Distillate, Gas Oil, Propane, and Butane) as well as steam and cooling water. *Id.* By contrast, Exxon points out, the Heavy Distillate hydrotreater estimate is limited only to the two storage tanks that would be required. *Id.*

1302. Fourth, Exxon states that the Eight Parties's suggestion that Jenkins underestimated distillate hydrotreater OSBL costs to further Exxon's economic interests is particularly difficult to understand. *Id.* It notes that Jenkins's estimated distillate hydrotreater OSBL costs total $22 million; while O'Brien's estimated distillate hydrotreater OSBL costs total only $14.36 million. *Id.*

1303. Finally, Exxon asserts that the Eight Parties's claim that O'Brien's approach is somehow consistent with the approach taken in the Gary & Handwerk textbook is incorrect. *Id.* at p. 162. Contrary to O'Brien's testimony, Exxon states that the Gary & Handwerk textbook does not provide an estimate of the OSBL costs required to add process units to an existing refinery on the basis of a percentage of total capital costs. *Id.* Consequently, explains Exxon, the fact that O'Brien's OSBL estimate equals 29% of his total ISBL cost estimate merely indicates that his offsite costs percentage is somewhat higher than the percentage range in the Gary & Handwerk textbook for offsite costs not including storage costs, steam generating facility costs, or water cooling facility costs. *Id.* It does not, in Exxon's view, justify O'Brien's failure to include any costs for storage in his OSBL cost estimate. *Id.*

2. Location Factor

1304. The Eight Parties explain that a location factor is an adjustment factor used to translate a construction cost estimate developed for a specific project in a specific location (usually the U. S. Gulf Coast) to a cost estimate for the same project in a different part of the country. Eight Parties Initial Brief at p. 138. They claim that their underlying assumption is that the cost to build a similar facility will vary depending on where it is located. *Id.* The issue with respect to location factor, according to the Eight Parties, is twofold: (1) is it appropriate to apply a location factor to a cost estimate developed for a generic project location in determining the cost of the distillate hydrotreater to reduce the sulfur content of the ANS Heavy Distillate that will be subtracted from the product price used to value the Heavy Distillate of the Quality Bank; and (2) if it is appropriate to use a location factor, what location factor should be used. *Id.* at pp. 138-39.

1305. The use of a location factor, the Eight Parties argue, is not appropriate when estimating the cost of the Heavy Distillate high-pressure distillate hydrotreater for purposes of the Quality Bank, because "the Distillate hydrotreater proposed is not for a specific project defined in sufficient detail and pinned down to a specific location." *Id.* at p. 139. Instead, they recommend the use of generic cost curves. *Id.* The Eight Parties state that this is the most appropriate method when, as in this case, one is dealing with a general project with limited information. *Id.* They acknowledge that costs can be higher on the West Coast, but point out that they can sometimes be lower than on the Gulf coast as well. *Id.* at p. 140.

1306. As part of its justification for its position that a 1.3 West Coast location factor should be used when adjusting sulfur processing costs, the Eight Parties state, Exxon uses the September 11, 2000, edition of the *Engineering News Record* and its information on New Orleans, Louisiana. *Id.* The Eight Parties note that Exxon only looks at the hourly rate for common labor, which is 222% higher in New Orleans than it is on the West Coast. *Id.* They claim that it is surprising that Jenkins picked labor to compare and that he makes a big point of the large difference. *Id.*

1307. To bolster this point, the Eight Parties refer to a redacted portion of a Jacobs Consultancy report titled "Cost Structure and Employment Scheme for Operations in United States Refineries."[519] *Id.* They point out that average refinery operators's wages, which should include operators of a refinery distillate hydrotreater, for the West Coast are either 1.04 (average), or 1.02 (median), times the wages of operators on the Gulf coast. *Id.* at pp. 140-41. However, the Eight Parties note that the "California factor" that Jenkins uses in his detailed cost estimate for the Coker to convert the Gulf Coast labor dollar amount to a West Coast labor dollar amount is 1.35. *Id.* at p. 141. In addition, while he agreed that materials cost was virtually identical between New Orleans and Los Angeles, he nonetheless used a factor of 1.02 to convert Gulf Coast materials costs to West Coast materials costs in computing "coker" costs. *Id.*

1308. According to the Eight Parties, this empirical data supports their argument that, until you have a specific project, it is appropriate to use only a generic cost curve and not apply a location factor because the costs might be lower. *Id.* As all of the data is for 2000 and as Jenkins expresses his cost calculations in 2000 dollars, and as the costs for two key cost centers, operators of refinery process units (i.e., labor) and materials between a refining center on the Gulf Coast (New Orleans) and a refining center in California (Los Angeles) are almost the same, the Eight Parties argue, there appears to be no factual justification for applying a location factor of 1.3 to the capital costs for the Heavy Distillate hydrotreater. *Id.* at pp. 141-42.

1309. Another concern of the Eight Parties with respect to the use of location factors is that they are highly subjective and vary too widely among analysts for their use to be appropriate in this proceeding. *Id.* at p. 142. The Eight Parties contend that the evidence in this proceeding supports this view. *Id.* They contend that there is little consensus on what such factors should be for various areas of the country and that they differ according to the judgment of the analysts computing them even for the same area. *Id.* The Eight Parties point out that Exxon's own witness, Toof, reached the conclusion that different analysts will derive different location factors for the same locations. *Id.*

1310. The Eight Parties also note that the PRISM model (owned by O'Brien's company) shows no difference between costs for locations in California and Alaska, contrary to the

[519] *See* Exhibit No. PAI-100.

expectations of Exxon's witness, Toof.[520] *Id.* at pp. 142-43. Similarly, while Exxon's witness expected a refinery in Los Angeles, California, to cost more than a refinery in St. Louis, Missouri, the Eight Parties claim that, according to the Gary & Handwerk textbook, St. Louis has a higher location factor than Los Angeles. *Id.* at pp. 143-44. The Eight Parties argue that this demonstrates that at least some of the location factors in both the PRISM model and the Gary & Handwerk textbook were counterintuitive to what Exxon's lead witness, Toof, expected with respect to comparisons of costs involving refineries in California and other geographic locations. *Id.* at p. 144. They assert that these examples unquestionably demonstrate just how subjective location factors are and further bolster their argument that they should not be used. *Id.*

1311. Another indicator of subjectivity, according to the Eight Parties, is that Exxon's own witnesses acknowledge the fact that "you can get different location factors by different analysts." *Id.* As the Eight Parties discussed in the Resid section, Exxon's support for the use of location factors for both its Heavy Distillate cost estimate and its Resid cost estimate, is the September 11, 2000, edition of *Engineering News Record*, which provides relative cost indices for U.S. cities. *Id.* According to Exxon, data in that report shows that West Coast construction is far more costly than Gulf Coast construction. *Id.*

1312. The Eight Parties contend that a more detailed review of the *Engineering News Record* than Exxon's cursory glance at labor costs further reveals the subjectivity of location factors. *Id.* First, they point out that in the October 2, 2000, edition of *Engineering News Record*, the costs for common labor, skilled labor and materials are lower in St. Louis compared to Los Angeles, which is the exact opposite of what the Gary & Handwerk textbook shows for location factors for the two cities. *Id.* at pp. 144-45. Second, they note that Jenkins expects costs in Chicago to be lower than costs in Los Angeles, but in fact the available literature does not consistently show that to be true. *Id.* at p. 145. The Eight Parties state that comparison of costs and location factors for a Chicago and Los Angeles refinery used in *Engineering News Record* and the Gary & Handwerk textbook shows the same dichotomy of results. *Id.* In the *Engineering News Record*, Chicago has higher common labor, skilled labor and materials costs than Los Angeles, while the Gary & Handwerk textbook location factor for Chicago is less than that for Los Angeles. *Id.* The Eight Parties argue that this shows that location factors are extremely dependent on the analysts developing them. *Id.*

[520] The Eight Parties note that Baker & O'Brien did not develop the PRISM model; rather it purchased the company that developed the model. Eight Parties Initial Brief at p. 143, n.86. Even though Exxon introduced Baker & O'Brien's PRISM model to bolster its case for use of a location factor, the Eight Parties point out, Exxon's expert witness questioned its reasonableness and therefore its usefulness in this proceeding, particularly with respect to California. *Id.* (citing Transcript at pp. 3732-33).

1313. In conclusion, the Eight Parties argue that what has been introduced into the record concerning location factors shows that they are highly subjective with no consistent pattern whatsoever. *Id.* This fact, coupled with the data in the record showing that: (1) Year 2000 operator costs and materials were almost the same in New Orleans and Los Angeles, and (2) the cost of a delayed coker on the West Coast, when compared on an equivalent basis with the cost of a delayed coker on the Gulf Coast, is lower, underscores and justifies, in the opinion of the Eight Parties, the use of a generic cost curve without applying any location factor. *Id.* The Eight Parties believe this will establish a cost estimate applicable on a general basis over a large geographical area which is not to the level of detail justifying the attempt to quantify the cost on a specific location basis which is the function of a location factor. *Id.* at pp. 145-46.

1314. In the alternative, the Eight Parties argue, if a location factor is applied, it should be less than 1.30. *Id.* at p. 146. They restate their claim that the record provides no basis for use of a location factor, but assert that if one is used it cannot be the 1.3 factor Exxon favors for the processing cost estimate for the Heavy Distillate valuation. *Id.*

1315. According to the Eight Parties, there is clear evidence in the record of the subjectivity of Exxon's detailed cost estimate and any location factors stemming from it. *Id.* For example, they cite data concerning indirect factors used to calculate the cost estimates. *Id.* Also, they point out that a very slight change to the ratios of indirect dollar costs to labor costs produces a significantly larger change to the overall resulting West Coast location factor: it reduces it from 1.26 to 1.20. *Id.* at pp. 146-47.[521] The Eight Parties acknowledge that the record shows Exxon does not agree with the premise behind this change, however, they point out that Exxon concedes that the change in independent variable does produce the cited change in the location factor. *Id.* at p. 147. They further argue that the West Coast location factor reasonably could be as low as 1.19 depending on exactly how one defines "West Coast." *Id.* The Eight Parties arrive at this figure by averaging the numbers from the PRISM model for Portland, Seattle, Los Angeles, San Francisco, and the inland California refineries.[522] *Id.*

1316. However, the Eight Parties argue that even the 1.20 figure for a location factor is likely high. *Id.* They point out that, because Jenkins's calculations effectively assume a Los Angeles location for the Delayed Coker, the corrected 1.20 is not reflective of the West Coast, but rather only California (hence Jenkins refers to the numbers as "California factors.") *Id.* Because the PRISM model shows that Los Angeles costs are higher than Seattle and Portland costs, they argue that a further (equally weighted) averaging could

[521] S*ee also* Exhibit Nos. WAP-80, WAP-81, WAP-83.

[522] S*ee also* Exhibit No. EMT-208.

be done using the 1.20 calculated number, and the PRISM 1.20 for Seattle and 1.08 for Portland, the result of which is 1.16. *Id.* at pp. 147-48. Moreover, the Eight Parties argue that the *Engineering News Record* 2000 materials comparison and the Jacobs Consultancy 2000 operators's compensation comparison also support there being no location factor applied. *Id.* at p. 148.

1317. What all of the above demonstrates, according to the Eight Parties, is the subjectivity of using location factors and how they are affected by simply changing one number. *Id.* Using the 1.3 location factor changes the capital cost number by 30%, they claim, if Exxon's approach is adopted. *Id.* The Eight Parties maintain there has been no showing that such a result is reasonable. *Id.* Indeed, they assert, the exact opposite has been shown by the empirical data related to the Shell Martinez West Coast Refinery and the Shell Deer Park Gulf Refinery that show, on a barrels/day basis, the cost of a Gulf Coast delayed coker project was higher than the cost of a delayed coker on the West Coast. *Id.*

1318. In conclusion, the Eight Parties do not advocate that any location factor be applied to O'Brien's processing costs. Eight Parties Reply Brief at p. 116. They maintain that it would be inconsistent to apply a location factor to O'Brien's Resid costs, but not to his Heavy Distillate processing costs. *Id.* The Eight Parties assert that they have demonstrated that application of any location factor to any calculations related to the Quality Bank would be subjective, unsupported by the empirical evidence, unreliable, and, hence, would result in skewed cost figures. *Id.* at pp. 116-17.

1319. By contrast, Exxon insists, it is the Eight Parties's cost estimate for the distillate hydrotreater that is deficient in that, although purporting to estimate the cost of constructing and operating such a unit on the West Coast, they failed to make any adjustment to the Gulf Coast costs used in the cost estimate to reflect higher West Coast costs. Exxon Initial Brief at p. 156. For this reason, Exxon asserts Jenkins's sulfur processing cost adjustment is clearly more reasonable than the Eight Parties's sulfur processing adjustment, because Jenkins used an appropriate West Coast location factor to reflect the higher West Coast costs. *Id.* at pp. 156-57.

1320. Exxon argues that failing to account for the higher West Coast costs is unreasonable, because the reference price for Heavy Distillate, at issue here, is a West Coast price. *Id.* at p. 157. It asserts that it is beyond reasonable dispute that construction costs, including labor costs, environmental costs, and regulatory costs, are significantly higher on the West Coast than they are on the Gulf Coast. *Id.* In support of this assertion, Exxon states that it introduced evidence that a West Coast location factor of 1.3 is both conservative and well supported by industry standards, by the Gary & Handwerk textbook, and even by a study prepared by O'Brien's own firm. *Id.* For this reason, Exxon recommends that the proper method is to first determine the cost of constructing a medium-pressure distillate hydrotreater on the Gulf Coast and then apply a location factor of 1.3 to adjust the cost estimate for the higher costs that would be incurred on the West Coast. *Id.*

1321. In sharp contrast to its recommended approach, Exxon points out, the Eight Parties failed to adjust their Gulf Coast sulfur processing cost estimate to reflect the higher level of costs found on the West Coast, even though O'Brien admitted that he was using Gulf Coast costs to estimate the sulfur processing cost adjustment that would be applied to the West Coast reference price. *Id.* at pp. 157-58. In the opinion of Exxon, this failure results in a significant understatement of the costs to be applied to the West Coast reference price. *Id.* at p. 158.

1322. Further, Exxon notes that, even though the Eight Parties claim that O'Brien's cost curves are generic, they are not. Exxon Reply Brief at p. 164. Exxon explains that the cost curves are clearly based on Gulf Coast construction costs. *Id.* It argues that, in view of O'Brien's admission that costs are significantly higher on the West Coast and the fact that both the Gary & Handwerk textbook and O'Brien's own company[523] employ location factors in doing similar cost estimates, the record evidence clearly shows that the Eight Parties's failure to adjust their Gulf Coast costs for the higher level of West Coast costs was an indefensible departure from standard industry practice. Exxon Initial Brief at p. 158.

1323. Exxon emphasizes that Issue No. 2 addresses the level of the sulfur processing cost adjustment to be applied to the West Coast reference price to determine the net value of the Heavy Distillate cut on the West Coast.[524] *Id.* It necessarily follows, in Exxon's view, that West Coast costs must be used to determine the level of the sulfur processing cost adjustment rather than Gulf Coast costs.[525] *Id.* at pp. 158-59. This is especially true,

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[523] Exxon notes that, in a study for the American Petroleum Institute, Baker & O'Brien applied location factors to their cost curve estimates to derive the ISBL costs of distillate hydrotreaters at various locations throughout the country. Exxon Initial Brief at p. 161 (citing Exhibit Nos. EMT-82, EMT-208; Transcript at pp. 238-39, 2106-08). Similarly, it asserts that the evidence shows that the PRISM database (formerly known as the Vector database) that is marketed by Baker & O'Brien assigns location factors ranging from 1.08 for Washington and Oregon to 1.35 for most California locations. *Id.* Exxon suggests that the Eight Parties's attempts to distance themselves from the use of the PRISM is unsuccessful in view of their expert's continued use and advertisement of this software package. Exxon Reply Brief at p. 166, n.88.

[524] *Trans Alaska Pipeline System*, 97 FERC at pp. 61,650, 61,652.

[525] In fact, Exxon points out, the Eight Parties's expert has indicated that he recognized this need when he used California natural gas prices in estimating fuel costs for both the Coker and the distillate hydrotreater. Exxon Initial Brief at p. 159, at n.69

according to Exxon because, it asserts, there is no dispute that plant location can have "a significant influence" on costs. *Id.* at p. 159. For this reason, Exxon's position is that it is essential that a location factor be used to reflect regional cost differences when estimating costs applicable to a particular location like the West Coast. *Id.*

1324. There is also no dispute, according to Exxon, that construction costs, labor costs, and permitting costs are widely known in the industry to be significantly higher on the West Coast than on the Gulf Coast. *Id.* In particular, it contends that the evidence supports the conclusion that construction costs are from 20% to 40% higher on the West Coast than they are on the Gulf Coast. *Id.* at p. 160.

1325. Further, Exxon presents what it considers undisputed evidence that use of location factors when doing cost studies (including studies based on cost curves) is an appropriate and well-established industry practice. *Id.* For example, it points out that the Gary & Handwerk textbook gives a location adjustment of 1.4 for Los Angeles and 1.2 for Portland and Seattle,[526] for an average West Coast location factor of 1.3. *Id.* at pp. 163-64. Similarly, it cites a National Petroleum Council-commissioned study by Bechtel[527] which estimated that, in 1992, the cost to build a unit on the West Coast would be 20% higher than on the Gulf Coast and that differences in building codes, environmental rules, and other design parameters would add another 20%, for a total California factor of 1.4. *Id.* at p. 164. Lastly, Exxon cites the August 2000 study for the American Petroleum Institute, prepared jointly by Charles River Associates and O'Brien's firm, Baker and O'Brien, which used a West Coast location factor in the range of 1.4 to 1.5.[528] *Id.* The undisputed evidence relating to location factors for use in the petroleum industry clearly shows, in Exxon's opinion, that its use of 1.3 as a West Coast location factor is both appropriate and conservative. *Id.*

1326. Exxon also states that O'Brien conceded that there is no authority at all supporting his position that a location factor should not be used in preparing cost estimates. Exxon Initial Brief at p. 161. O'Brien's contention, according to Exxon, that it is too early in the cost estimating process to use a location factor is not credible and is plainly wrong.[529] *Id.* All of the information required for the application of a location factor is clearly available,

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(citing Exhibit Nos. PAI-12, n.2, PAI-19, n.1).

[526] Exhibit No. EMT-169 at p. 6.

[527] Exhibit Nos. EMT-87, EMT-295.

[528] Exhibit No. EMT-82.

[529] S*ee* Exhibit No. PAI-42 at p. 20.

Exxon suggests. *Id.* It argues that, in the circumstances presented here, "any credible analyst," including one using a cost curve, would use a location factor to reflect the higher expected cost of the project on the West Coast. *Id.* at pp. 161-62.

1327. In Exxon's opinion, there also is no valid basis for the Eight Parties's attempt to confuse a West Coast location factor with site preparation costs. *Id.* at p. 162. "Site preparation costs [are the] costs associated with getting a site prepared to build on," Exxon states, such as terracing a hilly site to have flat land on which to build. *Id.* It contends that site preparation costs are specific to a particular site, and involve costs that are separate and apart from the location costs that are addressed by the geographic location factors used by its expert. *Id.* Neither party's expert included site preparation costs in their respective cost estimates. *Id.* Instead, because Jenkins assumed that the distillate hydrotreater would be added to an existing refinery, he assumed that the refinery site would already have been prepared and that no further site preparation costs would be required. *Id.* Exxon agrees with this approach. *Id.*

1328. Nor does the mere hypothetical possibility that some costs might be lower on the West Coast – a possibility that Exxon finds is wholly lacking in evidentiary support – provide any justification, in Exxon's view, for the failure to apply an appropriate West Coast location factor to reflect the undisputed fact that West Coast costs are generally higher than Gulf Coast costs. *Id.* Although the Eight Parties suggested that a refinery built on swampy ground in the Mississippi River Delta of Louisiana might be particularly costly to construct, Exxon notes they provided no evidence to support this claim. *Id.* at pp. 162-63. Further, Exxon suggests, neither the PRISM database of O'Brien's own firm, nor any other source of location factors, makes any distinction between different Gulf Coast locations based on the nature of the terrain involved. *Id.* at p. 163. Moreover, as discussed above, Exxon argues that any such additional costs would be included in site preparation costs and would not be part of the location factor. *Id.*

1329. Furthermore, Exxon maintains, the evidence is overwhelming that a location factor should be used in connection with a study using a cost curve. Exxon Reply Brief at p. 165. For example, Exxon notes, the Gary & Handwerk textbook specifically states that "[t]he cost curve method of estimating, if carefully used and properly adjusted for local construction conditions, can predict costs within 25%." *Id.* (quoting Exhibit No. EMT-169 at p. 3). Exxon asserts that the accepted method, when making a cost curve estimate, is to estimate costs as accurately as possible, including ISBL and OSBL, and then multiple the total by a location factor. *Id.*

1330. Exxon argues that this conclusion is also confirmed by other, more general, materials relating to construction and building costs for different locations. Exxon Initial Brief at p. 164. For example it cites the September 11, 2000, edition of *Engineering News Record* which provides relative cost indices applicable to all types of construction and buildings for U.S. cities, including New Orleans where numerous Gulf Coast refineries are located. *Id.* These data show, according to Exxon, that West Coast construction costs are from 139% to 222% higher than Gulf Coast construction costs.[530] *Id.* at pp. 164-65. Exxon cites a similar study by the R.S. Means Company, which it claims shows that general construction cost location factors are approximately 1.3 for Los Angeles, and between 1.25 and 1.29 overall for the whole West Coast.[531] *Id.* at 165. The location factor for Gulf Coast cities that have refining capacity was set at 1.0 in this study, according to Exxon. *Id.*

1331. The Eight Parties, Exxon asserts, make a number of unsuccessful arguments that attempt to cast doubt on the use of a West Coast location factor. Exxon Reply Brief at p. 167 (citing Eight Parties Initial Brief at pp. 140-46). For example, notes Exxon, the Eight Parties claim that Exxon's witness, Jenkins, detailed Coker capital cost estimate used a labor cost that was much higher than the West Coast data contained in a report by Jacobs Consultancy. *Id.* at pp. 167-68 (citing Eight Parties Initial Brief at pp. 140-41). Exxon asserts that this criticism is wholly misplaced, in that the Jacobs Consultancy report plainly addresses labor costs involving refinery operations, not labor costs related to refinery construction. *Id.* at p. 168. (citing Exhibit No. PAI-100 at p. 2).[532] It notes that O'Brien recognized this significant difference when he agreed[533] that Exhibit No. PAI-100's costs related to operators, and not construction laborers. *Id.*

1332. Exxon also states that the Eight Parties's reliance on data contained in an October 4, 2000, issue of *Engineering News Record*, which indicated that the cost of materials in New Orleans and Los Angeles were almost the same, also misses the mark. *Id.* Contrary to the Eight Parties's claim, Exxon maintains, this information does not call into question or cast doubt on Jenkins's use of a 1.02 location adjustment with respect to such costs in his detailed Coker cost estimate. *Id.* Exxon expresses surprise that the Eight Parties would focus on an adjustment of 2/100ths and asserts that that adjustment was inconsistent with an observation that material costs were almost the same on the two Coasts. *Id.* at pp. 168-69. Further, Exxon states, it was not material that had the most

[530] In point of fact, the September 11, 2000, ENR shows a 180% differential for Construction Costs, a 139% differential for Building Costs, a 222% differential for Common Labor, a 178% differential for Skilled Labor, and a 99% differential for Materials. Exhibit No. EMT-41.

[531] Exhibit Nos. EMT-296, WAP-80.

[532] Exxon notes that such costs were covered in Jenkins's fixed operating cost estimates, not his construction cost estimate which is the subject of the Eight Parties's criticism. Exxon Reply Brief at p. 168, n.90.

[533] Transcript at p. 1269.

impact on Jenkins's location factors; rather, it was differences in construction labor costs, building costs, and permitting costs. *Id.* at p. 169. Ironically, according to Exxon, the *Engineering News Record* data on which the Eight Parties's rely in mounting this particular criticism help to establish this point. *Id.*

1333. The Eight Parties's use, according to Exxon, of St. Louis, Alaska, and Chicago to support their point that location factors are subjective and have no consistent pattern is misleading. *Id.* It notes that, as with Resid, comparisons involving St. Louis, Chicago, or Alaska say nothing about Gulf Coast versus West Coast costs and are intended only to distract the Commission from the key issue of whether O'Brien's cost curves—which use primarily Gulf Coast data—should be adjusted to reflect higher West Coast costs. *Id.*

1334. Exxon argues that the Eight Parties present no foundation for their assertion that the 1.3 location factor is too high. *Id.* at p. 171. For example, explains Exxon, the Eight Parties give no justification for their proposal to calculate an equal weighted average of the location factors in the PRISM model for Portland (1.08), Seattle (1.20) and California (1.35), to arrive at a West Coast location factor of 1.21. *Id.* (citing Eight Parties Initial Brief at p. 147).[534] Exxon asserts that no justification exists and recommends a weighted average, producing a location factor of approximately 1.3, which accounts for relative refining capacity.[535] *Id.*

1335. The Eight Parties's suggestion that inland California refineries should be included in the California location factor also is wrong, Exxon declares. *Id.* at p. 172. In addition to the fact that the three inland refineries have a combined capacity of approximately 10% and would thus have a minimum effect on the calculations, Exxon claims, including them would be inconsistent with the fact that the agreed upon Heavy Distillate reference price is a Los Angeles assessment. *Id.* (citing Exhibit No. WAP-96 at pp. 7-9). Additionally, Exxon points out, Fuel Gas costs, which are an important component of the

[534] Exxon points out that the 2000 EIA data contained in Exhibit No. WAP-96 shows that there is only one refinery in the entire state of Oregon, the Chevron Willbridge plant in Portland, which has no Coker and has a total vacuum distillation capacity of only 12,000 barrels/stream day. Exxon Reply Brief at p. 171, n.92 (citing Exhibit No. WAP-96 at p. 15). By contrast, explains Exxon, California contains over 20 refineries with a total crude capacity of over 2,000,000 barrels/stream day and vacuum distillation capacity of 1,162,900 barrels/stream day. *Id.* (citing Exhibit No. WAP-96 at pp. 7-9).

[535] Exxon points out that the Eight Parties weighted average of 1.16 included only the California location factors and the straight averages for Seattle and Portland. Exxon Reply Brief at p. 171, n.93. According to Exxon, a valid weighted average would have to include, as Jenkins did, all refineries on a total capacity basis, not merely the refineries in California. *Id.*

cost of operating a distillate hydrotreater, are also Los Angeles based. *Id.*

1336. Exxon asserts that all of the industry studies in the record, in addition to the testimony of Jenkins, Gary, Dickman, and Toof, demonstrate that a 1.3 West Coast location factor constitutes an appropriate and conservative adjustment.[536] *Id.* Consequently, Exxon states that the Eight Parties present no grounds for correcting Jenkins's indirect costs factor, or for utilizing a location factor of less than 1.3. *Id.*

3. Operating Costs

1337. The Eight Parties view the major difference in operating costs between the parties's experts as being the amount of hydrogen[537] that each expert assumes is required to hydrotreat Heavy Distillate. Eight Parties Initial Brief at p. 148. They state that O'Brien assumed that 250 cubic feet of hydrogen is required to process one barrel of Heavy Distillate, while Jenkins assumed that 180 cubic feet/barrel was necessary. *Id.* According to them, this difference works out to 0.3¢/gallon in the total processing cost calculation. *Id.*

1338. Exxon's hydrogen consumption value used in calculating sulfur treating costs, the Eight Parties contend, was inconsistent with estimates contained in the Maples and the Gary & Handwerk texts. *Id.* Even though Exxon stated that its calculation was based on the specific qualities of ANS Heavy Distillate and is, therefore, more reliable than the textbooks's estimate, it became evident during the hearing, in the Eight Parties's view, that this was not entirely true. *Id.* at 148-49.[538]

1339. The Eight Parties argue that the discrepancy is related to the value of "solution loss" used in the hydrogen consumption calculation. *Id.* at p. 149. According to them, the record shows that Exxon based this solution loss value not on ANS Heavy Distillate, but on its expert's experience with a completely different technology from 1980. *Id.* This solution loss value is much lower than that suggested by either the Gary & Handwerk textbook or that used by the Eight Parties, according to them. *Id.* at p. 149.

1340. If either the Gary & Handwerk or Eight Parties's value for solution loss is used in Exxon's calculations for hydrogen consumption, according to the Eight Parties, then the

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[536] Exxon cites: Transcript at pp. 2097-98, 2745; Exhibit Nos. EMT-37 at p. 14-15, EMT-116 at p. 8, EMT-118 at p. 20, EMT-76 at p. 22 – 23.

[537] In their brief, the Eight Parties actually stated "the amount of sulfur," Eight Parties Initial Brief at p. 148. However, I am sure they meant "hydrogen."

[538] *See also* Exhibit No. EMT-166.

resulting value for hydrogen consumption is even higher than the value initially calculated by the Eight Parties themselves. *Id.* The Eight Parties point out that this result was acknowledged by Exxon's expert during the hearing. *Id.*

1341. Thus, even were Jenkins's calculations based on the qualities of ANS Heavy Distillate correct, the Eight Parties assert, this does not completely answer the question of which hydrogen consumption estimate is correct. *Id.* at p. 150. The answer to that question depends on the validity of Jenkins's solution loss estimate, they state. *Id.* The Eight Parties frame the Commission's choice as follows: accept either (1) Jenkins's estimate based on his experience in 1980 with a project that is not a Heavy Distillate hydrotreater, or (2) the higher estimates from the Gary & Handwerk and Maples texts that do relate specifically to Heavy Distillate hydrotreaters. *Id.* The Eight Parties argue that choice two is clearly the correct one, because the texts are written by disinterested third parties based on their industry experience with the exact equipment that is at issue here. *Id.* They conclude that the textbooks support O'Brien's assumption, which should be adopted. *Id.*

1342. Further, the Eight Parties believe that Exxon's reference to a graph contained in a study jointly performed by Charles River Associates and Baker & O'Brien leaves the Commission with conflicting authorities regarding hydrogen consumption. Eight Parties Reply Brief at p. 117. It is the Eight Parties's position that the Commission should accept the consumption estimates from the texts cited by the Eight Parties in their Initial Brief. *Id.* According to the Eight Parties, this is appropriate because those texts have been used by both parties for a number of issues in this proceeding, and because the study that Exxon uses[539] was presented with no opportunity for discovery or cross-examination of Jenkins's testimony regarding the study. *Id.* at pp. 117-18. The Eight Parties do not assert that it was improper for Exxon to have presented Exhibit No. EMT-294 on redirect examination, only that this study was not subjected to the same scrutiny as other evidence and, therefore, should carry less weight. *Id.* at p. 118.

1343. Exxon agrees that the amount of hydrogen required for hydrotreating is the area of contention with respect to the level of the sulfur processing cost adjustment and advocates for the hydrogen consumption figure presented by its expert, Jenkins. Exxon Initial Brief at p. 165. According to it, the evidence shows that "a key objective of hydrotreating for sulfur removal is to minimize hydrogen consumption while achieving the desired sulfur reduction." *Id.* Exxon explains that O'Brien assumed that 250 standard cubic feet of hydrogen would be consumed per barrel of ANS Heavy Distillate processed; while Jenkins estimated the hydrogen consumption at 180 standard cubic feet/barrel. *Id.* at pp. 165-66. It notes that both Jenkins and O'Brien testified that their respective estimates of hydrogen consumption were correct. *Id.* at p. 166.

[539] Exhibit No. EMT-294.

1344. In the view of Exxon, however, the evidence shows that its expert's estimate of hydrogen consumption was reasonably based on the specific properties of the ANS Heavy Distillate cut being valued. *Id.* Exxon claims that Jenkins made his calculation on the basis of chemical reactions that take place in a distillate hydrotreater, and that he provided exhibits which showed the basis for his estimate of hydrogen consumption. *Id.* Exxon also believes in the reasonableness of Jenkins's estimate of hydrogen consumption, because it is supported by a study by Charles River Associates and O'Brien's firm. *Id.* That study estimated hydrogen consumption for a distillate with a sulfur content similar to ANS Heavy Distillate in the range of 160 to 170 standard cubic feet/barrel – much closer to Jenkins's estimate of 180 standard cubic feet/barrel than to O'Brien's estimate of 250 standard cubic feet/barrel. *Id.*

1345. According to Exxon, the reason the parties's estimates of hydrogen consumption differ is because of the difference in the parties's assumptions regarding the pressure of the distillate hydrotreater rather than the value of solution loss used. *Id.* at p. 166. Exxon asserts that, as hydrotreater pressure goes up, the amount of hydrogen used also goes up. *Id.* at pp. 166-67. It points out that, if it had used the same high-pressure hydrotreater that the Eight Parties used, its hydrogen consumption estimate would have been even higher than the Eight Parties's estimate. *Id.* at p. 167.

1346. Exxon also points out that Jenkins's testimony on solution loss was in fact based on both the qualities of the ANS cut and his personal experience and not just his personal experience as the Eight Parties allege. Exxon Reply Brief at pp. 174-75 (citing Eight Parties Initial Brief at p. 149). It asserts that solution loss, and hence the amount of hydrogen consumed, is determined by the hydrotreater pressure one assumes. *Id.* Further, Exxon explains, Jenkins's choice of a medium-pressure hydrotreater is reasonable in this case, because it was based on the qualities of the ANS Heavy Distillate cut. *Id.* Therefore, according to Exxon, there is no basis in the record for postulating different values of solution loss from either the Gary & Handwerk or Maples texts as the Eight Parties advocate (Eight Parties Initial Brief at p. 149) in order to arrive at a higher value for hydrogen consumption. Exxon Reply Brief at pp. 174-75. Because it is the pressure of the hydrotreater that drives solution loss and hydrogen consumption, and not the other way around, Exxon asserts, one cannot use either the Gary & Handwerk or Maples solution loss figures accurately without knowing how they were derived. *Id.* at pp. 175-76. Exxon also argues that the fact that no witness supported such high rates of solution loss also casts doubt on the reasonableness of relying on these figures in the context of this case. *Id.* at p. 176.

1347. Finally, Exxon notes, O'Brien provided no evidentiary support for his calculation of either solution loss or hydrogen consumption. *Id.* In addition, Exxon points out, O'Brien acknowledged that he has never designed a distillate hydrotreater. *Id.* Jenkins, according to Exxon, had such experience and in the context of this case made specific hydrogen consumption calculations based on the facts of this case. *Id.*

D. LOGISTICS ADJUSTMENT

1348. In addition to the desulfurization costs, the Eight Parties advocate a "logistics adjustment" to bring the Heavy Distillate reference price onto a consistent basis with all of the other liquid Quality Bank cuts. Eight Parties Initial Brief at p. 150. The Eight Parties recommended adjustment, derived using a cost-based measure, is 1.1¢/gallon. *Id.* This adjustment is based on the cost of transporting product from harbor to pipeline, and the Eight Parties advocate its deduction from the Los Angeles Pipeline No. 2 price after the sulfur processing costs described by O'Brien are deducted. *Id.* The Eight Parties argue that consistent valuation of the Quality Bank cuts is essential in order to achieve a just and reasonable valuation methodology. *Id.* In order to achieve this consistency, the Eight Parties believe it is important to value all of the liquid Quality Bank cuts at a common location where each of them is currently or proposed to be valued - on a waterborne basis. *Id.* They argue that their proposed 1.1¢/gallon logistics adjustment to the Heavy Distillate reference price will do that. *Id.*

1349. It cannot be disputed, the Eight Parties contend, that consistency within the Quality Bank is a goal which all parties to this proceeding and the Commission have sought to achieve. *Id.* at p. 151. Baumol, Exxon's witness, they assert, stated that "[a]ll parties agree, as logic dictates, that to achieve the purpose of the Quality Bank the valuation of each of the component cuts, including the Resid cut and the Coker products into which the Resid cut is processed, should therefore be carried out on a comparable basis." *Id.* (citing Exhibit No. EMT-66 at p. 10). Further, the Eight Parties note that the Circuit Court has stated that "the [Commission] must accurately value all cuts - not merely some or most of them - or it must overvalue or undervalue all cuts to approximately the same degree." *Id.* (quoting *Oxy*, 64 F.3d at p. 693).

1350. The Eight Parties believe that, should the Commission adopt their proposal, every liquid product on both coasts will be valued on a consistent waterborne basis. *Id.* They argue that waterborne prices are the most appropriate and consistent basis for valuing liquid products, because they represent cargoes or barges at their source or destination harbor. *Id.* As such, they are generally the largest parcels available and include the least marketing margins. *Id.* Thus, the Eight Parties contend, the most desirable consistency can be achieved by deducting logistics costs (in addition to desulfurization costs) from the Heavy Distillate reference price to bring it to a consistent valuation basis with the other liquid cuts - waterborne. *Id.*

1351. Their proposed logistics adjustment, the Eight Parties argue, represents the average of costs incurred in transporting product inland to the pipeline from its arrival point at the harbor. *Id.* at p. 152. With such inland movement to the pipeline, the Eight Parties suggest, value is added as a result of the logistics costs of moving the product from waterborne status to the pipeline terminal. *Id.* This allows it, they contend, to command a higher price than waterborne deliveries. *Id.* The Eight Parties argue that this logistics related transportation cost must be deducted to bring the value of the product back to a consistent waterborne location, because the Los Angeles product primarily flows from the harbor to the pipeline. *Id.*

1352. The average, over time, for all of these transportation costs ranges from 1.04¢ to 2.09¢/gallon.[540] *Id.* at p. 153. To determine what costs are actually incurred in the marketplace, the Eight Parties suggest the use of a value calculated on behalf of BP.[541] *Id.* Thus, calculating the cost for transporting Waterborne Low Sulfur Gasoil to the pipeline is a proper calculation, according to them, to ascertain the differential between these waterborne and pipeline prices. *Id.* As further support for the market-realized transportation costs, the Eight Parties also cite waterborne/pipeline differentials in reported prices for the similarly situated products of regular gasoline and jet fuel. *Id.*

1353. The Eight Parties argue that each of the three waterborne/pipeline differentials supports their 1.1¢/gallon proposed logistics adjustment. *Id.* Specifically, they point out that the annual average difference between Waterborne Low Sulfur Gasoil and Los Angeles Pipeline No. 2 shows that the waterborne price is almost precisely 1.1¢/gallon less than the pipeline price. *Id.* at pp. 153-54. Further, they argue that, from 1997 through 2001, the waterborne/pipeline differential for regular gasoline totaled 1.23¢/gallon and for jet fuel totaled 0.95¢/gallon. *Id.* at p. 154. The close match of the differentials for regular gasoline and jet fuel as compared to the differential between West Coast Waterborne Low Sulfur Gasoil and LA Pipeline No. 2 is cited by the Eight Parties as strong support for their proposed 1.1¢/gallon logistics adjustment. *Id.*

1354. In addition to the price differentials cited above, the Eight Parties argue that statistical tests support their contention that there is a statistically significant differential between West Coast Waterborne Low Sulfur Gasoil and Los Angeles Pipeline No. 2 and that the differential is consistent with the proposed logistics adjustment of 1.1¢/gallon.[542]

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[540] The Eight Parties list the costs incurred in transporting product to the pipeline from the harbor as: cargo inspection, dock and wharf fees, terminal charges and pipeline tariff charges. Eight Parties Initial Brief at p. 153.

[541] According to the Eight Parties, this value is the actual observed waterborne/pipeline differentials between West Coast Waterborne Low Sulfur Gasoil and LA Pipeline No. 2. *Id.* While these two products are not identical, the Eight Parties cite Platts and state that it specifically stated that they are considered interchangeable. *Id.* The value was calculated by Ross, whose testimony is sponsored by BP, and supported by the Eight Parties. *Id.*

[542] These statistical tests were conducted by Cavanagh whose testimony was

Id. The Eight Parties argue that the statistical tests Cavanagh performed properly led him to conclude that, in each of these cases, the hypothesis that there is no systematic difference must be rejected in favor of the hypothesis that pipeline prices are systematically and statistically significantly higher than waterborne prices.[543] *Id.* at p. 156. They claim that these tests show that the observed differences cannot be explained as occurring through random chance and that there is no close relationship in time that would account for the differences. *Id.* at pp. 154-56.

1355. The Eight Parties go on to take exception with Exxon's challenges to the proposed logistics adjustment. *Id.* at p. 156. They present five reasons why Exxon's challenges should be found unavailing: (1) the logistics adjustment is clearly within the scope of the proceedings, (2) consistency is a factor utilized in valuing the various Quality Bank cuts, (3) the predominate flow of West Coast Waterborne Low Sulfur Gasoil is from harbor to pipeline, (4) the proposed logistics adjustment is sound and grounded in fact, and (5) there are consistent price differentials between West Coast and Gulf Coast products. *Id.* at pp. 156-58; Eight Parties Reply Brief at pp. 118-19.

1356. First, the Eight Parties state that the proposed logistics adjustment is clearly within the scope of these proceedings. Eight Parties Reply Brief at p. 119. They assert that the logistics adjustment was fully briefed by Exxon and the Eight Parties beginning in February of 2002; it was the subject of several rounds of discovery; it was included in opening statements; and it was the subject of several witnesses's testimony during the

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sponsored by BP and supported by the Eight Parties. Eight Parties Initial Brief at p. 154. The Eight Parties state that Cavanagh first showed that there is a high correlation between waterborne and pipeline prices, indicating the samples are highly interdependent. *Id.* at p. 155. Then, the Eight Parties state, because the samples are interdependent, he used a matched pairs t-test to show that there is a systematic difference between pipeline and waterborne prices. *Id.* Finally, the Eight Parties note, Cavanagh also performed the same waterborne/pipeline comparison for regular gasoline and jet fuel. *Id.* at pp. 154-55.

[543] The Eight Parties explain that using the matched pairs t-test, Cavanagh computed t-statistics as follows: (1) 14.27 for jet fuel; (2) 11.86 for gasoline; and (3) 9.95 for West Coast Waterborne Low Sulfur Gasoil versus Los Angeles Pipeline No. 2. Eight Parties Initial Brief at p. 155. They also explain that, to interpret these statistics, Cavanagh computed the corresponding p-values. *Id.* (A p-value is the "probability that we would observe, by chance, a statistic at least as large as that which we actually observe if there were no systematic difference between the waterborne and pipeline prices." Exhibit No. BPX-60 at p. 12.) According to the Eight Parties, small p-values indicate that the observed differences are much larger than one would observe by pure chance. Eight Parties Initial Brief at p. 155. Here, the Eight Parties note, the p-values for each of the three relationships discussed above are less than one in one billion. *Id.*

hearing. *Id.* Yet, note the Eight Parties, Exxon never moved to strike the testimony, never objected to the opening statement, and never sought to exclude testimony or evidence on the grounds that it was outside the scope of these proceedings. *Id.* The Eight Parties point out that Exxon has, in fact, submitted testimony on this issue at every stage of these proceedings. *Id.* They argue that Exxon's failure to object until now on these grounds, and its decision to present testimony on the proposed logistics adjustment, should be fatal to Exxon's argument.[544] *Id.* at pp. 119-20. In arguing that the logistics adjustment issue is not within the scope of these proceedings, the Eight Parties maintain, Exxon ignores the fact that neither the Commission nor the Circuit Court has ever ruled as to what is properly considered part of the adjustment to be made to West Coast LA Pipeline No. 2 in order to arrive at a just and reasonable reference price for the Heavy Distillate cut. *Id.* at p. 120.

1357. The Eight Parties explain that, because they proposed that the new Heavy Distillate reference price be adjusted for desulfurization and logistics (i.e., transportation) costs and this issue was included in the issues set for hearing in this proceeding, that all of the issues raised in the Eight Parties's contested settlement, including both the proposed desulfurization and logistics adjustments to the Heavy Distillate reference price, are properly before the Commission and properly within the scope of these proceedings. *Id.* at pp. 120-21. Further, the Eight Parties argue that is true even though the Commission used the term "processing costs" in its order consolidating these proceedings, the Commission did not completely define the scope of that term and, therefore, it would be inappropriate to exclude the proposed logistics adjustment from consideration. *Id.* at p. 121.

1358. Second, the Eight Parties disagree with Exxon's assessment that there is no consistency utilized in valuing the various Quality Bank cuts. Eight Parties Initial Brief at p. 156. As set forth in the discussion regarding coke value, the Eight Parties aver that a consistency does exist. *Id.* According to them, all four gas plant products are valued on a pipeline basis on the Gulf Coast and on a truck/rail basis on the West Coast. *Id.* Accordingly, all of the gas plant products are consistently valued on each coast using the largest parcel sizes available. *Id.* As for the liquid products, the Eight Parties argue, all five Gulf Coast liquid products are consistently valued on a waterborne basis. *Id.* at pp. 156-57. Additionally, on the West Coast, they point out that Naphtha, Light Distillate and VGO are currently valued on a waterborne basis. *Id.* at p. 157. Further, the Eight Parties propose that the remaining two West Coast liquid cuts, Heavy Distillate and Resid, be valued on a waterborne basis. *Id.*

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[544] In support, the Eight Parties cite *City of Alma, Michigan*, 97 FERC ¶ 61,147, at p. 61,639 (2001); *Jupiter Energy Corp.*, 41 FERC ¶ 63,008, at p. 65,013 (1987). Eight Parties Reply Brief at p. 119.

1359. Third, the Eight Parties argue, Exxon's witness, Pavlovic, attempted to obscure the fact that the predominate flow of West Coast Waterborne Low Sulfur Gasoil is from harbor to pipeline by focusing on the movement of all petroleum products across the West Coast in addition to discussing refinery production data and product movement. *Id.* In fact, in the Eight Parties's view, most of this product movement is irrelevant and their witness, Ross, properly focused his analysis on whether the proposed logistics adjustment captures the cost associated with moving West Coast Waterborne Low Sulfur Gasoil from the harbor to the pipeline hub. *Id.*

1360. Exxon's argument related to product flow is, in the Eight Parties's view, pointed in the wrong direction, and they maintain that Exxon continues its attempts to obscure the facts by focusing on the predominance of all products moving from refineries to pipeline terminals on the West Coast. Eight Parties Reply Brief at p. 123 (citing Exhibit No. EMT-102 at pp. 7-11). The Eight Parties argue that such movement has nothing to do with the relationships between waterborne and pipeline prices in Los Angeles for low sulfur gasoil. *Id.*

1361. To establish the proper logistics adjustment necessary to bring pipeline prices onto a consistent waterborne basis, the Eight Parties maintain that all that needs to be determined is whether the products at issue are imported or exported from Los Angeles. *Id.* Since 1999, explain the Eight Parties, imports of low sulfur gasoil[545] into the ports of Los Angeles and Long Beach have far exceeded exports. *Id.* at pp. 123-24 (citing Exhibit Nos. BPX-55 at p. 6, BPX-56). Once imported, continue the Eight Parties, cargoes with the product specifications matching that of low sulfur gasoil or West Coast LA Pipeline No. 2, which cannot be used in California due to CARB standards, must be shipped by pipeline to markets east of California. *Id.* at p. 124. Accordingly, the Eight Parties state, they must be transported to the pipeline for disposition, thereby adding value to the product, reflected in the transportation cost, and allowing for a higher price than waterborne deliveries. *Id.* In order to bring the West Coast LA Pipeline No. 2 price back to a consistent waterborne basis with all of the other liquid products, they argue, the Quality Bank must subtract this added value from the pipeline price. *Id.*

1362. Fourth, the Eight Parties characterize Pavlovic's attack on the cost basis used by Ross in determining the appropriate logistics adjustment as unsound and ungrounded in fact. Eight Parties Initial Brief at p. 157. They assert that even Pavlovic's own data set forth on page 13 of Exhibit No. EMT-102 shows that there is a consistent differential between pipeline and waterborne prices for like products such as gasoline and jet fuel.

[545] The Eight Parties explain that while not precisely the same product, "Platt's specifically stated that Low Sulfur No. 2 [West Coast LA Pipeline No. 2] and Low Sulfur 0.05% Gasoil are interchangeable." Eight Parties Reply Brief at p. 123, n.55 (citing Exhibit No. BPX-55 at p. 10).

Id. The observed differentials for these products range from 0.2¢ to 3.3¢/gallon according to them. *Id.* Although broader, the Eight Parties point out that this range is similar to Ross's cost estimate range of 1.04¢ to 2.09¢/gallon. *Id.* According to the Eight Parties, this similarity between the range of observed price differentials and the range of logistics costs provides powerful support for a causal relationship. *Id.* at pp. 157-58.

1363. Fifth, the Eight Parties argue, Pavlovic is wrong when he claims that there are no systematic price differentials between West Coast Waterborne Low Sulfur Gasoil versus LA Pipeline No.2, waterborne versus pipeline gasoline, or waterborne versus pipeline jet fuel. *Id.* at p. 158. They assert this is because Pavlovic used a statistical test suited for independent price samples rather than one suited for interdependent samples, which the Eight Parties believe is the correct test.[546] *Id.* After repeating their argument that a high correlation between analyzed products proves a high degree of interdependence, not independence, the Eight Parties assert that, because Cavanagh's critique went unanswered and unchallenged, this lack of independence invalidates Pavlovic's analysis using the two sample t-test. *Id.*

1364. Further, the Eight Parties point out, a simple review of the number of times that average waterborne prices were lower than average pipeline prices provides evidence that Pavlovic performed a faulty analysis. *Id.* at pp. 158-59. They quote Cavanagh's statement that: "If there truly were no systematic difference between [waterborne and pipeline] prices, we would expect to see waterborne prices greater than pipeline prices in about one-half of the months that we observe" as support of this proposition. *Id.* at p. 159 (quoting Exhibit No. BPX-60 at p. 10). However, the Eight Parties point out that Pavlovic's own work papers reveal that average pipeline prices were higher than average waterborne prices significantly more often, and in one case, always. *Id.* Specifically, the Eight Parties point to Cavanagh's testimony that pipeline prices were higher than waterborne prices in 26 out of 26 observed months for West Coast Waterborne Low Sulfur Gasoil versus LA Pipeline No. 2, in 134 out of 144 observed months for gasoline, and in 129 out of 144 observed months for jet fuel. *Id.*

1365. If there were no statistically significant difference between waterborne and pipeline prices, then, in the Eight Parties view, the chances that pipeline prices would be higher than waterborne prices to such a great degree would be either close to or less than one in one million. *Id.* Hence, based on the undisputed evidence presented by Cavanagh, the Eight Parties argue that Pavlovic's conclusion that there is no statistically significant

[546] Rather than applying what the Eight Parties view as the proper matched pairs t-test to the data, the Eight Parties complain that Pavlovic used a two-sample t-test, which is only proper, according to them, if the samples are independent of each other. Eight Parties Initial Brief at p. 158. The Eight Parties also question Pavlovic's qualifications as a statistician. *Id.*

difference between pipeline and waterborne prices is plainly wrong and must be entirely discarded. *Id.*

1366. According to the Eight Parties, Exxon's argument that the Eight Parties 1.1¢/gallon logistics adjustment is not supported by any evidence reveals that Exxon has chosen to ignore the facts presented in this case. Eight Parties Reply Brief at p. 124. The Eight Parties assert that the 1.1¢/gallon figure is based on undisputed evidence and, therefore, it cannot be overlooked. *Id.* In addition to the pipeline charges established through a tariff, the Eight Parties point out that there is evidence of the cost of Los Angeles cargo inspection, dock and wharf fees and of terminal charges. *Id.* (citing Exhibit No. BPX-1 at pp. 12-13). The Eight Parties argue that the fact that these costs were developed through phone calls, discussions, and other forms of information does not make them suspect. *Id.* They maintain that these are the best and only sources of evidence for these market-driven rates, which are confidentially negotiated between suppliers and users of these services. *Id.* at pp.124-25. According to them, there are no published tariffs for such costs and other information is not widely available, particularly as a time series. *Id.* at p. 125. However, they note, just because it may be difficult to establish a consistent basis upon which to place values, this does not mean that one is excused from putting forth ones best efforts to do so. *Id.* The Eight Parties contend that Ross has attempted to provide his best estimate, based on the best information available, to determine the proper logistics adjustment for the Heavy Distillate reference price. *Id.*

1367. Furthermore, state the Eight Parties, both Ross and Cavanagh conducted significant analysis to verify that 1.1¢/gallon reflects the costs of moving product from the harbor to the pipeline. *Id.* They believe that the fact that Exxon stipulated that Cavanagh need not appear at the hearing and did not mention Cavanagh in their brief indicates that Exxon found nothing to challenge about Cavanagh's testimony. *Id.* Further, the Eight Parties assert, the fact that the waterborne prices were not below the pipeline prices every single month, as Exxon points out, in no way alters the fact that, on average, these differentials are consistent with a 1.1¢/gallon proposed adjustment. *Id.* at p. 126. Indeed, the Eight Parties claim, Pavlovic's own testimony shows that, for regular gasoline, only in nine out of 144 months, and not once since July 1992, were waterborne prices higher than pipeline prices and that in only fourteen of 144 months, and only once since May 1992, were West Coast jet fuel waterborne prices higher than pipeline prices. *Id.*

1368. Exxon argues that, as the proponents of this logistics adjustment, the Eight Parties have the burden of proving both the need for the proposed adjustment and the reasonableness of the amount proposed. Exxon Initial Brief at p. 167. Further, Exxon asserts, the Eight Parties have not met either of these burdens, and it presents five reasons why they have not. *Id.* As a threshold matter, Exxon argues that the proposed logistics adjustment is clearly not a "sulfur processing cost adjustment," and is thus outside the scope of the issues to be addressed in this case. *Id.* Second, contrary to Ross's claim, Exxon asserts the proposed logistics adjustment is neither required nor justified on the alleged ground that it will achieve consistency with the other liquid cuts. *Id.* at pp. 167-68. Third, in Exxon's opinion, the size of the proposed 1.1¢/gallon logistics adjustment is plainly not supported by substantial evidence. *Id.* at p. 168. Fourth, the proposed logistics adjustment is premised on what Exxon states is a false assumption – that the predominant flow of low sulfur fuel oil on the West Coast is from harbor to pipeline. *Id.* Fifth, Exxon views Ross's attempt to validate his proposed logistics adjustment on the basis of waterborne/pipeline price differentials for low sulfur fuel oil and other products as based on invalid assumptions and not supported by substantial evidence. *Id.*

1369. According to Exxon, the proposed "logistics adjustment" must be rejected as a threshold matter because it is outside the scope of the Heavy Distillate issue that was referred for hearing in this case. *Id.* Exxon points out that the Commission stated repeatedly in its order establishing this consolidated hearing that the only issue relating to Heavy Distillate to be addressed in this case was the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the new reference price. *Id.* Further, notes Exxon, the Eight Parties did not address this jurisdictional issue in their initial brief, stating, without support, that a logistics adjustment is required for consistency. Exxon Reply Brief at p. 178.

1370. Exxon explains that, when Platts ceased publication of the price for West Coast High Sulfur Gas Oil, all parties agreed that the Platts LA Pipeline Low Sulfur No. 2 Fuel Oil price should be used as the new West Coast proxy price for valuing the Quality Bank Heavy Distillate cut. Exxon Initial Brief at pp. 168-69. However, the parties were unable to agree on the cost that would be incurred to bring the sulfur content of the Heavy Distillate cut into line with the much lower sulfur level on which the new reference price was to be based. *Id.* at p. 169.

1371. Exxon points out that, in its order accepting the new West Coast reference product for the Heavy Distillate cut,[547] the Commission rejected the Eight Parties's proposal for a sulfur processing cost adjustment of 6.0¢/gallon because that adjustment did not "reflect the actual processing cost differential." *Id.* Exxon also points out that, in the same order,[548] the Commission declined to accept Tesoro's proposal for a 3.5¢/gallon sulfur processing cost adjustment because all parties had not reviewed it. *Id.* Further, Exxon notes that the Commission made clear that the issue to be resolved was "the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line

[547] *Trans Alaska Pipeline System*, 90 FERC at p. 61,371.

[548] *Trans Alaska Pipeline System*, 90 FERC at pp. 61,371-72.

with the [new] quoted price."[549] *Id.*

1372. Further, according to Exxon, any possible uncertainty on the proper scope of the term "sulfur processing adjustment" is eliminated by the Commission's subsequent order establishing this consolidated hearing, in which the Commission described the sole issue in the "replacement product proceeding" relating to the new West Coast Heavy Distillate reference price as follows:[550] "At issue in the replacement product proceeding is the level of the *sulfur processing adjustment* necessary to bring the TAPS Heavy Distillate cut into line with the quoted price." *Id.* at p. 170. And again, in framing the "Replacement Product Issue" being set for hearing, Exxon claims, the Commission stated[551] that the only matter "[a]t issue in the replacement product proceeding is the level of the *sulfur processing adjustment* necessary to bring the Trans-Alaska Pipeline System Heavy Distillate cut into line with the quoted price." *Id.* at pp. 170-71. Consequently, Exxon asserts, there can be no doubt that the sole issue relating to the new West Coast reference price for the Heavy Distillate cut set for hearing is the level of the sulfur processing cost adjustment required to bring the sulfur content of the ANS Heavy Distillate cut to the sulfur level on which the reference price is based. *Id.* at p. 171.

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[549] *Trans Alaska Pipeline System*, 90 FERC at p. 61,371. Exxon points out that Williams recognized this fact when it sought judicial review of the Commission's February 9, 2000, order (*Trans Alaska Pipeline System*, 90 FERC ¶ 61,123 (2000)), setting the sulfur "processing cost adjustment issue" for hearing, claiming that the Commission order was a "final determination" that certain other costs, which Williams referred to as "terminal fees," would not be included in the adjustment to the replacement proxy price for Heavy Distillate. Exxon Initial Brief at p. 170, n.70. It points out that the Commission's February 9, 2000, referral order was plainly "not a reviewable final order," and Williams's appeal was dismissed as premature by the Circuit Court. *Williams Alaska Petroleum Inc. v. FERC*, Case No. 00-1153 (D.C. Cir. June 29, 2000). Exxon argues that, therefore, contrary to Williams's argument, the court's statement that Williams "may raise on appeal, after a final Commission order establishing the appropriate processing cost adjustment, any issue it may have with respect to the processing cost adjustment, including whether terminal fees are properly included" (*id.*), does not support Williams' position regarding the proposed "logistics adjustment." Exxon Initial Brief at p. 170, n.70. By that language, Exxon believes the court plainly intended only that Williams could again raise on appeal from the Commission's final order its claim that the Commission erred in limiting the scope of the issue to only sulfur processing costs and not broadening the scope to include non-processing costs, such as terminal fees. *Id.*

[550] *Trans Alaska Pipeline System*, 97 FERC at p. 61,650 (emphasis added by Exxon).

[551] *Trans Alaska Pipeline System*, 97 FERC at p. 61,652 (emphasis added by Exxon).

1373. Therefore, Exxon argues, under no conceivable theory is the "logistics adjustment" proposed by the Eight Parties a "sulfur processing adjustment." *Id.* Exxon views as undisputed that the Eight Parties's proposed logistics adjustment has nothing to do with the cost of desulfurizing the Quality Bank Heavy Distillate cut to the lower sulfur level of the agreed-upon reference price. *Id.* Rather, Exxon's view is that the proposed logistics adjustment is a completely separate adjustment that attempts to take the agreed-upon Platts LA Pipeline Low Sulfur reference price and convert it to a waterborne cargo price. *Id.* Exxon also explains that BP acknowledged that the proposed Heavy Distillate logistics adjustment differed from the N+A adjustment for Naphtha in that the logistics adjustment is not based on the chemical characteristics of Heavy Distillate. Exxon Reply Brief at p. 178. Accordingly, Exxon contends that the logistics adjustment proposed by the Eight Parties is outside the scope of this proceeding and should be rejected on that ground alone. Exxon Initial Brief at p. 171.

1374. According to Exxon, the sole reason offered by Ross for his proposed logistics adjustment was that "a logistics adjustment is needed to ensure that the Heavy Distillate cut is valued on a consistent basis with all other liquid cuts." *Id.* at p. 172 (citing Exhibit No. BPX-1 at p. 9). Exxon asserts, however, that the evidence shows that there is no factual basis for Ross's claim that valuation of the various cuts must be done on a consistent basis. *Id.*

1375. First, Exxon states that Ross's assumption that all of the Quality Bank "liquid cuts" are valued on a waterborne basis is wrong. *Id.* Exxon maintains that the evidence clearly shows that LSR – one of the "liquid products" initially identified by Ross – is valued on a Bakersfield truck/rail basis.[552] *Id.* Furthermore, Exxon points out that Ross's attempt at the hearing to repudiate his prior written testimony (identifying LSR as a "liquid cut" that is valued on a "waterborne basis") as an editing error was itself repudiated by his subsequent testimony that LSR is in fact a "liquid" that is not valued by the Quality Bank on the basis of a "waterborne price." *Id.* (citing Transcript at pp. 1722-23).

1376. Exxon goes on to argue that the evidence shows that, of the nine West Coast Quality Bank proxy products, only one – Light Distillate (jet fuel) – is currently valued on a West Coast waterborne basis. *Id.* at p. 173. Further, Exxon points out, Ross himself conceded that all of the natural gas liquids – including Propane, Isobutane, Normal

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[552] Exxon points out that when this error was brought to Ross's attention by Exxon in a data request, BP filed a "Revised Version" of Exhibit No. BPX-1 on March 8, 2002, which eliminated LSR from Ross's list of "liquid products." *See* Exhibit No. BPX-1 at p. 5. Exxon points out that O'Brien, the Eight Parties's expert, views LSR as a liquid product. Exxon Initial Brief at p. 172, n.71.

Butane, and LSR – are valued on the West Coast on a "land-based" truck or railcar basis, rather than on a waterborne basis. *Id.*

1377. Nor, in the opinion of Exxon and contrary to Ross's contention, is a logistics adjustment necessary to ensure that the Quality Bank pricing bases are consistent with respect to transaction size. *Id.* According to Exxon, the Quality Bank has never articulated or followed a course of choosing the largest available transaction quantities, and, as Ross himself admitted, the Quality Bank does not always value cuts based on the largest parcel of product available. *Id.* For example, Exxon notes that the VGO cut has been valued on both the West Coast and Gulf Coast on the basis of the OPIS Gulf Coast High Sulfur VGO barge price assessment, which represents transactions that are much smaller than the transactions represented by the OPIS Gulf Coast High Sulfur VGO cargo price assessment. *Id.* As Ross acknowledged, the smaller cargo price was selected for VGO valuation because it was more "robust," that is, "[t]here's a greater frequency of transactions and therefore, it is a more reliable indication of the actual spot market on the day it was picked." *Id.* (citing Transcript at p. 1719). According to Exxon, this same reasoning is equally applicable to the Platts LA Pipeline Low Sulfur price that has been accepted by the Commission as the reference price for West Coast Heavy Distillate. *Id.* at p. 174.

1378. The evidence also shows, in Exxon's view, that many other Quality Bank proxy prices are not presently consistent with regard to location. *Id.* Exxon contends that the Eight Parties's proposed logistics adjustment would do nothing to cure this inconsistency. *Id.* For example, Exxon notes that the West Coast Propane, Isobutane, and Butane proxy products are priced at Los Angeles, while the LSR proxy product is priced at Bakersfield in the San Joaquin Valley. *Id.* Similarly, Exxon notes that, on the Gulf Coast, the Propane, Isobutane, Butane, and LSR proxy products are priced at Mt. Belvieu, Texas, which is significantly removed from the marine terminals on which the waterborne price assessments for the Naphtha through Resid cuts on the Gulf Coast are based.[553] *Id.* Contrary to Ross's contention, therefore, Exxon argues that the evidence clearly shows that a consistent location has never been a requirement in the selection of the Quality Bank proxy prices. *Id.*

1379. Finally, according to Exxon, the Eight Parties's claim regarding "largest available parcels" is not supported by the Energy Information Administration data that Ross presented in support of his testimony regarding the valuation of West Coast Naphtha. Exxon Reply Brief at p. 182. It is common for products to be shipped in part cargoes, i.e., ships with more than one product contained in segregated compartments, Exxon

[553] Similarly, Exxon notes that the new proposals for valuing the Resid cut are not based exclusively on waterborne prices, but rather are a mixture of prices at different locations. Exxon Initial Brief at p. 174, n.72.

contends. *Id.* (citing Transcript at pp. 10021-22). Indeed, continues Exxon, Platts recognizes this in its specifications for products including diesel fuel. *Id.* (citing Exhibit No. EMT-105 at p. 4). Exxon asserts that Ross's testimony regarding the purported need for a logistics adjustment does not take this fact into account. *Id.* at pp. 182-83.

1380. Rather than focusing on such issues as whether the reference price is set forth on a waterborne basis or whether it represents the largest parcels available, Exxon points out, the Circuit Court[554] and the Commission[555] have made it abundantly clear that the Quality Bank methodology requires that the reference price for each cut should reflect the market value of that cut. *Id.* at pp. 180-81. In Exxon's opinion, the evidence makes clear that the Quality Bank Administrator, a neutral, independent party, has, in managing the Quality Bank, abided by the principle that each cut should be valued in a way that best captures its market value. *Id.* at p. 181. For example, in 1998, Exxon explains, the Quality Bank Administrator recommended adopting the OPIS VGO barge assessment because that price assessment was "the most representative indicator of High Sulfur VGO market value and therefore seems to be the best single price to reflect the market for High Sulfur VGO on the Gulf Coast." *Id.* (quoting Exhibit No. TC-23 at p. 4). Similarly, notes Exxon, in recommending the adoption of the Platts Gulf Coast "Heavy Naphtha" assessment in February 2003, the Quality Bank Administrator specifically relied on this same guiding principle: "It is . . . my understanding that the intent of the [Commission] . . . is that all components be valued on the basis that best reflects their value in the market."[556] *Id.* (quoting Exhibit No. PAI-222 at p. 4).

1381. Exxon argues that the Platts LA Pipeline Low Sulfur No. 2 Fuel Oil price is a better representation of "the real market for low-sulfur heavy distillate than the waterborne price." Exxon Initial Brief at p. 174. It notes that Ross conceded the "vast majority of Los Angeles refinery production" of Heavy Distillate that is sold by refineries is sold "at the pipeline terminal," and not on the basis of any waterborne price. *Id.* at pp. 174-75 (citing Transcript at pp. 1792-93). By attempting to place the pipeline price on a waterborne basis, therefore, according to Exxon, Ross's proposed logistics adjustment

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[554] Exxon cites *Tesoro*, 234 F.3d at p. 1289; *Exxon*, 182 F.3d at p. 35.

[555] Exxon cites *Trans Alaska Pipeline System*, 97 FERC at p. 61,649; *Trans Alaska Pipeline System*, 81 FERC at p. 62,457.

[556] Exxon notes that the Quality Bank Tariff's provision governing "Unanticipated Implementation Issues" expressly authorizes the Quality Bank Administrator to resolve such issues "in accordance with the best understanding of the intent of the [Commission] that the Quality Bank Administrator can derive from [its] orders regarding the Quality Bank methodology." Exxon Reply Brief at p. 181, n.98 (quoting Exhibit No. TC-3 at p. 8).

violates Ross's own purported objective of establishing a price that is "more representative of the values of these streams to the refinery." *Id.* at p. 175 (citing Exhibit No. BPX-1 at p. 16). The true value to the refiner, according to Exxon, of the various Quality Bank cuts, is the value of the cut at the refinery gate. *Id.* In Exxon's view, Ross's proposed logistics adjustment does not represent this true value, but seeks, instead, to adjust the agreed-upon pipeline reference price not to the refinery gate, but to the harbor – a location that has no relevance either to the refiner or to the reference price. *Id.*

1382. There is also no substantial evidentiary support, according to Exxon, for the 1.1¢/gallon figure that Ross proposed for his logistics adjustment. *Id.* It states that the Eight Parties represent this amount to be the sum of three categories of costs that would be incurred in moving a product from the Los Angeles harbor to the Kinder Morgan pipeline terminal at Watson, California: (1) Los Angeles cargo inspection, dock and wharf fees, (2) terminal charges in the Port of Los Angeles, and (3) pipeline tariff charges from the port to Watson. *Id.* However, Exxon claims that Ross stated at the hearing that he had no reliable evidence to back up any of this data, and that his estimates were based on information from a small number of telephone calls that he made no effort to verify. *Id.* at pp. 175-76.

1383. In addition, Exxon argues that the evidence presented regarding terminal and pipeline tariff charges is based on only one or two telephone calls and has not been verified with any substantial data records. *Id.* at p. 176. For example, Exxon states, the evidence presented by Ross of typical terminal charges was based entirely on two telephone conversations from 2000 and 2002. *Id.*

1384. Ross also stated that he did not know what the range of terminal charges was over the longer five to ten year period, according to Exxon. *Id.;* Exxon Reply Brief at p. 183. Similarly, with respect to the pipeline tariff charges, Exxon asserts that Ross admitted that he did not know what these charges were for any year earlier than 2002 and that he had no work papers showing any of those changes, even though he claimed to have tracked the changes in the tariffs and other charges. Exxon Initial Brief at p. 176. Exxon also declares that, despite his professed concern for consistency, Ross admitted that he never tried to get 1996 data for the pipeline tariffs, even though O'Brien used 1996 costs for his estimate of sulfur processing costs for valuing the Heavy Distillate cut. *Id.*

1385. Exxon also argues that Ross premised his logistics adjustment upon an incorrect factual assumption: that the predominant flow of low sulfur fuel oil in West Coast markets is from harbor to pipeline. Exxon Initial Brief at p. 177. While Exhibit No. BPX-5 purports to show that there is a significant net inflow of certain petroleum products to the West Coast, Exxon contends that there is an error in the Exhibit. *Id.* The error, according to Exxon, is in combining waterborne and pipeline shipments and calling them net receipts, thereby giving what Exxon believes is a false impression that waterborne shipments into the West Coast outweighed waterborne shipments out of the West Coast. *Id.* Exxon asserts that, in fact, the overwhelming majority of the shipments that Ross reported as net receipts were actually pipeline shipments to the West Coast, which do not pass through West Coast harbor terminals. *Id.* If this error is corrected, Exxon states that it becomes clear both that product outflows in general dwarf waterborne inflows to the West Coast, and that waterborne low sulfur fuel oil outflows have exceeded or roughly equaled waterborne inflows in all but one of the last seven years. *Id.*

1386. Further, Exxon asserts, Pavlovic also demonstrated that the predominant flow of products in the Los Angeles market is not from harbor to pipeline, but from the refineries (1) to the pipeline terminal for further shipment to inland markets in California, Nevada, and Arizona, or (2) to the harbor for export or shipment to other West Coast domestic markets, supplemented by imports and domestic shipments from other refinery centers. *Id.* at pp. 177-78. It states that, during the hearing, Ross conceded that the majority of the product sold at the pipeline is produced in California. *Id.* at p. 178.

1387. Exxon also maintains that the Eight Parties's claim that Pavlovic was attempting "to obscure the fact that the predominate flow of West Coast Waterborne Low Sulfur Gasoil is from harbor to pipeline by focusing on the movement of all petroleum products across the West Coast" is false. Exxon Reply Brief at p. 185 (quoting Eight Parties Initial Brief at p. 157). While Pavlovic looked at other products, Exxon points out that he also focused specifically on low sulfur No. 2 distillate fuel oil with a sulfur content less than 0.05% — the very product chosen by all parties as the reference product for the Heavy Distillate cut — and determined that "with regard to LS No. 2 waterborne outflows have balanced or exceeded waterborne inflows in all but one of the last seven years." *Id.* (quoting Exhibit No. EMT-102 at pp. 10-12; citing Exhibit No. EMT-106 (showing separately the net waterborne flows for "Distillate Fuel Oil <0.05% S" and that only in the year 2000 did imports exceed exports)).

1388. Further, by making the assertion that the movement of other West Coast products is irrelevant (Eight Parties Initial Brief at p. 157), Exxon states that the Eight Parties apparently concede that, as the record amply shows, "refinery production and its attendant product outflows dwarf import and domestic waterborne inflows to the West Coast market" for other Quality Bank reference products, such as jet fuel. *Id.* at pp. 185-86 (quoting Exhibit No. EMT-102 at p. 10). Moreover, asserts Exxon, Ross's claim in this regard is difficult to square with his reliance on the waterborne-pipeline price differentials of other products to support his proposed logistics adjustment of 1.1¢/gallon. *Id.* at p. 186.

1389. Exxon concludes, therefore, that the evidence shows that Ross's assumption about the predominance of the harbor-to-pipeline flow was erroneous. Exxon Initial Brief at p. 178. Indeed, according to Exxon, Ross's own testimony showed that he had no substantial evidence to support his assumptions about product flow. *Id.* To bolster this assertion, Exxon cites testimony in which Ross admitted that he did not know what actually happened to waterborne cargoes, and that he could not say whether any waterborne cargo was actually moved from the Port of Los Angeles to a pipeline to be sold at the pipeline hub.[557] *Id.* Exxon notes that Ross further admitted that the net flow of products on the West Coast has been changing over time and the predominant flow prior to 1999 was not from harbor to pipeline.[558] *Id.* As a result, Exxon states that Ross was unable to say whether his proposed logistics adjustment would have been appropriate prior to 1999.[559] *Id.*

1390. Moreover, even if one were to assume that the harbor price reflected an import price, as Ross contended, Exxon asserts this would buttress the conclusion that the pipeline price, not the waterborne price, is the best indicator of the value of the reference product to a refiner. *Id.* Exxon argues for this conclusion because, it claims, Ross's proposed logistics adjustment assumes that the harbor price is equal to the pipeline price minus the costs of moving the Heavy Distillate from the harbor to the pipeline. *Id.* It asserts that, were this the case, a West Coast refiner would never sell at the harbor price, because it would always be able to sell for a higher price at the pipeline. *Id.* at pp. 178-79. Because the purpose, according to Exxon, of the Quality Bank is to establish the value of the Heavy Distillate cut to a West Coast refiner, the only logical conclusion is that Ross's assumed harbor price has no relevance to the valuation of the West Coast Heavy Distillate cut. *Id.* at p. 179.

1391. Having argued that a proposed 1.1¢/gallon logistics adjustment has no substantial evidentiary basis, Exxon then takes exception to Ross's attempts to validate his figure by comparing the "waterborne/pipeline differentials in the reported prices for similarly situated products," namely, regular gasoline and jet fuel. *Id.* Exxon contends that Ross's analysis in this effort is wholly lacking in credible evidentiary support. *Id.*

1392. Exxon points out that Pavlovic presented substantial evidence that during the period from 1990-2001 there were four West Coast refined petroleum products[560] for which Platts published both waterborne and pipeline daily spot price assessments, and that his analysis demonstrates that the waterborne price was not consistently lower than

[557] Transcript at pp. 1707-08.

[558] Transcript at pp. 1739-40.

[559] Transcript at p. 1740.

[560] Exxon states that the four products are: regular gasoline (1990-2001), jet fuel (1990-2001), FO 380 residual fuel oil (1990-1995), and FO 180 residual fuel oil (1994-95). Exxon Initial Brief at p. 179.

the pipeline price for any of the four price pairs. *Id.* Indeed, notes Exxon, there have been a number of times when the waterborne price was higher than the pipeline price. *Id.* at pp. 179-80. The same is also true, continues Exxon, of the comparison of LA Pipeline LS No. 2 with West Coast Waterborne LS gas oil. Exxon Reply Brief at p. 187.

1393. If Ross is correct, Exxon suggests, that both the pipeline/waterborne price differentials reflect a simple logistics cost relationship for moving from the harbor to the pipeline terminal and that such costs have been generally stable over time, then those price differentials should be stable over time as well. Exxon Initial Brief at p. 180. Exxon points out that, in fact, the differentials between the waterborne and pipeline prices have fluctuated widely over time. *Id.*

1394. As support for this, Exxon cites evidence that, for example, the differential for regular gasoline ranged from –9.6¢/gallon to +16.3¢/gallon over a 10-year period.[561] *Id.* Further, notes Exxon, Pavlovic found no stable differential over time looking even at the annual averages for regular gasoline, jet fuel, F.O. 380, and F.O. 180.[562] Exxon Reply Brief at p. 188. For this reason, explains Exxon, Pavlovic concluded that "there is no consistent pipeline/waterborne differential – only many average differentials, the values of which depend on the period over which the average is taken." *Id.* (quoting Exhibit EMT-102 at pp.13-14). In light of this variability, Exxon argues there is no evidence that Ross's proposed logistics adjustment of 1.1¢ is any more than coincidentally related to waterborne/pipeline price differentials.[563] Exxon Initial Brief at p. 180.

1395. Further, Exxon contends that, if Ross were correct that pipeline/waterborne price differentials in the West Coast market bore a direct relationship to the costs of transport from the harbor to the pipeline terminal, then the logistics costs for similar products should be the same, because the products use the same basic facilities – the same docks and pipelines – and should incur the same costs in moving from the harbor to the pipeline

[561] Exhibit No. EMT-102 at p. 12.

[562] Exhibit No. EMT-102 at p. 13.

[563] Exxon asserts that none of the Eight Parties's statistical arguments support adoption of the proposed logistics adjustment. Exxon Reply Brief at p. 188, n.101. For example, Exxon argues, the fact that, when averaged over a five-year basis, the waterborne/pipeline differentials for regular gasoline and jet fuel come out "close" (1.23¢ and 0.95¢/gallon, respectively) to Ross's proposed 1.1¢/gallon proposed logistics adjustment does not establish the reasonableness of using that adjustment. *Id.* This averaging over several years, it declares, masks significant variation in the differentials and fails to explain why the regular gasoline and jet fuel differentials do not behave like cost-based differentials when viewed on a daily, monthly, or even annual basis. *Id.*

terminal. Exxon Initial Brief at p. 180. Yet, Exxon notes, Platts prices show that there is an average variance of 40% between the average waterborne/pipeline differential for regular gasoline (1.5¢/gallon) and that for jet fuel (1.1¢/gallon.) *Id.* at pp. 180-81.

1396. Exxon also points out that the differential between the Platts published LA pipeline reference price for low sulfur fuel oil and the Platts West Coast waterborne price was only within the range of 1.0¢ to 1.5¢/gallon about 60% of the time, and that, on a number of occasions, the waterborne price was actually lower than the pipeline price. *Id.* at p. 181. These data squarely, Exxon suggests, refute Ross's claim that a logistics adjustment of 1.1¢/gallon is based on any valid, real world evidence of a waterborne/pipeline price differential.[564] *Id.*

1397. Ross's analysis concerning an alleged price differential, Exxon also argues, is based on the erroneous assumption that the Platts West Coast waterborne low sulfur fuel oil price is reliable when Exxon asserts that the record evidence shows that it is not. *Id.* First, it notes, Platts must often estimate, as conceded by Ross, the waterborne price due to the infrequency of waterborne transactions and, as a result, "there is that tendency of an upward bias between cargoes." *Id.* (citing Transcript at pp. 1779-80). Second, Exxon states, Ross's waterborne/pipeline price differential is not based on a true apples to apples comparison because, although the agreed-upon pipeline reference price is a Los Angeles-based price, Ross compares this Los Angeles pipeline price to a West Coast waterborne price, which consists of prices from San Francisco and Seattle, as well as Los Angeles. *Id.* at pp. 181-82. Moreover, Exxon points out, Ross conceded at the hearing that any price differential is due at least in part to the undisputed fact that Platts West Coast low sulfur waterborne price is based on a product specification that is superior to the product on which the Platts Los Angeles pipeline low sulfur reference price is based. *Id.* at p. 182.

1398. Relying on Ross's testimony, states Exxon, the Eight Parties also argue that the 0.2 to 3.3¢/gallon range observed in the annual average waterborne/pipeline differential for unleaded regular gasoline from 1990 to 2001 is similar to Ross's 1.04¢ to 2.09¢/gallon low-high range estimate for the logistics costs, and that this "powerfully supports a causal relationship." Exxon Reply Brief at p. 189 (quoting Eight Parties Initial Brief at p. 158). In fact, according to Exxon, the ranges are not comparable. *Id.* It asserts that the regular gasoline differential is almost three times wider than Ross's

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[564] Exxon notes that Ross conceded both the points in the paragraph and also admitted that the chart (*see* Exhibit No. BPX-22) he was using in this proceeding to justify a combined adjustment of 5.2¢/gallon (his logistics adjustment of 1.1¢/gallon combined with O'Brien's proposed 4.1¢/gallon sulfur processing cost adjustment) was the same chart that he had used in 2000 in an attempt to justify a proposed 6¢/gallon adjustment to the Heavy Distillate price. Exxon Initial Brief at p. 181, n.73.

logistics costs. *Id.* Additionally, continues Exxon, the comparisons are based on different time periods: 1990-2001 for the annual average gasoline differential versus 2000-2001 for the logistics cost figures that Ross gathered in his one or two telephone conversations. *Id.* Consequently, Exxon maintains that this comparison clearly does not prove a causal relationship based on logistics costs. *Id.*

1399. Finally, Exxon states, the Eight Parties's reliance on the testimony of Cavanagh is misplaced. *Id.*[565] While Cavanagh concluded that there is a statistically significant "difference between pipeline and waterborne prices in favor of the hypothesis that pipeline prices are higher than waterborne prices,"[566] Exxon notes, he testified that he had no information that explained why pipeline prices tended to be higher and offered no testimony as to whether logistics costs were the cause. *Id.* at pp. 189-90. Exxon also notes that Cavanagh conceded that his "statistical analysis has not sought to identify the source or the reason" for the statistically significant difference he found. *Id.* at p. 190 (quoting Exhibit No. BPX-114 at pp. 7-8).

1400. By contrast, according to Exxon, Pavlovic concluded that West Coast waterborne/pipeline differentials were the result of market conditions, not logistics costs. *Id.* Exxon declares that Cavanagh agreed that waterborne and pipeline prices could differ because of supply, demand or other market conditions and testified that he had not analyzed these factors to see if they explained the price differentials he found. *Id.* In addition, notes Exxon, Cavanagh conceded that he had not done the additional analysis that would be needed to explain the difference between his and Pavlovic's testimony, determine who was correct, or discover whether the differences are market driven or cost driven. *Id.*

1401. Further, Exxon points out that despite the fact that Cavanagh agreed that it is necessary in most cases to understand how the data used in a statistical test is gathered, he testified that he did not understand how the price data he analyzed had been gathered. *Id.* at p. 191. Exxon notes that Cavanagh mistakenly believed that the reported West Coast waterborne prices reflected solely transactions at LA, rather than transactions

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[565] The Eight Parties's claim that "Cavanagh's critique went unanswered and unchallenged" (Eight Parties Brief at p. 158) is misleading, according to Exxon, since he submitted only rebuttal testimony; thus Exxon's witnesses had no opportunity to respond to his critique. Exxon Reply Brief at p. 189, n.102. Moreover, Exxon claims it "waived cross-examination" of "Cavanagh and instead [relied] on his deposition transcript . . . because that testimony clearly demonstrates that his written testimony did not answer the myriad problems with the Eight Parties' proposed 'logistics adjustment.'" *Id.* (citing Exhibit No. BPX-114; Transcript at pp. 158, 1884–85).

[566] Exhibit No. BPX-60 at p. 12.

occurring at other terminals on the West Coast. *Id.* Finally, Exxon states that Cavanagh also agreed it was accurate to state that he had not done any analysis on whether the way the data was collected had any impact on the price differentials he identified. *Id.*

E. BASE YEAR

1402. As explained in the section concerning Resid, the Eight Parties state they chose 1996 as the base year for calculating Heavy Distillate processing costs in order to put all of the processing cost calculations on a consistent basis. Eight Parties Initial Brief at p. 160. The Eight Parties assert that no issue regarding appropriate assumptions about facilities configuration in the base year was raised for Heavy Distillate. *Id.* They do not believe that choice of a base year should have a material impact on the outcome of the Heavy Distillate issue. *Id.*

1403. According to the Eight Parties, the need to use different indices is even less material for the Heavy Distillate cut than it is for the Resid cut. Eight Parties Reply Brief at p. 127 (referring to the Resid cut section of the Eight Parties Reply Brief). They point out that the use of different indices changes O'Brien's capital cost calculation by 1¢/barrel of Heavy Distillate over the four years from 1996-2000. *Id.* at pp. 127-28.

1404. The parties have agreed that the effective date for the new West Coast Heavy Distillate price should be February 1, 2000, Exxon begins. Exxon Initial Brief at p. 182. Nevertheless, there is a dispute about what base year should be used in calculating the sulfur processing cost adjustment. *Id.* The sulfur processing cost estimate presented by the Eight Parties stated all costs using 1996 as the base year, while the cost analysis presented by Exxon states all costs using 2000 as the base year. *Id.*

1405. Exxon asserts that, in theory, it should not matter which year – 1996 or 2000 – is used as the base year. *Id.* It notes that whichever base year is used, the costs for that year can be converted to the costs in another year by inflating or deflating the base year costs using the Nelson Farrar cost index. *Id.* However, Exxon identifies a potential problem because there are two Nelson Farrar indices applicable to different types of costs – (1) the Nelson Farrar Refinery Construction Cost Index (sometimes referred to as the Nelson Farrar Capital Cost Index), and (2) the Nelson Farrar Refinery Operating Cost Index – which produce different results depending on how they are applied and which base year is used. *Id.* at pp. 182-83. The TAPS Carriers's Tariff, notes Exxon, currently provides that all costs (both capital and operating) be adjusted by the same cost index, the Nelson Farrar Operating Cost Index. Exxon Reply Brief at p. 192.

1406. In adjusting their costs to the base year, both parties adjusted their estimates of the capital costs by using the Nelson Farrar Construction Cost Index, and both parties used the Nelson Farrar Operating Cost Index to adjust their operating cost estimates. Exxon Initial Brief at p. 183. There was no dispute that it is appropriate to use the Nelson Farrar

Construction Cost Index to adjust capital costs to the base year. *Id.* Likewise, there was no dispute that it would not be appropriate to use the Nelson Farrar Operating Cost Index to adjust capital costs to the base year. *Id.*

1407. However, once the costs have been adjusted to the base year, Exxon states that the Eight Parties take the position that, with the exception of their proposed logistics adjustment, all costs, including the capital costs, should be adjusted thereafter using only the Nelson Farrar Operating Cost Index. *Id.* at pp. 183-84. This position, according to Exxon, is based on the fact that the parties previously stipulated to the use of that index for adjustments to the "value" of the Quality Bank cuts. *Id.* at p. 184. As applied to the capital cost portion of the sulfur processing cost adjustment, Exxon's concern is that this proposal would have an impact in all years other than the base year because, although all capital costs are adjusted to the base year by using the Nelson Farrar Construction Cost Index, those same capital costs would then be adjusted from the base year to subsequent years using the Nelson Farrar Operating Cost Index. *Id.* Moreover, according to Exxon this difference is exacerbated by the fact that, unlike the Nelson Farrar Construction Cost Index which has risen relatively steadily over time, the Nelson Farrar Operating Cost Index has gone up and down from year to year. *Id.*

1408. As a result, Exxon states the costs for future years will be quite different if the Nelson Farrar Operating Cost Index is used to adjust the capital costs of the Heavy Distillate hydrotreater relative to the base year instead of the Nelson Farrar Construction Cost Index; and the selection of the base year will have an impact on the capital cost figure for all subsequent years. *Id.* In particular, Exxon maintains that by selecting a base year of 1996 rather than 2000, the Eight Parties's approach of using the Operating Cost Index has the effect of reducing the capital costs of the Heavy Distillate hydrotreater in subsequent years. *Id.*

1409. Exxon believes this problem can and should be avoided. *Id.* The analytically correct solution, Exxon argues, would be simply to direct that capital costs should be adjusted from the base year by the Nelson Farrar Construction Cost Index rather than by the Nelson Farrar Operating Cost Index. *Id.* at pp. 184-85. Exxon maintains that it makes no sense for capital costs to be adjusted to the base year by the use of the Nelson Farrar Construction Cost Index – as all parties agree is the only appropriate approach – and then to adjust those same capital costs from the base year to subsequent years using the Nelson Farrar Operating Cost Index. *Id.* at p. 185. Exxon's preferred solution is to use the Nelson Farrar Construction Cost Index to adjust the base year capital costs for other years in order to eliminate this peculiar anomaly. *Id.*

1410. Alternatively, Exxon contends, the impact of the problem for future years can be limited by selecting the most current base year – namely, the base year 2000 proposed by Exxon rather than the base year 1996 proposed by the Eight Parties. Exxon Initial Brief at p. 185. Given the stipulation of the parties that the effective date for the new Heavy

Distillate price will be February 1, 2000, Exxon believes it makes no sense to use 1996 as the base year rather than 2000. *Id.* While the selection of 2000 as the base year will not eliminate the anomaly of using an Operating Cost Index to adjust capital costs, it would at least reduce the impact of that approach by bringing all of the capital costs forward to 2000. *Id.*

1411. Finally, Exxon argues that there is no merit to the claim that use of 1996 as the base year is necessary to ensure uniform implementation of the Quality Bank's procedures. Exxon Reply Brief at p. 194. Exxon notes that the use of a 1996 base year with the Nelson Farrar Operating Cost Index applied to all costs produces an inaccurate result. *Id.* According to Exxon, it is clear that principles of uniformity cannot be used to justify such a result. *Id.* (citing *Exxon*, 182 F.3d at p. 42).

F. ADMINISTRATIVE FEASIBILITY

1412. The Eight Parties state that their proposal for valuing Heavy Distillate is based on the Platts LA Pipeline No. 2 assessment, with adjustments made for sulfur processing costs and for logistics. Eight Parties Initial Brief at p. 160. In their opinion, the new valuation basis for Heavy Distillate should be made retroactive to February 1, 2000. *Id.* The Eight Parties claim that the Quality Bank Administrator has stated that the Eight Parties's proposal submitted for valuing Heavy Distillate is administratively feasible. *Id.* Moreover, they assert that, because none of the parties has challenged the administrative feasibility of the Eight Parties's proposal for valuing Heavy Distillate, the Quality Bank could use the Eight Parties's proposal to value Heavy Distillate on the West Coast. *Id.*

1413. According to Exxon, the Quality Bank Administrator testified that both the Exxon proposal and the Eight Parties proposal would be administratively feasible. Exxon Initial Brief at p. 185. Further, Exxon asserts, the proposal to use both the Nelson Farrar Construction Cost Index and the Nelson Farrar Operating Cost Index, rather than just the Nelson Farrar Operating Cost Index, also should not pose any problems. *Id.* at pp. 185-86. Both parties's cost estimates separately set forth the capital and operating costs for their respective base years, according to Exxon. *Id.* at p. 186. Consequently, Exxon states, all that would needed would be to adjust the capital costs of the distillate hydrotreater from the base year to the chosen year by the Nelson Farrar Construction Cost Index, while adjusting the operating costs of the hydrotreater by the Nelson Farrar Operating Cost Index. *Id.* Exxon believes this change would eliminate the base year issue and produce a more accurate result. *Id.*

1414. The TAPS Carriers state that there has been one change since Exxon and the Eight Parties submitted their proposals that needs to be reflected in any Commission order. TAPS Carriers Initial Brief at p. 11. Effective May 1, 2003, Platts renamed as "low sulfur diesel" the product formerly referred to in its price assessments as "low sulfur No. 2." *Id.* The TAPS Carriers point out that there was no change in Platts methodology in establishing its assessments. *Id.* at pp. 11-12. They recommend that the Commission's order specifically state that, in valuing Heavy Distillate, the base price should be Platts West Coast pipeline low sulfur No. 2 assessment through April 2003 and Platts West Coast pipeline low sulfur diesel assessment beginning May 1, 2003. *Id.*

ISSUE 2- DISCUSSION AND RULING

1415. Exxon and the Eight Parties agree that the starting point for establishing the value of Heavy Distillate is Platts West Coast LA Pipeline Low Sulfur No. 2 Fuel Oil price. Exxon Initial Brief at p. 143; Eight Parties Initial Brief at pp. 131-32. They disagree, however, as to in what manner that price ought to be adjusted.[567] Exxon Initial Brief at p. 144; Eight Parties Initial Brief at p. 132. The parties have agreed that the effective date for the new price ought to be February 1, 2000. Joint Stipulation, filed October 3, 2002, at p. 3. Not only do the parties disagree as to the extent of the desulfurization cost adjustment and whether there ought to be a logistics adjustment, they also disagree as to the base year which should be used.

A. SULFUR PROCESSING COSTS ADJUSTMENT

1. Capital Costs

a. ISBL Costs

1416. Stating that the cost of hydrotreating Heavy Distillate represents a significant cost, the Eight Parties reflect that O'Brien's estimate was 4.1¢/gallon in Year 1996 dollars and that Jenkins's estimate was 4.3¢/gallon in Year 2000 dollars. Eight Parties Initial Brief at p. 134 (citing Exhibit No. EMT-37 at p. 12). They add that O'Brien followed an approach which was consistent with that which he followed regarding Resid; he applied the "appropriate" Baker & O'Brien cost curve. *Id.*

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[567] In pertinent part the Joint Stipulation provides:

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

Joint Stipulation, filed October 3, 2002, at p. 3.

1417. Unlike the itemization approach he followed with regard to Resid, Jenkins used the Jacobs Consultancy data base to estimate the cost of desulfurizing virgin Heavy Distillate. Exhibit No. EMT-37 at p. 14. Under redirect examination, he explained that he did so because, while the Resid data showed "large variation," there was a "fair amount of data available about distillate hydrotreaters" which he felt "basically met the test." Transcript at p. 3721. He also stated that "[t]he use of a cost curve to estimate the ISBL costs for a hydrotreater, for example, is more reliable than for a Coker." Exhibit No. EMT-146 at p. 18.

1418. The Eight Parties, without effectively citing to any evidence in the record,[568] assert that, had Jenkins used the same approach in calculating the Heavy Distillate ISBL costs as he did with regard to those for Resid, "his cost number would have been considerably higher." Eight Parties Initial Brief at p. 134. They do, however, correctly note that Exxon admitted that it would benefit from a high Heavy Distillate value.[569] *Id.* at n.78. As to the latter, I do not consider this proof of anything as the reverse would be true for the Eight Parties; i.e., the Eight Parties would benefit from a low Heavy Distillate value.

1419. Unlike in the Resid value determination, I am not presented with two distinct methodologies from which to choose an approach to be followed to establish a capital ISBL cost. Here, I am presented with competing cost curves. A review of the evidence cited in the parties's briefs reflects that each side presented substantial evidence to support its position, but that neither side provided evidence compelling a decision in its favor. However, I am troubled by the change in approach which Jenkins made when estimating the Heavy Distillate capital ISBL value as compared with that which he followed in doing the same calculation for Resid. I find his explanation for doing so too facile. Moreover, I find that accepting O'Brien's Baker & O'Brien cost curve approach, as I did with Resid, to add a certain consistency to the Quality Bank calculations. As a result, I will require that it be used to establish the Heavy Distillate capital ISBL value.

1420. O'Brien, according to the Eight Parties, assumed a 50,000 barrels/day high-pressure hydrotreater installed at an existing refinery.[570] *Id.* at p. 135. While it is not

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[568] In a footnote, the Eight Parties make an arcane argument in support of their claim to which I give no credence. *See* Eight Parties Initial Brief at p. 134, n.78. *See also* Exhibit No. WAP-101 at p. 4.

[569] Exxon counsel stated on the record: "I don't think there's any dispute on the record, your Honor, that we're actually benefited by high heavy distillate price [sic]." Transcript at p. 3094.

[570] O'Brien testified that he chose the 50,000 barrels/day hydrotreater because he believed it "to be an economically sized unit that would be commonly installed at a large existing refinery." Exhibit No. PAI-1 at p. 42.

clear on the face of his direct testimony, it appears that it is a high-pressure hydrotreater as O'Brien's proposal is criticized on this point by Dickman. *See* Exhibit No. EMT-118 at pp. 20-21. According to Dickman, based on his "experience, all that would be needed would be a medium-pressure hydrotreater." *Id.* at p. 20.

1421. O'Brien, in response, notes that Dickman's sole support for his criticism is his claimed experience. Exhibit No. PAI-58 at p. 20. He adds that his "experience, however, is that a high pressure hydrotreater (around 800 pounds per square inch (psi) or above) will typically be employed to process virgin Heavy Distillate to a 0.05% sulfur specification" and further states:

> There are only a few refineries on the West Coast that process substantial ANS crude oil and do not have coking units. One of these is the Phillips refinery at Ferndale, Washington. This refinery is a good example because its hydrotreater presumably processes mostly virgin distillates. I understand that the distillate hydrotreater at Phillips' Ferndale refinery operates at a pressure over 1,000 pounds per square inch (psi), which confirms my operating assumption.

Id. at pp. 20-21.

1422. The Eight Parties also refer, in support of O'Brien's proposal, to a Charles River Associates, Inc./Baker & O'Brien study, published in 2000, in which the following comment is made:

> We have assumed that all new grass roots units constructed since 1992, in response to the EPA's 500 ppm diesel regulation, employ pressures in the higher range. Many refiners determined that the incremental cost to build at least an 800 psi unit versus a lower pressure unit was small, and an 800 psi unit protected their investment in the event diesel regulations lowered sulfur in the future.

Exhibit No. WAP-102 at p. 2.

1423. Jenkins conceded, under cross-examination, that an 800 psi hydrotreater is considered to be a high pressure unit. Transcript at p. 3083. While he indicated that he might agree that a high-pressure hydrotreater appropriately would be installed in 2003, in response to whether it would be prudent for a refinery to install such a unit, he replied that "the assertion that somebody in 1992 could anticipate a 15 ppm [EPA] diesel regulation that I don't believe even becomes active until 2005, I struggle with that." *Id.* at p. 3084.[571]

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[571] In response to another question on the same subject, Jenkins stated: "One can

1424. In his direct testimony, Jenkins testified that all that was required to reduce the sulfur content of virgin ANS Heavy Distillate from 0.57% to 0.05% is a medium-pressure hydrotreater. Exhibit No. EMT-37 at p. 13. Therefore, the hydrotreater he used in his concept was a 50,000 barrels/day medium-pressure unit. *Id.*

1425. While neither side presented strong evidence to support its position, I find that the evidence supporting O'Brien's use of a high-pressure hydrotreater is far stronger than that supporting Jenkins's medium-pressure hydrotreater proposal. The Eight Parties note the increasing stringency of the Environmental Protection Agency regulations governing sulfur content of diesel fuel require the use of a high-pressure hydrotreater. While Jenkins argued, during his cross-examination, that one could not forecast that fact in 1992, I do not think that we are compelled to view the case from a 1992 perspective. The parties have not even presented their evidence from this perspective.

1426. I recognize that Dickman testified that, in his "experience," all that was required is a medium-pressure unit. This testimony was countered by O'Brien who testified that his experience was to the contrary. O'Brien also pointed out that the Phillips Ferndale refinery used a high-pressure hydrotreater to process virgin ANS Heavy Distillate.

1427. Exxon argues that the Eight Parties failed to prove that a medium-pressure hydrotreater was not sufficient. Exxon Reply Brief at p. 158. I do not find this argument persuasive as Exxon had the affirmative burden of proving that its proposal was best, and it failed to do so. Indeed, other than Dickman's claim that a medium-pressure hydrotreater was all that was necessary, discussed above, I can find no evidence in the record, and Exxon has pointed to none on brief, which supports Jenkins's proposal.

1428. In view of the above, I find that the Heavy Distillate capital ISBL cost should be calculated on the basis of a high-pressure hydrotreater.

b. OSBL Costs

1429. O'Brien calculated the Heavy Distillate capital OSBL cost as being 29% of its ISBL cost.[572] Eight Parties Initial Brief at pp. 136-37. Referring to the Gary & Handwerk textbook, without providing a page citation, he claims that "this percentage is within the expected range for capital additions to existing refineries." Exhibit No. PAI-1 at p. 42.

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know in 1992 or whenever this date is that there was an EPA regulation requiring 500 ppm diesel. For one to say you know that the EPA 10 years later or nine is going to specify lower sulfur diesel, I don't see how we can say that." Transcript at p. 3084.

[572] Exhibit Nos. PAI-1 at p. 42, PAI-19.

1430. Exxon argues that, while Jenkins included them in his estimate, O'Brien "made no allowance at all for storage." Exxon Initial Brief at p. 154. In his testimony, Jenkins states:

> I have adopted the approach recommended in Gary & Handwerk's treatise (pp. 333 to 338). Most estimators refer to all facilities other than the process units themselves as "offsite facilities," and use a single offsite cost factor. However, in estimating the costs of offsite facilities required for the addition of individual process units in an existing refinery, Gary & Handwerk separately estimate costs for three specific types of major support facilities -- storage tanks, steam generation equipment, and cooling water systems -- and then apply a percentage factor to the process unit costs to account for the costs of all of the other offsite facilities. For these other facilities, Gary & Handwerk suggest a factor equal to 20% to 25% of the process unit costs.

Exhibit No. EMT-37 at p. 17. Despite this, in a footnote, Exxon admits that Jenkins did not fully apply the Gary & Handwerk methodology because he only provided a separate estimate for the storage costs and failed to do so for the costs of the steam generation equipment and cooling water systems because the hydrotreater does not use a large amount of either and because "'only minor modification' to existing steam or cooling water systems would be needed." Exxon Initial Brief at p. 154, n.67.

1431. According to Exxon, two intermediate storage tanks "with a combined capacity of 15 days' output" would be necessary to store the Heavy Distillate prior to processing. *Id.* at pp. 154-55. It notes that the reasonableness of Jenkins's $14/barrel cost for Heavy Distillate storage tanks was proven by the $31/barrel estimate contained in the Stillwater Report.[573] *Id.* at p. 155. However, the authors of the Stillwater Report, at least where it was cited by Exxon, were discussing the construction of a Strategic Fuel Reserve capable of holding 5 million barrels. Exhibit No. EMT-489 at pp. 83-84. Exxon has not pointed to any evidence in the record which supports a conclusion that the costs of such a product are comparable to the costs of building Heavy Distillate storage tanks capable of holding a 15 day supply.

1432. The Eight Parties argue that "[t]here is no reason to include storage tank costs because no new tanks had to be constructed, and there is not even any evidence that any existing storage tanks for the Heavy Distillate hydrotreater would have to be revamped at a Quality Bank refinery." Eight Parties Reply Brief at pp. 115-16.

1433. I find Jenkins's approach, once again, to present an anomaly. He claims to be

[573] Exhibit No. EMT-489 at pp. 83-84.

following the methodology set forth in Gary & Handwerk, but admits that he didn't totally accept it. In other words, though Gary & Handwerk recommend making separate estimates for the costs of storage, steam, and cooling water, Jenkins only separately estimated the costs of storage. His explanation, that the costs for steam and cooling water were insignificant, is too easy an explanation for omitting those steps and is not supported by any evidence.

1434. O'Brien followed an approach which is accepted by the industry. He estimated the OSBL cost to be 29% of the ISBL cost or 22.5% of the total capital cost. This is clearly within the range specified in the Gary & Handwerk textbook. Taking all of the evidence into consideration, I find this method to be appropriate, and the result to be just and reasonable.

2. Location Factor

1435. As noted above,

> [a] location factor is an adjustment factor used to translate a construction cost estimate developed for a specific project in a specific location (usually the U.S. Gulf Coast) to obtain a cost estimate for the same project in different parts of the country under the assumption that the cost to build a similar facility will vary depending on where it is located.

Eight Parties Initial Brief at p. 138. The Eight Parties and their witness, O'Brien, claim it is not appropriate to use a location factor here because the "Distillate hydrotreater proposed is not for a specific project defined in sufficient detail and pinned down to a specific location." *Id.* at p. 139. They also suggest that location factors are overly subjective. *Id.* at pp. 142-46. Moreover, they argue, were a location factor to be used, it should be no higher than 1.16, not the 1.3 proposed by Exxon. *Id.* at pp. 146-48.

1436. Exxon argues that the use of a location factor is appropriate because "it is beyond reasonable doubt that construction costs, including labor costs, environmental costs, and regulatory costs, are significantly higher on the West Coast than they are on the Gulf Coast." Exxon Initial Brief at p. 157. It suggests that the use of a 1.3 location factor "is both conservative and well supported by industry standards, by the Gary & Handwerk treatise, and even by a study prepared by Mr. O'Brien's own firm." *Id.*

1437. With respect to this issue, the parties make exactly the same argument as to the use of a location factor as they did with respect to the use of a location factor on the Resid estimates. Moreover, the evidence on which those arguments are based is exactly the same. As to Resid, I determined that a location factor should be used inasmuch as the record clearly supported a conclusion that construction costs were higher on the West Coast, that the fact that a "specific" site for construction of the plant on the West Coast was irrelevant, and that a just and reasonable location factor to be used was 1.27. For the reasons stated in that discussion I find that a location factor is appropriate to be used as to the Heavy Distillate cut and the appropriate location factor to be used is 1.27.

3. Operating Costs

1438. Another area of dispute between the parties revolves around the amount of hydrogen which would be used to reduce the sulfur content of the Heavy Distillate. Exxon Initial Brief at p. 165. It states that Jenkins assumed a consumption rate of 180 standard cubic feet/barrel. *Id.* at pp. 165-66. In his testimony, Jenkins claimed that he "calculated hydrogen consumption based on the specific properties of the ANS Heavy Distillate cut." Exhibit Nos. EMT-146 at p. 57, EMT-166. He adds that O'Brien did not do so, but based his estimate on Gary & Handwerk data. Exhibit No. EMT-146 at p. 57.

1439. Exxon, further, asserts that an August 2000 Charles River Associates, Inc./Baker & O'Brien study prepared for the American Petroleum Institute[574] supports Jenkins's testimony:

> That study estimated hydrogen consumption for a distillate with a sulfur content similar to ANS Heavy Distillate in the range of 160 to 170 standard cubic feet per barrel – much closer to Mr. Jenkins' estimate of 180 standard cubic feet per barrel than to Mr. O'Brien's estimate of 250 standard cubic feet per barrel.

Exxon Initial Brief at p. 166.

1440. According to Exxon, a difference between the Jenkins and O'Brien estimate of hydrogen consumption lies in O'Brien's use of a high-pressure hydrotreater and Jenkins's use of a medium-pressure hydrotreater. *Id.* at pp. 166-67. The former, it says, uses more hydrogen.[575] *Id.* at p. 167.

1441. The Eight Parties assert that, contrary to his claim, Jenkins did not base his calculations on ANS Heavy Distillate. Eight Parties Initial Brief at p. 149. Rather, they claim, he admitted that the last element in his calculation, solution loss, "is based not on ANS Heavy Distillate, but rather on his experience that solution loss is less than industry

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[574] Exhibit No. EMT-294, Figure 4.1 at p. 3.

[575] Jenkins testified that "[a]s pressure goes up, then hydrogen consumption goes up even if there's no change in desulfurization." Transcript at p. 3347. He also stated that, if he had assumed a pressure higher than the one he did (650 pounds), the hydrogen consumption he forecasted would rise. *Id.* at p. 3350.

rules of thumb."[576] *Id.* Moreover, the Eight Parties declare, Jenkins agreed that, had he used the Gary & Handwerk solution loss figure (190 cubic feet/barrel), his total hydrogen consumption estimate would increase to 324 cubic feet/barrel.[577] *Id.* (citing Transcript at pp. 3080-81).

1442. Exxon asserts that the real difference between O'Brien's and Jenkins's hydrogen consumption estimates lies in the pressure of the hydrotreater each used. Exxon Reply Brief at p. 174. O'Brien used a high-pressure hydrotreater and Jenkins used a medium-pressure hydrotreater. Above, I decided that the high-pressure hydrotreater should be used. Concomitantly, therefore, I am compelled to accept O'Brien's estimate of hydrogen consumption.

B. LOGISTICS ADJUSTMENT

1443. The Eight Parties argue that "the Heavy Distillate reference price requires a logistics adjustment to bring it onto a consistent basis with all of the other liquid Quality Bank cuts." Eight Parties Initial Brief at p. 150. They suggests that the adjustment should be 1.1¢/gallon. *Id.* According to them, the adjustment is required to place Heavy Distillate on the same waterborne basis as the other liquid cuts.[578] *Id.* at p. 151-52. In other words, the Eight Parties claim that the 1.1¢/gallon is "the average of costs incurred in transporting product inland [sic] to the pipeline from its arrival point at the harbor." *Id.* at p. 152. They suggest that, as the pipeline reference price is inflated by this cost factor, in order for the value of Heavy Distillate to be set at the same waterborne level as the other liquid cuts, the costs of transportation must be deducted. *Id.*

1444. Exxon asserts that this question is not before me at this time. Exxon Initial Brief

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[576] Under cross-examination, Jenkins testified that the 30% solution loss figure he used was based on his "experience" that solution loss "tends to be less than some of the rules of thumb." Transcript at p. 3077. He also said that the figure was not based on a design, but on a 1980 project "where we were trying to determine where hydrogen was lost in refineries." *Id.*

[577] This claim is not entirely accurate. Jenkins agreed with the math, but stated that he disagreed "with the premise, because hydrogen solution loss is a function of pressure. And so without knowing that and without having really better understanding, I really can't see how plugging that in works." Transcript at p. 3081.

[578] Ross testified that "product arriving by sea must first be transported from the harbor area to a pipeline hub before it can be sold. Value is added in moving product to the pipeline hub, which allows product at the pipeline hub to command a higher price than waterborne cargoes." Exhibit No. BPX-1 at p. 10.

at p. 167. According to it, with regard to Heavy Distillate, the only issue which the Commission referred to me regarded the appropriate sulfur processing adjustment. *Id.* at p. 168 (citing *Trans Alaska Pipeline System*, 97 FERC at pp. 61,650, 61,652).

1445. It also asserts that Ross, the Eight Parties's witness, erroneously stated that all of the liquid cuts, other than Heavy Distillate, were valued on a waterborne basis since LSR, also a liquid cut, was valued on a Bakersfield truck/rail basis. Exxon Initial Brief at p. 172 (citing Exhibit No. EMT-11 at p. 12). Exxon notes that, on cross-examination, Ross admitted that LSR was a liquid at room temperature which was not valued on a waterborne basis.[579] *Id.*

1446. Further, Exxon states, Ross's evidence in support of this proposal is questionable. It notes that much of his support for the proposal is based only on two telephone conversations, one in 2000 and the other in 2002, regarding the costs of transporting the product from the harbor to the pipeline.[580] *Id.* at p. 176 (citing Transcript at pp. 1690-92, 1698). Exxon also points out that Ross admitted that he did not know what the costs were in 1991 or 1992 or what the range was over a five or 10 year period. *Id.* (again citing Transcript at pp. 1690-92, 1698).

1447. The scope of the hearing is set by the Commission, and I cannot consider any matter not referred to me by it. *See Sierra Pacific Power Co.*, 104 FERC ¶ 61,223 at P 33-36 (2003). In its November 7, 2001, Order referring these matters to the Office of Administrative Law Judges for hearing, the Commission stated: "At issue in the replacement product proceeding is the level of the sulfur processing adjustment necessary to bring the TAPS Heavy Distillate cut into line with the quoted price." *Trans Alaska Pipeline System*, 97 FERC at p. 61,652.[581] In view of this, I find that the question of whether the Heavy Distillate reference price should be adjusted by the cost of transporting the product from the harbor to the pipeline is not before me.

1448. Even were the issue before me, I would find that the Eight Parties failed to satisfy their burden of showing that it was warranted, in general, and that its specific proposal, that the adjustment be 1.1¢/gallon, was just and reasonable. Though their argument is primarily justified on the Eight Parties's claim that the adjustment is necessary to place Heavy Distillate on the same waterborne basis as *all* of the other liquid cuts, even Ross admits, it is not the only liquid cut which is not valued on a waterborne basis. As a result,

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[579] See Transcript at pp. 1722-23.

[580] Ross admitted that he did not even verify the information he received in those phone conversations. Transcript at pp. 1699-1700.

[581] *See also Trans Alaska Pipeline System*, 90 FERC ¶ 61,123 at p. 61,371 (2000).

the Eight Parties's theory collapses. Moreover, there is no consistency in where cuts are valued; some are valued at truck/rail location, others at a pipeline, still others are valued on a waterborne basis.[582] Consequently, contrary to another of the Eight Parties's arguments, there is no necessity that the Heavy Distillate reference price be adjusted by the cost of placing it on a waterborne basis for the sake of consistency. Thus, had I been required to rule, I would have concluded that the Eight Parties failed to prove that their proposed adjustment was warranted. Furthermore, their proposed 1.1¢/gallon adjustment is based, at least in part, on specious evidence.[583]

C. BASE YEAR

1449. The Eight Parties note that O'Brien chose 1996 as the base year, but state that they "do not believe that choice of a base year should have a material impact on the outcome of the Heavy Distillate issue." Eight Parties Initial Brief at p. 160. Exxon notes that Jenkins used 2000 as his base year. Exxon Initial Brief at p. 182. Moreover, it makes the same argument regarding use of both the Nelson Farrar Construction Cost Index and the Nelson Farrar Operating Cost Index as it made with regard to Resid. *Id.* at pp. 183-85. Aside from that, Exxon concedes "it should not matter which year – 1996 or 2000 – is used as the base year." Exxon Reply Brief at p. 192.

1450. With regard to the base year to be used in connection with Heavy Distillate, the parties made the same arguments, based on the same evidence, as they made with regard to the base year to be used in connection with Resid. My rulings remain the same and for the same reasons: (1) only the Nelson Farrar Operating Cost Index should be used; and (2) the base year should be Year 2000 and the existence or non-existence of certain equipment should not be considered in making any calculations.

ISSUE NO. 3: WHETHER THE CURRENT METHOD FOR VALUING THE WEST COAST NAPHTHA CUT IS JUST AND REASONABLE, AND IF NOT, WHAT IS THE APPROPRIATE METHOD FOR VALUING THE NAPHTHA CUT? WHAT SHOULD BE THE EFFECTIVE DATE OF ANY CHANGE TO THE WEST COAST NAPHTHA CUT?

A. LEGAL STANDARD AND BURDEN OF PROOF

1. Exxon

[582] Exhibit No. EMT-253. *See also* Exxon Initial Brief at p. 174.

[583] *See* Transcript at pp. 1690-92.

1451. In response to a Circuit Court decision that the Commission's practice of valuing West Coast Naphtha on the basis of Platts Gulf Coast Naphtha price was not just and reasonable,[584] explains Exxon, the Commission set the issues of whether the current method of valuing the Quality Bank Naphtha cut on the West Coast is just and reasonable, and if not, what new methodology should be adopted for valuing West Coast Naphtha for hearing in this proceeding. Exxon Initial Brief at p. 187.

1452. Exxon argues, and other parties agree, that the Commission has an affirmative statutory obligation to ensure that the method selected for valuing the West Coast Naphtha cut produces a just and reasonable result. *Id.* at pp. 187-88; *see also* Exxon Reply Brief at p. 195. In particular, according to Exxon, the Commission has directed that the value produced must "bear a rational relationship to the actual value" of the particular product in the real world marketplace. Exxon Initial Brief at p. 188 (quoting *Trans Alaska Pipeline Co.,* 97 FERC at p. 61,651). In addition, Exxon notes, the Commission has directed that all proposals be administratively feasible. *Id*. And in prior decisions in this case, it points out, the Commission has also stressed that the methodology should "not [be] susceptible to manipulation." *Id.* (quoting *Trans Alaska Pipeline Co*., 65 FERC at p. 62,289).

1453. It is also well established, according to Exxon, that a prior determination that a particular rate or practice was just and reasonable does not preclude the Commission from later reviewing the evidence and making a new determination that the previously approved rate or practice is no longer just and reasonable. *Id.* Exxon points out that, according to the Circuit Court, the Commission has an ongoing obligation to ensure that rates are just and reasonable and a rate once found acceptable could later be found unreasonable. *Id.*

1454. For these reasons, Exxon asserts that Commission rate orders are never constrained by principles of res judicata. *Id.* at pp. 188-89. On the contrary, Exxon states that any party believing that an existing rate is not just and reasonable may file a complaint at any time, and the Commission has both the power and the duty to re-examine the reasonableness of such existing rates whenever there is evidence warranting a change. *Id.* at p. 189.

1455. Further, Exxon states that, contrary to the position of Williams, the law is clear that there is no need for the proponents of a new West Coast Naphtha valuation to show any changed circumstances above and beyond the new evidence that the Supreme Court held to be sufficient to require further Commission investigation. *Id.* In view of Supreme Court and Circuit Court decisions holding that new evidence imposes a duty upon an agency to investigate further the reasonableness of challenged rates, Exxon asserts, the Commission plainly has no authority to impose a higher burden on

[584] *Tesoro*, 234 F.3d at pp. 1292-93.

complainants before they will consider new evidence that a challenged rate is unreasonable. *Id.*; *see also* Exxon Reply Brief at p. 196. Accordingly, Exxon states, as a matter of law, any changed circumstances requirement must be construed to be equivalent to new evidence. Exxon Initial Brief at p. 189.

1456. In any event, Exxon asserts, the record in this case demonstrates beyond any possible question that there is both new evidence and changed circumstances regarding the value of Naphtha on the West Coast. *Id.* at p. 190. First, Exxon notes, the fact that the Commission has now abandoned its former policy of using only market prices instead of formulæ to value all ANS cuts by adopting adjusted prices for several ANS cuts is clearly a changed circumstance that bears directly on the reasonableness of the Commission's prior reliance on the Gulf Coast Naphtha price as a proxy for the value of West Coast Naphtha. *Id.*

1457. Second, Exxon states, the reduction in deliveries of ANS crude to the Gulf Coast from nearly 17% in 1994 to zero by mid-1999 is another changed circumstance that renders the use of the Gulf Coast Naphtha price to value West Coast Naphtha invalid. *Id.*

1458. Third, Exxon cites the large disparity between the Gulf Coast Naphtha price adopted by the Commission in 1993 as a proxy for the value of West Coast Naphtha and the actual market value of West Coast Naphtha as more than sufficient to establish changed circumstances. *Id.*

1459. Fourth, according to Exxon, the use of Naphtha to make gasoline on the West Coast (but not on the Gulf Coast) was impacted by the California Air Resources Board (sometimes "CARB") requirements that came into play in 1996. *Id.*

1460. Fifth, Exxon asserts, the evidence shows that, beginning in 1999, any similarities that may have previously existed between Gulf Coast and West Coast gasoline prices came to an end as gasoline prices on the West Coast and the Gulf Coast diverged even further. *Id.* at pp. 190-91.

1461. Lastly, Exxon claims, the mere passage of time between rate proceedings and the resulting different rate periods has been held to be sufficient to establish materially different circumstances. *Id.* at p. 191.

1462. Exxon concludes that, in these circumstances, the Commission has a clear statutory obligation to weigh the evidence that using the Gulf Coast Naphtha price to value Naphtha on the West Coast does not produce a just and reasonable result and, if it so finds, to determine what valuation methodology would produce a just and reasonable value for West Coast Naphtha. *Id.* Further, because the evidence presented in this case is more than sufficient to establish that the current method of valuing Naphtha is not just and reasonable; there is no need to resolve the distinction between "new evidence" and "changed circumstances" in this proceeding. Exxon Reply Brief at p. 197.

1463. In a complaint case, Exxon explains, challenging an existing rate as unjust and unreasonable, the complainant has the burden of proof. Exxon Initial Brief at p. 191. While the complainant always bears the ultimate burden of persuasion, once the complainant has established a prima facie case of unreasonableness, Exxon claims, a presumption of unreasonableness arises and the burden of going forward and producing evidence showing that the rate is just and reasonable shifts to the proponent of the rate.[585] *Id.* at pp. 191-92.

1464. Exxon states that there already has been a specific determination by the Circuit Court in *Tesoro* that the evidence previously presented by Tesoro to the court (showing that the Gulf Coast Naphtha price is not an appropriate proxy for valuing West Coast Naphtha) was more than sufficient to establish a prima facie case and that, therefore, the Commission was required to re-examine its policy of using the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at p. 192. It explains that the Circuit Court held the evidence of unreasonableness presented – including the rejection and abandonment of the Commission's no adjustment policy, the decline in Gulf Coast ANS sales since 1993, and the large disparity between the Gulf Coast Naphtha proxy price and the true market value of Naphtha on the West Coast – established at least a prima facie case of unreasonableness that warrants re-examination of how West Coast Naphtha should be valued. *Id.*

1465. Each of these three pieces of evidence also has been clearly established in this phase of the case, Exxon asserts. Exxon Reply Brief at p. 198. First, states Exxon, it is undisputed that deliveries of ANS crude to the Gulf Coast have not only nearly disappeared; they have completely disappeared for more than four years. *Id.* In accordance with the Circuit Court's *Tesoro* decision, continues Exxon, this evidence alone renders the current practice of using a Gulf Coast Naphtha price to value West Coast Naphtha more suspect than it was in 1993. *Id.*

1466. Second, explains Exxon, the fact that the Commission's 1993 decision to use the Platts Gulf Coast price to value West Coast Naphtha was rejected in the *OXY* decision and abandoned on remand clearly constitutes a changed circumstance. *Id.* at pp. 198-99.

1467. Third, Exxon notes, it has introduced substantial evidence that a large disparity exists between the Platts Gulf Coast Naphtha price and the actual market value of West Coast Naphtha and that disparity is growing larger. *Id.* at pp. 199-200. Contrary to

[585] Exxon cites two cases in support of the statement: *St. Mary's Honor Center v. Hicks*, 509 U.S. 502, at p. 506 (1993) and *Texas Dep't of Community Affairs v. Burdine*, 450 U.S. 248, at p. 254 (1981). Exxon Initial Brief at pp. 191-92.

Williams's contention, therefore, Exxon asserts, all three of the factors found by the *Tesoro* Court to establish at least a prima facie case that the use of a Gulf Coast price to value West Coast Naphtha is unreasonable are also clearly established in this case. *Id.* at pp. 200-01.

1468. In addition, Exxon argues, substantial new evidence has been presented in this proceeding that the use of the Gulf Coast price to value West Coast Naphtha is unreasonable. *Id.* at p. 201. For example, states Exxon, it is undisputed that, beginning in 1999, any similarities that may have previously existed between Gulf Coast and West Coast gasoline prices came to an end as gasoline prices on the West Coast spiked upward and diverged sharply from Gulf Coast gasoline prices. *Id.* Therefore, according to Exxon, it is no longer valid to link West Coast Naphtha values to Gulf Coast Naphtha prices. *Id.*

1469. Further, explains Exxon, there was a major change in the market for Naphtha on the West Coast, but not the Gulf Coast, in 1996, because of the introduction of CARB Phase II gasoline in California and the subsequent effect on the gasoline and jet fuel markets on the West Coast. *Id.* at pp. 201-02. While the parties dispute the impact of this change, Exxon asserts that there is no dispute that the 1996 CARB gasoline requirements are a changed circumstance that has affected the relationship between the value of West Coast Naphtha and the Gulf Coast Naphtha price. *Id.* at p. 202.

1470. In light of this substantial new evidence that the Gulf Coast Naphtha price does not represent the value of West Coast Naphtha, Exxon, Phillips, BP, and Alaska have clearly met their burden of establishing a prima facie case that the current practice of using the Platts Gulf Coast Naphtha price to value West Coast Naphtha is not just and reasonable. *Id.* Indeed, under the Circuit Court's *Tesoro* decision, according to Exxon, that evidence has established a prima facie case as a matter of law. *Id.* (citing *Tesoro*, 234 F.3d at p. 1293). As a result, Exxon argues, a presumption that the use of the Gulf Coast Naphtha price to value West Coast Naphtha does not produce a just and reasonable result exists, and the burden of going forward to produce evidence that the use of the Gulf Coast Naphtha price to value West Coast Naphtha is just and reasonable should be shifted to those parties who advocate the continued use of the Gulf Coast Naphtha price to value West Coast Naphtha. Exxon Initial Brief at pp. 192-93.

1471. Regardless of how the burden of proof and the burden of producing evidence are allocated, however, Exxon's view is that the evidence introduced at the hearing in this case clearly establishes beyond any possible doubt that the use of the Gulf Coast Naphtha price to value West Coast Naphtha is not just and reasonable, and that some other method is required to value West Coast Naphtha consistent with the Commission's statutory mandate to establish just and reasonable rates and practices. *Id.* at p. 193.

1472. In an attempt to avoid its burden of defending the use of a Gulf Coast price to value West Coast Naphtha, states Exxon, Williams also seeks to impose additional burdens on those parties that wish to change the existing practice by expanding their burden into a "three part inquiry:" (1) that there are changed circumstances, (2) that those changed circumstances render the existing methodology unjust and unreasonable, and (3) that the proposed alternative methodology is just and reasonable. Exxon Reply Brief at p. 204. Exxon suggests that, as noted above, the first two of these hurdles are obviously one and the same because changed circumstances are one form of new evidence that can render the existing methodology unjust and unreasonable. *Id.* Nor, in Exxon's view, is there any basis for Williams's third hurdle since, as the law is clear that once it has been established that the existing methodology is unreasonable and unlawful, the Commission has a statutory obligation to put in place a new valuation methodology that is just and reasonable. *Id.* It explains that at least six new valuation methodologies have been proposed in this proceeding, and with respect to those proposed methodologies, each party has the burden of supporting its own proposal. *Id.*

2. Phillips

1473. According to Phillips,[586] three decisions by the Circuit Court regarding the Quality Bank methodology provide guidance for the valuation of the West Coast Naphtha cut.[587] Phillips Initial Brief at p. 5. In particular, Phillips asserts, court precedent and the tenet of reasoned decision making requires uniform approach and consistency in the Commission's approach to valuation of West Coast Naphtha. *Id.* at p. 6.

1474. As all parties have agreed that West Coast VGO should be valued based on the published West Coast price for VGO, Phillips states, Naphtha is the only cut where any party contends that West Coast deliveries should be valued based on Gulf Coast prices. *Id.* To meet the uniformity requirement, Phillips argues, Naphtha also should be valued on the same basis as the other West Coast cuts; that is, on a West Coast basis. *Id.* at pp. 6-7.

1475. To be able to satisfy the *OXY* uniformity requirement, Phillips asserts, the evidence in the record supporting the use of a Gulf Coast price to value West Coast Naphtha would have to demonstrate that the published Gulf Coast Naphtha price would consistently match the West Coast value of Naphtha almost exactly over a long period of time. *Id.* at p. 7. Here, points out Phillips, the evidence not only fails to show the

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[586] Except as regards a proposed minor modification to O'Brien's proposal regarding valuing West Coast Naphtha, and additional commentary on the Naphtha contract analyses, both discussed below, Alaska states that it joins and supports Phillips's position on Issue No. 3. Alaska Initial Brief at p. 1.

[587] Philips cites *Tesoro*, 234 F.3d 1286; *Exxon*, 182 F.3d 30; *OXY*, 64 F.3d 679.

requisite close correlation between the Gulf Coast proxy and the West Coast value, but it also demonstrates that the West Coast value continually exceeds the Gulf Coast proxy by amounts that clearly are significant under *OXY*. *Id.*

1476. Phillips explains that the *OXY* decision also provides guidance for evaluating the various proposed alternative West Coast Naphtha valuation methodologies. *Id.* at p. 8. Because all other Quality Bank cuts are valued at the published price on the coast where the cut is delivered less the processing costs, Phillips asserts, in order to satisfy the *OXY* consistency requirement, the West Coast Naphtha price adopted by the Commission should follow the same approach. *Id.* It points out that the proponents of using the Gulf Coast Naphtha price to value West Coast Naphtha have completely ignored the *OXY* holding, and notes that they did not attempt to explain how valuing West Coast Naphtha with Gulf Coast prices could satisfy this standard when no other cut will have its West Coast value determined through Gulf Coast prices. Phillips Reply Brief at p. 8. Phillips states that Williams, in particular, fails to acknowledge the central holding of *OXY* that cut valuations must be uniform to the extent possible. *Id*. at p. 8, n.8.

1477. According to Phillips, the *Exxon* decision requires that the Gulf Coast Naphtha price be more than similar to the value of West Coast Naphtha or just fall within some observed range of West Coast Naphtha values. Phillips Initial Brief at p. 9. Instead, explains Phillips, there must be some rational relationship between the Gulf Coast price and the actual market value of West Coast Naphtha. *Id.* Further, notes Phillips, they must correlate consistently and closely over the long term. *Id.* Phillips also notes that the *Exxon* court specifically stated that "the goal of administrative efficiency and objectivity [did] not free [an] agency from [this] requirement." *Id.* (quoting *Exxon*, 182 F.3d at p. 42).

1478. Phillips concedes that it is difficult to apply the *Exxon* holding here where the actual market value of West Coast Naphtha is not known. *Id.* There is, according to Phillips, abundant evidence on the record regarding the differences between the Gulf Coast and West Coast markets, in general, as well as of West Coast Naphtha contract prices. *Id.* at pp. 9-10. As this evidence strongly supports the conclusion that the Gulf Coast Naphtha price does not correlate consistently and closely with the West Coast Naphtha value over the long term, Phillips argues, the use of the Gulf Coast Naphtha price to value West Coast Naphtha violates the *Exxon* holding. *Id.* at p. 10. Nevertheless, explains Phillips, the Gulf Coast pricing advocates simply ignore the "rational relationship" requirement and base their case on a hypothesis of long term price "similarity" that is indistinguishable from the one rejected in *Exxon*. Phillips Reply Brief at p. 9.

1479. Phillips notes that Williams cites *Exxon* for the following proposition: "the fact that a more precise method exists for determining the relative value of the streams [would] not render [a] decision to adopt a less accurate, but more administrable, method arbitrary and capricious." *Id.* (quoting *Exxon*, 182 F.3d at p. 40). It notes that the language Williams quotes, however, dealt with Exxon's claim that there should be intra-cut differentials established for the Resid and Heavy Distillate cuts. *Id.* However, it states, the Circuit Court was referring to the valuation of "streams," rather than cuts, and nothing in that proposition suggests any basis on which Gulf Coast pricing of the Naphtha cut could be reconciled with West Coast valuation of all other cuts. *Id.* It also states that the *Exxon* court reiterated the requirement that there be "reasoned relative uniformity" in the valuation of all Quality Bank cuts, and it imposed the additional requirement that there be a demonstrable "rational relationship" between the values of the proxy and the cut. *Id.* at pp. 9-10 (quoting *Exxon*, 182 F.3d at p. 38). Phillips states these are all requirements that the Gulf Coast Naphtha proxy cannot meet. *Id.* at p. 10.

1480. According to Phillips, the Circuit Court's decision in *Tesoro* provides the most directly applicable guidance for the West Coast Naphtha issue. Phillips Initial Brief at p. 10. It explains that Tesoro relied on three propositions in its complaint to support its claim that use of Gulf Coast Naphtha prices to value West Coast Naphtha is not just and reasonable. *Id.* The first, states Phillips, was that Gulf Coast ANS deliveries "have declined considerably from the somewhat less than 20% level that existed in 1993." *Id.* (quoting *Tesoro*, 234 F.3d at p. 1292). It further notes that the Court found that "[t]he nearly complete disappearance of Gulf Coast ANS sales suggests that the Commission's current reliance [on Gulf Coast prices] is more dubious now than in 1993." *Id.*

1481. Second, continues Phillips, Tesoro asserted that the decision to use the Gulf Coast Naphtha price was based on a "No Adjustment Policy" that the Circuit Court rejected and which, since then, has been abandoned by the Commission. *Id.* It notes that the Circuit Court further made clear that the principle of uniformity announced in *OXY* "would be breached if the availability of an adequate non-adjusted benchmark for the Gulf Coast prevented the use of an adjusted benchmark for the West Coast." *Id.* at p. 11 (quoting *Tesoro*, 234 F.3d at p. 1293). In Phillips's view, this ruling clearly precludes the use of the Gulf Coast price for Naphtha in lieu of an adjusted West Coast value – the very point at issue here. *Id.*

1482. Phillips states that the proponents of Gulf Coast pricing not only ignore this holding, they affirmatively rely on the No Adjustment Policy to support their position. Phillips Reply Brief at p. 14. It notes that both Williams and Unocal/OXY cite the policy as if it were still in effect without even mentioning the controlling contrary ruling by the *Tesoro* court or attempting to explain why that ruling does not apply. *Id.* at p. 15.

1483. The Circuit Court noted, Phillips explains, that Tesoro had presented calculations showing that the Gulf Coast Naphtha price in December 1996 undervalued West Coast Naphtha by $2.71/barrel: "This alleged disparity dwarfs the ones that required remand in *OXY*. *See* 81 FERC at 62,462 (revising valuation of light distillate by $0.005 per gallon, or $0.21 per barrel, after *OXY* remand)." Phillips Initial Brief at p. 11 (quoting *Tesoro*, 234 F.3d at p. 1293). For that reason, it states, the issue of West Coast Naphtha valuation was remanded for hearing. Phillips Reply Brief at p. 15.

1484. Phillips claims that there were two categories of evidence in the hearing record as to the actual value of Naphtha in the West Coast market. *Id.* The first consists of the Naphtha contracts, and the second is the valuation methodologies advanced by the experts. *Id.* It asserts that the Naphtha contracts constitute the only direct evidence of value. *Id.* Phillips claims that the contracts provided the most accurate benchmark because they represent actual prices that sophisticated market participants paid in arms-length transactions over a number of years. *Id.* Further, it explains, four different experts from differing points of view offered analyses of the prices paid in these transactions (O'Brien, Pulliam, Tallett and Culberson). *Id.* According to Phillips, despite the range in their views regarding Naphtha contracts, their analyses all showed that the West Coast Naphtha values exceeded the Gulf Coast by at least 6¢/gallon in the period 1994-2001 and by considerably more in the period 1999-2001. *Id.* Phillips notes that the differences are similar to or larger than the differences in value that were alleged in Tesoro's complaint and found by the Circuit Court to "dwarf" the differences that required remand in *OXY*. *Id.* at p. 16 (citing *Tesoro,* 234 F.3d at p. 1293).

1485. According to Phillips, the only experts who calculated West Coast values for Naphtha were O'Brien, Tallett and Dudley. *Id.* It contends that the values calculated by O'Brien and Tallett were soundly based technically, and they correlated well with the values proved in the Naphtha contracts. *Id.* Phillips asserts that Dudley's calculation had no rational basis and that he used an approach he created for this litigation that was wholly different from what he had done for clients in the past. *Id.* It argues that it was not reconcilable with the contract evidence and is not worthy of consideration in evaluating West Coast Naphtha values. *Id.*

1486. Under the Interstate Commerce Act, states Phillips, the burden of proof in a complaint proceeding rests with the party asserting that an existing rate or practice should be changed. Phillips Initial Brief at pp. 11-12. It asserts that the relevant statutory provision requires the Commission to make an affirmative finding that an existing rate or practice is unjust and unreasonable. *Id.* at p. 12.

1487. At the time the complaints were filed, notes Phillips, the TAPS Carriers had not proposed any change in the valuation of the West Coast Naphtha cut. *Id.* That cut was valued at the published Gulf Coast Naphtha price, and, explains Phillips, this valuation had been established by the Commission in 1993 and was not among the issues challenged on appeal to the Circuit Court. *Id.* As a result, under the complaint proceedings initiated to review the West Coast Naphtha value used in the Quality Bank, Phillips asserts, the parties proposing to change the West Coast Naphtha valuation have the burden of proving that the use of the published Gulf Coast price is unjust and unreasonable. *Id.*

1488. Phillips states that a party bearing the burden of proof has an "obligation to produce substantial evidence for the record" demonstrating the current methodology is unjust and unreasonable. *Id.* (quoting *Amerada Hess Pipeline Corp*., 71 FERC ¶ 61,040 at p. 61,166 (1995)). Once that substantial evidence is presented and a prima facie case is made, however, Phillips explains that the burden of going forward shifts to the other side. *Id.* (*citing SFPP, L.P*., 84 FERC ¶ 61,338 at p. 62,498 (1998)).

1489. In this proceeding, Phillips claims that it and the other parties opposing the continued use of the Gulf Coast published price to value West Coast Naphtha have submitted substantial evidence demonstrating that use of such prices is unjust and unreasonable. *Id.* The hearing record includes not only substantial evidence supporting the three points that the *Tesoro* Court found establish a prima facie case for reevaluation of the Naphtha methodology, but, in Phillips's view, also substantial additional evidence demonstrating the very significant differences between the two markets and the higher value Naphtha commands on the West Coast. *Id.* at pp. 12-13. As a result, Phillips believes that the parties advocating a West Coast value have met the burden of proof assigned to them in the complaint proceedings. *Id.* at p. 13.

1490. On the other hand, asserts Phillips, the parties advocating continued use of the Gulf Coast Naphtha price to value West Coast Naphtha have not met the burden of going forward placed on them as a consequence of the showing made by Phillips and others. *Id.* Phillips argues that the evidence that supporters of the current methodology have submitted does not justify continued use of the Gulf Coast price for West Coast Naphtha. *Id.* It points out that the proponents of the Gulf Coast price admit that the Gulf Coast and West Coast markets are different and that the value of Naphtha will be different in the two markets. *Id.*

1491. Further, Phillips states, the proponents of Gulf Coast pricing ignore the key holdings in the *Tesoro* opinion -- both its ruling as to what must be shown to satisfy the burden of proof and its ruling on the sufficiency of the three allegations in Tesoro's complaint. Phillips Reply Brief at p. 11. Indeed, it states that the proponents present arguments directly affected by the *Tesoro* decision as if that decision did not exist. *Id.* For example, Phillips notes, both Williams and Unocal/OXY discuss the changed circumstances issue at length and argue that no changed circumstances have been demonstrated. *Id.* However, it notes that neither Williams nor Unocal/OXY ever mentions the strong expression of doubt in the controlling *Tesoro* opinion as to whether a showing of changed circumstances is required at all. *Id.* at pp. 11-12.

1492. Furthermore, Phillips states that Williams and Unocal/OXY give scant attention to what it claims is the *Tesoro* court's holding that Tesoro's three factual allegations constituted a prima facie showing that the use of Gulf Coast pricing is no longer just and reasonable. *Id.* at p. 12. It notes that Williams argues that the Circuit Court did not hold that changed circumstances had already been demonstrated, but only that allegations had been raised that had to be answered. *Id.* In Phillips's view, that is not enough. *Id.* Now that substantial evidence has been submitted proving the three allegations that had been made by Tesoro in its complaint, it asserts that Williams and the other advocates of Gulf Coast pricing must introduce evidence that actually provides an answer. *Id.* Phillips further argues that this failure on the part of the proponents of Gulf Coast pricing to even address, much less answer, the Tesoro propositions is fatal.[588] *Id.*

1493. Phillips asserts that Williams is wrong to argue that the Commission must continue using the Gulf Coast Naphtha price, even if it is not just and reasonable, should the Commission also find that none of the proposed replacement methodologies is just and reasonable. *Id.* at p. 17. It points out that the Interstate Commerce Act prohibits the charging of rates that are unjust and unreasonable and provides that, whenever the Commission determines in a complaint proceeding that a rate is not just and reasonable, the Commission "is authorized and empowered to determine and prescribe what will be the just and reasonable individual or joint rate, fare, or charge." *Id.* (quoting Interstate Commerce Act, 49 U.S.C. App. § 15(1)(1988)). Phillips asserts that the Act does not limit the Commission's power to implement the proposals submitted by the parties to the proceeding. *Id.* Further, it contends that, if the Commission was to find flaws in all of the existing proposals, they would still be obligated by the controlling statutes to adjust these proposals as may be necessary to establish a West Coast Naphtha price that is just and reasonable. *Id.* at pp. 17-18.

3. BP

1494. BP states that the initial Naphtha related issue is whether, for the purpose of valuing Naphtha on the West Coast, the use of the Gulf Coast Platts Naphtha price should be replaced by a West Coast derived Naphtha valuation. BP Initial Brief at p. 3. Since the hearing began, continues BP, two other Naphtha issues have arisen. *Id.* It explains that the first new issue relates to Platts decision to publish a second Gulf Coast Naphtha price, which Platts calls "Heavy Naphtha." *Id.* This new quotation provides an additional Naphtha pricing point on the Gulf Coast, notes BP, and does not replace the pre-existing Platts Naphtha quotation. *Id.* According to BP, all parties agreed that Platts Heavy Naphtha's quality is closer than Platts Naphtha's quality to Quality Bank Naphtha's quality; therefore, all parties agreed that Platts Heavy Naphtha quotation should be used to value Gulf Coast Quality Bank Naphtha on a going-forward basis. *Id.* (citing Transcript at p. 13339).

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[588] Phillips also disagrees with Exxon's assertion that the *Tesoro* decision held that the burden of proof had already been met. Phillips Reply Brief at p. 13, n.11. Instead, it relies on the overwhelming evidence in the record in this proceeding demonstrating the factual validity of the three propositions alleged by Tesoro. *Id.*

1495. The second issue, continues BP, involves Exxon's and Phillips's claim that a naphthenes-plus-aromatics content (N+A) adjustment is needed to account for purported differences between the N+A of ANS Naphtha and Platts Heavy Naphtha. *Id.* at p. 4. Because the approved Quality Bank methodology does not include an N+A adjustment, BP asserts, Exxon and Phillips have the burden of proving that the existing Naphtha valuation approach, which does not account for N+A differences, no longer is just and reasonable. *Id.* (citing *Texas Eastern Transmission Corp. v. F.E.R.C.*, 893 F.2d 767 at p. 771 n.5 (5th Cir. 1990)). If Exxon and Phillips meet that burden, then, notes BP, any party proposing a Naphtha valuation approach that includes an N+A adjustment must show that its proposed replacement methodology is just and reasonable. *Id.*

4. Williams

1496. Williams explains that the court in *OXY*, 64 F.3d 679, affirmed the Commission's determination changing the Quality Bank methodology, and, in doing so, accepted the methodology set forth by the Commission except for the valuation of the Distillates and Resid cuts. Williams Initial Brief at p. 4. More importantly, states Williams, because the *OXY* Court did not remand the Commission's determination regarding the Naphtha cut, it follows that Court upheld its determination that the Naphtha valuation, under the distillation methodology, was just and reasonable. *Id.*

1497. Following *OXY*, states Williams, Exxon filed a complaint challenging the distillation methodology and the Commission consolidated Exxon's complaint with the *OXY* remand. *Id.* Contrary to Exxon's argument, Williams states, Exxon did not raise the propriety of the current Naphtha valuation methodology in its complaint. Williams Reply Brief at p. 5. Williams further suggests that simply joining with Tesoro to present its case does not make Exxon a party to Tesoro's original complaint and further notes that the Naphtha valuation issue is beyond the scope of the *Exxon* remand. *Id.* at p. 6.

1498. The Commission, according to Williams, approved the Nine-Party Settlement, as certified, in *Trans Alaska Pipeline System*, 81 FERC ¶ 61,319 (1997). Williams Initial Brief at p. 5. Williams adds that the changes ordered by the Commission were to take place on a prospective only basis. *Id.* Subsequent to the Commission's approval of the Nine-Party Settlement, continues Williams, the Eight Parties filed a Motion for Summary Disposition, which was granted over the opposition of Exxon, Tesoro and Phillips. *Id.* (citing *Exxon Company, U.S.A. v. Amerada Hess Pipeline Corporation*, 83 FERC ¶ 63,011 (1998)). In *Exxon*, Williams notes, the Nine-Party Settlement was affirmed in part. *Id.* at p. 6. However, Williams states, the Circuit Court held that the settlement proxy price for Resid did not meet "the requirement that the chosen proxy bear a rational relationship to the actual value of resid" and vacated and remanded that portion of the order pertaining to Resid valuation as well as the portion directing that the change take effect only prospectively. *Id.* (citing *Exxon* at p. 42). Tesoro intervened and attempted to bootstrap arguments that the Commission should have re-evaluated other cuts, specifically Naphtha and Gas oil; however, notes Williams, the Circuit Court noted that "[w]hatever the merits of these arguments might be, the issues they raise are beyond the scope of the limited remand, and therefore are not properly before us." *Id.* (citing *Exxon* at p. 46). In *Tesoro*, which dealt with Tesoro's complaint challenging the West Coast Naphtha and VGO valuations, Williams points out, the Circuit Court reversed the Commission because it failed to respond specifically to "objections that on their face appear legitimate," and thus remanded the case to the Commission for further proceedings. *Id.* at p. 6 (quoting *Tesoro*, 234 F.3d at pp. 1294-95).

1499. According to Williams's, as a result, the current Naphtha methodology has been in place since the initial adoption of the distillation methodology. *Id.* at p. 7. Moreover, explains Williams, the Commission and the Circuit Court have previously determined the Naphtha valuation to be just and reasonable. *Id.* Therefore, says Williams's, the proponents of any change must prove changed circumstances which have rendered the existing methodology unjust and unreasonable. *Id.*

1500. Any party seeking to change the current methodology, Williams states, bears the burden of proving that changed circumstances require the existing valuation be found to be unjust and unreasonable (or unduly preferential and discriminatory), and further, that the proposed replacement methodology is just and reasonable. *Id.* at p. 7. (citing *Texas Eastern Transmission Corp. v. F.E.R.C.*, 893 F.2d at p. 771 n.5). In essence, it states, the proponents of any change must satisfy a three part inquiry: (1) are there changed circumstances; (2) do the changed circumstances render the existing methodology no longer just and reasonable; and (3) if the existing methodology is no longer just and reasonable, is the methodology proposed just and reasonable. *Id.* at p. 7.

1501. Williams explains that the proponents must demonstrate that the record evidence not only raised, but also provided sufficient evidence of changed circumstances which materially impact and render the current methodology unjust and unreasonable. *Id.* at pp. 7-8. It notes that parties involved in the various TAPS Quality Bank proceedings have argued in the past that the doctrines of collateral estoppel and res judicata do not apply to Commission rate proceedings and, thus, a showing of changed circumstances is not required. *Id.* at p. 8. However, Williams asserts, the more correct view is that "the preclusion doctrines are applicable to rate proceedings unless the petitioner (or complainant) adduces new evidence or demonstrates changed circumstances." *Id.* (quoting *Exxon Company, U.S.A. v. Amerada Hess Pipeline Corp*., 83 FERC at p. 65,094). Further, states Williams, the Supreme Court has stated that "if new evidence warrants the change" a regulatory agency "has the power and duty to modify its order." *Id.* (quoting *Tagg Bros. & Moorehead v. United States*, 280 U.S. 420, at pp. 444-45 (1930)).

1502. The threshold inquiry, then, according to Williams, is whether there are any changed circumstances which allow the Commission to proceed with a determination of whether the changed circumstances make the existing methodology no longer just and reasonable. *Id.* It asserts that there is a long line of precedent holding that, where a challenged methodology previously has been approved by the Commission, there must be a showing of changed circumstances otherwise re-litigating settled issues is a waste of resources. *Id.* at pp. 8-9. Williams points out that Exxon itself has admitted that a failure to establish changed circumstances is fatal to an attempt to change the methodology.[589] *Id.* at p. 9.

1503. While the Commission has a continuing obligation to ensure that rates are just and reasonable, Williams reiterates, the inquiry nevertheless requires a showing of changed circumstances. *Id.* Indeed, Williams claims that, if the Commission were to initiate an investigation, it would bear the burden of proving that the existing provision is unjust and unreasonable. *Id.* (citing *Sea Robin Pipeline Co. v. F.E.R.C.*, 795 F.2d 182, at p. 188 (D.C. Cir. 1986)). Finally, Williams notes, the record evidence must show that the proponents adduced evidence demonstrating a "significant change in circumstances." *Id.* at pp. 9-10.

1504. Further, Williams argues, not only must the proponents present evidence of changed circumstances, the evidence they present must also be sufficiently substantial to warrant a conclusion that the existing provision is unjust. *Id.* at p. 10 (citing *Sea Robin Pipeline Co.,* 795 F.2d at pp. 187-89). Williams cites *Trans Alaska Pipeline System*, 80 FERC ¶ 63,015 at pp. 65,232-33 (1997), in support of its view that

> the disposition of the remanded issues is transformed into the question whether the record contains "substantial evidence" from which the Commission could reach a reasoned decision. Substantial evidence requires more than a scintilla, but less than a preponderance of the evidence. . . . It means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.

Id.

1505. In addition, Williams asserts that a party cannot simply show a changed circumstance without also demonstrating why the changed circumstance necessarily warrants a change in methodology. *Id.* Notes Williams, "[i]t is not every 'new factual

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[589] According to Williams, Exxon acknowledged that, in one of its prior attempts to force a return to the gravity-based Quality Bank, parties seeking to change the Quality Bank methodology "had the burden of demonstrating that changed circumstances had rendered that methodology no longer just and reasonable." Williams Initial Brief at p. 9, n.8.

assertion' or every 'new argument' which would permit relitigating a substantive ratemaking principle. There must be sufficient substance to the 'new' material so that there is a reasonable possibility the Presiding Judge or the Commission would decide the substantive ratemaking principle should be changed." *Id.* (quoting *Minnesota Power and Light Co.*, 13 FERC ¶ 63,014 at p. 65,030 (1980. Further, Williams explains, the fact that another method exists for valuation does not render the current methodology unjust and unreasonable. *Id.* (citing *Trans Alaska Pipeline System*, 29 FERC at p. 61,239).

1506. Williams notes that Exxon argued that the *Tesoro* decision definitively determined that there were changed circumstances warranting a change in the methodology valuing West Coast Naphtha and VGO and, therefore, Exxon has already satisfied its burden to show changed circumstances. *Id.* at p. 11; Williams Reply Brief at p. 7. However, Williams argues, Exxon's interpretation of the *Tesoro* decision is patently incorrect. Williams Initial Brief at p. 11. Instead, claims Williams, the *Tesoro* opinion simply found that the "evidence" submitted was "sufficiently compelling to require reconsideration of the earlier resolution" and therefore, remanded the case to allow the Commission to reconsider or to "provide a suitable explanation for why it should not." *Id.* (quoting *Tesoro* 234 F.3d at p. 1288). Williams claims that the court did not hold, or make any finding, with regard to whether or not Tesoro satisfied its burden to show that there are changed circumstances which warrant a finding that the current Naphtha and VGO valuations are unjust and unreasonable. *Id.*

1507. On reply, Williams notes that Exxon argues that the passage of time can be sufficient to establish material change in circumstances. Williams Reply Brief at p. 8. It argues that the case cited by Exxon[590] does not relate to a determination of the materiality of evidence relating to changed circumstances as Exxon would have the Commission believe. *Id.* at pp. 8-9. Williams also asserts that Exxon's reasoning that any changed circumstances must be construed to be the equivalent of new evidence is fundamentally flawed, and that new evidence does not directly translate into changed circumstances. *Id.* at p. 9. Instead, Williams suggests that the new evidence must be shown by a proponent of change to demonstrate changed circumstances which render the current methodology unjust and unreasonable. *Id.* In 1993, notes Williams, the Commission found that there were changed circumstances (an increase in the amount of natural gas liquids injected into the TAPS stream) and that those circumstances meant the then current methodology was no longer just and reasonable, namely the resulting increase in refining operations midstream and the return of an altered stream to the pipeline. Williams Initial Brief at p. 13 (citing *Trans Alaska Pipeline System*, 65 FERC at p. 62,287).

1508. William points out that all rates charged must be just and reasonable and it is

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[590] *Hawaiian Telephone v. P.U.C. of State of Hawaii*, 827 F.2d 1264, at p. 1274 (9th Cir. 1987).

within the province of the Commission to prescribe just and reasonable rates "when it determines that any rate or practice . . . is 'unjust or unreasonable.'" *Id.* at p. 14 (quoting *OXY*, 64 F.3d at p. 690). It notes that, if the Commission changes course and adopts a new methodology, the Commission "must supply a reasoned analysis indicating that prior policies and standards are being deliberately changed." *Id.* (quoting *OXY*, 64 F.3d at p. 690). Further, continues Williams, a significant change rendering a methodology unjust and unreasonable may be found when the evidence "strongly establishes the distortion of value caused" by the change and as applied no longer yields a just and reasonable result. *Id.* (quoting *Trans Alaska Pipeline System*, 57 FERC at pp. 65,049-50, 65,052-53.

1509. According to Williams, one should bear in mind that the Quality Bank's purpose is to "establish the relative value of the different quality oils that are tendered to TAPS. As such, it must incorporate a valuation methodology that is a reasonable proxy for the difference in the market value of the TAPS streams." *Id.* (quoting *Trans Alaska Pipeline System*, 65 FERC at p. 62,286). Therefore, Williams asserts, Phillips's argument regarding the uniformity requirement of *OXY* is incorrect. Williams Reply Brief at p. 11. It states that, while the basic precept is to use published intermediate feedstock product prices where available, the so-called uniformity requirement does not mandate only the use of published prices on a particular coast to value a product on that same coast. *Id.*

1510. Acknowledging that Exxon has set forth five examples of alleged changed circumstances, two of which are discussed here, Williams contends that it is substantively important that both Exxon's and Phillips's witnesses testified and admitted there have been no changed circumstances and that Tallett's baseline year for measuring changed circumstances is 2000. *Id.* at p. 12. It asserts that none of the five examples represents true changed circumstances, and that it does not follow that any and every change to TAPS valuation methodology automatically means the prior methodologies are now unjust and unreasonable. *Id.* at pp. 12-15.

1511. Williams notes that Exxon describes a great disparity between the Gulf Coast Naphtha price and the market value of West Coast Naphtha as reflected in the contract data as a changed circumstance. *Id.* at p. 13. It disagrees with Exxon's characterization of the contract analyses as actual sales which translate to a market value of West Coast Naphtha, and states that such an argument is patently disingenuous because the record demonstrates that the West Coast Naphtha market is opaque, i.e., the contract volumes represent almost non-existent volumes of the total Naphtha throughput on the West Coast, and most of the contracts do not represent spot volumes consistent with Platts method of pricing. *Id.* at pp. 13-14. Williams contends that the Naphtha contract analyses in no way can be construed to be representative of its "actual market value." *Id.* at p. 14. Moreover, Williams notes, these contracts existed during the period 1994-2001, a portion of which is before Tallett's baseline year. *Id.*

1512. According to Williams, if the introduction of California Air Resources Board requirements is a changed circumstance as Exxon suggests, then it renders Tallett's proposed regression formula totally meaningless and unusable. *Id.* It notes that Tallett testified that any major change would require a change in the formula, but that he made none to reflect the California Air Resources Board requirements and argues that the evidence demonstrates that CARB gasoline lessened the value of Naphtha on the West Coast, contrary to Exxon's assertion. *Id.*

1513. Williams argues that, contrary to BP's claim regarding the parties's agreement on the valuation of VGO and Ross's testimony, VGO and Naphtha are valued on a consistent price basis. *Id.* at p. 15. It notes that the pricing data shows that, for the period 1992 through 2002, the differential between the Gulf Coast and VGO published prices is approximately 1¢/gallon, and it maintains that a one-cent differential is not significant under the circumstances. *Id.* More importantly, Williams claims, the use of Platts Gulf Coast Heavy Naphtha (cargo) price assessment has increased the Gulf Coast Naphtha value by approximately 1¢/gallon. *Id.* at p. 16. It asserts that Ross's testimony, in effect, is that continued use of the Platts Gulf Coast Heavy Naphtha (cargo) price assessment is just and reasonable. *Id.*

1514. According to Williams, the changed circumstance alleged by BP is that differences between the Gulf and West Coasts, especially the lack of petrochemical demand for Naphtha on the West Coast, is a changed circumstance that supports the use of a West Coast based price assessment. *Id.* Williams asserts that the fallacy with this alleged changed circumstance is that the petrochemical market on the Gulf Coast existed long before 1994. *Id.* at pp. 16-17. It claims that Ross presented no evidence whatsoever that the Gulf Coast petrochemical market suddenly appeared once the TAPS Quality Bank adopted the distillation methodology in 1993. *Id.* at p. 17.

1515. Williams argues that Phillips incorrectly relies on *SFPP, L.P.*, 84 FERC at p. 62,498 for the proposition that a prima facie case has been established and that the burden of going forward has shifted to the proponents of the status quo. *Id.* at pp. 17-18. It states that because the *Tesoro* court did not find that a prima facie case had been established, no burden shifting has taken place, and the proponents of change continue to bear the burden of proof that the existing methodology is no longer just and reasonable. *Id.* at p. 18 (citing *Tesoro*, 234 F.3d at p. 1294).

1516. However, asserts Williams, the rate may only be changed prospectively. *Id.* (citing *Arizona Grocery*, 284 U.S. at p. 389). Because the Commission adopted the Gulf Coast Naphtha value to value West Coast Naphtha, it explains, the value is now the reasonable and lawful value for West Coast Naphtha. *Id.* at p. 20. Therefore, Williams maintains, it may only be changed prospectively from the date that the Commission decides that the valuation needs to be changed. *Id.*

5. Unocal/OXY

1517. Unocal/OXY submit that the current method for valuing the West Coast Naphtha cut is just and reasonable and that no change in the existing method is warranted. Unocal/OXY Initial Brief at p. 1. However, they state that, should a change be ordered, the Commission may make such change effective only on a prospective basis. *Id.* at p. 2.

1518. Unocal/OXY note that, in 1993, the Commission adopted a general provision in the Quality Bank that requires the use of prices from one market to value both the Gulf and West Coast products if pricing from only one market is available. *Id.* (citing *Trans Alaska Pipeline System*, 65 FERC at p. 62,289). Further, explains Unocal/OXY, the Commission specifically invoked its authority under the Interstate Commerce Act to determine a just and reasonable rate after investigation, and adopted the Naphtha provision as part of its own determination of what the just and reasonable Quality Bank methodology should be. *Id.*

1519. Phillips reads too much into the three appellate cases[591] it uses to argue that the Gulf Coast Naphtha price can no longer be used to value West Coast Naphtha, according to Unocal/OXY. Unocal/OXY Reply Brief at pp. 1-2. In *OXY*, they note, the Circuit Court approved the distillation methodology, notwithstanding the fact that it used Gulf Coast prices to value both the West Coast Naphtha and VGO cuts. *Id.* at p. 2. Further, Unocal/OXY explain, the Circuit Court remained entirely silent as to the Naphtha and VGO cuts and whether or not it was appropriate to use Gulf Coast prices to value West Coast cuts. *Id.* They assert that the same is true of the *Exxon* decision, where the court did not remand the Naphtha and VGO cuts, implying that these cuts had become final following the *OXY* decision. *Id.* Unocal/OXY state that while *Tesoro* did deal with the Naphtha and VGO cuts, the court did not foreclose the continued used of Gulf Coast prices. *Id.* Instead, they claim, the court found that Tesoro presented sufficient evidence that there was new evidence to warrant a review of how West Coast Naphtha should be valued. *Id.* at pp. 2-3. According to Unocal/OXY, this makes it clear that the use of Gulf Coast prices is not foreclosed. *Id.* at p. 3.

1520. Unocal/OXY also argue that Phillips is wrong when it argues that continued use of Gulf Coast prices for Naphtha would violate the consistency requirements of *OXY*. *Id.* Unocal/OXY state that use of Gulf Coast prices is acceptable because Gulf Coast prices value the Naphtha cut no less precisely than do the proxies for other cuts. *Id.* They explain that it is not inconsistent to retain Gulf Coast pricing for only one cut if there is a rational basis for doing so and that, in this case, the rational basis is the lack of a published West Coast price for Naphtha. *Id.* Further, Unocal/OXY assert that there is no convincing evidence that Naphtha has a higher value on the West Coast. *Id.*

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[591] Unocal/OXY refer to *OXY*, 64 F.3d 679; *Exxon*, 182 F.3d 30; *Tesoro,* 234 F.3d 1286. Unocal/OXY Reply Brief at p. 1.

1521. Unocal/OXY also contend that Gulf Coast prices meet the rational relationship criterion of the *Exxon* case because the evidence establishes that there is a rational relationship between the published Gulf Coast price and the West Coast value of Naphtha. *Id.* They maintain that a close correlation cannot be established for any method selected to value West Coast Naphtha because the actual value of West Coast Naphtha is not known, as conceded by Phillips. *Id.* Unocal/OXY also maintain that continued use of Gulf Coast prices is justified under the *Tesoro* ruling because evidence that answers the propositions submitted by Tesoro has been submitted by Williams, Unocal/OXY, and Petro Star. *Id.*

1522. Contrary to Phillips argument, Unocal/OXY assert, neither *OXY* nor *Exxon* should be interpreted as requiring proof of price equivalency between the Gulf and West Coasts in order to continue using Gulf Coast published prices in both markets. *Id.* at p. 4. They note that, because there are no published prices for West Coast Naphtha, price equivalency cannot be demonstrated as a matter of fact. *Id.* Unocal/OXY also state that, because of the sporadic, non-public nature of the West Coast Naphtha contracts, no average price obtained from the contracts is comparable to the published Gulf Coast price. *Id.*

1523. They argue that this point is further underscored by the fact that Naphtha deliveries under contracts such as the ones analyzed in this case are not, as Culbertson stated, even considered by Platts in establishing its Gulf Coast Naphtha price assessments. *Id.* Furthermore, Unocal/OXY note, Gulf Coast Naphtha contracts, like their West Coast counterparts, sometimes base their prices on the price of gasoline minus a deduction and reflect prices that vary by a penny or more from Platts published Gulf Coast Naphtha assessments. *Id.* at pp. 4-5. Thus, they conclude, the only available data on West Coast Naphtha prices is of a different character than the data used to establish Platts Gulf Coast assessments, and absolute equivalency, even if it could be demonstrated, would not prove that West Coast and Gulf Coast Naphtha values are equivalent. *Id.* at p. 5.

1524. Unocal/OXY point out that Sanderson did not admit, as Phillips appears to believe, that retaining single market pricing for Naphtha was inconsistent with the valuation of the other cuts of the Quality bank. *Id.* Instead, they note that he admitted that the proposal to retain Gulf Coast pricing for Naphtha was not consistent with the proposal to abandon single market pricing for VGO. *Id.*

1525. More importantly, in Unocal/OXY's view, all of the proposals for changing the current method of valuing the Naphtha cut are inconsistent with the valuation of the other cuts. *Id.* at p. 6. They note that no party claims that Tallett's proposal is consistent with the way other cuts are priced and also point out that the evidence shows that O'Brien's proposal is not consistent with the Eight Party proposal for Resid and is clearly inconsistent with the use of published prices for all other cuts. *Id.* In contrast, Unocal/OXY explain, Sanderson noted that continuation of the current method, based on single market pricing, is consistent with way other cuts are valued because it uses objective, published prices for Naphtha. *Id.*

1526. Unocal/OXY assert that Naphtha is unique, that it is the only cut in the Quality Bank with an acceptable price on one coast and no price published on the other, and that this differentiates it from Resid. *Id.* at pp. 6-7. In their view, any valuation method chosen to value the West Coast Naphtha cut must confront Naphtha's uniqueness, and the solution to this problem may require an approach that is different than the way in which other cuts are valued. *Id.* at p. 7.

1527. Arguably, state Unocal/OXY, single market pricing, because of its potential to apply to any cut, is a consistent policy that applies to all cuts. *Id.* They point out that the Circuit Court has expressed skepticism regarding the continued use of single market pricing, saying that the principle of uniformity announced in *OXY* "would be breached if the availability of an adequate non-adjusted benchmark for the Gulf Coast prevented the use of an adjusted benchmark for the West Coast." *Id.* (quoting *OXY*, 234 F.3d at p. 1293). Unocal/OXY contend that it is the lack of a benchmark for West Coast Naphtha, and not the lack of availability of a Gulf Coast price, that prevents the use of a proper adjusted West Coast Naphtha benchmark. *Id.* They also contend that the record demonstrates that there is no benchmark that could be adjusted and that only the experts who support the continued use of Gulf Coast prices as the unadjusted benchmark for West Coast Naphtha came to an agreement on this issue. *Id.*

1528. Unocal/OXY explain that single market pricing was not designed and used only for Naphtha. *Id.* at p. 8. They note that it has been applied to Naphtha, VGO and Resid. *Id.* Given that it is reflected in the Tariff and has been applied and upheld for three different cuts, Unocal/OXY believe that it retains its vitality despite the court's skepticism. *Id.* More than that, they contend that, under the facts of this case, single market pricing is appropriate for Naphtha because Gulf Coast Naphtha is the best benchmark for the value of West Coast Naphtha. *Id.* at pp. 8-9.

1529. Phillips concedes, Unocal/OXY claim, that were one to demonstrate a close correlation between the Naphtha value on the Gulf Coast and the West Coast that would satisfy the requirements of *OXY*. *Id.* at p. 9. They contend that, contrary to Phillips's view, the evidence shows just such a correlation. *Id.* Unocal/OXY note that the contracts show a rough equivalence, or close correlation, between the Gulf Coast Naphtha price and the Naphtha contract prices between 1994-1998, and also point out that the differential between the average West Coast contract price and Gulf Coast Platts price is less than 2¢/gallon, within the range of the spread between Gulf Coast contracts and the Platts Gulf Coast Naphtha price. *Id.* at pp. 9-10. Further, they state, the lack of West Coast imports of Naphtha and the existence of separate price series for intermediate products both show that West Coast Naphtha does not have a higher value than Gulf Coast Naphtha and may have a lower value. *Id.* at p. 10. Accordingly, they maintain that continued use of Gulf Coast pricing for Naphtha meets the correlation test of *Exxon*. *Id.*

1530. The just and reasonable standard emphasized by Exxon and contained in the statute and the *OXY* decision, Unocal/OXY agree, is the appropriate standard to use in this case. *Id.* (citing 49 U.S.C. App. §§ 1(5), 15(1)(1988)). They state that a just and reasonable determination must be made in light of the purpose of the Quality Bank, which is to establish relative values for the different cuts in the TAPS stream. *Id.* In their view, the valuation must also meet the consistency test of *OXY* and the rational relationship test of *Exxon*. *Id.* at pp. 10-11. They note, however, that these two criteria may be considered part of the just and reasonable standard, as construed and applied in *OXY* and *Exxon*. *Id.* at p. 11. According to Unocal/OXY, the Circuit Court in *OXY* stressed consistency over accuracy when it stated that relative accurate values are what is required. *Id.* They note that the Circuit Court recognized that there was no perfect way to value the different cuts and that the Commission should not be held to an impossibly high standard. *Id.* Therefore, they conclude, the evidence in this case demonstrates convincingly that continued use of Gulf Coast pricing to value the enter Naphtha is just and reasonable. *Id.*

1531. Unocal/OXY note that use of Gulf Coast pricing for this cut was not disturbed on appeal and thereby became an approved final part of the TAPS Quality Bank methodology. Unocal/OXY Initial Brief at p. 2 (citing *OXY*, 64 F.3d 679). As such, they assert that it is protected by the filed rate doctrine. *Id.* (citing *Arizona Grocery*). Thus, according to Unocal/OXY, any party seeking to change the current method of valuing the Naphtha cut bears the burden of proving that changed circumstances have caused the existing valuation to be unjust and unreasonable (or unduly preferential and discriminatory), and that the recommended replacement methodology is just and reasonable. *Id.* at pp. 2-3. (citing *Texas Eastern Transmission Corp.*, 893 F.2d at p. 771 n.5). The Naphtha issue is before the Commission now, they explain, because Tesoro made a sufficient showing of changed circumstances to require the Commission to determine whether the new evidence "warrants re-examination of how West Coast naphtha should be valued." *Id.* at p. 3 (quoting *Tesoro*, 234 F.3d at p. 1293). It is Unocal/OXY's position that the evidence submitted does not warrant a change in the current methodology. *Id.*

1532. In reply to the argument by Exxon that a showing of new evidence is sufficient to require a reexamination of the reasonableness of an existing rate, Unocal/OXY assert that Commission precedent uses the term changed circumstances. Unocal/OXY Reply Brief at p. 12. They assert that the Commission prefers, for reasons of administrative economy, not to reopen matters once they have been resolved merely because a party may have found a new approach to a previously litigated issue. *Id.* Unocal/OXY agree with Williams that the new evidence or changed circumstances must be substantial enough to call into question the reasonableness of the prior rulings. *Id.* They maintain that under the more stringent standard applicable to Commission proceeding, the parties arguing for change have not satisfied their burden of proof. *Id.*

1533. While claiming that they do not have a burden of going forward with evidence to support the current methodology, Unocal/OXY acknowledge that they must answer evidence submitted by the proponents of change. Unocal/OXY Initial Brief at p. 3. They claim that they have submitted the testimony of Culberson (Exhibit Nos. UNO-1 and UNO-7), Sanderson (Exhibit Nos. WAP-1, WAP-8, and WAP-33), and Boltz (Exhibit No. PSI-I), which taken together and supplemented by other record evidence, provide substantial, credible evidence to sustain the continued use of Gulf Coast Naphtha prices to value the West Coast Naphtha cut. *Id.* at pp. 3-4.

6. Petro Star

1534. Petro Star asserts that: (1) the current use of Gulf Coast Naphtha prices to value Naphtha on the West Coast continues to be just and reasonable; and (2) if the Commission decides to depart from the use of Gulf Coast Naphtha prices, then Dudley's methodology is the best of the alternatives that have been presented and should be selected. Petro Star Initial Brief at p. 2. It states that Boltz testified that Naphtha valuation is important to Petro Star despite the fact that Petro Star does not manufacture gasoline, and that Dudley presented an alternative Naphtha valuation to be implemented if the Commission finds that use of Gulf Coast prices to value West Coast Naphtha is no longer just and reasonable. *Id.*

B. STIPULATED MATTERS AND AREAS OF DISPUTE

1. Exxon

1535. Exxon states that there are no stipulated facts pertaining to the value of West Coast Naphtha, but that all parties agree that the central matter at issue is whether the current practice of using the Platts Gulf Coast Naphtha price assessment to value West Coast Naphtha produces a just and reasonable value. Exxon Reply Brief at p. 209. According to Exxon, at least six different proposals have been presented for valuing the West Coast Naphtha cut. Exxon Initial Brief at p. 194. It notes that the Alaska refiners (Petro Star and Williams) and Unocal/OXY argue in favor of maintaining the status quo by continuing to value the West Coast Naphtha cut on the basis of the prices published by Platts Oilgram ("Platts") for Naphtha on the Gulf Coast. *Id.* All of the other parties (Phillips, Exxon, BP, and Alaska) to this proceeding, states Exxon, reject that position as unjust and unreasonable, and take the position that the West Coast Naphtha cut should be valued on the basis of West Coast market conditions using the West Coast prices of the petroleum products that are produced from Naphtha. *Id.* However, according to Exxon, the latter disagree regarding the particular methodology that should be used to achieve that result. *Id.*

1536. Because, Exxon claims, Naphtha is used on both coasts as a feedstock to make gasoline and jet fuel, the West Coast Naphtha cut should be valued based on the prices of unleaded regular gasoline and jet fuel on the West Coast using a regression formula derived from the published prices of Naphtha, unleaded regular gasoline, and jet fuel on the Gulf Coast. *Id.* It notes that Phillips and Alaska agree that the West Coast price of gasoline is the appropriate starting point for developing a value for the West Coast Naphtha cut, but that they propose an alternative approach that values West Coast Naphtha on the basis of the price of unleaded regular gasoline on the West Coast less the cost of reforming and blending the Naphtha into gasoline. *Id.*

1537. Exxon points out that BP also initially proposed a formula that valued Naphtha on the West Coast based on the price of gasoline on the West Coast reduced by the cost of transforming Naphtha into gasoline. *Id.* at p. 195. However, notes Exxon, BP further proposed that a so-called "governor" should be imposed that would effectively cap the value of the West Coast Naphtha cut at $1.49/barrel above the Gulf Coast Naphtha price.[592] *Id.* At the hearing, explains Exxon, BP withdrew its proposal and, instead, stated that it was willing to accept either the Naphtha valuation proposed by Exxon or the valuation proposed by Phillips provided that the valuation selected was limited by its proposed "governor." *Id.* In addition, Exxon notes, during the hearings, BP suggested an alternative governor based on a variable transportation differential rather than the fixed price ceiling of $1.49/barrel. *Id.*

1538. Further, notes Exxon, as an alternative to its status quo proposal, Petro Star proposed a contingent alternative methodology under which the West Coast Naphtha cut would be valued based on the relationship between the Gulf Coast price of Naphtha and a weighted incremental differential between Gulf Coast and West Coast VGO prices and Gulf Coast and West Coast LSR prices. *Id.* During the hearing, Exxon states, the witness for Williams suggested yet another alternative approach for valuing Naphtha on the West Coast based on the market price of ANS crude plus the cost of producing Naphtha from the crude (ANS + $4.00/barrel). *Id.* at pp. 195-96.

1539. Although all parties agree that the new Platts Gulf Coast Heavy Naphtha price assessment more closely matches the quality of Quality Bank Naphtha than the Platts Full Range Naphtha price assessment for the Gulf Coast, Exxon notes that Petro Star and Unocal/OXY raise procedural objections to the steps taken by the TAPS Quality Bank Administrator to implement the use of the new heavy Naphtha quote. Exxon Reply Brief

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[592] Exxon notes that BP's proposed governor also contains a floor which would prevent West Coast Naphtha from being valued at less than the price of ANS crude plus $4.00/barrel. Exxon Initial Brief at p. 195, n.78.

at p. 210. In addition, Exxon and Phillips propose that the new Platts Heavy Naphtha price assessment for the Gulf Coast should be adjusted to reflect the higher naphthene plus aromatic ("N+A") content of Quality Bank Naphtha based on new evidence that the Platts Gulf Coast price assessments are based on an N+A that is much lower than the N+A of Quality Bank Naphtha. *Id.*

1540. Exxon states that the parties disagree over whether the Quality Bank Administrator's proposal to average the Platts monthly Heavy Naphtha barge and Heavy Naphtha cargo price assessments for the Gulf Coast should be approved. *Id.* at pp. 210-11. Exxon and Phillips take the position that the Quality Bank Administrator's averaging proposal should be adopted for the Gulf Coast, while Williams, Unocal/OXY, BP, and Petro Star oppose that proposal. *Id.* at p. 211.

1541. According to Exxon, both the Exxon proposal and the Phillips proposal (and BP's original proposal without the artificial "governor") value the West Coast Naphtha cut at levels that are significantly higher than the Platts Gulf Coast Naphtha price and that are close to the actual market value of Naphtha on the West Coast as indicated by the West Coast Naphtha contracts which were produced during discovery in this proceeding. Exxon Initial Brief at p. 196. By contrast, Exxon asserts, the application of the so-called "governor" proposed by BP, would reduce the value of the West Coast Naphtha cut to a level only slightly above the Platts Gulf Coast Naphtha price. *Id.* Similarly, Exxon states, the Petro Star alternative proposal values the West Coast Naphtha cut at or very close to the Platts Gulf Coast Naphtha price, while William's alternative West Coast Naphtha valuation using the price of ANS crude plus the cost of producing Naphtha from the crude, also produces a valuation at or very close to the Platts Gulf Coast Naphtha price depending on which proxy is used for the cost of producing Naphtha from crude. *Id.* at pp. 196-97.

2. Phillips

1542. Phillips states that the parties were unable to reach any stipulations with respect to the West Coast Naphtha value issue beyond agreeing on a description of following three broad areas of dispute: (1) whether a West Coast-based methodology should be used to value West Coast Naphtha instead of using the Gulf Coast price; (2) how West Coast Naphtha should be valued if the Commission decides to adopt a new valuation methodology; and (3) what the effective date should be for any new West Coast Naphtha valuation Phillips Initial Brief at p. 14.

3. BP

1543. BP states that the parties have entered into no stipulations on the primary Naphtha issue, the valuation of West Coast Naphtha. BP Initial Brief at p. 4. According to it, Williams, Petro Star, and Unocal/OXY posit that the Commission should continue to use a Gulf Coast assessment to value West Coast Naphtha. *Id.* Further, notes BP, Petro Star has proposed an alternate West Coast methodology to derive a West Coast Naphtha value if it is determined that a West Coast Naphtha methodology should replace the Gulf Coast price for valuing West Coast naphtha. *Id.* BP states that it, Exxon, Phillips, and Alaska agree that the Quality Bank should use a West Coast price to value Quality Bank naphtha on the West Coast, but have proposed three different valuation methodologies, with BP proposing one, Exxon proposing a second, and Phillips and Alaska proposing a third. *Id.* at pp. 4-5. Further, it states that all parties have agreed that the Platts Heavy Naphtha quotation should replace the Platts Naphtha quotation for valuing Naphtha on the Gulf Coast. *Id.* at p. 5. Finally, notes BP, Exxon, Phillips, and Alaska argue the Quality Bank additionally should adjust this reference price to account for alleged N+A differences. *Id.*

1544. Since creating the Platts Heavy Naphtha price, BP notes, Platts has added an additional Gulf Coast Naphtha assessment, so that there is now a Heavy Naphtha barge quote in addition to the Platts Heavy Naphtha quote. BP Reply Brief at p. 5. It states that the parties disagree as to whether Platts Heavy Naphtha quote should continue to be used to value Naphtha on the Gulf Coast or whether an average of the Platts Heavy Naphtha and Heavy Naphtha Barge price quotes should be used. *Id.* BP also states that it, Williams, Petro Star, and Unocal/OXY support continued use of the Platts Heavy Naphtha quote, while Exxon, Phillips, and the TAPS Carriers support use of the Quality Bank Administrator's averaging proposal. *Id.* Also, BP points out, Exxon, Phillips, and Alaska support adjusting any chosen Gulf Coast reference price to account for N+A differences. *Id.* at p. 6. Finally, BP notes, it, Williams, Unocal/OXY, and Petro Star oppose an N+A adjustment. *Id.*

4. Williams

1545. Williams agrees that the parties have not stipulated to any issues related to the valuation of the West Coast Naphtha. Williams Initial Brief at p. 15. It notes that the closest area of agreement among the parties appears to be that all support substitution of Platts Gulf Coast Heavy Naphtha price quote for the Platts Gulf Coast waterborne price quote that has been used to value both the Gulf Coast and West Coast Quality Bank Naphtha components since the effective date of use of a distillation methodology. *Id.* at pp. 15-16.

1546. According to Williams, it, along with Unocal/OXY and Petro Star, supports continued use of Platts Gulf Coast Heavy Naphtha price quote. *Id.* Conversely, states Williams, the remaining parties advocate discarding the use of a Gulf Coast published price and adopting some formula-based approach using West Coast gasoline prices as part of the formula. *Id.* But, notes Williams, even the parties who agree on the need for a changed methodology are not unified. *Id.* Williams explains that Exxon supports a regression-based formula approach, while Phillips and Alaska support a different processing-based formula approach, and that BP proposes that a governor with a floor and cap be applied to either the Exxon proposal or the Phillips proposal. *Id.*

1547. Although all the parties appear to support the use of Platts Gulf Coast Heavy Naphtha price quote, Williams points out, Exxon, Philips and Alaska seek to have 1.5¢/gallon added to that price by making an "N+A" adjustment to the published price. *Id.* Williams states that it, Unocal/OXY, Petro Star and BP oppose such an adjustment, particularly because no other Quality Bank component has the published price used to value that component adjusted based on a constituent characteristic of the product itself. *Id.* at pp. 16-17.

5. Unocal/OXY

1548. Unocal/OXY state that the areas of dispute are whether the current method of using Gulf Coast prices to value West Coast Naphtha is just and reasonable, and if not, what methodology should be used in its place. Unocal/OXY Initial Brief at p. 4. They explain that there is also a dispute as to which of the Platts Naphtha prices should be used, both for Gulf Coast Naphtha and for West Coast Naphtha. *Id.* Although the parties have not stipulated with respect to West Coast Naphtha prices, Unocal/OXY note that no party contends that prices for West Coast Naphtha are published by any price quoting services or are otherwise publicly available. *Id.*

1549. They also disagree with Exxon's statement that the Tallett and O'Brien proposals produce results close to the actual market value of Naphtha as measured by the contracts, and point out that, in their view, this is merely Exxon's opinion and that the actual market value of Naphtha on the West Coast is unknown. Unocal Reply Brief at p. 15.

6. TAPS Carriers

1550. The TAPS Carriers assert that by far the most important of the issues before the Commission with respect to valuing the Naphtha component is what methodology to use for valuing it on the West Coast. TAPS Carriers Initial Brief at p. 13. If the Commission adopts a methodology for valuing West Coast Naphtha other than using a Gulf Coast price assessment, the TAPS Carriers state, the Gulf Coast price assessments proposed by the Quality Bank Administrator will have significance only as interim prices (if the Exxon proposal to adopt the West Coast methodology retroactively is accepted) or for a relatively brief period from the date that the Quality Bank Administrator's proposal was accepted until a new methodology is adopted for valuing Naphtha on the West Coast (if one of the proposals for prospective adoption of a West Coast methodology is accepted). *Id.* This is so, explain the TAPS Carriers, because, under the Quality Bank methodology, prices are weighted by the percentage of ANS going to the Gulf Coast and West Coast, and since mid-1999 100% of ANS has been delivered to the West Coast. *Id.*

C. IS THE CURRENT NAPHTHA VALUE JUST AND REASONABLE?

1. Exxon

1551. Exxon points out that until March 1, 2003, the Quality Bank used a single Gulf Coast waterborne spot price published by Platts to value the Naphtha cut on both the Gulf Coast and the West Coast. Exxon Initial Brief at p. 197. Beginning on March 1, 2003, notes Exxon, the Quality Bank began using a new Platts Gulf Coast price for Heavy Naphtha (subject to refund) instead of the Platts Gulf Coast price for full range Naphtha.[593] *Id*. According to Exxon, the Alaska refiners (Petro Star and Williams) and Unocal/OXY argue in favor of continuing to value the West Coast Naphtha cut on the basis of one of these Platts Gulf Coast Naphtha prices. *Id.* Exxon states that this position is opposed by all other parties to the proceeding and the evidence overwhelmingly shows that this approach does not produce just and reasonable results. *Id.* at pp. 197-98.

1552. According to Exxon, the current policy of using a Platts Gulf Coast Naphtha price to value West Coast Naphtha was never advocated by any party. *Id*. at p. 198. Rather, Exxon states, it was adopted by the Commission, in 1993, based on the Commission's policy of making no adjustments to market prices. *Id*. Exxon asserts that this policy was subsequently rejected by the Circuit Court as arbitrary and capricious and abandoned by the Commission. *Id*. Eight years of experience have clearly shown, in Exxon's opinion, that the current methodology does not produce values for West Coast Naphtha that fairly reflect West Coast market conditions. *Id*. It states that the evidence reflects that the West Coast and the Gulf Coast are separate and distinct markets for petroleum products, and that prices on the West Coast are significantly different from those on the Gulf Coast, both a short term and a longer term basis. *Id.* In addition, according to Exxon, the contracts for the sale of Naphtha on the West Coast that were produced in this case show that West Coast Naphtha is almost always priced on the basis of higher West Coast gasoline prices and that the resulting West Coast Naphtha contract prices are on average substantially higher than the Gulf Coast Naphtha prices. *Id.* Similarly, continues Exxon, none of the Naphtha traders contacted by Unocal/OXY's witness supported the use of a

[593] Exxon notes that shortly after the conclusion of the hearing, the Quality Bank Administrator learned that, as of May 1, 2003, Platts began publishing *two* waterborne Heavy Naphtha prices for the Gulf Coast, one labeled "Heavy Naphtha" for large ship cargoes up to 250,000 barrels and the other labeled "Heavy Naphtha Barge" for smaller barge cargoes typically in the range of 50,000 barrels. Exxon Initial Brief at p. 197, n.79. To deal with this situation, the Quality Bank Administrator has proposed that all Quality Bank Naphtha should be valued on the basis of the arithmetic average of the Heavy Naphtha and Heavy Naphtha Barge average monthly prices reported by Platts. *Id.* By order dated August 18, 2003, the Commission accepted that rate on an interim basis subject to refund and directed that this issue be addressed in the context of this proceeding. *Id.*

Gulf Coast Naphtha price to value Naphtha on the West Coast, and at least one trader specifically rejected that approach in favor of a Naphtha price based on the price of gasoline. *Id.* at pp. 198-99. In short, Exxon argues, the evidence is overwhelming that it would be unjust and unreasonable to continue using a Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at p. 199. Each of these points is discussed below.

1553. Exxon notes that the settlement agreement presented to the Commission in 1993 proposed that Naphtha should be valued on the West Coast by "applying a Gulf Coast-derived ratio of naphtha to gasoline prices to the Platt's Los Angeles pipeline spot quote for gasoline." *Id*. (quoting *Trans Alaska Pipeline System*, 65 FERC at p. 62,288). This approach was proposed, according to Exxon, because there was no Platts or other published price quoted for Naphtha on the West Coast. *Id*. Exxon asserts that this formula appropriately recognized that the primary determinant of the value of Naphtha is the price of gasoline in the market because gasoline is the principal finished product that is produced from Naphtha.[594] *Id.*

1554. The Commission, Exxon notes, did not adopt the West Coast Naphtha valuation proposed by the parties in the 1993 settlement adopting, instead, a policy that all Quality Bank cuts had to be valued on the basis of "unadjusted quoted market prices." *Id.* at pp. 199-200. Under this policy, explains Exxon, the Commission directed the use of prices quoted in a single market for the entire stream when no price was posted for a given product. *Id*. at p. 200. Applying this policy to the West Coast Naphtha cut, states Exxon, the Commission required that the "Gulf Coast price be used to value the entire naphtha cut in both markets, instead of applying the settlement's formula" for West Coast Naphtha. *Id*. (quoting *Trans Alaska Pipeline System*, 65 FERC at p. 62,289). Further, notes Exxon, in its order on rehearing, the Commission specifically denied Exxon's request that the pricing methodologies contained in the settlement proposed by the parties be adopted without modification. *Id*.

1555. On review of the Commission's 1993 decision, explains Exxon, the Circuit Court held that the Commission's determination that the Quality Bank Administrator had to value all cuts at published market prices without adjustment was "arbitrary and capricious" and did not meet "the requirement of reasoned decisionmaking." *Id*. (quoting *OXY*, 64 F.3d at pp. 693-94). In particular, states Exxon, the Circuit Court found that the Commission's selection of unadjusted market proxies to value the Distillate and Resid cuts was arbitrary and capricious because the Commission had offered no data to indicate

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[594] Exxon notes that this 1993 settlement was supported by the Alaska, Amoco, BP, Exxon, Mapco, Petro Star, and Phillips; it was opposed by ARCO, Tesoro, Unocal, Conoco and OXY. Exxon Initial Brief at p. 199, n.80. According to Exxon, no party opposing the settlement advocated the use of the Gulf Coast Naphtha price to value Naphtha on the West Coast. *Id*

that the selected proxy market prices were a reasonable approximation of the market values of the cuts. *Id*. at pp. 200-01.

1556. On remand, continues Exxon, the Commission abandoned its policy of requiring the use of unadjusted market prices to value all ANS cuts, adopting new adjusted valuation methodologies for both the Light and Heavy Distillate and Resid cuts, with separate valuations for each on the Gulf Coast and the West Coast. *Id.* at p. 201. Although requests from Exxon and Tesoro that the Commission also consider whether other cuts – including West Coast Naphtha – were properly valued were declined at that time on the ground that those cuts were not within the limited scope of the *OXY* remand, Exxon asserts that claim is now squarely before the Commission as a result of the complaints which were filed by Tesoro and Exxon. *Id*.

1557. According to Exxon, at no time has any party ever presented any evidence demonstrating that the existing methodology accurately represents West Coast Naphtha values, and no prior decision of the Commission provides any logical or factual support for it. *Id.* at p. 202. Exxon maintains that the Circuit Court specifically has found that evidence previously presented by Tesoro – including the rejection and abandonment of the Commission's policy of no adjustment, the significant reduction in Gulf Coast ANS sales, and the disparity between the Gulf Coast Naphtha proxy and the true market value of Naphtha on the West Coast – was sufficient to establish a prima facie case that the current practice of using the Gulf Coast Naphtha price as a proxy for valuing West Coast Naphtha is not just and reasonable.[595] *Id.* It argues therefore, that no presumption of legality should be attached to the existing practice of valuing West Coast Naphtha on the basis of the Gulf Coast Naphtha price. *Id*.

1558. Ever since the distillation methodology was adopted in 1993, notes Exxon, the Commission and all parties to this proceeding have agreed that the valuation of each Quality Bank ANS cut should be market based. *Id*. at p. 203. Moreover, states Exxon, recognizing that the Gulf Coast and the West Coast are separate markets for petroleum products with different supply and demand conditions and different prices, the parties have proposed separate prices for the Gulf Coast and the West Coast for all Quality Bank cuts. *Id.* And with only two exceptions – Naphtha and VGO – Exxon explains that the Commission has adopted separate prices for the Gulf Coast and the West Coast for all Quality Bank cuts. *Id.*

1559. In the case of VGO, Exxon asserts that all parties now agree that the current

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[595] The Circuit Court actually held that Tesoro "at the least establish[ed] a prima facie case that new evidence warrants re-examination of how West Coast naphtha should be valued." *Tesoro*, 234 F.3d at p. 1293. This holding is significantly different than Exxon asserts.

method of valuing the West Coast VGO cut on the basis of the OPIS Gulf Coast spot price for high sulfur VGO does not produce a just and reasonable result, and that the proxy price for valuing the VGO cut on the West Coast should be changed to the OPIS West Coast spot price for high sulfur VGO. *Id*. at p. 203 (citing Joint Stipulation of the Parties, filed October 3, 2002, at p. 4). Therefore, states Exxon, for all Quality Bank cuts other than West Coast Naphtha, the parties agree that different market conditions on the West Coast require the use of West Coast prices to fairly value the West Coast cuts. *Id*. at pp. 203-04. In addition, notes Exxon, the use of a Gulf Coast price to value West Coast Naphtha does not meet the legal requirements established by the Circuit Court in *OXY*, where the court held that the Commission must adopt a sufficiently consistent approach in valuing the various Quality Bank cuts so as to assign accurate relative cut values. Exxon Reply Brief at p. 213. Accordingly, Exxon states, using a Gulf Coast price to value Naphtha on the West Coast is inconsistent with the methodologies that have been adopted for all other Quality Bank cuts, or in the case of VGO, with the methodology that is supported by all parties. Exxon Initial Brief at p. 204.

1560. Exxon cites evidence in the record and argues that this evidence clearly shows that the West Coast and the Gulf Coast are separate and distinct markets with different market prices for both intermediate and finished petroleum products. *Id*. For example, according to Exxon, the evidence shows that, throughout the 1994-2001 period, both the price of gasoline and the price of every intermediate petroleum product valued by the Quality Bank was significantly different on the Gulf Coast and the West Coast, and the price differentials between the West Coast and the Gulf Coast prices varied widely on both a monthly and an annual basis.[596] *Id.* Exxon notes that these price differentials between the West Coast and the Gulf Coast were acknowledged to be significant even by those parties advocating the use of the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.*

1561. Further, Exxon asserts, Williams's claim that the Gulf Coast price should be similar to the value of Naphtha on the West Coast over the long run, a claim that is not substantiated by the evidence, does not meet the requirements of the *OXY* and *Exxon* decisions that more than "a limited and unquantified relationship" between the proposed proxy price and the actual market value of the cut must be established, and that the proxy price must be shown to "correlate consistently within some specified range" with the market value of the cut. Exxon Reply Brief at pp. 213-14 (quoting *Exxon*, 182 F.3d at pp. 36, 42). Indeed, Exxon asserts, the evidence is undisputed that the current practice of using a Platts Gulf Coast Naphtha price to value the West Coast Naphtha cut was never justified by the Commission under those standards, but was based solely on a now abandoned 1993 policy of using only "unadjusted quoted market prices" to value all

[596] In support, Exxon cites Exhibit Nos. BPX-35, EMT-14, EMT-453, EMT 477 through EMT-482, PAI-176. Exxon Initial Brief at p. 204.

Quality Bank cuts. *Id.* at p. 214.

1562. According to Exxon, no party contends that the value of Naphtha is actually the same on the Gulf Coast and the West Coast. Exxon Initial Brief at p. 205. On the contrary, Exxon states, it is undisputed and conceded by opposing party witnesses that there have been, and will continue to be, different supply and demand forces at work in the markets for Naphtha on the two coasts. *Id*. pp. 205-06. To ascertain the value of Naphtha on the West Coast, Exxon argues, one has to look at the supply and demand for Naphtha on the West Coast. *Id*. at p. 206. In recognition of this market reality, Williams's witness, Sanderson, stated that when he worked at a West Coast refinery he did not rely on Gulf Coast prices for Naphtha and would not recommend that anyone now assume that Gulf Coast and West Coast Naphtha prices were the same. *Id*. Further, Exxon notes that Sanderson viewed the question of whether the Platts Gulf Coast price for Naphtha was an accurate value for West Coast Naphtha to be an exercise of subjective judgment. *Id.*

1563. Exxon also notes that, while Naphtha is used on the Gulf Coast to make both gasoline and jet fuel and as a petrochemical feedstock, virtually its only use on the West Coast is to make gasoline and jet fuel. *Id*. at pp. 206-07. Nonetheless, Exxon states, the use of Naphtha as a petrochemical feedstock on the Gulf Coast does not impact the price of Quality Bank Naphtha because a substantial portion of the Naphtha used there as a petrochemical feedstock is a different, lighter Naphtha that is used to produce ethylene rather than the reformer grade Naphtha used to produce gasoline on the West Coast. *Id.* at p. 207.

1564. There are a number of other differences that distinguish the West Coast market for Naphtha from the Gulf Coast market, Exxon states. *Id*. For example, explains Exxon, much of the gasoline on the West Coast is required to meet more stringent environmental requirements established by the California Air Resources Board or by the Federal reformulated gasoline specifications that apply in Las Vegas and Phoenix, whereas most of the gasoline produced on the Gulf Coast must meet only conventional gasoline standards. *Id*. at pp. 207-08. As a result, Exxon explains, gasoline prices on the West Coast have consistently been higher than on the Gulf Coast by several cents per gallon. *Id*. at p.208. Further, according to Exxon, the much larger size of the Gulf Coast gasoline market also makes it less volatile and better able to absorb the impact on supply caused by refinery outages. *Id*. In addition, Exxon explains, Gulf Coast refiners routinely import Naphtha from nearby Caribbean sources. *Id.* On the West Coast, according to Exxon, refiners are generally able to satisfy their demand for Naphtha from internal sources and do not, therefore, require imports. *Id*. As a result, Exxon notes, West Coast refineries have not constructed the tankage and terminal facilities needed to import substantial quantities of Naphtha. *Id*. at pp. 208-09.

1565. Exxon points out that the quality specifications for the Platts Gulf Coast Naphtha prices are also different from the quality of the ANS Naphtha. *Id.* at p. 209. In particular, Exxon notes, the reported Platts prices for both Heavy Naphtha and Full Range Naphtha are based on an N+A specification of 40, whereas ANS crude produces Naphtha with an N+A in the 55 to 60 range. *Id*. According to Exxon, this means that Naphtha produced from ANS crude will be higher in quality because it will produce reformate with a higher octane, and thus be more valuable than the Naphtha specified in the Gulf Coast price published by Platts. *Id*. Exxon also notes that West Coast refineries also have a greater percentage of hydrocracking capacity as a percentage of crude than Gulf Coast refineries, with the result that West Coast refineries have a greater ability to alter the amount of Naphtha or jet fuel that is produced from the crude oil. *Id*. pp.209-10.

1566. Given these many differences, Exxon argues, none of the evidence introduced supports the conclusion that the price of Naphtha on the Gulf Coast is a good representation of the value of West Coast Naphtha. *Id.* at p. 210. On the contrary, Exxon asserts that the evidence shows that the current method of valuing the West Coast Naphtha cut on the basis of a Gulf Coast Naphtha price has significantly undervalued West Coast Naphtha over the past 10 years by, on average, over $2/barrel. *Id.*

1567. Exxon cites extensive contract data produced in the proceeding to support its contention that West Coast Naphtha has a higher value than Gulf Coast Naphtha. *Id.* at p. 211. It asserts that these contracts provide the best available direct evidence of the value of West Coast Naphtha, because they reflect the result of negotiations between independent and knowledgeable parties seeking to maximize their own profit. *Id.* Exxon notes that it is significant that none of the nearly 300 contracts produced in this proceeding priced Naphtha on the West Coast on the basis of an unadjusted Gulf Coast price of Naphtha. *Id.* at p. 212. Further, Exxon notes that only three of those West Coast Naphtha contracts even used an adjusted Gulf Coast price. *Id.* Two of those three contracts priced West Coast Naphtha on the basis of a Gulf Coast Naphtha price plus a premium, and the third contract only included a Gulf Coast price as part of a complex series of pricing terms that included a price cap and floor. *Id*.

1568. The West Coast Naphtha contracts, Exxon contends, also consistently valued West Coast Naphtha at levels that were significantly higher than the Platts Gulf Coast Naphtha price, thereby further demonstrating that the current Quality Bank practice of valuing West Coast Naphtha at the Platts Gulf Coast Naphtha price is, in Exxon's view, unjust and unreasonable. *Id*. at p. 213. It cites numerous studies and exhibits introduced into the record that show that the contract price of Naphtha on the West Coast exceed Platts Gulf Coast Naphtha by from 2 to 12¢/gallon during the period 1994-2001.[597] *Id*. According to Exxon, this conclusion was also confirmed by all of the witnesses who

[597] *See, e.g.,* Exhibit Nos. SOA-1, SOA-8, SOA-28, EMT-133, EMT-140, EMT-380, EMT-381, WAP-230.

addressed the issue. *Id*. at pp. 213-14. Exxon argues that the contract evidence shows that sellers of Naphtha on the West Coast have been able, in fact, to charge prices that were higher than Platts Gulf Coast Naphtha price. *Id*. at p. 214. Further, Exxon notes, Sanderson stated that he did not know of any sales of Naphtha on the West Coast that were made at the Platts Gulf Coast Naphtha price. *Id.* Also, Exxon cites an analysis of West Coast Naphtha contracts by Culbertson that showed that, on a volume weighted basis, the price of Naphtha reflected in the West Coast contracts exceeded the Platts Gulf Coast Naphtha price by more than 8¢/gallon.[598] *Id*.

1569. Exxon argues that evidence presented during trial regarding discussions held with Naphtha traders did not show a consistent approach to the use of a Platts Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at pp. 214-15. It states that the notes of these discussions show that none of the traders endorsed the use of a Gulf Coast Naphtha price to value West Coast Naphtha. *Id*. at p. 215. Instead, according to Exxon, the traders either expressly rejected that approach or they were never asked for their opinion on that issue. *Id.*

1570. Moreover, while the interview notes introduced by Culberson included a representative of Platts, Exxon points out that Culberson admitted that the Platts representative was never asked whether it would be appropriate to use a Platts Gulf Coast price to value Naphtha on the West Coast. *Id.* at pp. 216-217. Although Culberson sought to defend this omission on the ground that he did not believe that the Platts representative was qualified to have an opinion on that issue, Exxon states that Culberson admitted that he had never tried to contact anyone at Platts to find out whether they thought it would be reasonable to use Platts Gulf Coast Naphtha prices to value West Coast Naphtha. *Id.* at p. 217. Exxon concludes, therefore, that the only traders who were asked to express an opinion on Culberson's proposal to use Platts Gulf Coast Naphtha prices to value West Coast Naphtha rejected that proposal. *Id.*

1571. The evidence, Exxon argues, also makes clear that those parties who advocate the continued use of the Platts Gulf Coast Naphtha price to value the West Coast Naphtha cut have not carried their burden. *Id*. According to Exxon, the *Exxon* ruling requires that there be a rational, demonstrated relationship between the proposed proxy price and the value of the cut sufficient to show a consistent correlation between the proxy and the cut being valued. *Id*. at pp. 217-18. It maintains that this relationship test has not been met. *Id*. at p. 218. Further, Exxon asserts, there is no evidence to support the claim of Williams and Unocal that the prices of Naphtha on the West Coast and Gulf Coast are linked by the ability to move crude oil imports or Naphtha between the two markets in such a manner that the differential between the price of Gulf Coast Naphtha and the value of Naphtha on the West Coast would, on average, be expected to be zero. *Id.* Nor,

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[598] *See* Exhibit Nos. UNO-52, UNO-56.

according to Exxon, is there any evidence to support Williams's argument that sellers of Naphtha on the West Coast would be unable to capture any portion of the higher gasoline refining margins found on the West Coast, or that the 1996 California Air Resources Board requirements somehow justify the use of a Gulf Coast Naphtha price. *Id.* Finally, Exxon states, the evidence is clear that the mere fact that the use of the Platts Gulf Coast Naphtha price to value West Coast Naphtha has provided a financial benefit to Petro Star and Williams plainly does not support the continued use of the Platts Gulf Coast price to value West Coast Naphtha. *Id.*

1572. According to Exxon, Williams defends using a Gulf Coast Naphtha price to value West Coast Naphtha by first repeating Sanderson's pre-filed testimony that the Gulf Coast published price is the only objective method of valuing West Coast Naphtha, because it is published by a recognized publishing service. Exxon Reply Brief at p. 216. It points out, however, that Williams fails to note that Sanderson admitted at the hearings that, while the published Gulf Coast price may be an objective measure of Gulf Coast value, his belief that the Gulf Coast price was a suitable measure for West Coast value was his subjective judgment. *Id.* Therefore, Exxon asserts, there is no factual basis whatsoever for the attempt of Williams and Unocal/OXY to claim that their proposal to continue using the published Gulf Coast Naphtha price to value West Coast Naphtha is more objective than the methodology presented by Tallett on behalf of Exxon, which is based entirely on objective published prices for gasoline and jet fuel. *Id.* at p. 217.

1573. Similarly, Exxon states that there is no basis for Williams's reliance on the claim in Sanderson's pre-filed testimony that the use of a published Gulf Coast Naphtha price to value West Coast Naphtha is "the most consistent with the valuation of the other Quality Bank cuts." *Id.* (quoting Exhibit No. WAP-33 at p. 2). Exxon notes that Sanderson conceded at the hearings that all of the Quality Bank cuts except Naphtha and VGO are valued on the West Coast using West Coast prices, and that, if the Commission accepts the unanimous proposal of the parties to value West Coast VGO on the basis of the West Coast VGO price, all of the Quality Bank cuts other than Naphtha will be valued on the West Coast using West Coast prices. *Id.* For this reason, Sanderson conceded at the hearing, contrary to his pre-filed testimony, that it would be most consistent to use a West Coast value rather a Gulf Coast value for Naphtha if one can be derived. *Id.*

1574. In Exxon's view, Williams's legal arguments in support of continued use of a Gulf Coast Naphtha price are also without merit. *Id.* at. p. 218. For example, Exxon asserts, Williams's reliance on a 1994 statement by the Commission that it had "strictly held to posted spot prices instead of formulæ or adjusted prices to establish relative prices for the Alaska North Slope crude components" is obviously out of date. *Id*. (quoting *Trans Alaska Pipeline System*, 67 FERC at p. 61,531). As all parties have recognized, Exxon states, the Commission's "no adjustments to market prices" policy was specifically rejected on review eight years ago by the Circuit Court in *OXY* and abandoned by the

Commission on remand. *Id*.

1575. Nor is there any basis, according to Exxon, for Williams's suggestion that the *OXY* decision only applies when there is no reliable published price for a cut in either market, and that otherwise the TAPS Carriers's Tariff recognizes that the published price in one market may be used to value the cut in both markets. *Id.* Exxon asserts that the Circuit Court clearly rejected this argument in *Tesoro*, stating that its decision in *OXY* "would be breached if the availability of an adequate non-adjusted benchmark for [Naphtha on] the Gulf Coast prevented the use of an adjusted benchmark for [Naphtha on] the West Coast." *Id*. (quoting *Tesoro*, 234 F.3d at 1293).

1576. Sanderson, according to Exxon, failed to support his contentions that the Gulf Coast Naphtha price was an appropriate proxy for the value of Naphtha on the West Coast based upon his claim that, because crude oil prices on the two coasts were "similar," the prices of Naphtha and other feedstocks should also be "similar" on both coasts. Exxon Initial Brief at p. 219. Moreover, Exxon states that, even if Williams had been able to support this claim, the similarity of prices posited by Sanderson would not be sufficient to meet the requirements for reasoned decision making established for this proceeding by the Circuit Court in Exxon. Exxon Reply Brief at p. 220. Exxon claims that Sanderson based his theory primarily on his contention that the price of ANS crude on the West Coast was similar to the price of Isthmus crude on the Gulf Coast. Exxon Initial Brief at p. 219; Exxon Reply Brief at p. 220. However, Exxon states, there was no direct evidence of any actual linkage between these prices. *Id.*

1577. Exxon declares that Sanderson admitted at the hearing that the market dynamics for VGO are quite different on the Gulf Coast and West Coast due to the substantially larger Gulf Coast demand for VGO for the production of heating oil for markets in the Northeast and Midwest. Exxon Reply Brief at p. 223. In addition, Exxon notes, Sanderson admitted that strict environmental restrictions on sulfur have increased the cost of processing VGO on the West Coast and thereby reduced its value; a problem that does not arise with Naphtha because all of the sulfur in Naphtha is removed by hydrotreating on both coasts before the Naphtha is processed into reformate in order to protect the reformer catalyst. *Id.*

1578. Sanderson's theory, by his own admission, according to Exxon, did not work for VGO in either 2000 or 2001 where the VGO price differential between the two coasts varied widely. Exxon Initial Brief at p. 223. In those years, Exxon points out, the VGO price was influenced by sharp spikes in the price of gasoline. *Id*. Further, Exxon asserts, the evidence shows that, contrary to Sanderson's theory, the price differential between crude oil prices and VGO fluctuated widely over time on both coasts even when smoothed out by the use of a 12-month moving average. *Id.* What the VGO price data actually show, according to Exxon, is that – directly contrary to Sanderson's theory – VGO prices on the West Coast have closely tracked the price of gasoline on the West

Coast, not the price of crude oil, with the result that VGO prices on the West Coast have generally been higher in recent years than VGO prices on the Gulf Coast. Exxon Reply Brief at p. 224. Further, Exxon notes that Sanderson's theory does not work for other feedstocks such as Heavy Distillate, Isobutane, or Butane. Exxon Initial Brief at p. 223.

1579. Indeed, Exxon asserts, the evidence shows that, contrary to Sanderson's theory, there were wide fluctuations in the differentials between the prices of all the Quality Bank cuts and crude oil prices on the West Coast and the Gulf Coast. *Id.* It states that Exhibit No. EMT-533, which compares the differential between the Gulf Coast price of each of seven Quality Bank cuts and the price of Isthmus crude on the Gulf Coast with the differential between the West Coast price of the same cut and the West Coast price of ANS crude, shows that there was no similarity at all between the price differentials on the Gulf Coast and the price differentials on the West Coast. *Id.* at p. 223-24. Exxon also states that this fact is confirmed by a regression analysis performed on its behalf which showed there was no significant correlation between the price differentials on the two coasts. *Id.* (citing Exhibit No. EMT-534).

1580. Further Exxon argues, the evidence[599] also shows that, notwithstanding any alleged similarity of crude oil prices on the two coasts, both intermediate petroleum product prices and finished petroleum product prices have varied widely between the two coasts. *Id*. at p. 224. For example, Exxon states, the evidence shows that the average annual differential between the price of VGO on the West Coast and the price of VGO on the Gulf Coast ranged from a negative 1.0 in 1996 to a positive 3.5 in 2000, and that the monthly average price differentials also fluctuated widely from month to month between the two coasts. *Id.*

1581. Furthermore, asserts Exxon, even were Sanderson correct that "similar" crude oil prices should result in "similar" prices for intermediate feedstocks, the so-called "similarity" that he posited between Gulf Coast Naphtha prices and the value of West Coast Naphtha would not meet the requirements for reasoned decisionmaking established by the Circuit Court. Exxon Reply Brief at p. 226. Exxon notes that Williams concedes that Sanderson did not contend that the value of Naphtha was actually ever the same on the two coasts. *Id*. At most, notes Exxon, Sanderson argued that crude oil and VGO prices gave him some guidance as to the value of Naphtha on the West Coast, and that, based on that guidance, he believed that the value of Naphtha on both coasts should be 'similar' in the long run. *Id.* Indeed, explains Exxon, Sanderson contended that it would be sufficient if two prices "may average out over ten or more years" even though they

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[599] In support, Exxon cites Exhibit Nos. BPX-35, EMT-14, EMT-453, EMT-477, EMT-478, EMT-479, EMT-480, EMT-481, EMT-482, PAI-176. Exxon Initial Brief at pp. 223-24.

"may vary widely from year to year." *Id*. at pp. 226-27 (quoting Transcript at p. 8830).[600]

1582. The theory presented by both Williams and Unocal/OXY that the availability of transportation would link the West Coast Naphtha price to the Gulf Coast price is also invalid, according to Exxon. Exxon Initial Brief at p. 225. First, Exxon argues, this theory plainly does not support the use of the same price to value Naphtha on both the Gulf Coast and the West Coast. *Id.* Instead, in Exxon's view, transportation costs would only constrain or limit the price of West Coast Naphtha to some value above the Gulf Coast price based on the transportation differential for shipping Naphtha to the West Coast. *Id.* Therefore, according to Exxon, the transportation differentials claimed by Williams and Unocal/OXY would, at best, only support a cap on the price of West Coast Naphtha analogous to the "governor" proposed by Ross on behalf of BP. *Id.*

1583. Further, Exxon states, the evidence shows the transportation cost differentials for Naphtha proposed by Sanderson and Culberson were too low. *Id.* at pp. 225-26. For example, Exxon notes that Sanderson's overall Naphtha transportation differential of $1.30/barrel (3.1¢/gallon) was based on the difference between the Worldscale shipping cost from Venezuela to Los Angeles and the Worldscale shipping cost from Venezuela to Houston. *Id*. at p. 226. According to Exxon, however, Sanderson acknowledged that this estimate of the transportation differential was a subjective estimate based on his judgment and a variety of assumptions. *Id.* Exxon also notes that Sanderson's estimate was based solely on Los Angeles, did not take into account barriers to entry that would impose additional costs on shipments of Naphtha to the West Coast, and that he conceded that the differential would be larger for other destinations on the West Coast.[601] *Id.*

1584. Second, Exxon asserts, there is no valid factual basis for Culberson's claims regarding either the magnitude or the effect of transportation costs on West Coast prices. *Id.* at p. 227. Exxon notes that Culberson himself admitted that his estimate of the cost of transporting Naphtha from the Caribbean to the West Coast was significantly below the actual average transportation rates publicly reported by Platts, and that it was based solely on his speculation that cheaper rates might be obtainable based on rates in other parts of the world and that there should be no transport differential between the Gulf Coast and

[600] Exxon notes that Sanderson conceded that any linkage between the price of crude and the price of a petroleum product was "not a rigid relationship" that would permit the Commissions to compute a West Coast Naphtha price. Exxon Reply Brief at p. 226, n.133 (quoting Transcript at pp. 9056-57).

[601] Exxon notes the following barriers to entry: the cost of building additional storage and terminal facilities, the higher risks associated with the longer lead time for shipments to West Coast markets, and the lack of market liquidity that makes hedging more difficult. Exxon Initial Brief at p. 226.

the West Coast. *Id*. Asserts Exxon, the evidence showed that the rates for shipping to the West Coast were actually nowhere near as low as Culberson had assumed and suggested in his prepared testimony. *Id*. Indeed, Exxon states, Culberson testified at the hearing that March 2003 tanker rates were significantly higher and that any opinion about future rates would be total speculation. *Id*. at pp. 227-28. It points out that Culberson's conclusion that West Coast Naphtha values must be at, or near, the Gulf Coast Naphtha price was based squarely on speculation about future transportation rates that they view is clearly invalid. *Id*. at p. 228. Nor, according to Exxon, did Culberson take into account a number of other costs that would be incurred in any movement of Naphtha to the West Coast, such as the higher risk involved in longer shipments to the smaller West Coast market, the cost to the refinery of changing its crude slate, and the lack of tank and terminal facilities on the West Coast.[602] *Id.*

1585. Finally, Exxon argues, both Sanderson's and Culberson's theories are directly undercut by evidence in the record[603] that there have been substantial and persistent differences between prices on the West Coast and Gulf Coast for virtually all intermediate and finished petroleum products. *Id*. at pp. 228-29. If West Coast and Gulf Coast petroleum prices were in fact linked by transportation in the manner suggested by Williams and Unocal, Exxon submits, the substantial and persistent differences between West Coast and Gulf Coast prices for both intermediate and finished petroleum products would not exist. *Id.* at p. 229. In Exxon's opinion these price differentials only serve to highlight the inappropriateness of the Quality Bank's use of a Gulf Coast price to value West Coast product. *Id*.

1586. Although Sanderson criticized the O'Brien and Tallett West Coast Naphtha

[602] Equally lacking in merit, in Exxon's view, was Culberson's assertion that the absence of imported volumes to the West Coast supported his claim that the Gulf Coast and West Coast markets were linked by transportation. *Id.* at p. 228, n.89. In support of this position, explains Exxon, Culberson pointed to import data which, when properly analyzed, showed that imports to the West Coast were not driven by the existence of transportation differentials. *Id.* Further, Exxon notes that Culberson's import data demonstrated that petroleum products, and particularly unleaded regular gasoline, did not move to the West Coast even during periods of high West Coast product prices. *Id.* Finally, Exxon states that Culberson's speculation about the availability of imported volumes from the West Coast of South America or the Far East proved nothing as to the reasonableness of using a Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at pp. 228-29, n.89.

[603] In support, Exxon cites Exhibit Nos. BPX-35, EMT-14, EMT-453, EMT-477, EMT-478, EMT-479, EMT-480, EMT-481, EMT-482, PAI-176. Exxon Initial Brief at pp. 228-29.

methodologies on the ground that, by setting the value of West Coast Naphtha based on the price of West Coast gasoline, they attributed all of the higher West Coast refining margin to Naphtha, Exxon points out that Sanderson conceded that his approach would do precisely the opposite – attribute none of the higher West Coast refining margin to West Coast Naphtha. *Id.* Moreover, Exxon notes that while Sanderson admitted that refining margins for finished petroleum products are higher on the West Coast in relation to crude oil prices, neither he nor Culberson presented any evidence regarding actual West Coast refining margins for intermediate feedstocks like Naphtha to support Sanderson's theory that none of the higher West Coast refining margin should be attributed to Naphtha.[604] *Id.* at p. 230.

1587. Exxon claims that the evidence shows the higher West Coast refining margins were likely to result in correspondingly higher West Coast Naphtha values. *Id.* It notes that Culberson testified that he believed the entire margin was not being captured at the refinery, but rather that some of it may be captured elsewhere. *Id.* Exxon suggests that one place where it is captured may be via an increase in the value of gasoline feedstocks like Naphtha. *Id.* Similarly, Exxon notes, Sanderson admitted that West Coast Naphtha contracts showed that during periods of gasoline price volatility, sellers of Naphtha on the West Coast were able to capture a large portion of the higher refining margin. *Id.* at. pp. 230-31.

1588. Furthermore, according to Exxon, Sanderson's theory was not based on any evidence regarding actual refining margins, but only upon inferences drawn by him from price differentials (West Coast less Gulf Coast) for two selected feedstocks, LSR and VGO, and for certain finished petroleum products. *Id.* p. 231. However, it claims, Sanderson admitted that the price differentials were a reflection of market forces, including both supply and demand factors, unique to each specific product and may not have anything to do with refining margins. *Id*. For example, Exxon notes, Sanderson acknowledged that LSR had a lower value on the West Coast, not because of anything to do with refining margins, but because stricter environmental regulations on the West Coast have severely limited the ability of West Coast refiners to use LSR in the production of gasoline, and because, unlike on the Gulf Coast, there is no petrochemical demand for LSR on the West Coast. *Id*. Therefore, Exxon asserts that Sanderson's refining margin did not work at all for LSR. *Id.*

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[604] Exxon views this omission as particularly noteworthy in Sanderson's case because he admitted that when he worked for a California refinery in the 1980s advising traders on potential purchases of Naphtha and other feedstocks, he used linear programming models to determine the value of Naphtha to the refinery based on the value of the gasoline that could be made from the Naphtha less the cost of processing and blending the Naphtha into gasoline. Exxon Initial Brief at p. 230, n.90.

1589. Exxon also notes that Sanderson admitted that market dynamics for VGO were different on the Gulf Coast and West Coast due to the use of VGO on the Gulf Coast in the production of heating oil. *Id*. Further, points out Exxon, he admitted that environmental regulations regarding sulfur also affect the markets for VGO differently on the two coasts. *Id.* at pp. 231-32.

1590. In addition, Exxon asserts, Sanderson omitted a number of price differentials for other products that undercut his theory, including Propane, Isobutane, normal Butane, MTBE, low sulfur VGO, and high sulfur fuel oil from his analysis. *Id*. p. 232. When those additional products are taken into account, Exxon asserts, the conclusion that Sanderson purports to draw – that finished petroleum products (such as gasoline) have a higher price differential than feedstocks (such as Naphtha) – was shown to be wholly without foundation. *Id.*

1591. Sanderson's analysis, Exxon also states, was undercut by the fact that the price differentials on which he relied varied significantly over time. *Id*. For this reason, Exxon states, Sanderson admitted that his reasoning also did not work for VGO for the years 1999 through 2001 when the differential between the West Coast price of VGO and the Gulf Coast VGO price went up sharply along with the price differential for regular unleaded gasoline. *Id*. In fact, according to Exxon, there was no factual basis for any of Sanderson's conclusions about the alleged relationship between the Gulf Coast-West Coast price differential for VGO and the Naphtha price differential between the two coasts of zero which he advocated. *Id*. at pp. 232-33.

1592. Exxon contends that Williams argues that the Gulf Coast Naphtha price should continue to be used to value West Coast Naphtha because the CARB gasoline requirements introduced in 1996 have lessened the demand for Naphtha on the West Coast. Exxon Reply Brief at p. 231. It asserts that this provides no support for the continued use of Gulf Coast prices to value West Coast Naphtha and, in fact, would only further confirm that use of the Gulf Coast Naphtha price is not an appropriate proxy for valuing West Coast Naphtha because the markets for Naphtha on the Gulf Coast and the West Coast have different demand characteristics. *Id.*

1593. Further, although Williams argues that the California Air Resources Board requirements have "curbed the demand for Naphtha" and thereby made Naphtha less valuable to refiners on the West Coast, Exxon claims, Williams provides no evidence at all as to how much the value of West Coast Naphtha was affected by this change in the marketplace, or how this change affected the relationship between the value of Naphtha on the two coasts. *Id.* Accordingly, Exxon asserts that this argument provides no useful guidance regarding either the "actual market value" of West Coast Naphtha or whether the Platts Gulf Coast Naphtha price "bear[s] a rational relationship to the actual market value" of West Coast Naphtha. *Id*. at pp. 231-32 (quoting *Exxon*, 182 F.3d at 42).

1594. There was also no evidence, according to Exxon, to support Sanderson's claim that the stringent benzene and aromatics requirements for CARB gasoline in California have made Naphtha less valuable on the West Coast as shown by the allegedly low utilization levels for catalytic reformers on the West Coast since 1994. Exxon Initial Brief at p. 233. Exxon asserts that Sanderson's claim about low utilization levels for West Coast reforming capacity was directly contradicted by a report prepared by Sanderson's firm, Purvin & Gertz, which stated that reforming capacities in California were utilized at about 90% during the year 2000, a fact that was also confirmed by Sanderson's colleague, Michael Sarna.[605] *Id.* at pp. 233-34. In addition, states Exxon, the West Coast Naphtha contracts show that the value of West Coast Naphtha has increased substantially since the California Air Resources Board requirements went into effect in May 1996. Exxon Reply Brief at p. 232.

1595. Further, continues Exxon, the evidence shows that prior to the introduction of the California Air Resources Board requirements, most California refiners had already installed the equipment required to remove benzene from the reformate made from Naphtha. Exxon Initial Brief at p. 234. As a result, Exxon states, California refineries are not limited in their use of Naphtha to produce CARB gasoline. *Id*. And for this reason, claims Exxon, Sorenson testified, he would strongly disagree with anyone suggesting that Naphtha lost value on the West Coast due to the California Air Resources Board requirements. *Id.*

1596. Additionally, Exxon also states, Sanderson's theory failed to take into account that the additional costs that California refineries have had to incur to produce CARB gasoline have resulted in significantly higher prices for it than for conventional gasoline. *Id*. at p. 235. More specifically, Exxon asserts, the evidence shows that the price of CARB gasoline has been $2.67/barrel (or 6.35¢/gallon) higher on average than the price of regular unleaded gasoline on the West Coast over the period May 1996 (when the California Air Resources Board requirements went into effect) through 2001. *Id.* The mere fact that some additional costs must be incurred to process Naphtha into CARB gasoline does not, according to Exxon, mean that Naphtha has lost value as compared to its value in producing conventional gasoline. *Id.*

[605] Exxon states that, later in his testimony, Sarna attempted to diminish this fact by asserting that the 90% reformer utilization rate reported by Purvin & Gertz was a calendar day figure and that the stream day utilization rate would be lower. Exxon Initial Brief at p. 234, n.92. It asserts that that claim made no sense because, by definition, the calendar day utilization rate can never be higher than the stream day rate, which represents operation of the unit under optimal conditions, while the calendar day includes downtime for maintenance and other unexpected problems. *Id.* Accordingly, the calendar rate will only equal the stream day rate if the unit is operating at full capacity every day of the year, and it can never be higher. *Id.*

1597. Furthermore, Exxon argues, the evidence clearly shows that Naphtha has other qualities that are valuable in the production of CARB gasoline. *Id.* According to Exxon, the aromatics in the reformate made from Naphtha result in "very high octane," and higher octane makes the gasoline more valuable. *Id*. In addition, continues Exxon, reformate made from Naphtha has a low Reid Vapor Pressure, a zero olefin content, and a zero sulfur content, all of which make reformate a particularly valuable feedstock for making CARB gasoline. *Id.* Exxon points out that, as a result of these, a study of "refining options" available to California refineries done by Sanderson's firm, Purvin & Gertz, showed that a refinery on the West Coast making 100% CARB gasoline would be expected to use a higher percentage of reformate in its gasoline pool than a refinery on the Gulf Coast producing 100% reformulated gasoline. *Id.* at pp. 235-36. Exxon asserts that this study squarely contradicts both Williams's and Sanderson's claim that Naphtha has lost value on the West Coast due to the requirements for producing CARB gasoline. *Id*. at p. 236.

1598. Exxon asserts that the weakness of Williams's argument is graphically demonstrated by Williams's extensive reliance on a 1999 paper about the possible future effects of new gasoline specifications that were scheduled to go into effect in Europe in 2000 and 2005, and the possibility that those new specifications might affect the use of reformate made from Naphtha by European refineries.[606] *Id.* at p. 235. It notes that Williams's own witness conceded that the European refining industry and gas markets are markedly different than those in the U.S. *Id*. Given these many differences, Exxon argues, the conjectures in Exhibit No. WAP-266 about the possible future impact of new European gasoline specifications on the use of reformate made from Naphtha by European refineries plainly have no probative value whatsoever in this case, and Williams's extensive reliance on that paper in its initial brief only highlights the lack of evidentiary support for its position. *Id*. at pp. 235-36.

1599. Nor, according to Exxon, will the fact that new California Air Resources Board standards are scheduled to go into effect cause Naphtha to lose value on the West Coast. Exxon Initial Brief at p. 236. As Sorenson made clear, states Exxon, the benzene reduction equipment already in place will be able to handle the new California Air Resources Board standards*.* *Id.* Moreover, explains Exxon, as Sanderson's own exhibit (Exhibit No. WAP-273) shows, the new California Air Resources Board specifications actually increase the maximum amount of aromatics allowed from 30% to 35% a change that should make Naphtha, which has a high aromatics content, more valuable under the

[606] I noted during the hearing that Exhibit No. WAP-266, a 1999 paper about the possible future use of Naphtha by European refiners, "has little probative value" to the matters at issue in this case and that no witness "verified the facts" in that paper. Transcript at pp. 13516-17, 13523.

new California Air Resources Board specifications. *Id.*

1600. Finally, even if Sanderson's claim that the introduction of the CARB gasoline requirements made Naphtha relatively less valuable on the West Coast were true, Exxon argues that claim would still provide no support for Williams's position that the Platts Gulf Coast Naphtha price should be used to value West Coast Naphtha. *Id.* Regardless of their impact on the value of West Coast Naphtha, Exxon asserts that the CARB gasoline requirements plainly do not tie the value of West Coast Naphtha to the price of Gulf Coast Naphtha. *Id.* Sanderson's argument, therefore, provides no support whatsoever for the use of the Platts Gulf Coast price to value West Coast Naphtha because, Exxon states, it wholly fails to show that "the chosen proxy bear[s] a rational relationship to the actual market value" of West Coast Naphtha. *Id*. (quoting *Exxon*, 182 F.3d at p. 42).

1601. Exxon also disagrees with Petro Star's contention that any methodology that values West Coast Naphtha above the Platts Gulf Coast Naphtha price would impose an unfair financial burden on Petro Star. *Id*. at p. 237. The sole purpose of the Quality Bank is to make the shipper whose product is devalued economically indifferent to the diminution of his stream, not, in Exxon's view, to require shippers to subsidize Petro Star. *Id*. (citing *OXY*, 64 F.3d at p. 684). Exxon argues that the truth is that Petro Star has been receiving an unfair and inappropriate financial subsidy at the expense of the producers for many years because, in Exxon's view, the West Coast Naphtha cut has been undervalued by the Quality Bank, and there is no justification whatsoever for perpetuating that subsidy. *Id*. It points out that Boltz, Petro Star's own witness, testified that the Commission should value the Naphtha cut on the West Coast on the basis of the methodology that best captures its market value and not based on any possible financial effect on Petro Star. *Id.*

1602. Furthermore, continues Exxon, Petro Star substantially overstated the financial impact of valuing the West Coast Naphtha cut on the basis of West Coast market conditions. *Id*. It points out that Boltz acknowledged that Petro Star would be readily able to mitigate the financial impact of valuing West Coast Naphtha at a higher level simply by reducing the quantity of jet fuel that it produces from Naphtha. *Id.* at pp. 237-38. Exxon also notes that Boltz conceded that Petro Star's contention that West Coast Naphtha should be valued on the basis of the Gulf Coast Naphtha price was inconsistent with its position that the Quality Bank should value every one of the other West Coast cuts on the basis of West Coast prices. *Id.* at p. 238.

1603. Petro Star's hardship claim is also inconsistent, in Exxon's view, with the 1993 Settlement Agreement to which Petro Star was a signatory. *Id*. (citing Exhibit No. EMT-613). The 1993 Settlement Agreement, explains Exxon, set forth a methodology to calculate the value of West Coast Naphtha based on the Platts Los Angeles pipeline spot price of regular gasoline adjusted by the monthly price differential between Naphtha and gasoline on the Gulf Coast – a formula that tied the West Coast Naphtha value to the price of West Coast gasoline. *Id.* Exxon notes that the West Coast Naphtha value under the 1993 Settlement Agreement was even higher than it would be under any of the gasoline-based valuations proposed by the parties in this proceeding.[607] *Id.* Therefore, the alleged financial burden of an appropriate West Coast Naphtha valuation on Petro Star provides, in Exxon's opinion, no valid ground for continuing to use the Platts Gulf Coast Naphtha price to value West Coast Naphtha. *Id.* at pp. 238-39.

1604. The evidence also shows, states Exxon, that Williams's Alaskan subsidiary, Williams Alaska Petroleum, has been taking advantage of the substantial undervaluation of the West Coast Naphtha cut by extracting significant volumes of Naphtha from the TAPS crude stream. *Id*. at p. 239. According to Exxon, Williams extracts this Naphtha not for the purpose of producing gasoline or jet fuel, but solely for the purpose of exporting the Naphtha from Alaska to the Far East. *Id*. In this manner, according to Exxon, Williams arbitrages the below-market Quality Bank West Coast Naphtha value in clear contravention of the Quality Bank's purpose. *Id.* Moreover, continues Exxon, Williams has publicly announced its intention to extract even larger amounts of Naphtha from TAPS in the future for sale in the Far East and the West Coast, and to electric power generators and other refineries in Alaska. *Id*. This arbitrage opportunity is made possible solely because, asserts Exxon, by valuing all of the Naphtha in the TAPS crude stream at the published Gulf Coast Naphtha price, the Naphtha in the TAPS stream has been significantly undervalued on the West Coast. *Id.*

1605. Exxon states that Williams's and Unocal/OXY's argument that, because reforming Naphtha's price on the Gulf Coast is elevated by its use as a petrochemical feedstock, the use of a published Gulf Coast price to value West Coast Naphtha is not valid. Exxon Reply Brief at p. 227. Exxon asserts that this argument would not establish that the Gulf Coast Naphtha price is an appropriate proxy for the value of Naphtha on the West Coast, because it assumes that the markets for Naphtha on the Gulf Coast and the West Coast have different demand characteristics. *Id*. at pp. 227-28.

1606. Furthermore, continues Exxon, the theory that the Gulf Coast Naphtha price might be elevated due to petrochemical demand does not meet the standard established in the *Exxon* decision because, according to Exxon, even were there some added value due to

[607] Exxon cites Exhibit No. EMT-432 at p. 4 (showing average value of West Coast Naphtha under 1993 Settlement Agreement of $26.57/barrel) and compares it with Exhibit No. EMT-431 at p. 4 (showing average value of West Coast Naphtha under the O'Brien valuation methodology of $26.29/barrel) to support this assertion. Exxon Initial Brief at p. 238, n.93. Exxon also cites Exhibit No. EMT-433 at p. 4 (showing average value of West Coast Naphtha under Tallett valuation methodology of $25.49/barrel) to support this statement. *Id.*

petrochemical demand as a result, it clearly does not establish that the Gulf Coast Naphtha price "will correlate consistently within some specified range" with the value of West Coast Naphtha. *Id.* at p. 228 (quoting *Exxon*, 182 F.3d at p. 42). Exxon states that this is particularly true as there are many other factors, such as the greater supply of Naphtha on the Gulf Coast from nearby sources in the Caribbean, which tend to reduce the price of Gulf Coast Naphtha, and the much higher prices of West Coast gasoline and jet fuel, which elevate the value of Naphtha on the West Coast. *Id.*

1607. According to Exxon, this conclusion is also confirmed by Tallett's regression analysis, which shows that nearly all of the variation in Gulf Coast Naphtha prices can be explained by changes in the gasoline and jet fuel prices. *Id*. at p. 229. Exxon notes that this means that, at a maximum, no more than about 3% of the variation in the Gulf Coast price of Naphtha might be caused by all other market factors, including the demand for Naphtha as a petrochemical feedstock. *Id.*

1608. Exxon asserts that the fact that petrochemical usage does not significantly influence the demand for reformer-grade Naphtha on the Gulf Coast is further confirmed by the fact that the prices for Gulf Coast Naphtha follow very closely the movements in Gulf Coast gasoline prices, including both peaks and troughs, and there is no "non-coincident spiking." *Id*. Moreover, notes Exxon, the evidence shows that the small variations between the Gulf Coast prices of Naphtha and gasoline are almost entirely explained by movements in the Gulf Coast price of jet fuel. *Id.* at pp. 229-30. According to Exxon, this evidence squarely refutes Williams's argument that petrochemical demand props up the Gulf Coast price of Naphtha during periods of low gasoline prices; for it demonstrates that it is jet fuel demand, not petrochemical demand, which props up the price of Naphtha during periods of low gasoline prices. *Id.* at p. 230. Finally, states Exxon, neither Williams nor Unocal/OXY cite any evidence supporting their claim that the demand for petrochemical products produced from Naphtha such as ethylene and benzene influence the price of reformer-grade Naphtha on the Gulf Coast. *Id*. To the contrary, Exxon claims that the evidence shows that there is a very low correlation between the prices of either ethylene or benzene and the price of Naphtha on the Gulf Coast. *Id.*

1609. In Exxon's view, there is also no merit to the argument of Unocal/OXY (based on Culberson's testimony) that, in view of the fact that Naphtha is imported into the Gulf Coast and the potential exists for similar shipments of Naphtha to the West Coast, one can infer from the absence of imports of Naphtha on the West Coast that the market value of Naphtha on the West Coast is no higher than the Gulf Coast Naphtha price. *Id*. at p. 236. First, Exxon asserts, this theory does not support the current practice of using the Gulf Coast price to value Naphtha on the West Coast. *Id.* Exxon notes that Unocal/OXY concede that, even assuming that Culberson's theory were otherwise valid, his import theory only suggests that the West Coast price of Naphtha can only exceed the Gulf Coast price by an amount sufficient to compensate for the cost of importing the Naphtha to the West Coast. *Id*. Accordingly, the lack of imports on the West Coast does not tell what either the West Coast price should be or that the West Coast price should be identical to the Gulf Coast Naphtha price. *Id*.

1610. Exxon argues that the inference that Unocal/OXY attempt to draw from the lack of West Coast imports is also contrary to the evidence. *Id*. According to Exxon and as Culberson testified, the evidence shows that very little Naphtha is imported on the West Coast because West Coast refineries are generally able to satisfy their demand for Naphtha from internal sources and do not require imports of Naphtha to produce gasoline or jet fuel.[608] *Id*. at pp. 236-37.

1611. In his rebuttal testimony, notes Exxon, Culberson attempted to avoid the obvious conflict between this balance of the supply and demand for Naphtha on the West Coast and his import theory by arguing that West Coast refiners could still choose to import naphtha if its price were less than the internally generated value of Naphtha and by changing the refinery's crude slate. *Id*. at p. 238. However, states Exxon, the record shows that Culberson seriously underestimated or wholly ignored a number of costs that a refiner would have to incur in order to take advantage of any available imported Naphtha. *Id*. Among other things, continues Exxon, Culberson ignored the fact that a refiner switching to a different crude would also be changing both the amount and the quality of all the other products produced through the distillation process. *Id.* The evidence also shows, explains Exxon, that West Coast refineries typically purchase a significant quantity of crude under long-term purchase contracts and vessels are scheduled months in advance, with the result that switching crude slates can involve a considerable amount of time and expense. *Id*.

1612. Exxon argues that Culberson also completely ignored a number of significant barriers that limit imports on the West Coast. *Id*. For example, states Exxon, Culberson ignored the higher risks involved in shipments with longer transit times to the smaller West Coast market. *Id*. Further, notes Exxon, Culberson also ignored the fact that, as a result of the balance between supply and demand on the West Coast, West Coast refineries have not constructed the tankage and terminal facilities that would be required to import substantial quantities of Naphtha. *Id*. at p. 239. As a result of these barriers, Exxon asserts that a West Coast refiner would not purchase imported Naphtha unless the price was so much lower for an extended period of time that the refiner would be compensated for all the costs and opportunity costs that would be incurred to import

[608] Exxon argues that Culberson's analysis is also undercut by his reliance on Energy Information Administration import data, which, it claims, was shown at the hearing to use different, subjective categories and to be unreliable. Exxon Reply Brief at p. 237, n.138.

Naphtha.[609] *Id*.

1613. Exxon points out that Culberson's theory also is directly undercut by the fact that there have been substantial and persistent differences between prices on the West Coast and Gulf Coast for virtually all intermediate and finished petroleum products. *Id.* at pp. 240-41. If West Coast and Gulf Coast petroleum prices were in fact equalized by the potential for imports in the manner suggested by Culberson, Exxon argues that the substantial and persistent differences between West Coast and Gulf Coast prices for both intermediate and finished petroleum products would not exist. *Id.* at p. 241. In Exxon's view, these persistent price differentials clearly demonstrate that it is inappropriate to use a Gulf Coast price to value a West Coast product. *Id*.

1614. Culberson's conclusion, Exxon insists, that the Commission should infer that the value of West Coast Naphtha does not exceed the Gulf Coast Naphtha price from the absence of Naphtha imports on the West Coast is squarely refuted by the West Coast Naphtha contracts. *Id*. Exxon maintains that these contracts provide the best available direct evidence of the value of West Coast Naphtha. *Id*. It points out that those contracts consistently valued West Coast Naphtha at levels that were significantly higher than the Platts Gulf Coast Naphtha price, thereby directly refuting Culberson's theory that it is appropriate to infer from the lack of Naphtha imports on the West Coast that the value of West Coast Naphtha does not exceed the Gulf Coast Naphtha price.[610] *Id*. at p. 242.

1615. Equally devoid of merit, in the view of Exxon, is Unocal/OXY's argument that intermediate petroleum products such as Naphtha do not have West Coast/Gulf Coast price differentials that are as high as the West Coast/Gulf Coast price differentials for finished petroleum products. *Id*. This argument is based on Exhibit No. BPX-162 which

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[609] Exxon claims that the effect of these barriers to imports was confirmed by the two Stillwater reports, Exhibit Nos. EMT-385 (Stillwater report on MTBE Phase-Out in California) and EMT-489 (Stillwater report on California Strategic Fuels Reserve). Exxon Reply Brief at p. 239, n.139.

[610] Exxon asserts that Unocal/OXY are wrong in arguing that the contract studies validate the use of Gulf Coast pricing because the average price found in the contracts is not more than two cents above the average Gulf Coast price for the period prior to 1999. Exxon Reply Brief at p. 242, n.141. Although the disparity between the average contract price and the Gulf Coast price is not as large during the earlier period, Exxon maintains that the Gulf Coast price is still well below the contract price during the 1994-1998 period. *Id.* Furthermore, Exxon states that what is required is not a methodology that may function in certain selected years, but a methodology that will function reasonably at all times, and the evidence is clear that the use of the Gulf Coast price produces the largest disparity for the overall 1994-2001 period. *Id.*

Exxon asserts was contrived by Ross in an effort to avoid the obvious deficiencies in his theory that intermediate petroleum products have lower West Coast/Gulf Coast price differentials than finished petroleum products. *Id.* at pp. 242-43.

1616. Exxon argues that Exhibit No. PAI-176 shows that there is no discernible pattern among the price differentials for intermediate and finished products, and thus no factual basis for Unocal/OXY's argument that West Coast/Gulf Coast price differentials are higher for finished products than they are for intermediate products. *Id*. at p. 243. Further, states Exxon, when the long-term average price differentials shown on this exhibit were replaced by annual average West Coast/Gulf Coast price differentials for the same intermediate and finished products (Exhibit No. PAI-202), it became readily apparent that the price differentials for most of these products – and for the intermediate and finished products as a group – have been changing over time, with the result that the conclusions that one might draw about relative price differentials in one year would be very different from the conclusions that one might draw in another year. *Id*.

1617. During the hearing, notes Exxon, Ross attempted to modify Exhibit No. PAI-176 by arbitrarily reclassifying a number of products that were obviously inconsistent with his theory. *Id.* For example, explains Exxon, in order to avoid the obvious conflict between his theory and the high West Coast/Gulf Coast price differential for Isobutane, Ross first reclassified Isobutane along with three other Quality Bank cuts into a third category, natural gas plant products, in an effort simply to eliminate those products from the analysis. *Id*. at pp. 243-44. According to Exxon, however, it is undisputed that Isobutane is an important intermediate feedstock in the production of gasoline. *Id.* at p. 244. Similarly, continues Exxon, in a further effort to salvage his theory, Ross reclassified MTBE from an intermediate product to a finished product, notwithstanding the undisputed fact that MTBE is a blendstock that is an important ingredient in the production of gasoline. *Id.*

1618. As a result of Ross's contrived reclassification of those intermediate petroleum products that were inconsistent with his theory, Exxon asserts, Exhibit No. BPX-162 does not accurately reflect the West Coast/Gulf Coast price differentials for either intermediate or finished petroleum products. *Id*. at pp. 244-45. Rather, according to Exxon, what the evidence in fact shows about West Coast/Gulf Coast price differentials is that each petroleum product has its own special market characteristics and pricing pattern. *Id*. at p. 245. For example, notes Exxon, the low West Coast/Gulf Coast price differential for LSR is explained by the fact that LSR is worth much less on the West Coast because of its high Reid Vapor Pressure, which significantly curtails its use as a gasoline feedstock on the West Coast, particularly during the summer months, coupled with the demand for LSR on the Gulf Coast as a petrochemical feedstock. *Id*. By contrast, states Exxon, it is undisputed that Naphtha doesn't have the same problem with Reid Vapor Pressure that LSR does, with the result that the LSR differential has no relevance to the Naphtha valuation question. *Id.*

1619. Similarly, argues Exxon, the relatively low West Coast/Gulf Coast price differential for VGO is largely a result of the demand for VGO on the Gulf Coast for use in the production of heating oil for markets in the Northeast and Midwest, a demand that is not present on the West Coast, coupled with strict environmental restrictions on sulfur on the West Coast that have increased processing costs for VGO on the West Coast and thereby reduced its value. *Id*. at pp. 245-46. Neither of these factors applies to Naphtha, notes Exxon, because Naphtha is not used in the production of heating oil, and because all of the sulfur in Naphtha is removed by hydrotreating on both coasts before the Naphtha is processed into reformate in order to protect the reformer catalyst. *Id*. at p. 246. Therefore, states Exxon, the evidence shows that the West Coast/Gulf Coast price differentials for each Quality Bank cut are determined by market factors that are unique to each cut and may have no application to Naphtha. *Id*.

2. Phillips

1620. Phillips argues that it would be inconsistent to continue to use the Platts Gulf Coast Naphtha price to value West Coast Naphtha when all the other cuts will have separate Gulf Coast and West Coast values. Phillips Initial Brief at p. 15. Further, states Phillips, when this inconsistency is combined with the undisputed fact that the Gulf Coast and West Coast markets are economically distinct (with different supply and demand profiles for Naphtha and the gasoline it is used to make), it is clearly not acceptable to use the Gulf Coast price as a proxy for the West Coast Naphtha value. *Id*. In Phillips's opinion, the overwhelming weight of the evidence demonstrates that continued use of the Gulf Coast price would be unjust and unreasonable, and the parties proposing to continue using that price to value West Coast Naphtha have utterly failed to rebut this evidence or otherwise show how doing so could conceivably meet the uniformity and reasoned decision making standards set by the Circuit Court. *Id.*

1621. The *OXY* decision, Phillips states, requires the assignment of accurate and relatively uniform values to all cuts. *Id*. Yet, asserts Phillips, the use of the Gulf Coast price to value West Coast Naphtha is patently inconsistent with the method used to value all other cuts – that is, using an adjusted or unadjusted proxy from the local market area. *Id*. Phillips points out that Sanderson conceded that the most consistent approach would be to separately value Naphtha on the West Coast using a West Coast value if one can be derived. *Id.* at pp. 15-16.

1622. In Phillips's opinion, the only way for this inconsistent approach to Naphtha to meet the uniformity requirement of *OXY* is if the proponents could show that the non-uniformity nevertheless permitted a West Coast Naphtha valuation consistent with the valuation of all other cuts. *Id*. at p. 16. But, according to Phillips, this would require record evidence proving that there is some demonstrable, continuing close correlation between the Naphtha value on the Gulf Coast and that on the West Coast. *Id*. Phillips asserts that there is no such evidence. *Id.* To the contrary, explains Phillips, the record is replete with admissions and empirical evidence that the two markets are quite different and that the Naphtha prices in the two markets also are quite different. *Id.*

1623. Phillips points out that Sanderson conceded that the Gulf Coast and West Coast markets are different markets, with different market forces, different supply and demand profiles and different environmental regulations that affect the supply of gasoline feedstocks and blendstocks like Naphtha. *Id.* at pp. 16-17. Because the primary use of Quality Bank (or reformer-grade) Naphtha on both coasts is to make gasoline, Phillips states, the value of Naphtha on each coast is largely based on its value in making the gasoline sold on that coast. *Id.* at p. 17. It notes that Sanderson agreed with this point when he said that "what a refiner would be willing to pay for naphtha is its value when made into gasoline, less a margin for his processing the naphtha and blending it into gasoline." *Id*. (quoting Transcript at p. 8818). But, explains Phillips, gasoline is priced very differently on the two coasts, with West Coast prices generally higher, and Sanderson admitted that there is consistently a differential between the two that ranges from 2.5¢ to 18¢/gallon. *Id.*

1624. According to Phillips, neither Sanderson nor Culberson could quantify the size of the difference between the published Gulf Coast price and actual West Coast Naphtha values or suggest any way the Commission could adjust for the differences*.* *Id*. at p. 18. Phillips states they could only rest on the unsubstantiated hope that over the long term the prices would be similar. *Id.* However, Phillips asserts, the record overwhelming establishes that the differences are significant, that they fluctuate widely and that they are certainly much higher than the 0.5¢/gallon that required a processing cost adjustment for Light Distillate. *Id.* Phillips argues that all four contract analyses presented in this hearing showed West Coast Naphtha prices that exceed the published Gulf Coast price by several cents per gallon. *Id.* at pp. 18-19. In addition, according to Phillips, all four alternative methodologies for calculating West Coast Naphtha values presented in this proceeding result in West Coast Naphtha values that frequently exceed the published Gulf Coast Naphtha value by several cents per gallon. *Id.* at p. 19.

1625. Given the uncontroverted differences in value between the published Gulf Coast Naphtha prices and actual West Coast Naphtha values, Phillips claims that *OXY* teaches that it is inappropriate to value West Coast Naphtha based on published Gulf Coast prices. *Id*. To satisfy the *OXY* uniformity requirement, Phillips states, West Coast Naphtha should be valued based on published West Coast prices less processing costs, and their proposal is the only one that meets this requirement. *Id*.

1626. Although the witnesses supporting the use of a Gulf Coast price to value West Coast Naphtha acknowledge that the published Gulf Coast price will not be the same as the value of Naphtha on the West Coast, Phillips notes that they advocate the continued use of the Gulf Coast price based on their assertion that the Gulf Coast and West Coast values will be similar. *Id*. Phillips points out that Sanderson acknowledged that, in his judgment, the Gulf Coast Platts assessment would be a suitable proxy for the West Coast value was a subjective one, and that he said that, while there may be differences from time to time, he believed the two would be similarly priced over the long term. *Id.* After acknowledging that price differentials between the two coasts for other cuts had varied for eight to ten years without evening out, Phillips notes that Sanderson still considered it reasonable to use a method that had large year-to-year variations as a proxy. *Id*. at p. 20.

1627. Sanderson's assertions regarding the reasonableness of the use of the Gulf Coast Naphtha price to value West Coast Naphtha suffer, argues Phillips, from the same defect as the reasoning rejected by the Circuit Court in *Exxon*. *Id.* Just as it was not good enough in the *Exxon* case for the Resid proxy value to be "within the range" of the calculated Coker feedstock values, Phillips asserts, Sanderson cannot rely on the hope that differences in Gulf Coast and West Coast Naphtha prices may even out over the long run. *Id*. (quoting *Exxon*, 182 F.3d at p. 42). Phillips points out that the Circuit Court ruled in Exxon that "a limited and unquantified relation" between the cut and the proposed proxy is not enough. *Id.* (quoting *Exxon*, 182 F.3d at p. 36). Here, as there, Phillips states, nothing "guarantees" that the value of the proxy and the cut "will correlate consistently within some specified range." *Id*. (quoting *Exxon*, 182 F.3d at p. 42).

1628. According to Phillips, Sanderson offered no evidence that the values will be similar, could only offer hope that they would be, and presented nothing other than unsupported opinions to counter what Phillips views as overwhelming evidence that the values would not be similar. *Id.* Phillips asserts that Sanderson based his claim that West Coast Naphtha prices should be similar to those on the Gulf Coast over the long term on the supposition that these prices are linked via a very convoluted relationship through crude oil. *Id.* at pp. 20-21. It notes that Sanderson claimed this linkage existed because of "the refiner's ability to substitute crude oils of different naphtha content for naphtha purchases, then naphtha prices also would be linked through the crude oil substitution mechanism." *Id*. at p. 21 (quoting Exhibit No. WAP-1 at p. 10). Phillips, however, asserts that this link is too vague and is unsupported by facts and, therefore, cannot support the consistent and quantifiable relationship between the Naphtha prices on the two coasts that was set as the standard by the Circuit Court in *Exxon*. *Id.*

1629. Even were the Gulf Coast pricing advocates able to show "an observed rough correlation in price" over some significant period, Phillips suggests, that would not have sufficed absent a demonstration that the values continuously move in synch with each other. Phillips Reply Brief at p. 19 (citing *Exxon*, 182 F.3d at p. 41). Not only was no such showing made, Phillips states, the evidence in the record demonstrates that the use of the Gulf Coast proxy materially undervalues West Coast Naphtha and any "similarity" in value is the result of haphazard coincidence rather than a continuing rational relationship between the values themselves. *Id*.

1630. Phillips states that the parties supporting a West Coast value offered direct proof of the value of West Coast Naphtha through the Naphtha contracts and the opinions of experts. *Id.* Apart from Dudley, whose attempt, it claims, was not credible, Phillips states, their experts carefully avoided any effort to calculate a West Coast value for Naphtha. *Id.* Moreover, unable to explain why the West Coast contracts consistently showed values far higher than the proxy, Phillips notes that all but Culberson also declined to do an independent analysis of the contract data. *Id.* Phillips states that the reason for their reluctance is apparent from Culberson's work: No matter how hard he tried to find reasons to exclude contracts from his analysis, the remaining data still showed West Coast values far above the proxy price. *Id*.

1631. Because they lack affirmative proof that the Gulf Coast proxy actually correlates with the West Coast Naphtha value, Phillips explains, the advocates of Gulf Coast pricing sought to rely on theories that they claimed suggested that the prices should not be too far apart. *Id*. at p. 20. It argues that that was the point of the "crude equalization theory" as well as the several attempts to limit West Coast Naphtha values to some the Gulf Coast proxy plus the transportation and other costs required to bring Gulf Coast Naphtha to the West Coast. *Id.* Phillips suggests that offering theories as to why the prices might not be too far apart is a far cry from establishing a rational relationship between them, and it insists that the welter of admissions in the hearing and briefs regarding the differences between the markets make it clear that no such relationship exists*.* *Id.*

1632. In *Tesoro*, Phillips explains, the court described three factors that it found relevant to the question of whether it is just and reasonable to continue to use the published Gulf Coast prices to value West Coast Naphtha: (1) the level of ANS deliveries to the Gulf Coast; (2) whether the "No Adjustment Policy" has been abandoned; and (3) whether use of published Gulf Coast prices undervalues West Coast Naphtha. Phillips Initial Brief at p. 22. It claims that the evidence submitted in this hearing addressed these three factors, and, according to Phillips, shows that all three propositions retain their validity even after a full evidentiary hearing. *Id.* at pp. 22-23.

1633. At the hearing, explained Phillips, the TAPS Carriers presented evidence showing that (1) there have been no Gulf Coast ANS deliveries since July of 1999, and (2) less than 3% of all ANS was delivered to the Gulf Coast for a year and a half prior to that time. *Id*. at p. 23. This evidence was uncontroverted, according to Phillips, and no witness even attempted to explain how the Gulf Coast Naphtha price retains any relevance to ANS Naphtha values when no ANS is delivered to the Gulf Coast. *Id*.

1634. Phillips contends that the *Tesoro* court found that the Commission's no adjustment policy had been abandoned, and that the Circuit Court made it clear that the policy would not in any event pass muster as a justification for departing from the required uniformity in treatment of the cuts. *Id.* Since that time, according to Phillips, the Commission has done nothing that could be said to have reinstated that policy. *Id*. On the contrary, Phillips asserts, the parties now have agreed to value West Coast VGO on the West Coast, which constitutes an even greater shift away from the policy. *Id.*

1635. A considerable portion of the Naphtha phase of the hearing, Phillips states, was devoted to the differences between Gulf Coast and West Coast Naphtha markets and values. *Id.* at p. 24. Although the quantification of those differences was contested, Phillips asserts, the only supportable conclusion that can be reached regarding the market differences is that there are significant differences in Gulf Coast and West Coast Naphtha markets and, therefore, significant differences in Naphtha prices. *Id*. As a result, Phillips states, the record supports the same conclusion that was presented in a single untested affidavit in *Tesoro* – that use of the published Gulf Coast price significantly undervalues West Coast Naphtha. *Id*.

1636. It is incontestable and uncontested, in Phillips's view, that the Gulf Coast and West Coast petroleum and refining markets are separate markets with different product prices. *Id.* Phillips states that this is the reason that the Quality Bank attempts to derive product prices on both the Gulf Coast and West Coast for each of the other Quality Bank cuts. *Id.*

1637. According to Phillips, the most complete description of the differences in the markets came during the cross-examination of Sanderson. *Id.* It notes that he agreed that the two markets were different with respect to: (1) supply and demand profile; (2) environmental regulations; (3) the ability to build or expand refinery capacity to meet increasing demand; (4) ability to address supply disruptions; (5) size of refining base; (6) price volatility; and (7) size of market supplied. *Id.* Phillips states that the testimony of every other witness who testified on this issue was generally in accord.[611] *Id*. at p. 25.

1638. The evidence also is incontestable, according to Phillips, that the differences in the market forces at work cause there to be significant differences between the Gulf Coast and West Coast prices for all products that do have prices reported on both coasts. *Id.* Phillips states that there are numerous exhibits presented by parties on all sides of the issue that include price information that support this proposition. *Id.* According to it, Exhibit No. PAI-176 has a comprehensive set of data for a large number of products. *Id.* Phillips notes that this exhibit has monthly price data for 13 different products on the Gulf Coast and West Coast for the years 1992 to 2001, and explains that it shows average price differentials for three different periods: (1) 1992-2001; (2) 1992-98; and (3) 1999-2001. *Id.* As this chart illustrates, explains Phillips, only one product, High Sulfur

[611] Phillips cites the following witness testimony in support of this claim: O'Brien, Exhibit No. PAI-33 at pp. 4-5; Tallett, Exhibit No. EMT-11 at p. 14; Baumol, Exhibit No. EMT-144 at pp. 21-22; Ross, Exhibit No. BPX-8 at p. 3; Culberson, Transcript at p. 10207-09; and Dudley, Transcript at pp. 10045-46. Phillips Initial Brief at p. 25, n.8.

VGO, had West Coast minus Gulf Coast price differentials that averaged within 0.5¢/gallon over one of the periods, and that was only for the 1992-98 time frame. *Id.* at p. 27. When the entire 1992-2001 time frame is considered, Phillips notes, High Sulfur VGO was, on average, worth 1.02¢/gallon more on the West Coast than on the Gulf Coast. *Id.* Furthermore, continues Phillips, in looking at the 39 price differentials shown on this chart, only 3 (7.6%) were less than 2¢/gallon, and only 6 (15.4%) were less than 4¢/gallon. *Id.*

1639. Because of these short-term fluctuations, Phillips argues, the Commission cannot rely on any smoothing effects of looking only at long-term average price differentials. Phillips Reply Brief at p. 24. It states that the method adopted by the Quality Bank must be just and reasonable as applied each month, and not just over long periods of time. *Id.*

1640. Phillips claims that the proponents of the status quo attempt to avoid the implications of the price differential data by creating artificial divisions of products such as "finished products," "gas liquids products," "intermediate products," "other products." Phillips Reply Brief at p. 23. It states that, no matter how the data is grouped and displayed in order to show different patterns of price differentials, these divisions are meaningless for this proceeding, and there are significant price differentials for almost every product. *Id*. (citing Exhibit Nos. BPX-162, WAP-39, and WAP-221).

1641. While the data for other products does not reveal what the price differentials should be for Naphtha, Phillips contends, they do reflect that there are very different supply and demand factors at work in the two markets. *Id.* at p. 24. It states that, because the differences cause wide fluctuations in the market differentials for all other petroleum products, there is every reason to believe that the same is true for Naphtha. *Id*. Therefore, according to Phillips, it is extremely unlikely that Gulf Coast Naphtha prices could reflect West Coast Naphtha values in any but the most haphazard manner. *Id.*

1642. Phillips states that another uncontested fact is that Naphtha primarily is made into gasoline, and that the price of gasoline is very important to the value of Naphtha. Phillips Initial Brief at p. 27. It notes that Sanderson testified to this effect when he stated that the Naphtha cut under discussion is a reformer grade Naphtha used primarily to make gasoline and that its value on the West Coast is very closely related to this use. *Id.* at pp. 27-28. According to Phillips, the other witnesses who testified on this issue were all in accord.[612] *Id.* at p. 28.

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[612] Phillips cites the following witness testimony in support of this assertion: O'Brien, Exhibit No. PAI-33 at p. 3; Toof, Exhibit No. EMT-1 at pp. 25-26; Tallett, Exhibit No. EMT-11 at pp. 16-17; Ross, Exhibit No. BPX-8 at p. 2; Culberson, Transcript at p. 10338; Dudley, Transcript at p. 10107. Phillips Initial Brief at p. 28, n.10.

1643. There also was uncontested quantitative evidence, asserts Phillips, showing a close relationship between Naphtha prices and gasoline prices. *Id.* Phillips notes that Exhibit No. EMT-459 provides monthly Gulf Coast Naphtha and Unleaded Regular Gasoline prices for the time period 1994-2001 that show that the two prices track closely, a fact corroborated by the statistical analysis conducted by Tallett on the relationship between the two prices on the Gulf Coast. *Id.*

1644. There are, according to Phillips, two categories of evidence that quantify the extent to which West Coast Naphtha values exceed the published Gulf Coast prices. *Id.* at p. 29. The first category, states Phillips, consists of the approximately 300 Naphtha contracts that were produced in discovery in this proceeding. *Id.* Four analysts, according to Phillips, including Culberson (who supports use of Gulf Coast Naphtha prices to value West Coast Naphtha), reviewed these contracts. *Id.* at pp. 29-30. Notwithstanding the differences in the four analyses that were presented at the hearing, Phillips asserts, each shows that the West Coast Naphtha prices exceed Gulf Coast prices by at least 6¢/gallon during 1994-2001 and by considerably more than that in 1999-2001. *Id*. at p. 30. These differences, states Phillips, are similar to or exceed the difference in values alleged in *Tesoro*, which was $2.71/barrel or 6.45¢/gallon. *Id.*

1645. Phillips states that another source of evidence quantifying the difference between Gulf Coast published prices and West Coast Naphtha values is the various alternative West Coast Naphtha valuation methodologies presented by the various parties. *Id*. at p. 31. One striking aspect of all the approaches is, according to Phillips, that even though the various proposals vary widely, they all show significant differences between Gulf Coast and West Coast prices. *Id*. Thus, no matter which approach the Commission believes best captures West Coast Naphtha prices, Phillips asserts that approach supports the conclusion that Gulf Coast prices should not be used to value West Coast Naphtha. *Id*.

1646. Exhibit No. SOA-28, Phillips suggests, shows that the Dudley methodology – which Phillips states has an extremely weak factual basis – is on average very close to the Gulf Coast published price for the 1994-2001 time period.[613] *Id*. at p. 32. However, notes Phillips, even the Dudley methodology varies from the Gulf Coast published price by more than 1¢/gallon in both the 1994-1998 and 1999-2001 time frames. *Id*. Further, Phillips points out, every other proposed methodology results in West Coast Naphtha prices that are at least 2¢/gallon above the Gulf Coast price for every time frame studied. *Id.* The ungoverned O'Brien and Tallett methodologies provide the best indications of

[613] Phillips notes that the Sanderson/Culberson proposal in Exhibit No. SOA-28 at p. 2 is the Gulf Coast published price to which they are referring. Phillips Initial Brief at p. 32 and p. 33, n.12.

actual West Coast values in Phillips's view, and they show differences ranging from 4.5¢/gallon to 15¢/gallon above the published Gulf Coast price, depending on the time period considered. *Id.*

1647. Phillips argues that the parties opposing the continued use of the Gulf Coast price have presented a prima facie case that use of the Gulf Coast price is unjust and unreasonable. *Id.* at p. 35. It asserts that the proponents of the Gulf Coast price failed to carry their burden of going forward with evidence supporting continued use of the Gulf Coast price to value West Coast Naphtha. *Id.* In attempting to deny the undeniable fact that West Coast market values are significantly different from Gulf Coast market prices, Phillips notes, the proponents argue that, unlike all the other Quality Bank cuts, Naphtha has similar values on both coasts. *Id.* It also states that the proponents assert that only Naphtha fails to track the higher product prices – particularly gasoline – that generally prevail on the West Coast. *Id*.

1648. Responding to testimony from Sanderson,[614] Phillips argues that use of the Gulf Coast price to value West Coast Naphtha is not more objective than the West Coast-based proposals. *Id.* at p. 36. While the published Gulf Coast price certainly is an objective price, according to Phillips, the assertion that this Gulf Coast price accurately reflects the value of Naphtha on the West Coast is subjective. *Id.* Sanderson acknowledged that this was the case, admitting that "my analysis by necessity has to be subjective." *Id.* at pp. 36-37 (quoting Transcript at p. 8837). Phillips states that this admission utterly destroys Sanderson's claim of the superiority of using the Gulf Coast price. *Id.* at p. 37. By contrast, notes Phillips, every West Coast Naphtha proposal is based on objective prices. *Id.*

1649. Phillips points out that Sanderson's principal theory as to why Naphtha prices on the two coasts should be similar is that these prices are linked through refiner's substitution of crude oil with different Naphtha content and the direct linkage of crude prices on the two coasts. *Id.* It argues that a claim of such a generalized, unquantifiable similarity would not satisfy the Circuit Court. *Id. at* p. 38. At some level of generality, explains Phillips, there is a linkage between the price of any petroleum product and crude oil, and Sanderson admits that there is not a fixed relationship between Naphtha and crude oil prices that would allow the Commission to develop an exact Naphtha price. *Id.* In order to be just and reasonable, states Phillips, the proxy price used to value West Coast Naphtha must be more than approximately equal to the value of West Coast Naphtha, it must provide a value that is consistent with the other Quality Bank cuts and which consistently and reasonably tracks the value of West Coast Naphtha over the long term. *Id*.

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[614] *See* Exhibit No. WAP-33 at p. 3.

1650. In addition, Phillips claims, it is apparent that Sanderson's theory is factually incorrect. *Id*. If crude price equalization on the two coasts caused Naphtha prices on the two coasts to equalize, then, according to Phillips, the same should be true for other cuts as well. *Id*. However, Phillips states, if the price data submitted in this proceeding reveal anything, they reveal that prices for other products on the two coasts are neither similar nor even approximately the same. *Id.* According to Phillips, Exhibit No. PAI-176 demonstrates that there are significant differences in prices between the West Coast and the Gulf Coast with regard to a wide variety of products. *Id.* In Phillips's opinion, Sanderson's crude equalization theory provides no explanation for why only Naphtha prices on the two coasts would be equal. *Id.*

1651. Moreover, Phillips states, the data Sanderson presents does not support his conclusion that crude prices on the two coasts have equalized. *Id*. First, notes Phillips, he used different crudes on each coast as the centerpiece of his argument. *Id*. at pp. 38-39. Phillips explains that, as ANS is not sold on the Gulf Coast, Sanderson chose to compare it to Isthmus crude, which is sold on the Gulf Coast, but not on the West Coast. *Id.* at p. 39. It notes that Sanderson claimed that the qualities of these two crudes were similar, but it became apparent on cross-examination that there are a number of significant differences.[615] *Id.* In addition, notes Phillips, Sanderson agreed that ANS Naphtha has a higher N+A than Isthmus Naphtha. *Id.* Because Sanderson conceded these differences in qualities would cause refineries to value the two crudes differently, Phillips asserts that a comparison of the prices of these two crudes does not necessarily demonstrate that crude prices on the two coasts have equalized. *Id.*

1652. Finally, Phillips claims, it is not even accurate to say that the prices of ANS on the West Coast and Isthmus on the Gulf Coast have equalized*.* *Id*. Phillips notes that Exhibit No. PAI-207, which shows the differences in the prices of these two crudes for the time period 1994 through 2001, shows that ANS has become more valuable relative to Isthmus, but does not show that the two prices have equalized. *Id.* Rather, Phillips asserts, the prices of the two crudes are generally different, and those price differences are subject to large swings.[616] *Id.*

1653. In support of the continued use of Gulf Coast prices to value West Coast Naphtha, Phillips notes, Culberson asserts that Gulf and West Coast prices are linked by demand and transportation factors*. Id*. at p. 40. Further, continues Phillips, Culberson testified

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[615] According to Phillips, Sanderson conceded that ANS has a lower API gravity, less sulfur, and more Isobutane, VGO and Resid than Isthmus. Phillips Initial Brief at p. 39 (citing Transcript at pp. 9045-49).

[616] Phillips notes that Exhibit No. PAI-207 shows that, in 2000 and 2001, there was a swing of over $3/barrel in the relative prices of ANS and Isthmus crudes. Phillips Initial Brief at p. 39 (citing Transcript at pp. 9051-52).

that, if Gulf and West Coast Naphtha prices are not aligned, then Naphtha produced in West Coast refineries could be displaced by imported Naphtha. *Id.* They explain that Culberson goes on to assert that there have not been significant imports of Naphtha into the West Coast from the Caribbean and that he concludes from this assertion that this means West Coast Naphtha should not be valued above Gulf Coast Naphtha. *Id.*

1654. Phillips states that Sanderson similarly points to an alleged lack of imports of Naphtha into the West Coast to support his position. *Id*. He claims, according to Phillips, that the lack of imports into the West Coast indicates that West Coast refiners were not using significant amounts of naphtha to meet gasoline demand. *Id.*

1655. Whatever the merits of the abstract theory that market prices ought not to exceed the cost of alternative supplies plus the costs of acquiring them, Phillips argues, this theory cannot support a decision that the published Gulf Coast Naphtha prices should be used to value West Coast Naphtha. *Id.*

1656. Both Culberson and Sanderson acknowledge, according to Phillips, that it is more costly to transport Naphtha from the Caribbean to the West Coast than to the Gulf Coast. *Id*. at p. 41. Their calculations, which Phillips asserts contain many flaws, show that it costs from 2.7¢/gallon to 3.1¢/gallon more to transport Naphtha from the Caribbean to the West Coast than to the Gulf Coast. *Id.* (citing Exhibit Nos. UNO-7 at p. 24, WAP-33 at p. 15).

1657. Phillips notes that Culberson and Sanderson assert that, if West Coast Naphtha prices had exceeded their calculated transportation cost differentials, imports would have come into the West Coast and disciplined the West Coast prices. *Id.* It claims that the "flip side of this argument," however, is that West Coast Naphtha prices can exceed Gulf Coast prices by amounts less than these supposed transportation cost differentials and not attract any imports. *Id.* As a consequence, explains Phillips, Culberson is incorrect when he stated that the lack of Caribbean imports to the West Coast means that the West Coast Naphtha's price is not higher than the Gulf Coast price over a sustained period of time. *Id.* At most, Phillips states the import data means that the value of Naphtha on the West Coast has not exceeded the Gulf Coast price by more than the transportation differential between the two coasts. *Id.* Thus, continues Phillips, the transportation cost differential does not cause the prices on the two coasts to be equal but, at best, acts as a cap on what the difference in prices can be between the two coasts. *Id.* Phillips states that Sanderson admitted that this is a fair interpretation of the significance of the transportation cost differential. *Id.*

1658. Even Culberson's admittedly low estimate, points out Phillips, shows a transportation differential of 2.7¢/gallon. *Id*. at p. 42. Phillips asserts that this would allow the value of West Coast Naphtha to be up to 2.7¢/gallon higher than the published Gulf Coast price. *Id.* Phillips argues that such a difference would be significant under the test established by the Circuit Court in *Tesoro* and could not support the continued use of the published Gulf Coast price. *Id.*

1659. Another fundamental problem, in the view of Phillips, with Culberson's and Sanderson's theory is that it depends on a determination of the relative costs associated with transporting Naphtha from the Caribbean to the Gulf Coast and the West Coast. *Id.* at p. 43. Phillips points out that there is no publicly available objective cost calculation to show what the transportation costs might be, and no simple way to perform a calculation. *Id.* Indeed, Phillips notes that Exhibit No. PAI-178 shows that Culberson's and Sanderson's calculations do not agree. *Id*. Ross, continued Phillips, who performed a similar calculation to support his proposed governor, made three different calculations in his pre-filed testimony, and then further refined his calculation on the stand. *Id.* at pp. 43-44. It states that these calculations all used different assumptions and all reached different results. *Id*. at p. 44.

1660. Furthermore, Phillips asserts, even the transportation calculations that they finally settled on, 2.7¢/gallon (Culberson) and 3.1¢/gallon (Sanderson), were clearly "lowball" estimates. *Id.* As such, Phillips argues that these estimates understate the price differentials that would be required to attract imports to the West Coast. *Id.*

1661. Phillips states that Culberson's transportation cost calculations are deeply flawed and deserve no consideration whatsoever. *Id*. First, notes Phillips, Culberson has based his calculation solely on published spot tanker rates for the period of January 11 through May 9, 2002. *Id*. (citing Exhibit No. UNO-15 at pp. 2-3; Transcript at p. 10294). It points out that Culberson could not provide any explanation for why the Commission should look to this period, and he admitted that this time period is not representative of previous time periods. *Id*. In Phillips's view, this concession is critical, because Culberson's import data was from the years 1999-2001, which does not match up with the January-May 2002 time period on which his transportation cost calculation was based. *Id*.

1662. Second, even under the limited time period that he chose, Phillips states, Culberson used a lower spot tanker rate that he developed on his own rather than the published spot tanker rates for transportation from the Caribbean to the Gulf Coast. *Id.* at pp. 44-45 (citing Exhibit No. UNO-7 at p. 23; Transcript at pp. 10273-83, 10294-95). Also, Phillips asserts, Culberson included such irrelevant routes as Singapore to Japan, Baltic Sea to the Mediterranean, Asian Gulf to India and Asian Gulf to Japan. *Id*. at p. 45. For that reason, Phillips argues, Culberson's use of an average of these rates cannot be relied upon to give an accurate picture of the transportation costs at issue here. *Id.*

1663. Moreover, explains Phillips, when Culberson was asked why he applied his artificially low transportation cost rate from 2002 – which he agreed was lower than the published rate – to earlier time periods, he replied that "it was a deliberate exercise to see if you could get movements with very low rates." *Id*. (quoting Transcript at p. 10285). The problem with this, asserts Phillips, is that, in reality, Caribbean refiners in the 1999-2001 time period could not ship cargoes at Culberson's artificially low rate. *Id.*

1664. Unlike Culberson, states Phillips, Sanderson did use actual published spot tanker rates for the years that import data were available, and he did include a higher cost for West Coast trips, which results in Sanderson having a higher estimate of the transportation cost differential than Culberson. *Id*. at p. 46. Phillips asserts that like Culberson, however, Sanderson still ignored significant barriers to entry and the risk that price differentials would decrease in the two to three weeks that it takes to transport Naphtha from the Caribbean to the West Coast. *Id.*

1665. The import theory proposed by Sanderson and Culberson, Phillips contends, does not need to be considered in a theoretical vacuum, without any way of validating who is wrong and who is right. *Id*. It states that the record contains a considerable amount of empirical data demonstrating that West Coast/Gulf Coast price differentials far exceed the levels that Sanderson and Culberson have hypothesized. *Id.*

1666. In Phillips's opinion, perhaps the best evidence as to whether West Coast Naphtha prices are capped by the Gulf Coast price plus the 2.7 to 3.1¢/gallon transportation estimates made by Culberson and Sanderson are the prices paid in real transactions by West Coast Naphtha purchasers. *Id*. at pp. 46-47. Exhibit No. SOA-28 shows, according to Phillips, that Naphtha contract prices for the 1999-2001 time period for which Culberson submitted import data were from 11.6¢/gallon to 13.7¢/gallon above Gulf Coast prices, depending upon which contract analysis is considered. *Id*. at p. 47. Further, notes Phillips, the average differential above the Gulf Coast price was in the 6¢/gallon to 9¢/gallon range for the full 1994-2001 time frame, depending upon which contract analysis is used. *Id.*

1667. Phillips points out that these differentials are approximately four times higher than the 2.7¢/gallon to 3.1¢/gallon transportation cost differences calculated by Culberson and Sanderson. *Id*. Clearly, states Phillips, the purchasers under these contracts did not share the view of Culberson and Sanderson that they should pay no more than Gulf Coast plus 2.7¢ to 3.1¢/gallon. *Id*. Argues Phillips, the differentials stands as uncontroverted proof that the Culberson/Sanderson theory about the levels of imports and transportation costs do not in fact (1) support using the Gulf Coast price or (2) undercut the higher West Coast Naphtha values calculated under alternative methods proposed by Phillips or Exxon. *Id*.

1668. Were Platts Gulf Coast Naphtha price assessments a reliable indicator of the value of West Coast Naphtha, according to Phillips, one would expect that West Coast refiners would use them as an index for the price of Naphtha on the West Coast, but they do not. *Id*. It notes that Sanderson admitted that the West Coast refiner for whom he worked did not pay any attention to the Gulf Coast price when pricing West Coast Naphtha transactions, and the hundreds of West Coast Naphtha contracts produced make the same point. *Id.* Phillips argues that almost none of them even refer to the Platts Gulf Coast assessments, and the few that do give strong support to the fact that the value on the West Coast was higher. *Id*. at p. 48.

1669. According to Phillips, there are only three West Coast Naphtha contracts included in the various contract analyses that have a price referenced to Gulf Coast Naphtha. *Id*. The first, states Phillips, is the contract that Ross relied upon to justify his governor proposal. *Id.* Phillips explains that Ross testified that there was a cap in this contract equal to the Gulf Coast Naphtha price plus 7.05¢/gallon, or $2.96/barrel. *Id.* Phillips points out that this is about 2 1/2 times the differentials calculated by Culberson and. Sanderson. *Id.*

1670. Phillips states that the second such contract (Exhibit No. PAI-183) involved shipment in a tanker whose loading port was in Aruba. *Id.* Thus, explains Phillips, it represents an import from the Caribbean to the West Coast of the type hypothesized by Culberson and Sanderson. *Id.* However, notes Phillips, the price of this Naphtha was the Gulf Coast price plus 5.5¢/gallon. *Id.* Explains Phillips, this is approximately twice the differentials calculated by Culberson and Sanderson. *Id.*

1671. The third contract (Exhibit No. UNO-42) is priced, according to Phillips, at Gulf Coast Naphtha plus 2.75¢/gallon, which is much closer to Culberson's and Sanderson's differentials. *Id*. However, notes Phillips, the specifications on the same page of the contract show that the product has a boiling range of from 72°F to 189°F. *Id.* Phillips explains that this means that the material being sold was almost entirely Quality Bank LSR, which has a much lower value than Quality Bank Naphtha. *Id.* Quality Bank Naphtha is worth more than Quality Bank LSR, according to Phillips, and would have commanded a much higher differential. *Id.*

1672. Phillips states that another flaw in the no import theory is that it ignores the fact that most West Coast refiners produce most of the Naphtha that they need from the crude that they refine, and thus their supply and demand for Naphtha is in balance. *Id.* at p. 49. Phillips explains that this limits the volume of Naphtha that West Coast refiners acquire from third parties on the West Coast or elsewhere. *Id.* Contrary to the Culberson/Sanderson theory, Phillips contends, the West Coast refiners's supply/demand balance is the most fundamental reason why import volumes are not higher. *Id.*

1673. According to Phillips, while Culberson acknowledges the implications of this fact, he argues, nonetheless, that even if refiners produce all the Naphtha that they need, they could still choose to buy Naphtha instead of making it if the value of the Naphtha that they make is significantly higher than the price of Naphtha on the Gulf Coast plus transportation. *Id.* Phillips notes that Culberson asserts that this could be accomplished by substituting cheaper crude oils that produce lower Naphtha fractions. *Id.* The problem with this argument, explains Phillips, is that there are significant costs associated with substituting cheaper crudes that produce lower Naphtha fractions. *Id.* at p. 50. It notes that Culberson admitted that changing the crude slate does not change just the amount of Naphtha refined from the new crude, but also the amount of other products produced by the crude, as well as their quality, and states that the cost of all of these changes would need to be factored in as well before a refiner would choose to substitute a cheaper crude for ANS and import Naphtha from the Gulf Coast. *Id.* Culberson agreed that crude substitution imposes these additional costs, notes Phillips, and testified that the Naphtha price would have to be such that it enticed this substitution. *Id.* Finally, Phillips states that neither Culberson's, Sanderson's nor Ross's transportation cost differentials account for these costs. *Id.*

1674. Phillips explains that Culberson further bases his opinion regarding the value of West Coast Naphtha on a related point he makes based on statistics involving imports from Western South America. *Id.* Phillips states that Culberson asserts that, because there are imports of Naphtha from Mexico, Colombia, Ecuador, Peru and Chile to the Gulf Coast, but not to the West Coast, and because it costs more to transport Naphtha through the Panama Canal from the West Coast of South America to the Gulf Coast than it does to the West Coast of the United States, this must mean that the Naphtha price on the Gulf Coast is higher than the value of Naphtha on the West Coast. *Id.* It argues that this theory is not supported by the import data in Exhibit No. UNO-5 on which Culberson relies. *Id.* at p. 51. First, notes Phillips, it is not possible to tell from the categories of products reported by the EIA whether a cargo is reformer-grade Naphtha or some other product, so it really is not possible to tell if these countries are sending Quality Bank Naphtha comparable products to the Gulf Coast or the West Coast and, if so, in what amounts. *Id.*

1675. Second, Phillips points out, of the countries listed by Culberson, Exhibit No. UNO-5 shows that, by far, the greatest volume of imports to the Gulf Coast are from Mexico and Colombia. *Id.* It is, in Phillips's view, disingenuous of Culberson to characterize these countries as being on the West Coast of South America because the major ports and refining industries in both countries are located on the Caribbean and imports to the Gulf Coast from ports in these countries that are located on the Caribbean do not have to pass through the Panama Canal. *Id.* As these ports are closer to the Gulf Coast than the West Coast, Phillips states, it is cheaper for these imports to go to the Gulf Coast, and in no way can those shipments be considered to support Culberson's theory. *Id.* at pp. 51-52.

1676. Third, explains Phillips, by far the greatest amount of imports to the Gulf Coast from these countries is in the "Naphtha for Petrochemical Feedstock Use" category. *Id.* at p. 52. This is the true, according to Phillips, not only for Mexico and Colombia, but also for Ecuador and Peru, which are located on the West Coast of South America. *Id.*

Because it is undisputed that there is no petrochemical industry on the West Coast, Phillips states, it is not surprising that such cargoes would go elsewhere. *Id*.

1677. Fourth, the data on Exhibit No. UNO-5 at pp. 14-28 with respect to PADD V (West Coast) shows, in the opinion of Phillips, that not only did the countries identified by Culberson not export any Naphtha to the West Coast, but they also exported almost no products of any kind to the West Coast. *Id*. Further, according to Phillips, Exhibit No. UNO-5, at pp. 14-28, shows that there were no West Coast imports of any products from Mexico, Columbia or Chile, while Ecuador had one West Coast shipment of "Special Naphtha" and Peru had two West Coast shipments of "Unfinished Oils." *Id.* Phillips concludes that the virtually complete absence of imports of any kind of product from these countries suggests nothing more than that those countries do not view the West Coast as a market for any product, including Naphtha. *Id.*

1678. Unocal/OXY, Phillips states, also rely on data regarding Far East imports to support the use of Gulf Coast Naphtha pricing. Phillips Reply Brief at p. 35. It explains that Unocal/OXY make two arguments from this data: (1) it costs less to transport Naphtha from the Far East to the West Coast than to the Gulf Coast, so Gulf Coast imports from the Far East must indicate that Gulf Coast Naphtha prices are higher than West Coast prices, and (2) Far East imports can discipline Naphtha prices on the West Coast at prices lower than required for imports from the Caribbean. *Id.*

1679. According to Phillips, Unocal/OXY's first point is not supported by the data that they cite. *Id.* at p. 36. It points out that Exhibit No. UNO-4 is nothing more than a map, and states that, while Exhibit No. EMT-455, at pp. 6-30, does have detailed data regarding Gulf Coast Naphtha imports, the data show, however, that all of the Naphtha imported into the Gulf Coast from the Far East was Naphtha for petrochemical use and not reforming grade Naphtha. *Id.* Because there is no petrochemical industry on the West Coast, Phillips asserts, the fact that Naphtha for petrochemical use goes from the Far East to the Gulf Coast does not have much relevance to the value of reforming grade, i.e.*,* Quality Bank Naphtha on the West Coast*.* *Id.*

1680. Phillips also argues that the second point is unsupported. *Id*. From the limited data on Naphtha imports shown in Exhibit No. EMT-449, Phillips contends, it is impossible to conclude that three cargos of Far East Naphtha (only two of which are reforming grade) imported over a six year period can discipline West Coast Naphtha prices, particularly because there is no data in the record on the Far East Naphtha market supply, demand, prices, or transportation costs to the West Coast*.* *Id.*

1681. Further, Phillips notes, Unocal/OXY also point to the fact that there have been significant West Coast imports of jet fuel from the Far East. *Id.* at p. 37. It notes that Unocal/OXY believe this means there also could be imports of Naphtha as well. *Id.* Again, Phillips contends, this speculative theory does not support the conclusion that

Gulf Coast Naphtha prices represent an appropriate proxy for West Coast Naphtha, and maintains that, in order to evaluate the potential for West Coast Naphtha imports from the Far East, it is necessary to have data on alternative Naphtha markets in the Far East and how they compare with West Coast markets. *Id.* Without this data, Phillips states, it is impossible to know what impact imports of Naphtha might have on the West Coast, regardless of what the volume of jet fuel imports from the Far East has been. *Id.*

1682. Finally, even were Unocal/OXY's arguments regarding Far East Naphtha imports to be accepted, Phillips suggests that all they say is that there is some general link between Gulf Coast Naphtha prices and West Coast Naphtha values. *Id.* It asserts that none of the arguments raised by Unocal/OXY indicates that Gulf Coast Naphtha is a good proxy for West Coast Naphtha or would be acceptable under the *OXY* and *Exxon* decisions. *Id.*

1683. Phillips explains that another theory advanced by Sanderson and Culberson is that Naphtha has lost its value on the West Coast due to the stringent aromatics and benzene limitations in the California Air Resources Board specifications for gasoline. Phillips Initial Brief at pp. 52-53 (citing Exhibit No. WAP-8 at pp. 11-12, 16-19; Transcript at pp. 12060-61). As an initial matter, notes Phillips, Sanderson provides no quantification of how much value he asserts Naphtha has lost, or what the value of Naphtha was on the West Coast before the implementation of the California Air Resources Board requirements. *Id.* at p. 53. As a result, states Phillips, his theory does not provide (1) any support for the proposition that West Coast Naphtha should be based on published Gulf Coast prices, or (2) any useful guidance as to the value of Naphtha on the West Coast. *Id.*

1684. Second, Phillips asserts that the theory is wrong. *Id.* It notes that Sorenson explained that most California refiners, including his own, already have installed the equipment necessary to take benzene out of the reformate they make from Naphtha. *Id.* As a result, continues Phillips, California refiners do not discount the value of Naphtha on the basis of its high benzene and aromatics content because they can be handled. *Id.* Sorenson stated that, therefore, he would disagree with the claim that Naphtha had lost its value on the West Coast due to the imposition of California Air Resources Board requirements. *Id.*

1685. Phillips concedes that the benzene treatment equipment installed by California refineries imposes additional costs on their production of CARB gasoline, but, according to Phillips, the CARB gasoline these refiners produce commands a much higher price than conventional gasoline. *Id.* at pp. 53-54. It states that Exhibit No. EMT-399 shows that, from the time that the CARB II gasoline regulations went into effect in 1996 to the end of 2001, the price of that gasoline has been, on average, $2.67/barrel higher than the price of West Coast conventional gasoline. *Id.* at p. 54. Given this significant price advantage, over 6¢/gallon, for CARB gasoline, Phillips asserts that the fact that refiners have had to incur some additional costs to process their Naphtha into CARB gasoline does not mean that Naphtha has lost its value in making CARB gasoline compared to its value in making conventional gasoline. *Id.*

1686. Furthermore, continues Phillips, Naphtha has other qualities that are valuable in making CARB gasoline. *Id.* For example, reformate made from Naphtha has high octane and, as Sorenson testified, California refiners find octane to be a valuable commodity. *Id.* Phillips notes that O'Brien testified that reformate also is almost free of both olefins and sulfur, and has a very low Reid Vapor Pressure. *Id.* The California Air Resources Board specifications have strict limitations on olefins, sulfur, and Reid Vapor Pressure, and Phillips explains that reformate's low levels of these specifications makes it valuable for producing CARB gasoline. *Id.*

1687. Given the above, Phillips states, it is not surprising that in a study performed by Sarna, a hypothetical West Coast refinery making only CARB gasoline used more reformate than the hypothetical Gulf Coast refinery used in the same study. *Id.* (citing Exhibit No. EMT-382 at p. 7). The study also showed, continues Phillips, that the West Coast refinery used more reformate than any other blendstock in the production of CARB gasoline. *Id.* It also notes these results are inconsistent with Williams's assertion that Naphtha has lost its value on the West Coast. *Id*.

1688. Phillips argues that, even though the California Air Resources Board may implement new standards for gasoline in the future, Naphtha would not lose its value. *Id*. at p. 55. It notes that Sorenson testified that the new CARB III standards can be met with the benzene equipment that is in place and that the CARB III aromatics specification actually has been increased to allow more octane to be produced from reformers. *Id.* Exhibit No. WAP-273, notes Phillips, shows that the aromatics cap has increased from 30% under CARB II to 35% for CARB III. *Id.* In Phillips's opinion, this increase in the amount of aromatics allowed should, if it has any effect, cause reformate to become even more valuable under CARB III than it is under CARB II. *Id*.

1689. Even had the introduction of the CARB specifications reduced the demand for Naphtha on the West Coast somewhat, Phillips argues that this alone would not mean that it is appropriate to use Gulf Coast prices to value West Coast Naphtha. Phillips Reply Brief at p. 34. It notes that nowhere have the proponents of Gulf Coast pricing provided any quantification of how CARB specifications may have reduced the value of Naphtha on the West Coast or how that compares with the Gulf Coast price of Naphtha. *Id.* at pp. 34-35. Without any such quantification, Phillips argues, the mere assertion that CARB specifications have caused demand for Naphtha on the West Coast to decline cannot be relied upon to demonstrate that Gulf Coast prices reflect West Coast Naphtha values to the same degree of accuracy as the proxy prices for the other cuts. *Id.* at p. 35.

1690. Phillips notes that the final argument advanced by Sanderson in support of the continued use of the published Gulf Coast Naphtha price is his assertion that the West Coast/Gulf Coast price differential for Naphtha falls somewhere between the West Coast/Gulf Coast price differentials for LSR and VGO. Phillips Initial Brief at p. 55. However, Phillips points out that Sanderson admitted "there's a wide range between the differentials between LSR and VGO," and so this argument cannot demonstrate that the Gulf Coast price is an adequate proxy for the West Coast value. *Id.* (citing Transcript at p. 8833).

1691. Sanderson again failed to present facts to support his assertion, opines Phillips. *Id.* In particular, it notes, Sanderson has not supported his theory that the West Coast/Gulf Coast Naphtha differential is lower than the West Coast/Gulf Coast VGO price differential.[617] *Id.* at pp. 55-56. To the contrary, according to Phillips, the evidence that Sanderson cites supports the opposite conclusion. *Id*. at p. 56.

1692. Phillips states that the primary evidence relied upon by Sanderson to support his position is Exhibit No. WAP-48, which, it explains, contains Sanderson's estimate of the relative contribution of Naphtha and VGO to the West Coast gasoline pool. *Id*. Further, states Phillips, the Exhibit shows the capacity and utilization of Fluid Catalytic Converter units (units that process VGO) for the years 1994-2001 and compares that to the capacity and utilization of reforming units that process Naphtha for the same time period.[618] *Id*.

1693. It is impossible, Phillips maintains, to reach any conclusions about West Coast/Gulf Coast price differentials, however, from the data presented. *Id*. It advances two reasons for this: First, a product's market value is determined by supply and demand factors, but the data in Exhibit No. WAP-48 does not show the interrelationship between supply and demand for either Naphtha or VGO. *Id.* at pp. 56-57. Thus, Phillips states, Sanderson's estimate of the relative volumetric contribution of VGO and Naphtha to the West Coast gasoline pool says nothing about which product will be more valuable. *Id.* at

[617] There is no dispute, according to Phillips, that the West Coast/Gulf Coast price differential of Naphtha is higher than the West Coast/Gulf Coast LSR price differential. Phillips Initial Brief at p. 56, n.18. All witnesses agreed that LSR's high Reid Vapor Pressure causes it to have problems on the West Coast, and that Naphtha does not have this Reid Vapor Pressure problem. *Id.*

[618] Sanderson argues, according to Phillips, that this Exhibit demonstrates that (1) VGO contributed more volume to the West Coast gasoline pool than did Naphtha, (2) Fluid Catalytic Converter unit capacity increased on the West Coast while reforming capacity declined, and (3) reforming capacity on the West Coast was underutilized. Phillips Initial Brief at p. 56. From this, states Phillips, Sanderson concludes that "the analysis indicates that the West Coast less Gulf Coast price differential for Naphtha should be below that of VGO." *Id.* (quoting Exhibit No. WAP-33 at p. 18).

p. 57.

1694. The second reason why Exhibit No. WAP-48 tells nothing about West Coast/Gulf Coast differentials, Phillips claims, is that it contains absolutely no information about Naphtha or VGO on the Gulf Coast. *Id.* It states that a comparison of statistics between VGO and Naphtha on the West Coast might conceivably support an inference regarding which of these two products has a higher price on the West Coast, but it says nothing about which product will be valued more highly on the West Coast than on the Gulf Coast. *Id.*

1695. According to Phillips, evidence presented by Williams suffers from a similar defect. Phillips Reply Brief at p. 29. It asserts that data regarding the relative amounts of VGO and Naphtha processed on the West Coast do not reflect the demand for those products, but rather the supply, and point out that it is not possible to tell which product has a higher price based on which one is processed more. *Id*. Phillips explains that much more VGO is processed on the West Coast than Isobutane, because much more VGO is contained in crude oil than Isobutane and, therefore, there is a greater supply of VGO than Isobutane. *Id.* Nevertheless, they state that the price of Isobutane is higher than VGO on the West Coast, and the West Coast/Gulf Coast price differentials for Isobutane also are much higher than for VGO. *Id.* (citing Exhibit No. PAI-176 at pp. 10, 14).

1696. While Sanderson did not provide any information about Naphtha and VGO on the Gulf Coast, Phillips claims to have adduced some evidence during cross-examination, to wit: Exhibit No. PAI-213. Phillips Initial Brief at p. 57. It states that the Exhibit provides a comparison of utilization rates for the years 1994-2001 for the Fluid Catalytic Cracking[619] units that process VGO and the reforming units that process Naphtha, and notes that Sanderson testified that he found utilization rates to provide some indication of demand for the two products. *Id*. at pp. 57-58. According to Phillips, the Exhibit shows that utilization rates for cat crackers on the West Coast in 2001 are over 5% lower than on the Gulf Coast, which it suggests, if anything, that demand for VGO is lower on the West Coast than on the Gulf Coast. *Id.* at p. 58. By contrast, Phillips points out, the utilization rate for reforming units on the West Coast is much closer (within 2%) to the Gulf Coast for 2001. *Id.*

1697. Furthermore, Phillips notes that Sanderson acknowledged that Naphtha produced from a VGO hydrocracker requires more expensive processing than straight run Naphtha, because VGO first must be processed in a hydrocracker before it can be run through the reformer. *Id.* at p. 60. If West Coast refiners are more willing than Gulf Coast refiners to invest in a hydrocracker and then incur the increased costs to run VGO through a

[619] Sometimes called an FCC unit, other times referred to as a cat cracker. Transcript at pp 10781, 10788.

hydrocracker to produce more Naphtha, this suggests, in Phillips's view, that there is a relatively greater demand for Naphtha than VGO on the West Coast than on the Gulf Coast, because West Coast refiners are willing to expend considerable funds to convert their VGO into Naphtha. *Id.* at pp. 60-61.

1698. Phillips also argues that the evidence regarding utilization rates of reformers and cat crackers does not necessarily prove anything about demand, and instead may again be more an indication of supply. Phillips Reply Brief at p. 30. It states that the record reflects that ANS production has declined significantly since the early 1990s.[620] *Id.* To the extent that refiners have replaced medium ANS with heavy California, South American and Far Eastern crudes that contain more VGO and less Naphtha,[621] Phillips asserts, this would cause refiners to have a lesser supply of Naphtha and a greater supply of VGO than they did in the early 1990s. *Id.*

1699. The evidence submitted by Williams, Phillips argues, does not show what crudes have replaced ANS or what their Naphtha contents may be. *Id.* However, given the reduction in the supply of ANS, it contends that the reduction in reformer utilization rates could simply reflect that West Coast refiners are now refining crudes that contain less Naphtha than before. *Id.* at pp. 30-31. Far from reflecting a reduction in demand for Naphtha, it asserts, this would indicate a reduction in supply, which would make Naphtha more valuable relative to VGO, not less. *Id.* at p. 31.

1700. There is other evidence in the record, according to Phillips, that also supports the conclusion that demand for VGO is not greater than demand for Naphtha on the West Coast. *Id*. It notes that, as the proponents of Gulf Coast pricing have pointed out, West Coast refiners have invested in expensive hydrocrackers to a greater degree relative to the amount of crude they process than have Gulf Coast refiners, and explains that these hydrocrackers have been used to process VGO into "hydrocracker Naphtha" that then can be processed through a reformer to make reformate. *Id.* Phillips explains that these units, as Sanderson admitted, have higher capital and operating expenses than reformers, and asserts that, if there were a greater demand for VGO than Naphtha, one would not expect

[620] Phillips explains that the total ANS shipped from Valdez is shown on Exhibit No. EMT-243 as the PSVR "Common Stream" barrels. Phillips Reply Brief at p. 30, n.16. It states that Exhibit No. EMT-243 shows that these barrels declined from about 51.5 million in December 1993 to about 31 million in December of 2001, approximately a 40% decline in total barrels/month. *Id.*

[621] Phillips notes that the assays of the individual North Slope streams, Exhibit Nos. EMT-627 through EMT-631, show that the heavier crudes have less Naphtha than the lighter crudes. Phillips Reply Brief at p. 30, n.17. It states that Exhibit No. PAI-203 also shows that the heavier Oriente and Maya crudes have less Naphtha than ANS. *Id.*

to see the refiners making the large capital and operating cost expenditures required to convert their VGO into Naphtha. *Id.*

1701. Phillips suggests that the other evidence cited by Williams to support the proposition that VGO has a greater West Coast/Gulf Coast price differential than Naphtha is even less compelling than the evidence on relative amounts of VGO and Naphtha that have been processed on the West Coast. *Id.* It argues that Exhibit Nos. WAP-39 and WAP-221 merely show the average of the West Coast/Gulf Coast price differentials, including differentials under the various West Coast Naphtha proposals raised in this proceeding, over the years 1994-2001. *Id*. at pp. 31-32. Phillips asserts that the charts do not show any actual price differentials for Naphtha because there is no published West Coast Naphtha price. *Id.* at p. 32.

1702. Exhibit No. WAP-44 does not show, as Williams argues, according to Phillips, that there was a lack of demand for Naphtha during periods of high VGO prices. *Id.* It also asserts that the Exhibit does not show that Naphtha supplies were unimportant to West Coast refiners's gasoline demand. *Id.* Phillips notes that the exhibit does not show any data regarding VGO at all; therefore it cannot say anything about a demand for Naphtha relative to demand for VGO. *Id.* at pp. 32-33. Further, Phillips notes that, because the chart does not show how Naphtha produced by refiners on the West Coast is being used, it says very little about Naphtha demand, and certainly cannot be used to support the contention that "naphtha supplies were not instrumental to West Coast refiners to meet gasoline demand." *Id*. at p. 33 (quoting Williams Initial Brief at p. 37).

1703. Finally, Phillips takes exception to Williams's final argument that the ideal West Coast Naphtha cut is from 208°F - 330°F. *Id.* It states that this argument is somewhat convoluted, and that it is difficult to understand the point being made. *Id.* Phillips suggests that nothing in Williams's argument addresses the question of whether the West Coast/Gulf Coast VGO price differential is greater than the Naphtha differential. *Id.*

1704. However, Phillips asserts that, to the extent that Williams is implying that the "ideal" Naphtha cut contains some Full Range Naphtha and thus has a lower value than the Heavy Naphtha whose price is quoted by Platts, it is misstating the facts. *Id*. Phillips maintains that the ideal cut does not transcend the Heavy Naphtha and Full Range Naphtha cuts, and points out that the 208°F - 330°F ideal cut describe by Williams is contained entirely within the Heavy Naphtha cut that starts at 180°F and ends in the high 300s°F. *Id*. If anything, Phillips contends, the Heavy Naphtha cut specifications in Platts are for a lower-valued product than the Williams's ideal 208° - 330°F cut, not a higher valued product as Williams suggests. *Id.* at pp. 33-34.

1705. Phillips explains that Williams and Unocal/OXY argue that the Gulf Coast price of Naphtha is higher than the West Coast price because there is petrochemical demand for Naphtha on the Gulf Coast that does not exist on the West Coast. Phillips Reply Brief at

p. 25. It asserts that, in doing so, Williams and Unocal/OXY have misapplied economic theory in advancing this argument. *Id*. Phillips states that, while all other things being equal, increased demand for a product would increase its price, all other things are not equal between the Gulf Coast and the West Coast. *Id.* at pp. 25-26. It points out it is uncontroverted that, in addition to having a petrochemical industry, the Gulf Coast market has a much larger refining capacity and also routinely receives Naphtha imports. *Id.* at p. 26. Thus, Phillips explains that the Gulf Coast also has a much greater supply of Naphtha than the West Coast, and this tends to drive the price of Naphtha down there. *Id.*

1706. The only way to know definitively, according to Phillips, whether the petrochemical demand on the Gulf Coast causes Gulf Coast Naphtha values to be elevated compared to the West Coast would be to prepare a detailed study of all of the various supplies and demands for Naphtha in each market. *Id*. at p. 26. It states that no such study was entered into the record, and that, as a result, there is no evidence in the record that petrochemical demand on the Gulf Coast causes a higher Naphtha price on the Gulf Coast than on the West Coast. *Id.* Moreover, Phillips contends that the contract data in this record provides strong empirical evidence that, in fact, the opposite is true. *Id*.

1707. Phillips argues that Williams's additional assertion that that the use of Naphtha on the Gulf Coast for aromatics extraction gives it a premium over the use of reformate in gasoline is the result of equally fuzzy economic thinking. *Id*. at p. 27. If, in fact, a refiner still has a supply of Naphtha after the demand for reformate to make gasoline is satisfied, then that refiner, Phillips claims, may use the Naphtha for aromatics extraction even though it would receive a higher value from the Naphtha it uses in gasoline production. *Id.*

1708. Unocal/OXY, Phillips declares, are wrong to recommend that the Commission ignore the evidence regarding barriers to importation of Naphtha to the West Coast. Phillips Reply Brief at p. 37. It notes that Unocal/OXY, in making the argument that there still is substantial capability on the West Coast to import gasoline blendstocks and feedstocks, and that Naphtha could be imported as well, miss the point. *Id*. at pp. 37-38. While conceding that there are terminal and tankage facilities on the West Coast that could handle Naphtha imports, Phillips points out that, when there is a high demand for imports of a number of gasoline feedstocks and blendstocks, but insufficient facilities to handle all of those imports, the costs associated with the imports increase and there is a greater separation between West Coast prices and prices in other markets. *Id.* It notes that one of the Stillwater studies performed for the California Energy Commission makes this exact point.[622] *Id.*

[622] Phillips claims that, after noting that there are, in fact, "prolonged price excursions above world market plus" the cost of transportation, the report concludes that "the only remaining explanation" is that "import options are indeed restrained by physical

1709. Ultimately, asserts Phillips, the advocates of retaining the use of the Gulf Coast Naphtha price are forced to acknowledge that there are significant price differences between products on the Gulf Coast and on the West Coast and that the West Coast Naphtha contracts show significantly higher prices than those published on the Gulf Coast. Phillips Initial Brief at p. 61. According to it, they assert that the three-year time period from 1999-2001, when the price differences were the highest, was anomalous and that, therefore, the data from this time period should be ignored by the Commission. *Id.* at p. 62. Phillips states that this argument suffers from a number of defects including that, while it is true that the data from 1999-2001 show more elevated price differences between the West Coast and the Gulf Coast, there also were significant price differences in the earlier 1992-1998 time period. *Id*.

1710. Moreover, Phillips states, the assertion that this is an anomalous time period that can be ignored implicitly suggests that: (1) something other than market forces was at work; (2) the anomaly was short lived; and (3) the anomaly is unlikely to occur again in the future. *Id.* at p. 63. According to Phillips, none of these assumptions is correct. *Id*.

1711. Proof that use of the Gulf Coast price substantially undervalues West Coast Naphtha, Phillips declares, comes from the evidence that Williams makes significant sales of Naphtha to the West Coast and the Far East. *Id.* at p. 65 (citing Exhibit Nos. PAI-187, PAI-188, EMT-374; Transcript pp. 8892-94, 8897-98, and 8902-06). In order to make such sales, Phillips explains, Williams must refine Naphtha from ANS crude, and transport it by rail to Anchorage and then by tanker to the West Coast or Japan. *Id*. That Williams can make more money from such sales than from simply returning the Naphtha to TAPS and receiving the Quality Bank price means, in Phillips's opinion, that the Quality Bank West Coast Naphtha price is too low. *Id.*

1712. Phillips disagrees with Unocal/OXY's argument that the West Coast gasoline market is not competitive. Phillips Reply Brief at p. 39. It asserts that Culberson's testimony should be given no weight because of his lack of expertise in the economic field. Id. Furthermore, it states that Culberson's opinion is based on an extremely brief, superficial examination of market conditions on the West Coast that cannot constitute a responsible analysis of competitive issues. *Id.* (citing Exhibit No. UNO-7 at p. 6).

1713. Unocal/OXY overreach when they characterize the market in California as not being competitive, according to Phillips. *Id.* It states that, while the "Preliminary Report

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reasons (terminal capacity) and commercial factors (price volatility)." Phillips Reply Brief at p. 38 (quoting Exhibit No. EMT-489 at p. 101).

to the [California] Attorney General"[623] may indicate that there is greater competition in other parts of the country than in California, and may point out certain factors that reduce competition, nowhere does it conclude that there is not workable competition in California. *Id*. Phillips points out that Pulliam testified, using the standard adopted by the Department of Justice for measuring market concentration, that the California market is only moderately concentrated. *Id.* It further notes that Pulliam testified that "many, many industries throughout the U.S. are moderately concentrated, and competition works throughout those industries." *Id*. at pp. 39-40 (quoting Transcript at p. 7588A).

3. BP

1714. BP states that Naphtha currently is valued on both the West and Gulf Coasts using Platts Gulf Coast reported price. BP Initial Brief at p. 5. When the Commission made that decision in 1993, BP acknowledges, it made sense, but today, nearly a decade after that decision, things have changed, and those changes have made it inappropriate to value West Coast Naphtha using a Gulf Coast price. *Id.* With the change in the valuation of VGO to the Platts West Coast VGO reference price,[624] BP states that it no longer is just and reasonable to value West Coast Naphtha on the basis of a Gulf Coast price. *Id.* It asserts that it is extremely important to value Naphtha on a consistent basis with VGO, because both their values are driven by their use in making gasoline. *Id.*

1715. Further, BP claims, fundamental differences between the Gulf Coast and the West Coast markets support using a West Coast-based price assessment, if reliable, instead of a Gulf Coast price assessment for valuing the West Coast naphtha component. *Id.* at p. 6. It points out that the Gulf Coast petrochemical market for Naphtha isn't replicated on the West Coast, and that this difference leads to differences in the Naphtha value on the two coasts. *Id.* Because the Quality Bank will value West Coast VGO on a West Cost basis going forward, BP asserts, the Quality Bank should make a corresponding change to the valuation of West Coast naphtha. *Id.* at p. 7.

4. Williams

1716. It is Williams's position that the current Naphtha value[625] is and continues to be

[623] Exhibit No. WAP-199.

[624] BP argues that any danger that the West Coast VGO price could be manipulated by one party at the expense of another has been eliminated. BP Initial Brief at p. 6.

[625] Williams uses the term "Current Naphtha value" to mean both the use of Platts Gulf Coast Naphtha price quote before Platts introduced the Heavy Naphtha price quote and the Platts Gulf Coast Heavy Naphtha (waterborne) price quote starting in March

just and reasonable. Williams Initial Brief at p. 17. According to Williams, Exxon, Phillips, Alaska and BP have not shown that the current valuation of the Naphtha component is unjust and unreasonable. *Id.* It asserts that they have not even made the threshold showing that there have been changed circumstances that warrant revisiting the current valuation method that has been used since the commencement of the distillation methodology. *Id.* Williams states that, if anything, any changed circumstances support the continued use of the Gulf Coast Naphtha price quote to value the West Coast Naphtha component. *Id.* Moreover, Williams notes, the alternative proposals advanced by Exxon and Phillips, respectively, are unquestionably unjust and unreasonable. *Id.*

1717. Simply stated, argues Williams, neither Phillips's nor Exxon's witnesses provide any evidence of changed circumstances warranting a change in the current methodology to value the West Coast Naphtha component. *Id.* Further, notes Williams, their witnesses did not even allege any changed circumstances since the adoption of use of the Gulf Coast published Naphtha price to value the West Coast Naphtha cut. *Id.* at pp. 17-18. Williams points out that O'Brien testified in his direct testimony that there have been no material changes in the West Coast and Gulf Coast markets. *Id.* p. 18 (citing Exhibit No. PAI-33 at p. 6).

1718. In addition, Williams states, Exxon also did not assert, nor did it provide any evidence of, changed circumstances.[626] *Id.* Similarly, Williams notes that Tallett does not address any changed circumstances in his pre-filed testimony. *Id.* In his direct testimony, according to Williams, Tallett does state: "[I]t is my understanding that in subsequent proceedings the [Commission] has abandoned its so called 'no adjustment to market prices' approach and has instead approved the use of adjusted prices." *Id.* (quoting Exhibit No. EMT-11 at p. 13). However, notes Williams, Tallett did not characterize that as a changed circumstance warranting a change in the methodology and it points out that the relevant portion of Tallett's testimony is titled "There is no Evidence That 'Changed Circumstances.'" *Id.* at pp. 18-19 (quoting Exhibit No. EMT-133 at p. 35). Further, notes Williams, when Tallett was asked what changed circumstances have occurred since October 2000 that would support a view that the Gulf Coast Naphtha price is no longer the appropriate value for West Coast Naphtha, he said there were none. *Id.* at pp. 19-20 (citing Transcript at pp. 6654-57).

1719. According to Williams, in his pre-filed direct testimony, Ross does not address

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2003. Williams Initial Brief at p. 17, n.10.

[626] Williams states that Toof's only mention of changed circumstances occurs in his pre-filed testimony addressing Ross's reference to changed circumstances in gasoline since 1996. Williams Initial Brief at p. 18, n.11 (citing and quoting Exhibit No. EMT-123 at pp. 35-36).

any changed circumstances warranting a change in methodology. *Id.* at p. 20. In his answering testimony, Exhibit No. BPX-27, it notes, Ross addresses changed circumstances in the gasoline markets as they relate to Tallett's proposed methodology asserting that the relationship, looking at gasoline differentials, between the Gulf Coast and West Coast has changed, a factor not accounted for by Tallett. *Id.*

1720. Williams asserts that one has to be wary of any proposal that uses West Coast gasoline prices because extra precautions need to be taken to ensure that the increasing margin of West Coast gasoline compared to Gulf Coast gasoline is not attributed to Naphtha. *Id.* at pp. 20-21. It state that both Tallett's and O'Brien's proposals do exactly that. *Id.* at p. 21. Williams explains that it is in this context that Ross goes on to state:

> [T]here obviously have been changed circumstances that have altered the historic relationship between Gulf Coast gasoline and West Coast gasoline. While it may have been valid to link West Coast Naphtha value to Gulf Coast Naphtha prices and the differential between West Coast and Gulf Coast gasoline prices in 1993, it certainly is not today.

Id. at p. 21 (quoting Exhibit No. BPX-27 at pp. 10-11). From this testimony, Williams concludes, Ross is focusing on the proposals and their use of West Coast gasoline and not on the value of Naphtha between the two coasts. *Id.* at p. 21. Further, Williams points out, Ross did not believe that the Naphtha values increased along with increased in gasoline prices, and that he apparently believed that, if there were a market for Naphtha on the West Coast, its value would have declined during the same period. *Id.* Williams states that Ross's conclusion that there have been no changed circumstances that affect the value of Naphtha is consistent with the record evidence supporting the continued use of the Gulf Coast Naphtha price to value the West Coast Naphtha component of the Quality Bank.

1721. Thus, it is Williams's position that there has been no evidence submitted of changed circumstances that warrant abandoning the methodology used to value Naphtha since the inception of using a distillation methodology for the Quality Bank. *Id.* at p. 22. In its *Tesoro* decision, explains Williams, the Circuit Court did not rule that changed circumstances had occurred or that its remand of the proceeding to the Commission precluded further consideration of this threshold first step in the evidentiary process of trying to change a methodology that has, in effect, been found to be just and reasonable. *Id.* Rather, states Williams, the Circuit Court held that, on the face of its complaint, Tesoro had alleged changed circumstances of a nature sufficient to require the Commission to consider and address whether changed circumstances had occurred that warranted looking at whether the methodology to value Naphtha should be changed. *Id.* (citing *Tesoro*, 234 F.3d at p. 1293).

1722. Williams notes that both Phillips and Exxon argue, despite the fact that their own witnesses testified that there were no changed circumstances, that the near complete cessation of ANS deliveries to the Gulf Coast is proof that Gulf Coast prices can no longer be used to value West Coast Naphtha. Williams Reply Brief at pp. 24-25. It argues that this assertion has been rendered meaningless by the evidence, as Ross testified, that the Platts Gulf Coast Heavy Naphtha (cargo) price assessment now being used to value the Gulf Coast and the West Coast Naphtha components of the Quality Bank is approximately equivalent to ANS plus $4.00/barrel on the West Coast. *Id.* at p. 25 (citing Transcript at p. 9979). Therefore, it asserts, the Gulf Coast Naphtha price is directly linked to ANS on the West Coast and, if there is a concern, this alleged changed circumstance is easily accounted for by simply substituting the West Coast published price for ANS + $4.00/barrel as the methodology for valuing West Coast Naphtha. *Id.*

1723. Both Phillips and Exxon also claim, states Williams, that the prices in the West Coast contracts produced in this proceeding constitute a changed circumstance based on the higher prices in the Naphtha contracts. *Id.* Williams states that Exxon would, at the least, have to show that the 2001 contracts are different from the contracts during the period 1994 – 2000 in light of the testimony that Tallett gave that his baseline year for changed circumstances was 2000, and it asserts that Exxon made no such showing. *Id.* at p. 26. According to Williams, Phillips cannot overcome O'Brien's testimony that there have been no changed circumstances since 1994 when the Commission began using the Gulf Coast Naphtha price to value West Coast Naphtha. *Id.*

1724. Williams states that Phillips not only raises the difference in the product markets, it also pointed to the various proposals resulting in different values as a changed circumstance. *Id.* It suggests that there are two fatal flaws in this claim: first, Williams states that a person could simply skew the results of the valuation in order to support a changed circumstance based on that person's own results designed to achieve a high value for West Coast Naphtha when it is in that person's or party's economic interest; second, it states that the support that Phillips points to in *Tesoro* (234 F.3d at p. 1293) undermines Phillips's and Exxon's position that the Circuit Court, in that ruling, already decided that changed circumstances exist and that use of the Gulf Coast Naphtha price to value West Coast Naphtha is no longer appropriate. *Id.* at pp. 26-27. Further, Williams states, Tallett disavowed using the approach used in the *Tesoro* case. *Id.* at p. 27. Similarly, notes Williams, in 1998 O'Brien thought the *Tesoro* result unreasonable because it valued Naphtha higher than gasoline. *Id.*

1725. However, Williams points out that, because there was no evidentiary hearing on Tesoro's complaint, evidence of changed circumstances has to be presented in this proceeding. Williams Initial Brief at pp. 22-23. It declares that no evidence was presented here and that, therefore, the proponents have failed to clear the first of their three burden of proof hurdles. *Id.* at p. 23.

1726. Williams asserts, in support of its argument that the Gulf Coast and West Coast have different supply and demand characteristics,[627] that Exxon grossly misstates Sanderson's testimony in claiming that Sanderson stated that he would never suggest to anyone that they rely on Gulf Coast Naphtha prices to value West Coast Naphtha. Williams Reply Brief at pp. 27-28. Instead, Williams states that, when asked what prices he would advise his client to rely on to assess the risk of selling Naphtha on the West Coast, Sanderson clearly stated he would advise this client to rely on "a basket of prices, including the Gulf Coast [Naphtha] price." *Id.* at p. 28 (quoting Transcript at p. 9331).

1727. Exxon attempted to use testimony by Sanderson, according to Williams, that he did not rely on published Gulf Coast Naphtha prices when purchasing West Coast Naphtha. *Id.* at pp. 28-29. Williams argues that this testimony does not support Exxon's argument that the Gulf Coast Naphtha price is not a suitable proxy for the West Coast price in the 1993 through 2003 timeframe. *Id.* at p. 29. It contends that Sanderson clearly testified that the crude oil prices on the two coasts have been equalized since 1997. *Id.* Prior to that time, particularly in the 1980s when he was employed as the manager of economics and planning, Williams states, Sanderson indicated that crude oil prices on the West Coast, and therefore Naphtha prices on the West Coast, would have been below the Gulf Coast price. *Id.* Therefore, it maintains, the Gulf Coast Naphtha price would not have been germane to West Coast Naphtha transactions in the 1980s when Sanderson worked as the manager of economics and planning. *Id.*

1728. Williams explains that the Platts Gulf Coast waterborne Naphtha price was not created for the TAPS Quality Bank. Williams Initial Brief at p. 23. According to Williams, the reasonableness, robustness and reliability of this price quote for reforming grade Naphtha on the Gulf Coast has not been questioned or challenged since the time of its approval by the Commission and the Circuit Court for use in the TAPS Quality Bank. *Id.* It states that, in pre-filed testimony, Sanderson testified that Platts waterborne Naphtha price is a reliable indicator of reforming-grade Naphtha prices on the Gulf Coast: "In my experience, industry participants rely on the Platt's waterborne naphtha price quotation when an independent assessment of reforming-grade naphtha prices is needed as in the case of the TAPS Quality Bank." *Id.* at p. 23-24 (quoting Exhibit No. WAP-1 at p. 4).[628]

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[627] Williams maintains that Exxon's claim that there are different supply and demand characteristics on the Gulf Coast and West Coast constitutes an admission that Tallett's Gulf Coast relationship is not the same as the West Coast relationship and that, therefore, his regression formula is inapplicable and thus an unacceptable way of calculating the West Coast Naphtha value. Williams Reply Brief at p. 27, n.10.

[628] Williams also cites to Exhibit No. WAP-1 at p. 11. Williams Initial Brief at p. 24.

1729. No party, Williams notes, has contested the viability, reliability and robustness of the continued use of Platts Gulf Coast Naphtha price for valuing the Gulf Coast Naphtha component of the Quality Bank. *Id.* at p. 24. Therefore, Williams asserts, there is no issue as to reasonableness of the price and its continued use to value the West Coast Naphtha component of the Quality Bank should the decision be that (i) no changed circumstances exist that warrant discontinuing use of the Platts Gulf Coast waterborne Naphtha price on either the Gulf Coast or the West Coast, (ii) the current methodology should be continued because the record evidence does not support a finding that this valuation is no longer just and reasonable, and (iii) (should the assessment reach this point) that the record evidence shows that none of the proposals to replace the current valuation methodology are just and reasonable. *Id.*

1730. Williams asserts that the continued use of the Platts Gulf Coast waterborne Naphtha price on the Gulf Coast and on the West Coast is not affected by Platts February 2003 introduction of a Heavy Naphtha price quote, which the Quality Bank Administrator implemented in March 2003 for the TAPS Quality Bank. *Id.* According to Williams, no party opposes the switch to Platts Gulf Coast Heavy Naphtha waterborne price quote for valuing Gulf Coast Naphtha and its use to value the West Coast Naphtha component of the Quality Bank so long as the current methodology continues to be used for the West Coast Naphtha component.[629] *Id.* at p. 24-25. It notes that the Quality Bank Administrator's reason for making the change was based on the new price quote being more closely aligned with the properties of Quality Bank Naphtha. *Id.* at p. 25.

1731. A basic premise of the TAPS Quality Bank, Williams states, is to use objective price quotations from independent services to value the intermediate feedstocks whenever possible.[630] *Id.* at p. 26 (citing *Trans Alaska Pipeline System*, 65 FERC at p. 62,287; Exhibit No. WAP-33 at p. 3). It states that Sanderson testified that this approach gives an

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[629] Williams states that its position that Platts Gulf Coast Heavy Naphtha (waterborne) price quote is acceptable does not extend to averaging the two prices as the Quality Bank Administrator recommends. Williams Initial Brief at p. 25, n.16.

[630] Williams explains that the TAPS Quality Bank distillation methodology values the various components as intermediate feedstock or products and not as finished products. Williams Initial Brief at p. 26, n.17. Thus, notes Williams, if there is no published price for the intermediate feedstock/product, then a published price for a finished product made entirely or essentially from that intermediate feedstock/product is used with the appropriate adjustment for processing and any other necessary adjustment to transform that finished product price into an intermediate feedstock/product price on a consistent basis with the other Quality Bank components. *Id.* Williams points out that this is not necessary because a published intermediate feedstock price exists for Naphtha. *Id.*

objective, rather than a subjective, method to use in valuing a cut. *Id.* at p. 26-27. In addition, continues Williams, the Quality Bank provides for the use of a price used on one coast to be used for valuation purposes for that component on both coasts if the other coast loses the price quote that had been used. *Id.* at p. 27.[631] Thus, asserts Williams, the Naphtha component has been valued consistently with these two basic tenets from the advent of using the distillation based methodology for the TAPS Quality Bank at Pump Station No. 1, at Golden Valley and at the Valdez Refinery. *Id.* As no published price quote exists for Naphtha on the West Coast, explains Williams, the published price quote on the Gulf Coast has also been used on the West Coast. *Id.* Further, notes Williams, these premises and the use of Platts Gulf Coast Naphtha price quote to value both the Gulf Coast and West Coast Naphtha components were not appealed. *Id.* Therefore, Williams asserts that it was effectively approved and found just and reasonable by the Circuit Court in *OXY* and was not reversed by the Circuit Court in either *Tesoro* or *Exxon*. *Id.*

1732. Williams states that it is unquestioned that there is no current West Coast Naphtha price quote. *Id.* (citing Exhibit No. WAP-1 at p. 4). In addition, notes Williams, there has been no such price quote since the Quality Bank switched to the distillation methodology. *Id.* Thus, asserts Williams, use of Platts Gulf Coast Naphtha price quote, and now Platts Gulf Coast Heavy Naphtha waterborne price quote, is the only proposal based solely on intermediate feedstock Naphtha price quotes from an industry-recognized, independent price assessment source and therefore consistent with the prices used to value the other Quality Bank components. *Id.* at p. 28.

1733. Contrary to Phillips's and Exxon's statements that Sanderson presented no evidence to support his theory, Williams asserts, the record evidence supporting its claim that Naphtha prices on the two coasts are linked to crude oil prices and, therefore, must be similar because crude oil prices of similar quality have equalized is compelling. Williams Reply Brief at pp. 34-35. It declares that Exhibit Nos. EMT-382 and WAP-229 show that only part of Naphtha, in a typical West Coast refinery manufacturing CARB gasoline, comes from straight-run Naphtha, with the balance of the Naphtha processed is purchased as crude oil or converted through hydrocracking the VGO cut from crude oil.[632] *Id.* at p. 35. Williams contends that it is logical and fully consistent with refining

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[631] Williams cites to "Amerada Hess Pipeline Corporation, *et al.* Local Pipeline Tariff Part III.G.5.a." This document, however, was not offered in evidence and is not part of the record.

[632] Williams fails, however, to cite to the specific page(s) of Exhibit No. EMT-382, a multi-page exhibit, in which it finds support. Moreover, Exhibit No. WAP-229 involves a summary of the contract analyses performed by Tallett, Pulliam and O'Brien and, therefore, does not serve as proof of the point claimed by Williams.

economics to look to the crude oil price relationships between the West Coast and Gulf Coast to establish the relationship between Naphtha and VGO prices on the two coasts as Sanderson has done because we cannot look to Naphtha prices alone to verify this relationship. *Id.* It states that crude oil prices and VGO bear this relationship out. *Id.* According to Williams, it is clear from the record that VGO prices are similar and on average varied by only 0.9¢/gallon over the 1992 through 2002 period. *Id.*

1734. Williams notes that Sanderson testified that he would not expect the price relationships between intermediate feedstock prices on the two coasts that are not produced primarily from crude oil to be similar in price. *Id.* It states that Sanderson also testified that the price relationships of these commodities do not have any bearing on the price relationships between crude oil and Naphtha on the two coasts. *Id.* at pp. 35-36. Williams states that Sanderson also made a careful distinction between finished product prices and intermediate feedstock prices on the two coasts, and he was careful to explain that finished product prices are higher on the West Coast than the Gulf Coast because of the unique nature of the finished product markets on the West Coast leading to higher refining margins on the West Coast. *Id.* at p. 36.

1735. Exxon tries to blur this distinction, Williams states, by arguing that these higher refining margins on the West Coast should be attributed to the price of Naphtha and that the price of Naphtha is tied to the price of gasoline and not the price of crude. *Id.* Williams asserts that, the fact that the price of Naphtha is closer to the price of gasoline than the price of crude oil supports Sanderson's position that it is a suitable proxy for West Coast Naphtha. *Id.* It notes that Sanderson testified that the presence of a petrochemical industry on the Gulf Coast creates additional demand for Naphtha, thus elevating the price relative to what it would otherwise be, and argues that the robust demand for Naphtha on the Gulf Coast is substantiated by the fact that the Gulf Coast demand for it outstrips its supply from refineries requiring substantial volumes of imports. *Id.* at pp. 36-37. Williams believes that the price of Naphtha on the Gulf Coast must be sufficiently elevated to attract these imports. *Id.* at p. 37.

1736. According to Williams, since 1997, crude oil has been imported on the West Coast due to the decline of ANS as well as other West Coast (California) crude production. Williams Initial Brief at p. 28. It states that crude oil supply costs for the Gulf and West Coasts are similar and that this has caused crude oil prices to equalize. *Id.* at p. 29 (citing Exhibit No. WAP-1 at p. 7). Williams notes that Sanderson explained that this means prices are similar over a period of time. *Id.* (citing Transcript at p. 9398). In addition, notes Williams, because "West Coast refiners are importing increasing volumes of crude oil from several of the same crude oil suppliers as Gulf Coast refiners," Sanderson testified that "[t]he Gulf Coast and West Coast crude oil markets are linked." *Id.* (quoting Exhibit No. WAP-1 at p. 5). That does not mean, states Williams, that "prices are exactly the same" or that the "crude markets on the two coasts are identical." *Id.* (quoting Transcript at pp. 9029–30). Williams notes that Sanderson concluded that the

West Coast and Gulf Coast crude oil markets are linked because of the similarity in prices for delivered crude oil over an extended period of time. *Id.* at p. 30 (quoting Exhibit No. WAP-1 at pp. 8-9).

1737. The linkage of the Gulf Coast and West Coast crude markets, according to Williams, has significant implications with respect to the price of Naphtha on both the Gulf Coast and West Coast. *Id.* at p. 31. It points out that Sanderson testified that, because of this linkage, the price of Naphtha won't vary much between the Gulf and the West Coasts. *Id.* Williams explains, further, that the Platts Gulf Coast Naphtha price is a reasonable proxy for valuing Naphtha on the West Coast because the Platts price quote "values naphtha as an intermediate feedstock . . . [and] a refiner always has the option of running a crude oil with a higher naphtha content in lieu of acquiring naphtha as a feedstock." *Id.* at p. 32. (quoting Exhibit No. WAP-1 at p. 5).

1738. Williams states the additional demand for reforming Naphtha as a petrochemical feedstock on the Gulf Coast means that the price of reforming Naphtha on the Gulf Coast is elevated relative to what it would otherwise be. *Id.* at pp. 33-34 (citing Exhibit Nos. WAP-1 at p. 10, BPX-27 at p. 29). But, asserts Williams, there is no similar petrochemical demand on the West Coast. *Id.* at p. 34 (citing Transcript at p. 9028). It notes that Ross testified that about 70% of Heavy Naphtha in PADD III (Gulf Coast) is used for gasoline and about 30% is used in petrochemical and other applications. *Id.* (citing Transcript at pp. 9763, 6789). Further, continues Williams, both Tallett and O'Brien acknowledged that the aromatics extraction capacity on the Gulf Coast was approximately 12.4% of total reforming capacity. *Id.*

1739. It is reasonable to conclude, according to Williams, that the use of reforming grade Naphtha on the Gulf Coast to produce reformate for extraction of aromatic petrochemicals such as benzene, toluene and xylenes commands a premium over the reformate value in gasoline resulting in an elevation of the Gulf Coast Naphtha prices. *Id.* Otherwise, Williams states that the aromatic petrochemicals would not be extracted from the gasoline blending pool on the Gulf Coast. *Id.* Even an occasional use of reforming-grade Naphtha on the Gulf Coast as an ethylene cracker feedstock provides, Williams states, a floor for the reforming-grade Naphtha price on the Gulf Coast. *Id.* In support it refers to Exhibit No. EMT-89 at p. 2 which, it claims, shows that, during the winter months, the differential between Heavy Naphtha and conventional gasoline on the Gulf Coast did not drop as much. *Id.*

1740. Williams also states that the influence of the petrochemical markets on the Gulf Coast Naphtha price also helps to explain the narrower differential between gasoline and Naphtha on the Gulf Coast and the resulting higher Naphtha price. *Id.* at p. 34. It further explains that the Gulf Coast petrochemical demand and resulting higher Naphtha value also helps to explain why O'Brien's formula for valuing Naphtha appears to predict Gulf Coast prices. *Id.* at p. 35. (citing Exhibit No. WAP-133).

1741. On reply, Williams states that it believes that Exxon is wrong when it asserts that the use of Naphtha as a petrochemical feedstock on the Gulf Coast has no impact on the value of Quality Bank Naphtha. Williams Reply Brief at p. 29. In addition, it asserts that Exxon's statement concerning which aromatics are used to manufacture petrochemicals is also incorrect. *Id.* at pp. 29-30. According to Williams, the record evidence clearly indicates that 14.7% of the Quality Bank Naphtha cut is used in the production of aromatic petrochemicals such as benzene, toluene, and xylenes on the Gulf Coast. *Id.* O'Brien agrees with the magnitude of this estimate. *Id.* at pp. 30-31.

1742. In Williams's view, it is beyond question that the petrochemical demand for Naphtha on the Gulf Coast elevates the value of Naphtha while the lack of petrochemical demand for Naphtha on the West Coast coupled with much stricter benzene and aromatic restrictions for much of the gasoline produced on the West Coast lowers its value. *Id.* at pp. 33-34. When coupled with the increased value of Naphtha on the Gulf Coast of approximately 1¢/gallon as a result of using Platts Gulf Coast Heavy Naphtha (cargo) price assessment, this means, according to Williams, that the Gulf Coast Naphtha value is and continues to represent a just and reasonable value for the West Coast Naphtha component of the Quality Bank. *Id.* at p. 34.

1743. Williams explains that Sanderson's review of VGO, Naphtha and LSR prices on the Gulf Coast and VGO and LSR prices on the West Coast led him to conclude as follows:

> I remain convinced that reforming-grade naphtha should be valued as an intermediate feedstock consistent with other intermediate feedstocks produced primarily from crude oil and used primarily to make gasoline on the West Coast rather than through a subjective methodology that unfairly and improperly attributes the refiner's margin from gasoline production and marketing to naphtha, only one of the intermediate feedstocks used to make gasoline.

Williams Initial Brief at p. 35 (quoting Exhibit No. WAP-33 at p. 10). Based on this review, continues Williams, Sanderson also

> conclude[ed] that the relative value of the naphtha on the two coasts should fall between the values of VGO and LSR on the two coasts. In other words, the difference between the value of naphtha on the West Coast less the Gulf Coast naphtha price is higher than the LSR price differential (where the West Coast price is below the Gulf Coast price) and lower than the VGO price differential (where the West Coast VGO prices are currently above the Gulf Coast).

Id. (quoting Exhibit No. WAP-33 at p. 19).

1744. With the advent of CARB gasoline in California, Williams argues, it is not surprising, and in fact should be expected, that VGO's role in gasoline production would be enlarged while Naphtha's would diminish. *Id.* at p. 36. Williams points out that Exxon witness Tallett concurred with the increased importance of VGO with respect to making CARB gasoline. *Id.* (citing Exhibit Nos. WAP-33, 49).

1745. VGO prices on the West Coast and Gulf Coast have tracked each other, notes Williams, except for the extreme United States gasoline market disruptions in 2000 (due to Coker outages.) *Id.* (citing Exhibit No. WAP-224). Williams states that, as one might expect, Exhibit Nos. WAP-219 and WAP-224 show that a switchover in VGO price tracking on the two coasts occurred after 1996, which reflects VGO's increased importance to making CARB gasoline in California. *Id.* at pp. 36-37. However, notes Williams, over the 1992 through 2002 period, the price differential between VGO on the two coasts has averaged 0.9¢/gallon. *Id.* at p. 37.

1746. In contrast with VGO, Williams claims, LSR prices are significantly lower on the West Coast than on the Gulf Coast for two principal reasons. *Id.* at pp. 37-38 (citing Exhibit Nos. WAP-33 at p. 11, WAP-219, EMT-94). First, notes Williams, the high Reid Vapor Pressure of LSR and the isomerate manufactured from LSR make these components difficult to blend into CARB gasoline which has a very low Reid Vapor Pressure specification. *Id.* at p. 38. Because the Reid Vapor Pressure specifications change between the summer season (during which the Reid Vapor Pressure specifications are more severe) and the winter season in California, Williams explains, the demand for LSR is significantly curtailed during the summer season. *Id.* Without an alternative demand for LSR, Williams points out, such as a petrochemical feedstock, the LSR price is severely depressed. *Id.* Second, and conversely, states Williams, while there are also Reid Vapor Pressure limitations on the Gulf Coast (although not as severe as California), the increased demand for LSR as a petrochemical feedstock on the Gulf Coast acts to elevate LSR's price relative to the West Coast where no such demand exists. *Id.*

1747. Therefore, based on the uses of VGO, Naphtha and LSR in making gasoline, particularly CARB gasoline, on the West Coast, Williams asserts that the Naphtha value should fall between the prices of VGO and LSR. *Id.* It claims that this is true as well on the Gulf Coast. *Id.* Because all these intermediate prices are published on the Gulf Coast and, on average, and except during periods of severe disruptions, the VGO prices have been close on both coasts, Williams concludes, Platts Gulf Coast Naphtha price is representative of and should on average approximate the West Coast Naphtha price. *Id.*

1748. According to Williams, switching to CARB II gasoline on the West Coast, particularly in California, easily the largest gasoline market on the West Coast, has had a significant impact on the demand for Naphtha and thus its value in making gasoline. *Id.*

at p. 39. It notes that CARB gasoline made up approximately 71% of the West Coast gasoline production in 2000. *Id.* (citing Transcript at p. 12110).

1749. Two of the principal goals of the California Air Resources Board in establishing Phase II gasoline specifications, according to Williams, were to reduce the aromatic hydrocarbon content and the benzene content in California gasoline. *Id.* at pp. 39-40 (Exhibit No. WAP-228 at pp. 2-3). It points out that ANS Naphtha happens to be rich in both benzene and aromatic hydrocarbons. *Id.* at p. 40 (citing Exhibit No. WAP-278 at p. 6). The net result of these changes is that less reformate can be blended into the CARB gasoline pool, according to Williams, and thus less Naphtha is needed. *Id.* When compared to 1994 Naphtha throughput on an equivalent basis,[633] explains Williams, Naphtha demand on the West Coast has declined by approximately 23,000 barrels/day. *Id.* Even more revealing, notes Williams, is the fact that during this same time period, reforming capacity decreased by about 64,000 barrels/day. *Id.* (citing Transcript at p. 11028). Were Naphtha prices what O'Brien and Tallett claim they should be, Williams asserts, it is inconceivable that reforming capacity would have decreased and Naphtha throughput would have declined. *Id.* at pp. 40-41. Even with the decreased reforming capacity, Williams points out that reformer utilization still is not 90%.[634] *Id.* at p. 41. In contrast, continues Williams, Exhibit No. WAP-226 shows that both capacity and throughput have increased for VGO during the same time period, thereby demonstrating the increased importance of VGO in the manufacture of CARB gasoline and the decreased importance of Naphtha in making it. *Id.*

1750. Williams suggests, therefore, that the Gulf Coast Naphtha price, and particularly the Platts Gulf Coast Heavy Naphtha (waterborne) price, is representative of the price of Naphtha on the West Coast in that it clearly does not undervalue West Coast Naphtha. *Id.* at pp. 43-44. It asserts that there is no evidence in this record that shows any changed circumstances which have altered the relationship of Naphtha on the two coasts such that the use of the Gulf Coast Naphtha price is no longer just and reasonable. *Id.* at p. 44.

1751. Phillips wrongly states that Sanderson provided no quantification of the loss of value of Naphtha because of the CARB requirements, Williams argues. Williams Reply Brief at p. 41. It asserts that Sanderson did state that he believed the reduction to be 1.3¢/gallon, and that such a reduction in value is to be expected because of CARB

[633] Williams explains that the term "equivalent basis" means dividing the actual throughput each year by the reforming capacity that existed in 1994. Williams Initial Brief at p. 40, n.29.

[634] Williams explains that, with the introduction of CARB gasoline in 1996, reformer utilization in California dropped significantly to 66%. Williams Initial Brief at p. 41, n.30.

requirements resulting in restricted cut points for straight-run Naphtha which reduces the volume of it processed through the reformer resulting in a reduction in the value of reformate made from straight-run Naphtha. *Id.*

1752. Exxon isolates data from Exhibit No. EMT-382, Williams claims, to try to distort what the Exhibit shows in an attempt to bolster Tallett's calculated high Naphtha value. *Id.* It notes that Exxon asserts that a study of refining options available to California refineries done by Sanderson's firm, Purvin & Gertz, showed that a refinery on the West Coast making 100% CARB gasoline would be expected to use a higher percentage of reformate in its gasoline pool than a refinery on the Gulf Coast producing 100% reformulated gasoline. *Id.* Williams states that Exxon claims that this study squarely contradicts Sanderson's claim that Naphtha has lost value on the West Coast due to the requirements for producing CARB gasoline. *Id.* at pp. 41-42. In fact, according to Williams, Exhibit No. EMT-382 shows the lower contribution of straight-run reforming Naphtha (Quality Bank Naphtha) on the West Coast consistent with Sanderson's testimony that the CARB gasoline regulations have reduced the volumetric contribution of Quality Bank Naphtha. *Id.* at p. 42. Williams asserts that the volumetric comparison that is relevant to the valuation of Quality Bank Naphtha is the relative volumetric contribution of straight-run Naphtha produced from crude oil on the two coasts. *Id.*

1753. In addition, Williams notes, Phillips and Exxon try to rely on testimony from Sorenson to indicate that CARB gasoline has no effect on West Coast refineries because, as Exxon claims, "Sorenson made clear, the benzene reduction equipment already in place will be able to handle the new CARB standards." *Id.* at pp. 42-43. While that may address handling benzene at one refinery, Williams asserts, Exxon's and Phillips's statements and Sorenson's testimony do not address the fact that the volume of straight-run Naphtha that is run through reformer is reduced due to the change in cut points of the Naphtha cut. *Id.* at pp. 43-44. In addition, it states that they do not address other refineries, particularly those that run more ANS than the Phillips Los Angeles refinery. *Id.* at p. 44. Williams argues that there is no record support for the industry as a whole because Sorenson had no knowledge of any other refineries with respect to handling benzene and aromatics; nor did he know if they installed their environmental equipment on a 100% ANS basis. *Id.*

1754. Williams notes that, even at the Phillips Los Angeles refinery, Sorenson testified that "[t]o give ourselves flexibility, we have undercut the naphtha to the reformer and we blend back heavy material into the back end of gasoline." *Id.* (citing Transcript at p. 13254). It points out that this is for a refinery that in 1997 ran no ANS and now is only sometimes running 20–30,000 barrels/day of ANS. *Id.* (citing Transcript at pp. 13250-51). According to Williams, this represents only up to 15-23% of that refinery's crude slate. *Id.* Thus, since this refinery runs so little ANS, Williams asserts, its data, and therefore Sorenson's testimony, are not reflective of, and thus irrelevant to, a refinery running 100% ANS. *Id.*

1755. In addition, Williams argues, Exxon erroneously states that the shift to CARB III specifications will increase the maximum amount of aromatics allowed from 30% to 35% and make Naphtha more valuable. *Id.* at p. 45. It asserts that Exxon did not take into account that the benzene standard is being lowered from 1.2% to 0.8%. *Id.* Sorenson, Williams claims, testified that, had he altered the CARB II gasoline specification and used the lower benzene level for CARB III gasoline instead, the result would have been a higher percentage of the reformate being processed through the benzene saturation unit. *Id.* It believes that it is obvious that Exxon also forgot that ANS has a very high level of benzene and benzene precursors which also impacts negatively the ANS Naphtha ability to be processed through a reformer. *Id.*

1756. Contrary to the statements of Exxon and Phillips concerning his transportation differential analysis, Williams asserts, Sanderson's testimony that the Gulf Coast Heavy Naphtha quote is a just and reasonable valuation for West Coast Naphtha is supported by his transportation analysis in two key areas. Williams Reply Brief at pp. 37-38. First, Williams states, Sanderson uses his analysis of the relative costs of transporting Naphtha to the Gulf Coast from the Caribbean and to the West Coast from the Caribbean to test the reasonableness of the West Coast Naphtha valuation proposals. *Id.* at p. 38. It contends that the proposals of Tallett and O'Brien clearly fail this test as, during periods of extreme gasoline supply shortfalls and high gasoline prices which these proposals attribute to their Naphtha values, no measurable increase in Naphtha imports was observed. *Id.* Additionally, they state that Sanderson uses his analysis of crude oil transportation costs to illustrate the mechanism by which prices for crude oils of similar qualities on the two coasts have equalized. *Id.* at pp. 38-39.

1757. Williams argues that Exxon's argument that it costs 16¢/barrel more to ship Arabian Light crude oil to the West Coast than it does to ship it to the Gulf Coast ignores the key fact that 16¢/barrel or 0.4¢/gallon is de minimis with respect to the Gulf Coast and West Coast refiner's total cost of crude. *Id.* at p. 39. It notes that Sanderson testified that the transportation calculated by Turner Mason and published by Platts is unreliable. *Id.*

1758. Exxon's argument that Sanderson's analysis was deficient because he did not study all of the crude oils on the Gulf Coast and West Coast, Williams insists, is without merit. *Id.* at p. 40. It explains that Sanderson testified that the prices of different quality crudes even on the same coast would be different, and that the important consideration from a crude oil price perspective is that crude oils of similar quality are similarly priced on the two coasts. *Id.* at pp. 40-41. Furthermore, Williams argues that the question of whether crude oil suppliers from the Middle East can divert supplies sold to one coast to the other once a sale has been made to one coast or the other has no relevance to the relationship of crude oil prices on the two coasts. *Id.* at p. 41.

1759. Williams notes that Phillips argues that the fact that Williams makes significant sales of Naphtha to the West Coast and the Far East proves that use of the Gulf Coast price substantially undervalues West Coast Naphtha. *Id.* at p. 46. It explains that Phillips refers to this as an example of Williams's "arbitrage" of the difference between the Gulf and West Coast values of Naphtha. *Id.* Williams asserts that Phillips's statement and argument represent a blatant disregard for and misstatement of the record evidence. *Id.* First, Williams claims, the Naphtha sold is Full Range Naphtha, not Quality Bank Naphtha. *Id.* It notes that Sanderson testified that it is the fact that Williams's Naphtha is made up of between 23% and 35% LSR that enables Williams to make the Naphtha sale. *Id.* According to Williams, it is the low West Coast LSR price and not the use of the Gulf Coast Naphtha price that makes the sales possible. *Id.* at p. 47. Therefore, and contrary to Phillips's statement, Williams maintains these sales do not mean that the Quality Bank West Coast Naphtha price is too low. *Id.*

5. Unocal/OXY

1760. Unocal/OXY submit that, not only has the existing method not been shown to be unjust and unreasonable, but the evidence submitted by Unocal/OXY, Petro Star and Williams proves that continued use of Gulf Coast prices to value West Coast Naphtha is just and reasonable. Unocal/OXY Initial Brief at pp. 4-5. Moreover, continue Unocal/OXY, the proponents of change have not demonstrated that their respective proposals are just and reasonable. *Id.* at p. 5. Further, they note that the proponents of change have not satisfied their burden of showing changed circumstances. Unocal/OXY Reply Brief at p. 16.

1761. The parties opposing the continued use of Gulf Coast pricing to value West Coast Naphtha, Unocal/OXY claim, have cited the following evidence of changed circumstances: (a) abandonment of the "no adjustment" policy, (b) significant disparity between Gulf Coat prices and West Coast Naphtha value, (c) disappearance of ANS shipments to the Gulf Coast, (d) the impact of the CARB requirements and the run-up in gasoline prices beginning in 1999, and (e) the change in the way West Coast VGO is valued. *Id.* at pp. 16-17.

1762. The 1993 abandonment of the Commission's no adjustment policy does not constitute a changed circumstance that precludes continued use of a Gulf Coast price to value West Coast Naphtha, according to them. *Id.* at p. 17. They point out that, in addition to the no adjustment policy, the basis for the 1993 ruling also rested on the "single market pricing" policy, which requires that the published prices in one market be used to value products in both markets if there are no published prices in one of the markets.[635] *Id.* Unocal/OXY assert that this policy remains part of the Quality Bank

[635] Unocal/OXY cite *Trans Alaska Pipeline System*, 65 FERC at p. 62,289; *Trans Alaska Pipeline System*, 66 FERC at p. 61,418, in support.

Tariff and that no party has requested that it be changed. *Id.* at p. 18. They contend that the policy could potentially apply to all cuts in the Quality Bank, and that it is merely a coincidence that only the Naphtha cut meets the criteria of having a published price in only one market at this time. *Id.*

1763. Unocal/OXY contend that the proponents of change have not shown that there is any changed circumstance or new evidence respecting the single market pricing policy. *Id.* They note that the policy was adopted when there was a price quote for Naphtha in only one of two markets and that this situation has not changed. *Id.* Further, they explain that when the policy was adopted, there were separate price series for most intermediate and finished products on the two Coasts, and that has not changed either. *Id.*

1764. All arguments regarding the alleged disparity between West Coast Naphtha value and the Gulf Coast Naphtha price are based on guess work, supposition, or subjective judgments, according to Unocal/OXY. *Id.* at p. 19. They state that there is no hard evidence that West Coast Naphtha's market value is higher than that on the Gulf Coast, because there is no West Coast market price. *Id.* Further, they disagree with Exxon, Phillips and Alaska that the contracts presented here provide evidence of Naphtha's value. *Id.* Unocal/OXY believe that the evidence is anecdotal at best and certainly does not establish a West Coast Naphtha market value. *Id.* Finally, they assert that the contract evidence does not establish that a changed condition exists. *Id.*

1765. Unocal/OXY concede that ANS deliveries to the Gulf Coast, which were small in 1993, have virtually disappeared. *Id.* at p. 21. However, they assert that this is not by itself enough to change the existing Naphtha valuation if the use of Gulf Coast prices does not undervalue West Coast Naphtha. *Id.* According to them, when the Commission prescribed the use of single market pricing for Naphtha, Gulf Coast deliveries of ANS constituted somewhat less than 20% of deliveries. *Id.* (citing *Tesoro*, 234 F.3d at 1292). They argue that, if the use of Gulf Coast prices produced a just and reasonable value when 80% of the Naphtha cut was delivered to the West Coast and only 20% went to the Gulf Coast, then the use of Gulf Coast prices should still be just and reasonable when 100% of the cut is delivered to the West Coast. *Id.* Gulf Coast prices do not undervalue West Coast Naphtha, Unocal/OXY assert, and, therefore, the reduction in Gulf Coast deliveries does not constitute a significant change. *Id.*

1766. Ross, according to Unocal/OXY, suggests that the agreement of the parties to change the basis for valuing VGO from using Gulf Coast prices to using West Coast prices published by OPIS is a changed circumstance requiring a new Naphtha valuation. *Id.* at p. 22. They explain that Ross's rationale is that both Naphtha and VGO are closely related because of their role in the manufacture of gasoline, and that they should therefore be valued "on a consistent basis." *Id.* However, Unocal/OXY state that this is not a substantial enough change to call into question the current basis for valuing Naphtha. *Id.* They point out that there is no West Coast Naphtha price published by OPIS that could be used to put Naphtha and VGO on a consistent basis. *Id.* If a West Coast value is adopted based on either of the formulae sponsored by O'Brien or Tallett, they note, even then, if Ross's governor were also adopted, Naphtha and VGO will not be on any more of a consistent pricing basis than they would be if no change were made. *Id.* Unocal/OXY state that, in that case, Naphtha would be valued based on a formula with numerous data inputs; VGO would be valued based on a single, unadjusted published price. *Id.* By contrast, they point out that if no change to Naphtha is made, then both will be valued based on unadjusted, published prices. *Id.* Thus, Unocal/OXY believe that the "consistent basis" argument would seem to favor retention of the current pricing. *Id.*

1767. Unocal/OXY claim that the record reflects that Exxon, Phillips, and BP have all conceded that there have been no changed circumstances that would undermine the basis for the Commission's single market pricing policy adopted in 1993. *Id.* at pp. 22-23. They state that Tallett admitted in sworn testimony filed with the Commission as recently as 2000 that he had supported single market pricing and the use of Gulf Coast prices to value West Coast products in the Quality Bank, and that nothing specifically had changed since that time. *Id.* at p. 23. Tallett, they further claim, testified that "there is no evidence that 'changed circumstances' have undermined Naphtha’s value on the West Coast." *Id.* (citing Exhibit No. EMT-133 at p. 35).

1768. Further, Unocal/OXY point out, O'Brien testified that there had been no changes that would affect the Commission's decision to use single market pricing for Naphtha: "I testified that there have been no material changes in the West Coast or Gulf Coast Naphtha markets since the time the Commission held that all Naphtha should be valued based on the Gulf Coast price. That continues to be the case today." *Id.* (citing Exhibit No. PAI-33 at p. 6). Finally, they note that Ross testified that, while there had been changes that altered the relationship between Gulf Coast gasoline and West Coast gasoline, these changes did not affect the Naphtha relationship on the two coasts. *Id.* (citing Exhibit No. BPX-27 at pp. 10-11).

1769. Unocal/OXY point out that, because there is no published West Coast price for Naphtha, in trying to derive a value for West Coast Naphtha, no party's proposal can be proven to represent the true price of Naphtha on the West Coast. Unocal/OXY Initial Brief at p. 5. Significantly, according to Unocal/OXY, without proof of the actual value of Naphtha on the West Coast, it is difficult to conclude that the continued use of Gulf Coast prices to value this cut is no longer just and reasonable. *Id.* They assert that, even after an extended hearing, no empirical evidence has been adduced as to the actual price of Naphtha on the West Coast. *Id.* According to Unocal/OXY, while the Naphtha sales contracts come closest to providing such evidence, they are a sparse and imperfect sample. *Id.* And while the contracts may provide evidence of value as between the parties involved in the transaction, Unocal/OXY argue, they do not provide evidence of the actual West Coast market value of Naphtha. *Id.* Therefore, assert Unocal/OXY, whatever conclusions are made on this record respecting the value of West Coast Naphtha, the continued justness and reasonableness of the existing use of Gulf Coast prices must rest instead on the subjective opinion of the expert witnesses who testified on this issue. *Id.* at pp. 5-6. Unocal/OXY's position is that these opinions fail to demonstrate that the West Coast value of Naphtha is higher than the Gulf Coast value of Naphtha over any sustained period of time in any significant amount. *Id.* at p. 6.

1770. According to Unocal/OXY, the current method of valuing West Coast Naphtha is the only method that is completely objective and not subject to manipulation or distortion, a primary concern of the Commission when it adopted the current method. *Id.* (citing *Trans Alaska Pipeline System,* 65 FERC at p. 62,289). While Ross asserts that a separate West Coast price is required because all of the other cuts will have a separate West Coast price, Unocal/OXY maintain, that is not reason enough to require a change in the current method, absent evidence that the existing Gulf Coast price undervalues West Coast Naphtha. *Id.* Unocal/OXY state that the evidence submitted at trial, taken as a whole, does not prove that West Coast Naphtha is undervalued by the use of Gulf Coast prices. *Id.* (citing Exhibit Nos. UNO-7 at p. 2, WAP-33 at p. 2).

1771. In Exhibit No. UNO-1, note Unocal/OXY, Culberson uses EIA shipping data to show that there are very few imports of Naphtha into the West Coast, while there are very substantial imports into the Gulf Coast. *Id.* Unocal/OXY explain that he reasoned that, were Naphtha valued higher on the West Coast than it is on the Gulf Coast, then there would be shipments of Naphtha into the West Coast from the same origins that currently make shipments into the Gulf Coast. *Id.* at pp. 6-7. Further, note Unocal/OXY, his reasoning is based on the linkage between geographically separated markets provided by the global trade in petroleum products. *Id.* at p. 7.

1772. Unocal/OXY explain that data on Naphtha imports, and imports of other refined products, are collected by the EIA and made available in public reports. *Id.* They note that Naphtha used for refining is reported under two categories, "Petrochemical Naphtha" and "Unfinished Oils," the latter of which includes other feedstocks as well as Naphtha. *Id.* Over the past three years, according to Unocal/OXY, the Gulf Coast has imported over 85,000 barrels/day of Petrochemical Naphtha and 220,000 barrels/day of Unfinished Oils. *Id.* By contrast, Unocal/OXY point out, the West Coast has imported only about 1,000 barrels/day of Petrochemical Naphtha and 29,000 barrels/day of Unfinished Oils. *Id.* When the 29,000 barrels/day of Unfinished Oils is broken down to the category of "Naphtha and lighter," explain Unocal/OXY, the data show only a few import shipments each year: five in 1996, six in 1997, one per year in 1998, 2000, and 2001, and none in 1999. *Id.* According to Unocal/OXY, these data, showing that there are no West Coast Naphtha imports in most months, affirm Culberson's testimony that West Coast refineries import very little Naphtha. *Id.*

1773. The origin of the Naphtha which is shipped to the Gulf Coast includes the Far East and sources on the western side of South America, according to Unocal/OXY. *Id.* at p. 8. For these origins, they allege, it would be cheaper to deliver the cargo to the West Coast than to land it on the Gulf Coast, yet the Naphtha from these origins bypasses the West Coast, transits the Panama Canal, and lands on the Gulf Coast. *Id.* This is significant, in Unocal/OXY's view, because, they believe, if Naphtha had a higher value on the West Coast than on the East Coast, that higher price would attract imports from the same Far Eastern and South American origins that ship to the Gulf Coast. *Id.* Unocal/OXY point out that Caribbean origins and eastern South America are the major source for Naphtha imported to the Gulf Coast, and the additional cost to export to the West Coast, as compared to exporting to the Gulf Coast, is quite low. *Id.* Therefore, state Unocal/OXY, Culberson concludes that the absence of imports of Naphtha into the West Coast market indicates that there is not a higher West Coast Naphtha price over a sustained period of time. *Id.* Unocal/OXY note that both Ross and Tallett agree with the essential elements of this reasoning. *Id.* at p. 9. Because all the world's regions are connected by transport, Unocal/OXY state, the price of products in one region will not exceed for long the cost of imports from others. *Id.* (citing Exhibit No. BPX-27 at p. 14).

1774. Unocal/OXY note that Ross's view differs from Culberson's only with respect to how far below the cost of imports the West Coast Naphtha value may be. *Id.* They point out that Ross assumed that the West Coast value exceeds the Gulf Coast value by some amount that is not enough to induce imports and bases his governor on the cost of shipping Naphtha to the West Coast from Venezuelan ports using a shipping rate that is more than twice the rate used by Culberson. *Id.* at pp. 9-10. However, according to Unocal/OXY, Ross's use of Venezuela as the origin in his model causes the shipping rates to be too high and his governor, therefore, may be based on the faulty premise that Far East product does not act as a disciplinary force on the value of Naphtha on the West Coast. *Id.* at pp. 10-11.

1775. According to them, they also disagree with Phillips's and Exxon's criticism of the transportation costs developed by Culberson and Sanderson. Unocal/OXY Reply Brief at p. 53. They assert that Phillips and Exxon fail to understand that Culberson was only attempting to calculate the relative transportation cost difference to land a cargo on the West Coast as opposed to the Gulf Coast from the same point of origin. *Id.* For that reason, they note, his analysis was not an attempt to calculate exact shipping costs as part of a recommendation on how to value Naphtha. *Id.* at pp. 53-54. They explain that Culberson believed that "Naphtha on the high seas originating in the Pacific could be shipped more cheaply to the West Coast than to the Gulf Coast, and could be diverted to the Gulf Coast or West Coast, respectively, if prices dictate." *Id.* at p. 54. Unocal/OXY state that Culberson then tried to calculate the marginal cost to divert these shipments to the West Coast in order to respond to higher West Coast prices. *Id.*

1776. The lack of West Coast imports, Unocal/OXY argue, cannot be explained away by the fact that Naphtha demand at West Coast refineries is satisfied by internally generated Naphtha. Unocal/OXY Initial Brief at p. 11. They explain that, if Naphtha on the West Coast were in fact valued substantially higher than Gulf Coast Naphtha, refiners would choose to import the cheaper Naphtha rather than generate it internally. *Id.* Refiners use sophisticated computer programs to optimize their operations, according to Unocal/OXY. *Id.* Further, they continue, refiners generally have between 30% and 50% of their feedstock purchases available for spot purchases. *Id.* at pp. 11-12. This, according to Unocal/OXY, gives them the ability to constantly reassess their operations to take advantage of cost savings and marketing opportunities, including the availability of cheaper imported Naphtha. *Id.* at p. 12.

1777. The lead time needed to make the "make-or-buy" decision, Unocal/OXY claim, is typically only approximately three weeks and could be as short as several days for a cargo that is already in transit. *Id.* They further point out that a refinery could also reduce its need for Naphtha by increasing output from the cat cracker, which produces gasoline precursors from VGO, a change that would require very little lead time. *Id.* Therefore, maintain Unocal/OXY, Tallett's insistence that the balance between demand and supply on the West Coast explains the absence of imports does not address the operational flexibility and profit maximization that characterize refinery operations. *Id.* Not only does the ability to adjust crude slates explain why refiner self sufficiency does not prevent imports, Unocal/OXY state, it also explains why Naphtha has the same value to refiners on both coasts. *Id.* at p. 13.

1778. Unocal/OXY note that Ross was questioned concerning the Naphtha import issue, and particularly about where the additional demand or "room" for West Coast Naphtha would come from if refiners already satisfy their demand from their own crude oil. Unocal/OXY Reply Brief at p. 63. They state that Ross acknowledged that, as Culberson described, refiners can adjust their crude slate to purchase crude oils that produce less Naphtha and thereby make room for additional supplies, and note that, even in the short run, "room" would be made by substituting cheaper imported Naphtha for the volumes of Naphtha currently being purchased locally, as evidenced by the contracts. *Id.* at p. 64. They continue to explain that this, in turn, would cause local suppliers to drop their prices to try to recapture market share, and they would keep prices low after recapture due to the discipline of potential imports. *Id.*

1779. For the longer term, according to Unocal/OXY, the cheap Naphtha would force refiners to make the kinds of make-or-buy reassessments described by Culberson, using their computer models. *Id.* They claim that the refiners would either use the cheaper Naphtha to increase their gasoline production, and thereby drive out existing gasoline imports, or they would substitute cheaper crude oils that produce less Naphtha, and increase their profit margins. *Id.* Unocal/OXY state that Ross concluded that "the fact that the West Coast naphtha market is physically in supply and demand balance" does not prevent imports, or stop them from having an effect on price, and that the West Coast market is an opaque market, which has not reached an efficient equilibrium between supply and demand. *Id.* (quoting Transcript at p. 9988).

1780. Unocal/OXY assert that there are no barriers to entry that would explain the almost complete absence of any significant amount of Naphtha imports to the West Coast. Unocal/OXY Initial Brief at p. 13. They maintain that import data show an occasional shipment of Naphtha to the West Coast from Caribbean origins, western South America, and the Far East, which demonstrates the possibility of Naphtha imports from these sources. *Id.* More importantly, according to Unocal/OXY, the import evidence for other refined products contrasts sharply with the evidence for Naphtha. *Id.* at p. 14. In support, Unocal/OXY cites record evidence of the flow of gasoline, gasoline blend stocks, jet fuel and VGO into the West Coast from the Gulf Coast when the price of West Coast gasoline spikes which they assert has the effect of moderating the rise in gasoline prices on the West Coast. *Id.* at pp. 14-15.

1781. According to Unocal/OXY, this flow of gasoline and gasoline blend stocks tends to prove the point that Gulf Coast prices will discipline West Coast prices, even in a less than fully competitive gasoline market. *Id.* at p. 14. The flow of jet fuel and VGO is important to Naphtha values, according to Unocal/OXY, for three reasons. *Id.* at p. 15. First, state Unocal/OXY, it illustrates the phenomenon of market linkage described by Culberson. *Id.* Second, continue Unocal/OXY, it identifies that the Far East is a low cost source of supply for refined products destined for the West Coast. *Id.* Third, explain Unocal/OXY, it illustrates that market entry barriers would not impede Naphtha imports if there were a sufficient price differential to attract imports from the Caribbean. *Id.* With respect to the issue of entry barriers for Naphtha imports, Unocal/OXY note that jet fuel shipments use the same kind of "clean" tankers which are used for Naphtha and that the evidence shows that the West Coast infrastructure can handle imports of Naphtha. *Id.* (citing Transcript at pp. 8612, 8616; Exhibit No. BPX-79).

1782. Contrary to the claims of Exxon and Phillips, Unocal/OXY argue that the existence of separate West Coast and Gulf Coast pricing series for virtually all refined products other than Naphtha does not indicate that it is no longer just and reasonable to continue using Gulf Coast prices for West Coast Naphtha. *Id.* at p. 16. Unocal/OXY explains that separate pricing is not a new development and that there were different West Coast and Gulf Coast price series for refined products at the time the Commission adopted the Gulf Coast price to value West Coast Naphtha. *Id.* Accordingly, they suggest, this argument does not establish a basis for changing the Commission's prior ruling. *Id.*

1783. Unocal/OXY also assert that the existence of different price series does not prove that Gulf Coast prices undervalue West Coast Naphtha. *Id.* They claim that the prices used by Exxon and Phillips are selective, leave out some products, and, even for the products that are selected, do not show that West Coast prices are always higher. *Id.* at pp. 16-17. For example, Unocal/OXY point out that West Coast prices for N-butane and LSR are generally lower, and lower on average, than Gulf Coast prices. *Id.* at p. 17 (citing Exhibit No. EMT-14). Further, the West Coast/Gulf Coast differential for VGO is close to zero, indicating little variation on average for VGO between the two coasts. *Id.* (citing Exhibit No. PAI-56 at p. 3).

1784. A more complete depiction of price series for various products, according to Unocal/OXY, clearly shows that finished products such as gasoline, jet fuel, and diesel consistently have higher West Coast prices, but that intermediate products such as high and low sulfur VGO, and light cycle oil do not. *Id.* at pp. 17-18 (citing Exhibit No. BPX-162). Further, claim Unocal/OXY, Naphtha is considered an intermediate product and should display the same price behavior as VGO and LSR. *Id.* at p. 18 (citing Transcript at pp. 9682-83; Exhibit No. UNO-7 at p. 7). Finally, according to Unocal/OXY, the margins for intermediate products are the same on both coasts. *Id.*

1785. Unocal/OXY also take exception to criticism suggesting that Culberson claimed that the Gulf Coast Naphtha price is equal to the West Coast Naphtha price. *Id.* They assert Culberson's did not so testify; that his testimony was that there might be day to day variations between the two, but that over time average Gulf Coast prices would not undervalue West Coast Naphtha. *Id.* at pp. 18-19 (citing Exhibit No. UNO-7 at p. 5).

1786. The high West Coast/Gulf Coast price differentials for finished products, according to Unocal/OXY, are an indication that the West Coast market for finished products is markedly different than the Gulf Coast market for finished products. *Id.* at p. 20. They claim that the West Coast finished product market also behaves differently than the market for intermediate products, in their view. *Id.*

1787. Unocal/OXY contend that the West Coast gasoline market is not workably competitive because it is dominated by California where competition is constrained. *Id.* at p. 20 (citing Exhibit No. UNO-7 at p. 6). They point out that this constraint is caused by the CARB gasoline requirements which are not required in other markets, geographical isolation of the market, barriers to entry by new refiners and to expansion of existing refining facilities, and dominance of the market by a small number of large producers. *Id.* Unocal/OXY state that these factors have caused the price of gasoline in California, particularly in recent years, to exceed the prices in all other parts of the country by a substantial difference. *Id.* at pp. 20-22 (citing Exhibit Nos. WAP-199, EMT-489).

1788. In contrast to the West Coast market, Unocal/OXY point out that the Gulf Coast market is large, diverse and highly competitive, containing 30% of U.S. petroleum refining capacity and 75% of the petrochemical capacity. *Id.* at p. 22 (citing Exhibit No. UNO-1 at p. 7). Unocal/OXY explain that the Gulf Coast does not have the CARB gasoline restrictions, high taxes, or the environmental and permitting restrictions for new construction that apply in California. *Id.* An important feature of the Gulf Coast market, according to Unocal/OXY, is the petrochemical industry, which creates a demand for Naphtha that supplements the refinery demand. *Id.* (citing Exhibit Nos. PAI-33 at p. 4, BPX-8 at p. 3). Unocal/OXY state that the petrochemical demand, existence of Naphtha imports, and a significant Naphtha trade create a price support for Naphtha on the Gulf Coast that is absent from the West Coast. *Id.* (citing Exhibit Nos. BPX-67 at p. 31, PAI-33 at p. 4). They assert that the existence of the petrochemical demand for Naphtha on the Gulf Coast leads to the conclusion that Gulf Coast Naphtha may have a higher value than West Coast Naphtha. *Id.* at pp. 22-23 (citing Exhibit Nos. UNO-1 at p. 14, WAP-33 at p. 10, BPX-27 at p. 29).

1789. Unocal/OXY disagree with the position of Exxon and Phillips that the differences between the Gulf Coast and the West Coast markets require that different prices be used to value intermediate products, such as Naphtha, in each market. *Id.* at p. 23. As noted previously, they state that the price series for intermediate products tend to show either rough price equivalence between the two markets or that Gulf Coast prices are higher. *Id.* at pp. 23-24 (citing Exhibit Nos. EMT-94, EMT-480, EMT-93, EMT-429 at p. 3, EMT-453, UNO-62, BPX-27 at p. 10). Thus, claim Unocal/OXY, not only do LSR and VGO prices not follow gasoline trends in terms of West Coast/Gulf Coast differentials, they sometimes move in the opposite direction. *Id.* at p. 24.

1790. These price relationships, Unocal/OXY contend, answer a major argument of the opponents of single market pricing that market linkage and imports do not sufficiently discipline prices to justify the continued use of single market pricing. *Id.* (citing Exhibit Nos. EMT-76 at p. 11, EMT-84 at pp. 24, 29, 38-39). Unocal/OXY assert that this argument is easily answered and explain that market constraints cause the prices of finished products such as gasoline and jet fuel to remain high notwithstanding substantial imports, because supply is constrained and demand is high and growing. *Id.* Because that market is not workably competitive, continue Unocal/OXY, end refiners are taking advantage of that fact to hold prices high and increase their margins. *Id.*

1791. Unocal/OXY concede, however, that there is no evidence that the market for intermediate products is similarly constrained or not workably competitive. *Id.* at pp. 24-25. Nonetheless, Unocal/OXY maintain, upon closer examination, the argument falls apart. *Id.* at p. 25. They point out that VGO prices were higher on the West Coast for only a brief period, 1999-2002, and that prior to 1999 they were lower and have returned to that "pattern" starting in 2003. *Id.* Furthermore, according to Unocal/OXY, 1999-2002 was an anomalous period in the California gas market because of stringent air quality controls on gasoline, the spiking of natural gas prices in 2000-2001, manipulation of electric energy markets causing electricity prices to reach unprecedented levels, and several long and significant outages at California refineries. *Id.* (citing Exhibit Nos. UNO-7 at pp. 10-12, BPX-27 at p. 11, BPX -37).

1792. These conditions, Unocal/OXY assert, not only caused large increases in gasoline prices over this period, but they also caused the price of VGO to increase. *Id.* At the same time, according to them, the same conditions that caused gasoline and VGO prices to go up would cause the value of Naphtha to decrease. This, explain Unocal/OXY, is because the demand for reformate, and hence the demand for Naphtha, went down as a result of the constraints. *Id.* at pp. 25-26 (citing Exhibit No. BPX-27 at p. 12).

1793. Unocal/OXY note that Phillips and Exxon assert that California refiners have installed treatment equipment to remove benzene precursors from reformer feed, and that the higher prices that CARB gasoline commands have allowed them to recover the cost of these capital improvements. Unocal/OXY Reply Brief at pp. 67-68. This argument, according to them, fails to consider the evidence produced by Sanderson that, since the introduction of CARB requirements in 1996, Naphtha demand on the West Coast has declined, and reforming capacity has decreased by some 64,000 barrels/day. *Id.* at p. 68. They argue that if Naphtha were important in the production of CARB gasoline, then reformer capacity would not have declined. *Id.*

1794. In reply to arguments that CARB gasoline requirements are a changed circumstance, Unocal/OXY concede that it is true, but assert that the result was a decrease in value for Naphtha, and hence does not constitute new evidence that would call into question the Commission's prior rulings on Naphtha. Unocal/OXY Reply Brief at p. 20.

1795. Unocal/OXY explain that there are two competing views concerning how to value Naphtha. Unocal/OXY Initial Brief at p. 26. One view, state Unocal/OXY, is that its value is linked to the value of the end product, gasoline; because Naphtha's primary use on the West Coast is to make gasoline. *Id.* The other view, according to Unocal/OXY, is that Naphtha's value is best measured by determining its costs to produce it from crude oil. *Id.* The first view, espoused by Exxon and Phillips, results in a higher value for Naphtha on the West Coast, note Unocal/OXY. *Id.* (citing Exhibit Nos. EMT-11 at pp. 16-17, EMT-84 at pp. 13, 22, PAI-33 at p. 8). The second view, espoused by Unocal/OXY, results in Naphtha being valued the same on the West Coast as it is on the Gulf Coast, because crude oil costs are the same on both coasts and the cost of extracting Naphtha is the same. *Id.* (citing Exhibit No. WAP-1 at p. 10).

1796. According to Unocal/OXY, the second view is the logical choice because Naphtha itself is an intermediate product used to manufacture gasoline and not an end product, and, therefore, a refiner would regard Naphtha as a cost item like other feedstocks or blendstocks. *Id.* at pp. 26-27. Naphtha and other feedstocks are valuable because refiners can turn them into gasoline; but starting with the price of gasoline and working backward to derive a value for a feedstock is, in Unocal/OXY's view, a very subjective way to attempt to set a value. *Id.* at p. 27. In fact, state Unocal/OXY, a value set in this manner is going to differ depending on who is deriving the value, whereas starting with the cost of crude oil and adding the costs to extract the Naphtha is more objective. *Id.*

1797. Unocal/OXY note that several exhibits purport to show, in graphical form, the relationship between crude, Naphtha, and unleaded regular gasoline for both the Gulf and West Coasts. *Id.* (citing Exhibit Nos. EMT-476, EMT-536, EMT-541). Because Naphtha is processed from crude oil, and then used to manufacture gasoline, Unocal/OXY explain, it is not surprising that its price line falls between the crude oil and gasoline price lines. *Id.* They note that the question is whether the price line for Naphtha on the West Coast should be closer to crude oil or closer to gasoline. *Id.* Unocal/OXY point out that Exhibit No. EMT-536 places the Naphtha line close to the crude line, while Exhibit No. EMT-541 pushes the West Coast Naphtha line up close to the unleaded regular gasoline line. *Id.*

1798. Exhibit No. EMT-536 provides the correct representation, declare Unocal/OXY. *Id.* They assert that, as in Exhibit Nos. EMT-568 and EMT-569, which compare crude, VGO, and unleaded regular gasoline for the West Coast and Gulf Coast, respectively, there should be no major differences between Exhibit Nos. EMT-476 and EMT-536, except for the unleaded regular gasoline line. *Id.* at pp. 27-28. Unocal/OXY explain that the West Coast crude-Naphtha-unleaded regular gasoline graph would look much like the VGO graphs, except the Naphtha line would be farther above the crude line than the VGO line is because it costs more to process Naphtha from crude than VGO. *Id.* at p. 28 (citing Transcript at pp. 12051-52). According to Unocal/OXY, the main difference between Exhibit Nos. EMT-568 (West Coast VGO) and EMT-576 (West Coast Naphtha) is that the West Coast price of VGO did rise in the anomalous period (after 1999) due to refinery upsets constraining the supply of VGO. *Id.*

1799. Conversely, Unocal/OXY argue that Exhibit No. EMT-541 (a Tallett graph) is not an accurate representation. *Id.* In Unocal/OXY's view, it pushes the Naphtha price much too close to the unleaded regular gasoline price, transferring value or margin that belongs to the finished product to Naphtha, and thereby overvaluing Naphtha. *Id.* In addition, Unocal/OXY point out that, if Naphtha were actually priced that high, it would be priced above the cost of imports, and "refiners would have switched their crude oil slate and imported naphtha." *Id.* (quoting Transcript at p. 12057).

1800. On both the Naphtha and VGO sets of graphs, Unocal/OXY note, the West Coast unleaded regular gasoline line is much higher above the crude line than it is on the Gulf Coast. *Id.* According to Unocal/OXY, this means that the unleaded regular gasoline line will be higher above the Naphtha line on Exhibit No. EMT-536 than it is on Exhibit No. EMT-476. *Id.* They explain that this anomaly results from the much higher margins reflected in finished product prices, such as unleaded regular gasoline, on the West Coast, as described in the 1999 California Attorney General's Report. *Id.* at pp. 28-29 (citing Exhibit No. WAP-199).

1801. Unocal/OXY assert that the major problem with deriving a Naphtha value from the price of gasoline lies in the process of deducting the costs, including profit margin, from the price of gasoline. *Id.* at p. 29. They point out that most refiners are not anxious to reveal their profit figures and yet the 1999 Report to the California Attorney General identified very high margins on California gasoline. *Id.* (citing Exhibit No. WAP-199 at pp. 4-5, 39). Unocal/OXY note that the same report states that these margins are much higher than margins in other parts of the United States. *Id*. Further, explain Unocal/OXY, margins are assigned to the finished products and not to the intermediate products, because intermediate products are regarded as costs incurred to produce the finished product. *Id.* They state that a refiner would have no interest in raising the price of an intermediate product with a margin over cost, as he would be charging that margin to himself. *Id.* Instead, according to them, whatever margin can be earned is assigned to the finished product and passed on to the buyer. *Id.* Thus, if one were to attempt to value Naphtha starting with the price of gasoline, Unocal/OXY assert, it would be necessary to "strip these margins out of the finished product prices before intermediate product values are determined." *Id.* (citing Exhibit No. BPX-27 at p. 17).

1802. In addition, Unocal/OXY explain, even though essentially all of it is used on the West Coast to make gasoline, Naphtha is only one of several products that go into the gasoline pool, and it is blended to make reformate, which in turn accounts for only about one quarter of the West Coast gasoline pool. *Id.* (citing Exhibit No. BPX-67 at p. 5). In Unocal/OXY's view, VGO is more important in terms of its contribution to the gasoline pool. *Id.* at pp. 29-30. They note that a study done by Sanderson estimated that Naphtha contributed about 400,000 barrels/day to the West Coast gasoline pool, while VGO produced about 500,000 barrels/day, or 25% more. *Id.* at p. 30 (citing Exhibit Nos. WAP-33 at pp. 17-18, WAP-48). Further, Unocal/OXY explain, the requirements to produce CARB gasoline have imposed limits on aromatics, thereby limiting the amount of reformate in gasoline and causing the lower utilization rates for reformers that prevailed in the 1990's and a lower value for Naphtha. *Id.* (citing Exhibit No. UNO-7 at p. 15; Transcript at pp. 12060-61).

1803. The significance of these facts, according to Unocal/OXY, is that Naphtha does not appear to have been in high demand on the West Coast, based on low reformer utilization rates, at a time when West Coast gasoline prices relative to the rest of the country were at an all time high. *Id.* Compared to their Gulf Coast values, Unocal/OXY argue, West Coast Naphtha should trend with West Coast LSR and VGO, not gasoline, and should be below VGO but above LSR. *Id.* Particularly significant, in Unocal/OXY's view, is the fact that Naphtha imports did not occur when the price of California gasoline spiked in 1999 to 2001. *Id.* Imports of other refined products surged, explain Unocal/OXY, but there were still no imports of Naphtha. *Id.* Unocal/OXY assert that the absence of Naphtha imports at this time shows that the value of Naphtha is below that of import and possibly below that of Gulf Coast Naphtha as well. *Id.* at pp. 30-31. (citing

Exhibit No. UNO-1 at p. 14).

D. THE RELEVANCE OF THE WEST COAST NAPHTHA CONTRACTS

1. Exxon

1804. Exxon argues that the record demonstrates that West Coast Naphtha contracts provide the best available evidence of the actual market value of Naphtha on the West Coast in that they show how actual buyers and sellers in the marketplace have valued West Coast Naphtha. Exxon Initial Brief at p. 241. It claims that the contracts also confirm the reasonableness of the Tallett methodology and the unreasonableness of many of the other proposed methodologies, and points out that Phillips and Alaska share this view. Exxon Reply Brief at p. 247.

1805. According to Exxon, the West Coast Naphtha contracts are particularly relevant because they provide the only available direct evidence of the actual market value of Naphtha on the West Coast. Exxon Initial Brief at p. 241. It is undisputed, states Exxon, that the transactions reflected in the West Coast Naphtha contracts are arms-length purchases and sales of Naphtha between well informed, sophisticated parties, each of which had a strong business incentive to negotiate the most favorable deal possible. *Id.* at p. 242. Further, according to Exxon, all of the witnesses with economic training who testified at the hearing stated that the West Coast Naphtha contracts provide the best available evidence of the actual market value of Naphtha on the West Coast. Exxon Reply Brief at p. 247.

1806. Exxon states that the West Coast Naphtha contracts also are highly relevant because they reveal the manner in which actual buyers and sellers of Naphtha have determined the price to be paid for Naphtha on the West Coast. Exxon Initial Brief at p. 243. For example, continues Exxon, it is significant that not a single one of the nearly 300 contracts priced West Coast Naphtha on the basis of an unadjusted Gulf Coast price. *Id.* at p. 243. In contrast, notes Exxon, approximately 80% of the West Coast Naphtha contracts set the price of Naphtha based on the price of West Coast gasoline less a cost differential. *Id.* at p. 244. This strongly supports, according to Exxon, those Naphtha valuation methodologies, including the methodologies proposed by Exxon, Phillips, and Alaska, that tie the value of West Coast Naphtha to the value of gasoline on the West Coast. *Id.*

1807. Similarly, states Exxon, it is revealing that only two out of the hundreds of West Coast Naphtha contracts produced in this case set the price of West Coast Naphtha on the basis of a Gulf Coast Naphtha price plus a premium. *Id.* Moreover, Exxon notes, only one contract employed a pricing mechanism based on the Gulf Coast price that was in any way analogous to the governor or price cap proposed by BP, and that the particular price cap produced by the pricing formula in that contract was nearly double the size of the governor proposed by BP. *Id.* at pp. 244-45. Exxon concludes that, to the extent that the contract relied upon by Ross has any relevance, it shows that his proposed governor results in a Naphtha value that is much too low. *Id.* at p. 245.

1808. Further, notes Exxon, even those parties that argue that the contracts should be given no weight, at times, recognize their value and rely upon the contracts to support their positions. Exxon Reply Brief at p. 248. For example, Exxon states, Williams, which argues that the contracts are not relevant for determining the value of Naphtha on the West Coast, uses them to substantiate the Dudley valuation proposal; that the ANS + $4.00 proposal is supported by one of the contracts; that the N+A adjustment is not valid because the contracts don't have one; and that the contracts inform us about whether there is a spot market for Naphtha on the West Coast. *Id.*

1809. Unocal/OXY, which generally contend that the "the contracts do not provide reliable evidence of value," also rely on the contract data to support their contention that the Platts Gulf Coast Naphtha price, if used in conjunction with the Ross governor, would have provided reasonable results in the 1994-1998 period, according to Exxon. *Id.* And while both BP and Petro Star also generally oppose the use of the contracts, they too rely on the contracts to support particular proposals, arguing that the contracts cannot be used to evaluate the various validation proposals while using them to support the use of ANS + $4.00 proposal. *Id.* at pp. 248-49.

1810. In assessing the evidentiary significance of the contracts, Exxon argues that it is also important to keep in mind that no party has advocated that the contract data be used directly to value West Coast Naphtha. *Id.* at p. 249. Rather, explains Exxon, the contracts have consistently been presented only as useful evidence for judging the relative merits of the various Naphtha valuation proposals at issue in this case – a proposition which cannot credibly be disputed. *Id.*

1811. Exxon argues that, although criticized by Unocal/OXY, BP, and Petro Star on the ground that they represented only a small percentage (on the order of 1%) of the total Naphtha that is produced on the West Coast, the evidence demonstrates that this criticism was not well founded. Exxon Initial Brief at p. 245; Exxon Reply Brief at p. 250. In the first place, states Exxon, the evidence is clear that statisticians regularly rely on very small samples in a wide variety of commercial, governmental, and research applications. Exxon Initial Brief at p. 245. It notes that Toof testified that a statistician would consider a one percent sample as being fairly significant. *Id.* Further, while agreeing that it is always preferable to have more data, Exxon maintains that the amount of data provided by the West Coast contracts was more than sufficient to provide good quality data. *Id.*

1812. In addition, Exxon asserts that the evidence shows that the volume of sales reflected in the contracts is actually larger than the volumes that are often relied upon by

Platts and OPIS in making their price assessments for certain of the other Quality Bank products. Exxon Reply Brief at p. 251. For example, Exxon notes that Culberson stated at the hearing that the volumes reflected in the West Coast Naphtha contracts were greater than the total volume of trades behind the Quality Bank reference prices for both Propane and Isobutane, and that he did not know if the volume of trades behind the Quality Bank reference prices for VGO, Normal Butane, or LSR were greater or less than the volumes represented in the Naphtha contracts. *Id.* Similarly, Exxon states, Pulliam testified that the analyst who does the Platts VGO price assessment believed that the volume of trades behind the Quality Bank reference price is in the range of a couple of percent of the total, which is comparable to the percentage of West Coast Naphtha reflected in the contracts. *Id.* at pp. 251-52.

1813. Exxon also argues that Petro Star's argument that the limited size of the West Coast Naphtha market means that it is not likely that a refiner could find a buyer for Naphtha for a price near the price in the contracts is without merit. *Id.* at p. 252. It suggests that the contracts themselves provide direct and conclusive proof that West Coast refiners have in fact found buyers for Naphtha at the prices found in the contracts. *Id.*

1814. The further argument of Petro Star and BP that the contracts should be disregarded because they reflect sporadic rather than routine transactions, Exxon maintains, is also contrary to the facts. *Id.* It points out that several witnesses testified that there are a number of asphalt refiners on the West Coast who cannot process their Naphtha, with the result that there is a constant source of Naphtha for sale on the West Coast. *Id.* In addition, explains Exxon, the long term nature of many of the contracts, including the large contract between Companies 4 and 13 upon which Ross relied, and the large number of contracts entered into by both Company 31 and Company 41, demonstrates that Naphtha is frequently purchased to meet long term refinery requirements. *Id.*

1815. Likewise deficient, in Exxon's view, is BP's criticism that the contract studies are incomplete because they do not include transactions between traders. *Id.* Exxon asserts that BP's claim is directly at odds with its own contention that the actions of brokers and traders do not contribute to a transparent market, because they tend to do their work in secret. *Id.* If that claim by BP is true, Exxon states, transactions between traders would not be expected to shed much light on the market price, and there would be no basis for BP's criticism of the contract studies on the ground that they do not include such transactions. *Id.* at p. 253. Exxon also suggests that BP's claim is misleading because, although the contracts do not include strictly trader-to-trader transactions, there are many transactions involving Company 43, a West Coast trader. *Id.* In addition, Exxon states, the record shows that the contracts align very closely with the prices used by West Coast Naphtha traders. *Id.* For example, explains Exxon, Culberson's interview notes (Exhibit No. UNO-9) show that traders have had no difficulty in ascertaining the value of West Coast Naphtha in the regular course of business despite the fact that there is no published price. *Id.*

1816. Moreover, according to Exxon, the evidence demonstrates that the buyers involved in these contracts were particularly well informed buyers from very large firms who are regular participants in the Naphtha market and were thus highly unlikely to be vulnerable to any systematic overpricing of their purchases of Naphtha. Exxon Initial Brief at p. 246. It explains that, if the value of the other 99% of the West Coast Naphtha that is produced and used internally by refiners were not at least as high as the price of the Naphtha sold by contract, market forces would certainly be expected to cause producers to sell more of their Naphtha to obtain the higher sales price. *Id.*

1817. Exxon also asserts that extensive statistical studies performed on the pricing formulæ used in the West Coast Naphtha contract studies verify their validity as a means of accurately predicting the value of West Coast Naphtha and verify that prices in the West Coast Naphtha contracts are not the product of a dysfunctional market. *Id.* at pp. 246-47. In addition, Exxon claims that sensitivity analyses performed by Toof clearly demonstrate that regardless of which of several factors[636] associated with the West Coast Contract studies were taken into account, the average West Coast Naphtha value fell within the range of $24.39 to $25.53/barrel for the period January 1992 to December 2001. *Id.* at pp. 247-48.

1818. The Naphtha contracts are also helpful, in Exxon's view, in validating that the West Coast Naphtha valuation proposals presented by Tallett and O'Brien produce reliable results. *Id.* at p. 248. It explains that, because the West Coast Naphtha valuation methodology proposed by Tallett produces results that are very close to the market prices reflected in the West Coast Naphtha contracts, his valuation methodology is reasonable and appropriate. *Id.* at p. 249.

1819. The contract studies presented by the other witnesses also validate the conclusion, according to Exxon, that the Tallett methodology provided an average contract price that

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[636] The factors Exxon refers to are as follows: volume weighting the contracts (Exhibit No. EMT-356); using both Pulliam's "Spec" and his "Potential" contracts instead of just his "Spec" contracts (Exhibit No. EMT-357); using Seattle unleaded regular gasoline prices instead of West Coast unleaded gasoline prices as the pricing benchmark (Exhibit No. EMT-358); adding a time variable into the regression analysis (Exhibit No. EMT-359); and using various alternative dates within each month to determine the appropriate contract price in those instances in which the contract pricing date was indeterminate (Exhibit Nos. EMT-363, EMT-364, and EMT-365). Exxon Initial Brief at pp. 247-48. By comparison, according to Exxon, the average Platts Gulf Naphtha value for this same period was $22.47, $2 to $3/barrel below the range for West Coast Naphtha contract price. *Id.* at p. 248.

was nearly identical to the average price for that period derived from the West Coast contracts.[637] *Id.* Moreover, continues Exxon, even when the contracts were analyzed on a company specific basis, they supported Tallett's methodology. *Id.* at p. 250. For example, states Exxon, Ross's review of the Tosco contracts, which he labeled as reliable, showed that Tallett's methodology produced the closest fit when the analysis was done on a weighted average basis.[638] *Id.*

1820. Exxon also argues that BP's and Williams's criticism that the West Coast Naphtha contract data are suspect because they are different in certain respects from the pricing information that Platts and OPIS rely on is also without merit. Exxon Reply Brief at p. 254. Exxon states that for the limited purpose of testing the various valuation proposals, the contracts plainly provide the best evidence. *Id.*

1821. Furthermore, in Exxon's view, the record reflects that the West Coast Naphtha contracts provide more information than Platts or OPIS have available to them in making their assessments. *Id.* It points out that the pricing services do not have access to actual contract data; the only information that they get is what people tell them. *Id.* Moreover, Exxon notes, Ross conceded in a 1995 affidavit that the OPIS and Platts price assessments are sometimes based on small amounts of market data with transactions occurring only once a month. *Id.* According to Exxon, this also was confirmed by Sanderson, who testified, in 1994, that the West Coast VGO prices reported by OPIS were largely hypothetical and based on surveys of what participants thought the prices could be and not on actual transactions. *Id.* at pp. 254-55. Finally, Exxon notes, Pulliam

[637] Exxon cites the following in support of this assertion: Exhibit Nos. SOA-28, EMT-380, EMT-381, PAI-156, UNO-52. Exxon Initial Brief at p. 249. According to Exxon this negates Culberson's claim that the other witnesses inclusion of certain contracts in their analyses undermined the usefulness of the contracts. *Id.* at p. 249, n.96. Similarly lacking merit, states Exxon, were the claims of Ross and Culberson regarding the monthly variability of the prices in the contracts. *Id.* It was demonstrated at the hearing, according to Exxon, that there also is significant variability on a monthly basis in the West Coast prices reported by Platts and OPIS. *Id.* Moreover, Exxon notes that neither Ross nor Culberson made any allowance for the fact that the Platts and OPIS prices are reported for specific locations, whereas the contract analyses were done on a more general basis. *Id.*

[638] Exxon claims this analysis also undermines Williams's claim regarding the Company 31 contracts and their alleged impact on the reliability of the contract data. Exxon Initial Brief at p. 250, n.97. It also notes that the weakness of Williams's claim in this regard is also demonstrated by the fact that the Company 41 contracts produce results comparable to the Company 31 contracts and by the fact that the Company 31 contracts were often priced at or below the contracts of other companies, including Williams's. *Id.*

testified that crude oil traders believe that their information is often better than the published information. *Id.* at p. 255.

1822. Exxon asserts that BP's further argument that the contract studies should have excluded long term contracts because Platts uses spot assessments sounds particularly insincere given that Ross relied heavily on one long term contract to validate his governor proposal. *Id.* If a single long term contract can be relied upon by Ross to validate his proposed governor, then, in Exxon's opinion, the entire collection of contracts can certainly be relied upon to assess the reasonableness of that and other proposed methodologies. *Id.*

1823. Similarly, Exxon finds that Williams's argument that the West Coast Naphtha contracts are virtually meaningless because they include some longer term contracts as well as spot transactions is in direct conflict with its own witness's reliance upon other Platts price assessments that include term contracts. *Id.* at p. 256. It notes that Sanderson based his argument in favor of using the Platts Gulf Coast Naphtha price as a proxy for the value of West Coast Naphtha on a comparison of the reported prices of ANS crude oil on the West Coast and Isthmus crude oil on the Gulf Coast. *Id.* Exxon also notes that Sanderson conceded, at the hearing, that much of that crude oil is traded pursuant to term contracts, not cash spot transactions. *Id.* Therefore, asserts Exxon, the argument made by Sanderson for using the Platts Gulf Coast Naphtha quotation to value West Coast Naphtha is thus based squarely on published prices that include term contracts as well as spot transactions. *Id.*

1824. There also is no basis, according to Exxon, for BP's criticism that the studies of the West Coast Naphtha contracts done by Pulliam, Tallett, and O'Brien made no adjustments to the contract data. *Id.* It notes that BP acknowledges that both Platts and OPIS exercise editorial discretion in making adjustments to their price assessments. *Id.* at pp. 256-57. Exxon argues that there is nothing improper about this procedure, and it adds that it is appropriate for the Quality Bank to rely on these independent pricing services for product valuations. *Id.* at p. 257. Nevertheless, Exxon asserts, the fact that the contract studies presented in this case make no such adjustments should be praised, not criticized. *Id.* Exxon explains that the contract studies do not depend on any price assessor's opinion, but reflect instead the actual value of West Coast Naphtha bought and sold by actual market participants. *Id.* Therefore, states Exxon, the contract prices are actual market prices, not hypothetical assessments arrived at by uninvolved third parties. *Id.* Far from being useless, claims Exxon, the contract studies are, in fact, a superior measure of the true market price than the subjective appraisal of the price assessment services. *Id.*

1825. Exxon also asserts that BP's further argument that price reporting contributes to transparency and is a step towards a competitive market overstates the case. *Id.* In making this argument, states Exxon, BP relies extensively on two Platts statements regarding its services and the impact those services have on energy markets. *Id.* It points out that the usefulness of those statements is undercut to some degree by the very fact that Platts felt compelled to issue them. *Id.* Exxon also notes that BP fails to mention that Platts was accused of playing a key role in causing those crises because the prices that it reported were so inaccurate. *Id.* at pp. 257-58.

1826. Additionally, Exxon argues, BP's transparent market theory is wholly without any legal, economic, or factual support. *Id.* at p. 258. It states that the information available to buyers and sellers of Naphtha on the West Coast from a wide variety of sources is fully comparable to the information available to buyers and sellers in other competitive markets. *Id.* For that reason, Exxon asserts, there is no factual basis for Ross's contention that the incremental benefit of having a single additional item of pricing information – a published Platts or OPIS price assessment – would fundamentally transform the West Coast Naphtha market from opaque to transparent and would attract a large volume of imports. *Id.*

1827. Exxon contends that, in an effort to avoid larger differentials between the values produced by their proposed methodologies and the values found in the West Coast Naphtha contracts during the 1999-2001 period, Unocal/OXY, Williams and BP all argue that the West Coast Naphtha contracts from that period should be discounted. *Id.* at p. 259. Although the arguments made in an effort to achieve this result differ, it is Exxon's position that there is no merit to any of them. *Id.*

1828. Williams and Unocal/OXY contend, according to Exxon, that the fact that the prices in the West Coast Naphtha contracts were substantially higher than Gulf Coast Naphtha prices during the 1999 to 2001 period should be ignored because 85% of the contract volumes during the 1999-2001 period were from four participants, and because a single purchaser purportedly purchased nearly 80% of the volumes in 2001. *Id.* As a matter of basic economics, Exxon states, this argument makes no sense. *Id.* It explains that, in view of the fact that the price at which a product is sold is determined by the relative strength of the buyer and seller in the marketplace, unduly high prices would only be expected where sellers have greater market power than buyers. *Id.* at p. 260. In the situation postulated by Williams and Unocal/OXY where a few large buyers predominate, Exxon argues, basic economics would dictate that those purchasers would command lower prices. *Id.* Therefore, according to it, the prices found in the contracts might be unduly low, not too high. *Id.* at pp. 259-60.

1829. Additionally, Exxon notes, the purchasers of West Coast Naphtha are not primarily small firms who might be at a disadvantage in negotiations; instead more than 90% of the purchases of Naphtha on the West Coast were made by BP, Amoco, Exxon and other large firms who would be expected to be able to negotiate extremely favorable prices. *Id.* at p. 260. Thus, there is no logical economic basis, concludes Exxon, for the contention of Williams and Unocal/OXY that purchases by a few large companies would be expected to result in inflated prices. *Id.*

1830. Exxon asserts that Williams's and Unocal/OXY's arguments are also based on incomplete analyses of the West Coast Naphtha contract data, particularly as related to Williams's contentions that Company 31 became a dominant purchaser, going from 23.6% of West Coast Naphtha purchases in 1999 to 83.3% of the purchases in 2001, and that the prices which Company 31 paid were significantly above the prices of other participants during this time frame. *Id.* at p. 261. It claims that the evidence makes clear that the data on which Williams and Unocal/OXY rely for these assertions (Exhibit Nos. WAP-200, WAP-202) do not include a number of the larger contracts. *Id.* For example, continues Exxon, those exhibits do not include the long term contract between Companies 4 and 13 which Williams admits is the largest volume contract among all the West Coast Naphtha contracts. *Id.* That contract was for 200,000 barrels/month, or 2.4 million barrels/year, so that, states Exxon, even if only the Heavy Naphtha portion of the contract is considered, it involved 1.68 million barrels/year of Heavy Naphtha. *Id.* Including just this one large-volume contract would, Exxon claims, change the percentages depicted in Exhibit Nos. WAP-200 and WAP-202. *Id.* at p. 262. For example, Exxon explains that adding the additional 1.68 million barrels of Heavy Naphtha to the total of 1.30 million barrels included in the Exhibit No. WAP-200 for 2001 would have sharply reduced Company 31's percentage of the West Coast Heavy Naphtha contract purchases from 83.3% to 36.4%. *Id.* Additionally, notes Exxon, the back-up data for the Williams's charts shows that there were a number of different buyers and sellers in the West Coast Naphtha market. *Id.* In light of this evidence, Exxon asserts, Company 31's share of the West Coast market was not a matter of special significance to the contract studies. *Id.*

1831. There also is no factual basis, according to Exxon, for Williams's claim that Company 31 paid prices for West Coast Naphtha that were above what other companies paid. *Id.* at pp. 262-63. Exxon asserts that Company 41, another party with an interest in the outcome of this proceeding and a major purchaser of West Coast Naphtha in 1999 and 2000, had contract prices that were higher than the prices paid by Company 31 on both a straight and volume-weighted basis over the 1999-2001 period. *Id.* at p. 263. Similarly, Exxon notes that in both 1999 and 2000 Company 31's contracts were often priced lower than Williams's contracts. *Id.* Exxon asserts that this evidence squarely refutes Williams's claim that Company 31 paid higher prices for Naphtha. *Id.*

1832. Exxon claims that BP acknowledges that Naphtha contract values for 1999-2001 closely track the prices of finished products, especially gasoline, and capture the gasoline price spikes that occurred on the West Coast. *Id.* Nevertheless, Exxon notes, BP still argues that the Commission should give less weight to the West Coast Naphtha contracts for those years based on Ross's theory that there were price anomalies that might not have existed in a transparent market. *Id.* at pp. 263-64. Exxon opines that BP's argument regarding the weight to be given the 1999 to 2001 contracts fails because there is no economic or factual justification for Ross's transparent market theory. *Id.* at p. 264.

1833. According to Exxon, the concerns of Williams, Unocal/OXY, and BP that the contract studies contain subjective judgments and were thus prone to possible manipulation also are without foundation. *Id.* at pp. 264-65. In the first place, Exxon asserts, the undisputed evidence clearly refutes Williams's allegation that there was an attempt by the analysts to coordinate their studies so that they were based on the same set of contracts. *Id.* at p. 265. Exxon states that Toof expressly testified that he and Tallett did not rely on O'Brien's analysis in any way, and, while they compared the Tallett study against the Pulliam study in order to identify differences and check the accuracy of their results, they made no attempt to duplicate Pulliam's analysis. *Id.* According to Exxon, this is also confirmed by the fact that Tallett's contract study did not use the same set of contracts as either the O'Brien or the Pulliam studies. *Id.*

1834. Similarly, Exxon asserts, the argument of Williams and Unocal/OXY that the Naphtha contract analyses involved subjective judgments due to some contract's ambiguous product identification and pricing terms provides no ground for disregarding the contract studies, as the evidence clearly shows that any differences in how the contracts or their pricing terms were classified were immaterial to the results obtained. *Id.* at pp. 265-66. Exxon states that this was demonstrated at the hearing by a series of sensitivity tests which analyzed several variations of the data – including using alternative dates within each month where contract pricing was indeterminate – to assess the effect of any differences on the results of the Tallett and Pulliam studies. *Id.* at p. 266. It notes that the results clearly showed that no matter how one varies the contract data, the Tallett and Pulliam contract analyses come out with results that are very similar and are always about \$2 to \$3/barrel higher than the Gulf Coast Naphtha price. *Id.*

1835. Additionally, Exxon argues, Williams's and Unocal/OXY's alleged concerns about subjectivity in the contract analyses are refuted by Culberson's contract study, which produced results that are highly comparable to those produced by the other contract analyses. *Id.* at pp. 266-67. According to Exxon, Culberson acknowledged at the hearing that, despite the differences in the four contract studies that were put together by Tallett, Pulliam, O'Brien, and Culberson, the contract studies all follow the same pattern, and the results for both the 1994-1998 period and the 1999-2001 period were reasonably close. *Id.* at p. 267. Exxon points out that Culberson's study, which Unocal/OXY describes as taking a conservative approach, resulted in the highest overall West Coast/Gulf Coast price differential of all the contract analyses for the period 1994-2001. *Id.* Culberson's study thus strongly confirms, in Exxon's view, the significant price differentials found by all the contract studies between the value of West Coast Naphtha and the Gulf Coast Naphtha price, and puts to rest any possible concerns about subjectivity or manipulation of the contract data. *Id.*

1836. Exxon asserts that there is no merit whatever to BP's argument that the contract data are flawed because the range of monthly price variation found in the contracts appears wider than the variability reflected in the petroleum product price assessments published by Platts and OPIS. *Id.* According to Exxon, this argument is premised on a distinction that Ross drew at the hearing between what he called monthly price variability and what he termed monthly price volatility. *Id.* It states that, although BP argues that its measure of monthly price variability is more appropriate, it cites no record support whatsoever for that assertion and its attempt to apply its theory results in a meaningless apples-to-oranges comparison.[639] *Id.* at pp. 267-68.

1837. There is absolutely no record support for the idea that Ross's definition of monthly price variability has any value as a measure of price variability, and BP cites nothing that even remotely supports its assertion that this measure is the appropriate tool to use, Exxon maintains. *Id.* To the contrary, it claims, the definition of monthly price variability created by Ross doesn't explain what the price variability is during the month. *Id.* Nor, states Exxon, is there any basis for the contrived distinction that Ross purported to draw between the terms variability and volatility, which are generally regarded as synonyms and used interchangeably. *Id.* at pp. 268-69.

1838. The evidence also makes clear, states Exxon, that the measure of monthly price variability used in the BP exhibits is different from the more traditional measure of monthly price variability, which Ross defined as volatility. *Id.* at p. 269. As a result of the averaging of the reported daily high and low price assessments (which are themselves a blend of the underlying data), Exxon explains, the monthly spread produced using Ross's definition of variability is necessarily much more narrow than the spread produced by averaging the highest high and lowest low prices for the month. *Id.*

2. Phillips

1839. According to Phillips, over 300 "West Coast Naphtha" contracts were produced in discovery in this proceeding. Phillips Initial Brief at p. 65. It is Phillips's position that these contracts provide the best evidence of the value of West Coast Naphtha. *Id.* While it agrees that the contracts cannot be used to establish a West Coast Naphtha value for use in the Quality Bank, Phillips asserts they can be used to evaluate proposed proxies for the West Coast value. *Id.* at pp. 65-66. In addition, Phillips states, the contracts can be used

[639] Platts and OPIS, Exxon states, report both a high and a low price assessment for each day (or for some products, each week). Exxon Reply Brief at p. 268. It explains that Ross obtained his measure of monthly price variability by averaging the daily high price assessments for each month and the daily low price assessments for the month, and from these two averages derived a spread that he called the price variability for that month. *Id.* Exxon states that this calculation equates mathematically to the average spread between the high and the low daily assessment. *Id.*

to test various arguments about the issues that have been raised by the parties. *Id.* at p. 66.

1840. Phillips claims that these contracts represent the only direct evidence in the record as to what the value of Naphtha is on the West Coast and explains that, as such, they are the only evidence of the prices that actually were paid for Naphtha in arms-length transactions on the West Coast. *Id.* at p. 68.

1841. Sanderson, according to Phillips, urges that the Commission ignore the contracts because the volume of Naphtha represented by them is too small to have any relevance. *Id.* To support this assertion, explains Phillips, Sanderson presented Exhibit No. WAP-229, which shows that the contracts represent only about 1% of all Naphtha processed on the West Coast. *Id.* Culberson makes essentially the same argument, states Phillips, despite presenting his own contract analysis. *Id.* Ross also attacks use of the contracts, but, notes Phillips, he does not assert that the sample is too small, only that the West Coast market is an opaque market because there are no published prices. *Id.* Ross goes on, continues Phillips, to declare that the contract prices are higher than they would be in a transparent market where there are published prices. *Id.* According to Phillips, all of these arguments are without merit. *Id.*

1842. Phillips states that, because the contract data is inconsistent with their theories on West Coast Naphtha values, BP, Williams, Unocal and Petro Star all argue that the Commission should ignore this powerful direct evidence.[640] Phillips Reply Brief at p. 41. It notes that BP goes so far as to argue that the data from the hundreds of contracts, which represent sales of millions of barrels of Naphtha for hundreds of millions of dollars, are useless. *Id.* Further, it notes that, in contrast with the witnesses who testified in support of the relevance of the contracts, the witnesses opposing their use were not trained economists. *Id.*

1843. Williams acknowledges, according to Phillips, that the Naphtha contracts do have some probative worth as to the value of Naphtha on the West Coast when it relies on the contracts to argue that N+A does not have value on the West Coast. *Id.* at p. 42. Indeed, Phillips states, Williams introduced its own contract analysis, Exhibit No. WAP-267, in the N+A phase of the hearing. *Id.* That Williams is willing to use the contracts when it believes that they help its case undercuts its efforts, in Phillips's view, to argue that the

[640] Phillips notes that Petro Star's argument that the contracts are irrelevant runs contrary to the testimony of its own witness, Dudley, who agreed that "it would be useful to look at the naphtha contracts." Phillips Reply Brief at p. 41, n.19 (citing Transcript at p. 10108).

contracts should be ignored when they are inconsistent with Williams's position. *Id.*

1844. While it is true that the Naphtha contracts involve only about 1% of the Naphtha processed on the West Coast, Phillips argues, that does not detract from the fact that they represent substantial amounts of sales – millions of barrels and hundreds of millions of dollars. Phillips Initial Brief at p. 68. Baumol – who, notes Phillips, is an economist and well qualified to analyze the significance of market data, unlike Sanderson and Culberson – testified this is not an artificial market, but a very real one. *Id.* at pp. 68-69. Further, states Phillips, Baumol went on to testify that many business people want to enter that kind of market for the profits it offers. *Id.* at p. 69.

1845. Phillips notes that Baumol explained that if the contract values did not represent the approximate value of Naphtha on the West Coast then it was because buyers were being fooled into overpaying systematically year after year and that he found that possibility highly implausible.[641] *Id.* In addition, states Phillips, Pulliam, another economist, agreed with Baumol and testified that he found the contract data, the most direct evidence for establishing the value of Naphtha on the West Coast and the best information for appraising the valuation proposals. *Id.*

1846. According to Phillips, Baumol was asked, if Naphtha contracts represented all of the arms-length sales, but only 1% of the volume of Naphtha processed, "can the market price of that 1 percent be used to establish the value of the 99 percent of the naphtha which is not being sold" and answered that it could, but perhaps not to six decimal places.[642] *Id.* at p. 71. Phillips states that Baumol explained that the two markets are economically, if not legally, one. *Id.* This is because, according to Phillips, at any point in time, a refiner has a choice of either using its Naphtha internally, or engaging in a purchase or sale transaction with a third party. *Id.* If the price at which a refiner could buy or sell Naphtha varied significantly from its internal value, then, asserts Phillips, the refiner would have every incentive to buy or sell that Naphtha instead of using it internally. *Id.* It points out that Baumol believes that, even though this connection may be imperfect, it is "more perfect than simply transferring a Gulf Coast price to the West Coast because nobody there is voting with their feet. It is more representative than putting in a Gulf Coast governor on the West Coast because there, nobody is voting with

[641] Phillips states that the reason Baumol did not believe there was systematic overpayment for Naphtha under the contracts is because he considered the parties to the contracts to be sophisticated and large companies that would not be misled that way. Phillips Initial Brief at pp. 69-70. It was counsel for BP, claims Phillips, who challenged Baumol's assertion that BP is a sophisticated buyer and is reasonably well informed about Naphtha prices on the West Coast. *Id.* at p. 70.

[642] Phillips cites Transcript at p. 5159.

their feet." *Id.* (quoting Transcript at p. 5160). Further, notes Phillips, Baumol testified that the "market is not an artificial market. It is not a negligible market, and it is a market in which . . . knowledgeable parties, are there deciding on prices which have to be, in their opinion, representative of the value of naphtha in that arena for other uses." *Id.* (quoting Transcript at p. 5161).

1847. Phillips notes Pulliam was in agreement with Baumol on this point and stated:

> [T]he participants that are involved in these transactions are in the same market as . . . the 99 percent of the volume that is not moving through these third party transactions. The people that are purchasing the naphtha [via contract] are doing the same things with it that . . . the 99 percent that is being . . . internally transferred and consumed in the refinery. And there is opportunity here for parties who do use it internally to sell to parties who are interested in buying.

Id. at p. 72 (quoting Transcript at pp. 7584-85). Further, Phillips states, when asked whether economists would rely on contracts to represent the value of a product, even when most of the product is used internally instead of being bought and sold, Pulliam responded: "Yes . . . [t]hat's precisely the thing that economists in economics would look to. Those transactions represent the price at which markets are coming into balance, where supply and demand are coming into balance. That to an economist is evidence of the market value." *Id.* (quoting Transcript at pp. 7578A-79A).

1848. According to Phillips, each witness who analyzed the West Coast Naphtha contracts provided a consistent explanation of how he made decisions regarding those which he used, demonstrating that the choices made were, in fact, not arbitrary.[643] *Id.* at p. 73. It asserts that it is not necessary to address opposing parties's concerns in detail regarding choice of contracts for analysis. *Id.* In Phillips's opinion, the best defense against the attacks lies in the fact that each of the four contract analyses, all of which used different sets of contracts, reaches remarkably similar results. *Id.* at pp. 73-74. It explains that, despite the differences in approach among the witnesses, the four independently performed contract analyses show that Naphtha prices exceeded Gulf Coast prices to approximately the same degree for each of the time periods analyzed and that this should give the Commission confidence in the results of the analyses. *Id.* at p. 74.

1849. BP recognizes, Phillips maintains, the lack of a valid economic theory to support its contention that the contracts are not relevant and, therefore, attempts instead to

[643] In support, Phillips cites Transcript at pp. 5912-17, 6601-04, 7295-96. Phillips Initial Brief at p. 73.

establish a legal standard that would exclude the contracts without considering whether as an economic matter they provide useful information. Phillips Reply Brief at pp. 42-43. It suggests that this is a preposterous argument, and notes that no evidence, other than the prices reported by Platts or OPIS, could meet BP's standard. *Id.* at p. 43. Thus, Phillips explains, BP is suggesting that, when considering the theoretical arguments of Culberson, Sanderson and Ross, no West Coast refiner would ever pay more for Naphtha than the Gulf Coast price plus a small amount (2.7 to 3.5¢/barrel) representing transportation cost differentials, the Commissions should ignore the fact that there are approximately $300-$400 million dollars worth of sales of Naphtha on the West Coast at much higher average prices. *Id.*

1850. Phillips also asserts that BP's reliance on the *OXY* decision to support its argument is misplaced as nothing in *OXY* or the other Circuit Court opinions suggests that the Commission cannot use empirical data, such as the contracts, to determine that the continued use of Gulf Coast prices would undervalue West Coast Naphtha, or that use of BP's governor also would undervalue West Coast Naphtha. *Id.* at pp. 43-44. It contends that those decisions discuss the methodologies used to value Quality Bank cuts, not the evidence that is used to evaluate the reasonableness of the proposed methodologies. *Id.* at p. 44.

1851. BP theorizes, according to Phillips, that contract prices in an opaque market likely will be higher than they would be in a transparent market. *Id.* It explains that Ross's assertions on this matter are incorrect and likely stem from his unfamiliarity with economic theory. *Id.* There is no reason to believe, states Phillips, that the contract prices are significantly different from what they would be if there was a published West Coast price. *Id.* Phillips asserts that the somewhat concentrated nature of the purchasers of Naphtha and the fact that there are a number of sellers who do not make gasoline and hence have no alternative but to sell their Naphtha would suggest, if anything, that the prices paid for Naphtha might be below what they might be in a perfectly competitive market. *Id.* at pp. 44-45. This is the exact opposite of Ross's contention, declares Phillips. *Id.* at p. 45.

1852. Phillips posits that BP makes a further error in that, after discussing its theory that an opaque market can affect pricing, it assumes that the West Coast Naphtha market is almost completely opaque. *Id.* According to Phillips, this "leap" from the absence of a published Platts West Coast price assessment to an extreme exaggeration of what BP calls the "scarcity of information in the West Coast naphtha market" is unwarranted. *Id.* (quoting BP Initial Brief at p. 15). More importantly, according to Phillips, BP's assertions regarding the availability of information are incorrect. *Id.* It suggests that many sources of information are available to the West Coast refiners, including: (1) sources and availability of supply, (2) prices, and (3) availability and cost of imports. *Id.* at pp. 45-46. Further, it asserts that the West Coast refiners who purchase and sell Naphtha all have sophisticated computer models that tell them the internal value of the

Naphtha that they are purchasing and selling. *Id.* at p. 46. Therefore, Phillips contends that West Coast refiners know what prices they are paying and receiving for Naphtha. *Id.*

1853. Thus, Phillips contends that BP is wrong when it asserts that the West CoastNaphtha contracts were negotiated in the dark without any relevant information. *Id.* While there were no published Platts West Coast assessments, it states, the contracts were negotiated by sophisticated parties who are not in the business of giving money away and who had extensive amounts of data available to them in determining the prices to be paid under the contracts.[644] *Id.* at pp. 46-47. Thus, Phillips maintains, there is no reason to believe that the contract prices deviate to any significant extent from what they would have been if there were a published Platts West Coast assessment, and certainly no reason to believe that the prices on average are significantly higher than they would have been had there been a published price. *Id.* at p. 47.

1854. Phillips disagrees with BP's and Unocal/OXY's contention that the contracts for the 1999-2001 time period should not be considered. *Id.* It states that BP and Unocal/OXY argue that the contracts from this period are corrupted by gasoline price irregularities and that, in general, the Naphtha West Coast/Gulf Coast price differentials should be similar to the differentials for intermediate products, as Ross classifies them. *Id.* at pp. 47-48. Phillips asserts that Ross's theory, supported by BP, that in a transparent market prices would have been lower during this time period because of arbitrage opportunities to import Naphtha does not hold water. *Id.* at p. 47. It states that the 1999-2001 contracts are the most recent and most numerous, and thus most useful, and contends that, far from being corrupted by gasoline price irregularities, they demonstrate the extent to which West Coast Naphtha prices were influenced by gasoline price fluctuations. *Id.* at pp. 47-48. Given that West Coast Naphtha is made into gasoline, Phillips maintains that it is not at all surprising that Naphtha prices would reflect movements in the gasoline market, and this fact certainly does not constitute grounds for rejecting the contracts from 1999-2001. *Id.* at p. 48.

1855. BP's second argument, according to Phillips, should be rejected on much the same grounds. *Id.* It explains that Ross's hypothesis is that West Coast/Gulf Coast Naphtha price differentials should be similar to the differentials for intermediate products, as he classifies them. *Id.* It notes that, because the Naphtha contracts, during the 1999-2001 time period, tracked gasoline price differentials more than VGO differentials, BP asserts that the Naphtha contract prices must be unreliable. *Id.* Phillips claims that this turns

[644] Phillips points out that sophisticated market participants would likely not base their decisions solely on Platts in any event. Phillips Reply Brief at p. 47, n.21. It explains that participants realize that Platts might not accurately reflect all the current transactions, and states that they would look first to their internal values and then test the market by seeking quotations from other participants. *Id.*

reason on its head. *Id.*

3. Alaska

1856. Alaska argues that third party purchase and sales transactions, such as those reflected in the Naphtha contracts, represent the price at which supply and demand are coming into balance and that this is evidence of the market value to an economist. Alaska Initial Brief at p. 3. Further, explains Alaska, the published price assessments that the Quality Bank currently uses to value distillation cuts likewise constitute the publishers's assessments of the prices at which third party transactions are occurring or could occur. *Id.*

1857. While the Naphtha contract data thus are consistent with published price data as indicia of market value, Alaska states, there is a significant difference in their applications. *Id.* It points out that Platts and OPIS continuously collect information to assess and publish current market values on a daily or weekly basis, whereas the discrete set of Naphtha contract data collected in this case was intended to be used only to test the validity of the parties's proposed methodologies for valuing Naphtha in the Quality Bank. *Id.* Alaska asserts that the relevance of the contracts for the purposes of this case is not to publish an assessment of precise market value on any given day or week, but to see how the various methodologies performed relative to transactional information over longer periods of time. *Id.* For that purpose, Pulliam concluded, and Alaska agrees, one is justified in relying heavily on the contracts. *Id.* at p. 4.

1858. During the 1994-1998 period (or 1993-1998 for Culberson), states Alaska, the Pulliam, Tallett, and Culberson analyses[645] all found the contract prices to average a few cents per gallon above Platts Gulf Coast price, and during the 1999-2001 period, all found the contract prices to average about 11 to 14¢/gallon above Platts Gulf Coast price. *Id.* Alaska notes that O'Brien's analysis yielded a numerical average only for the entire 1994-2001 period, and his result – 9.4¢/gallon above Platts Gulf Coast price – is within about a penny and a half per gallon or less of the Culberson (1993-2002) and Tallett

[645] Alaska notes that Sanderson did not do his own contract analysis but examined what would happen under Tallett's analysis if all non-spot transactions were deleted. Alaska Initial Brief at p. 4, n.4. It asserts that those deletions made virtually no difference for the 1994-1998 period and reduced the contract/Gulf Coast differential from 12.65 to 10.16¢/gallon for the 1999-2001 period. *Id.* Alaska explains that the, apparently, greater effect of the deletions on the entire 1994-2001 period is an artifact of averaging because the deletions eliminated over half of the contract volume in the later years but hardly any volume in the early years. *Id.* Sanderson's average over 1994-2001 gave relatively greater weight to the early data, when West Coast and Gulf Coast Naphtha values were closer, than to the later data, when they were more divergent. *Id.*

results. *Id.* at pp. 4-5. While at first glance Pulliam's results for the entire 1994-2001 period appear lower, at 6.1 to 6.5¢/gallon above Platts Gulf Coast price, Alaska explains that this is due to a different method of aggregating the price data, not to a significant difference in the underlying findings.[646] *Id.* at p. 5.

1859. Alaska argues that these robust contract data are useful in several ways to test the various Naphtha valuation proposals. *Id.* It points out that the primary focus in this case was direct comparison between the Naphtha values predicted by those proposals and the Naphtha values derived from the contracts. *Id.* Thus, according to Alaska, the O'Brien and Tallett methods performed better than any of the others over the entire 1994-2001 time period, and dramatically better during the last three years. *Id.*

1860. Further, notes Alaska, other contract data also shed light on the validity of the competing proposals. *Id.* The O'Brien and Tallett methodologies are based primarily on West Coast gasoline prices, which, according to Alaska, is consistent with how Naphtha is priced in the contracts. *Id.* Further, continues Alaska, the prices of nearly 80% of the Naphtha contract volumes were directly tied to a West Coast gasoline price. *Id.* at pp. 5-6. In contrast, Alaska points out, only 2.3% of the volume was priced with reference to Gulf Coast Naphtha prices, despite some parties's claims that West Coast Naphtha should be valued at Gulf Coast Naphtha prices or that West Coast Naphtha values are subject to a governor that is tied to the price of Naphtha on the Gulf Coast. *Id.* at p. 6.

1861. Alaska also claims that the contracts allow the latter claim to be tested using statistical techniques. *Id.* If Ross's assertion was correct – that the option of importing Naphtha limits the value of Naphtha on the West Coast to no higher than import parity – then Alaska asserts, "we would expect that the spread between the naphtha contract prices and West Coast gasoline prices would *increase* whenever a gasoline-derived value for naphtha on the West Coast would otherwise exceed import parity." *Id.* (quoting

[646] Alaska explains that Pulliam derived a Naphtha price for each month by taking the volume-weighted average of the contract prices in effect for that month. Alaska Initial Brief at p. 5, n.5. When he compared these monthly prices to the various methodologies over a multi-year period, Alaska states, Pulliam used a straight average of the monthly comparisons during the period in question. *Id.* According to Alaska, this caused his average for the entire 1994-2001 period to fall close to the middle between his average figures for the early part of the period and for the later part of the period. *Id.* In contrast, points out Alaska, the other witnesses aggregated their price data either by volume-weighting all the data or by not using any volume weighting. *Id.* Because there were both more transactions and more Naphtha volume in the later part of the 1994-2001 period than in the early part, the later data had relatively more impact on those witnesses's overall averages for the entire 1994-2001 period, and consequently their overall averages are closer to the average figures for the later part of the period. *Id.*

Exhibit No. SOA-1 at p. 15) (emphasis in original). When Pulliam tested this hypothesis using a regression analysis, Alaska points out, he found that the Naphtha/gasoline price spread did not increase as Ross's theory would predict. *Id.* Instead, according to it, the results were the opposite of his theory. *Id.*

1862. Because the Naphtha contract data contradict the positions of parties who want the Quality Bank to keep valuing West Coast Naphtha using Gulf Coast prices or to use a Gulf Coast-based price cap, Alaska explains that those parties have devised several attacks on the reliability of the contract data, none of which, it believes, has merit. *Id.* Alaska argues that the number of Naphtha contracts analyzed is sufficient for the purposes of testing the parties's proposed Naphtha valuation methodologies. *Id.* at p. 7. It cites Pulliam's testimony who stated that, in his opinion, in view of the number of contracts, the transactions and the volume of Naphtha involved, the contracts may be relied upon for purposes of testing the parties's proposed valuation methodologies. *Id.* Further, it notes that Pulliam believed he had quite a bit of data to work with, particularly for the last three years. *Id.* Alaska notes that Pulliam's analysis involved 175 contracts, including 94 contracts in the last three years, involving 15 different sellers, and 12 different buyers, with an average of six contracts in effect each month during that period. *Id.*

1863. It is unlikely that the contracts collected in this case, Alaska conceded, constituted 100% of the transactions during the time periods studied, which raises questions of the randomness and validity of the sample. *Id.* It notes that Pulliam explained that randomness of a sample is a method used to ensure that a sample is not biased and that he had no reason to believe that the contract sample obtained in this case was biased. *Id.* at pp. 7-8. Further, according to Alaska, in this case, the nature of the buyers and sellers also gave Baumol a high level of confidence in the pertinence of the sample. *Id.* at p. 8.

1864. Furthermore, Alaska explains, Pulliam performed a sensitivity test for bias in the Naphtha contract sample. *Id.* This test, according Alaska, examined the possibility that the actual average West Coast Naphtha contract price in the 1999-2001 period, including the unknown transactions that were not obtained in this case, as well as the transactions that were obtained, might equal -- rather than substantially exceed -- the average Gulf Coast Naphtha price. *Id.* The result, noted Alaska, was that the average West Coast Naphtha price, from the contracts which were obtained, so greatly exceeds the Gulf Coast price that, to offset that differential, the average price of the missing contracts would need to be so low as to simply not be plausible. *Id.* Alaska asserts that none of the contracts that Pulliam reviewed had prices nearly that low. *Id.*

1865. Beyond the question of sample bias among the Naphtha contracts themselves, Alaska notes, there is a somewhat different question concerning the fact that only a small percentage of the Naphtha produced and used on the West Coast is bought and sold in third party transactions. *Id.* The issue, according to Alaska, is whether or not the market price of the 1% that is sold can validly be used to value the remaining 99%. *Id.* at pp. 8-9. Both economic theory and specific knowledge about the refining industry make clear, in Alaska's opinion, that the answer is an unequivocal yes. *Id.* at p. 9.

1866. Refiners, Alaska contends, constantly attempt to optimize their operations in order to stay profitable in the face of an array of choices and often use linear programming models. *Id.* For example, notes Alaska, with respect to the volume of Naphtha produced in a refinery, Culberson acknowledged that the options include changing the crude slate, changing the boiling ranges or cut-points in the crude unit, changing the cut-points in the Coker and hydrocracker, and importing VGO feedstock. *Id.* Further, explains Alaska, Sanderson testified that the West Coast refiner for whom he previously worked used Naphtha from its own crude runs and also Naphtha purchased from the outside, depending on which was more economical at any given time. *Id.*

1867. In the first part of the period for which Naphtha contracts were obtained, notes Alaska, Gulf Coast Naphtha prices tended to be close to the West Coast contract prices, and all of the proposed methodologies yield West Coast Naphtha values that average within a few cents per gallon of the contract prices. *Id.* at pp. 11-12. In the latter part of the period, continues Alaska, the contract prices tended to greatly exceed Gulf Coast Naphtha prices, and only the O'Brien and Tallett proposals yield West Coast Naphtha values close to the contract prices. *Id.* at p. 12. This, according to Alaska, reflects the fact that gasoline prices on both coasts were relatively close during the earlier years and then diverged during the later years. *Id.*

1868. According to Alaska, Ross claimed that the West Coast Naphtha market is an opaque market and that, therefore, West Coast Naphtha prices reflected in the contracts are probably higher than they would be if a company like Platts published a price assessment for West Coast Naphtha. *Id.* at p. 13. Notes Alaska, Ross claims that were there such a published Naphtha price assessment, that is if the market were transparent, West Coast Naphtha would not exceed import parity. *Id.*

1869. Ross's theory, according to Alaska, grossly exaggerates the role of published price assessments in the universe of market information. *Id.* It notes that he defines "opaque market" to mean "a market where there's little information available." *Id.* (quoting Transcript at p. 8219). Yet, explains Alaska, Baumol noted that, while most people have limited information, buyers and sellers of Naphtha are well informed, and do not need a published price to negotiate the best deals possible. *Id.* at pp. 13-14. Further, Alaska points out that even Ross admits that West Coast refiners have access to such information as the shadow price of Naphtha in computer models, the prices of Naphtha in the Caribbean and the Gulf Coast export markets, and to brokers operating in the West Coast market who are in touch with the refineries on a continuing basis. *Id.* at p. 14. Pulliam, according to Alaska, pointed out that a trader for one such broker who was interviewed estimated West Coast Naphtha prices that were very close to the prices calculated from the Naphtha contracts analyzed by Pulliam. *Id.*

1870. The additional piece of information that Ross contends makes all the difference – a Platts or OPIS price assessment – is, in Alaska's view, nothing more than what the assessor can find out as a result of phone calls. *Id.* Further, notes Alaska, sometimes such published assessments are based on very limited market transactions. *Id.* While there may be some incremental benefit to having that piece of information, Alaska argues, there is simply no basis for concluding that the absence of a published assessment in the West Coast Naphtha market has the material effect on Naphtha prices that Ross asserts. *Id.* It points out that traders themselves believe their information is often better than the published information. *Id.* at pp. 14-15.

1871. Alaska also states that BP makes several incorrect assertions regarding the its position on the opaque markets issue. Alaska Reply Brief at p. 3. First, it claims, BP states that Pulliam referred to the West Coast Naphtha market as opaque. *Id.* In fact, asserts Alaska, Pulliam testified that it is not at all opaque and information on the West Coast market is readily available. *Id.* Second, Alaska takes issue with BP's comments that there were few participants in the West Coast, arguing that there were at least ten refiners making gasoline on the West Coast and were thus potential ultimate purchasers of Naphtha during the time periods studied. *Id.* Third, Alaska argues, the record clearly shows that there are regular buyers of Naphtha on the West Coast and not only sporadic buyers, as BP claims. *Id.* at pp. 3-4. Further, Alaska asserts, a large volume of Naphtha, more that half of the contract volume during the 1999-2001 period, is purchased under term contracts. *Id.* at p. 4. According to Alaska, these contracts are, by definition, not used to meet immediate unplanned needs, as BP states. *Id.*

1872. BP errs in asserting that the contract analyses are not useful for evaluating proposed Naphtha valuation methodologies because they did not use exactly the same techniques to estimate market values as do Platts and OPIS, according to Alaska. Alaska Reply Brief at p. 5. It asserts that the different techniques are just slightly different methods for achieving a common result, namely, determining the prices at which actual market transactions in a product occur. *Id.* Alaska maintains that, if Platts published a price assessment for West Coast that was used to compare the proposed methodologies, Pulliam would expect similar results to those from his contract analysis. *Id.* Further, Alaska asserts, use of the contract data to test proposed methodologies is not inconsistent with how the Quality Bank uses the Platts and OPIS price assessments. *Id.* at pp. 5-6. Finally, Alaska claims, Pulliam's conclusions are supported by the fact that the contracts and published price assessments for ANS crude are "very close." *Id.* at p. 6.

1873. In response to the criticisms made by several parties that Pulliam's analysis is subjective, open to manipulation, or should not have included term contracts, Alaska argues, his approach was, in fact, objective and inclusive, made use of all relevant data, and used a volume-weighted approach for each month in question. *Id.* It rejects the assertion that a more filtered, subjective approach, such as that used by Platts, is more appropriate, noting that the purpose of Pulliam's analysis was not to arrive at precise, day-to-day calculations of the market value of Naphtha, but instead his purpose was to look at the market value over a longer period of time. *Id.* at pp. 6-7. Alaska asserts that it is absurd for parties to ask the Commission to ignore the fact that one proposed methodology deviates from actual market (contract) prices by an average of more than 14¢/gallon while another deviates by less than a penny per gallon. *Id.* at p. 7.

1874. Alaska further suggests that a party who does not find Pulliam's analysis valid could look at the contract data in Exhibit No. SOA-12 for validation that 95.5% of the contract Naphtha volume, between 1999 and 2001, was sold at prices above the Gulf Coast price, while over 60% of the Naphtha volume was sold within 2¢/gallon of the prices predicted by the O'Brien methodology. *Id.* In Alaska's view, these disparities cannot be filtered away as BP and Williams suggest. *Id.*

1875. BP argues, according to Alaska, that the contracts data is not useful because of their high degree of price variability when compared to the published price assessments. *Id.* This comparison is, Alaska states, misleading because, although BP claims to have compared underlying contract data with data underlying the price assessments, it did not and could not do that. *Id.* at pp. 7-8. Alaska points out that BP compared the data underlying the contracts with the actual price assessments from Platts, because the underlying data for the Platts assessments is not available. *Id.* at p. 8. Further, Alaska explains, because the Platts assessments themselves are averages, they necessarily show less variability than the underlying contract data. *Id.*

1876. The valid comparison, according to Alaska, is between the variability of the Platts and OPIS assessments and the variability of Pulliam's price estimates. *Id.* Alaska asserts that, because Pulliam's estimate is a single number, while those of Platts and OPIS are ranges, the "average monthly price variability" under Pulliam's analysis is zero as compared to several cents per gallon in the case of the Platts and OPIS assessments. *Id.* at pp. 8-9. It concedes that this comparison is not very meaningful, but states that it is more meaningful than BP's comparison. *Id.* at p. 9.

1877. Alaska asserts that, contrary to BP's theory, there is no pattern for price differentials that reliably distinguishes intermediate from finished products. *Id.* For example, explains Alaska, during 1992-1998, the differentials for unleaded regular gasoline and jet fuel (two finished products) were very similar, at 5.99 and 5.57¢/gallon respectively; while during 1999-2001 those two differentials were highly dissimilar, at 13.55 and 7.75¢/gallon respectively. *Id.* Moreover, notes Alaska, BP's classifications are biased: the differentials for blendstocks MTBE and feedstock isobutane strongly contradict the tidy pattern BP tries to create if they are correctly classified as intermediate products. *Id.* at pp. 9-10. Consequently, states Alaska, BP calls MTBE a finished product and assigns Isobutane to a third category, "gas plant products," so its pattern is preserved. *Id.* at p. 10. Alaska also finds BP's argument turns the scientific method backward, and explains that, if observations and data gathered do not support the theory, then, according to the scientific method, it is the theory that should be questioned and not the data. *Id.*

1878. BP and other critics of the contract data have stressed that refining on the West Coast experienced instability, disruptions, and anomalies during 1999-2001, states Alaska. *Id.* According to Alaska, it should not then be a surprise that the price patterns BP claims to see in the previous years do not persist into 1999-2001 period. *Id.* In Alaska's view, it is precisely during changing market conditions that the performance of the proposed Naphtha valuation methodologies is most meaningfully measured, and it is not relevant that the prices may be the result of disruptions or anomalies. *Id.* The only relevant question, asserts Alaska, is how well do the proposed methodologies track the market prices in the real world of change. *Id.*

1879. Petro Star is mistaken, explains Alaska, in its claim that there is no market demand for Naphtha on the West Coast. *Id.* at p. 12. It points out that most of the Naphtha sold under the contracts analyzed by Pulliam comes from refineries that do make gasoline, have no internal requirement for Naphtha, and therefore must sell it. *Id.* Alaska asserts that there is no evidence that refiners need to pay or are willing to pay a premium for convenience or that convenience is even a relevant consideration for refiners. *Id.*

1880. The changes to the contract analyses that have taken place during the course of the proceeding reflect the witness's desire to be as accurate as possible, according to Alaska. *Id.* at p. 13. They do not, it maintains, indicate that the analysis is subjective and ambiguous, nor do they indicate a conspiracy among the analysts. *Id.* at pp. 12-13. According to Alaska, the changes resulted from the fact that the analysts received more complete information about the transactions being analyzed or were correcting errors. *Id.* at pp. 13-14.

1881. Alaska explains that Williams cited the differences in price data contained in Pulliam's versus O'Brien's contract analyses as evidence of subjectivity in them. *Id.* at p. 14. Rather than indicating subjectivity, Alaska asserts, they reflect the difference in methods that the witnesses's used to apply a pricing formula based on delivery dates. *Id.* Further, notes Alaska, both methods are valid, and the choice does not make a significant difference in the results. *Id.* According to Alaska, Williams also criticized the analysis of Pulliam and O'Brien because, for some contracts, they used different volumes. *Id.* at p. 15. Alaska points out that this is not a reflection of their different interpretations of the contracts; rather it reflects that O'Brien had information on actual volume delivered and Pulliam used the volume stated in the contract. *Id.* It asserts that the quantitative impact of this deviation was immaterial; the difference between the contracted and delivered volumes for the 30% of contracts where that information is available was 7%. *Id.* at pp. 15-16.

1882. Unocal/OXY also err, according to Alaska, in characterizing the fluctuating gasoline reference prices in the contracts as ambiguous. *Id.* at p. 14. In Alaska's view, Pulliam's analysis appropriately managed these fluctuations and was not distorted by them. *Id.* It explains that Pulliam's analysis compared monthly averages of these contract reference prices with monthly averages from the valuation methodologies being evaluated in order to avoid timing mismatches. *Id.* at pp. 14-15. In addition, notes Alaska, Pulliam performed a sensitivity analysis that showed that the intra-month fluctuations do not have a material impact on the results of his analysis. *Id.* at p. 15.

1883. Alaska further notes that Unocal/OXY criticize the contract analysis suggesting that there is ambiguity concerning the classification of the product being sold. *Id.* at p. 16. It explains that this issue of classification was recognized by the analysts, and that they accounted for it by analyzing two sets of contracts each and running tests on the impact of the classification decision made by the analysts. *Id.* Alaska points out that the classification decisions were conservative and resulted in lower West Coast Naphtha values than would have otherwise resulted, and also points out that four other witnesses, including Unocal/OXY's, made independent classification decisions as part of their contract analyses and that those results were consistent with Pulliam's and O'Brien's. *Id.*

1884. Unocal/OXY also argue, according to Alaska, that the contract transactions are dominated by four large participants and involve few others. *Id.* at p. 17. It answers that this merely reflects the reality of the West Coast Naphtha market. *Id.* While conceding that the buyer side of the market appears more concentrated than the seller side, Alaska asserts, this market structure would tend to cause prices to be lower than they would be otherwise. *Id.* Alaska also notes that the total number of participants is substantial: 15 different sellers and 12 different buyers during 1999-2001. *Id.*

1885. Williams criticizes, Alaska points out, the contract analyses because it perceives that one company's contracts (Company 31) have a disproportionate impact on the total results, noting that the average spot contract price drops if Company 31's data is deleted from the analyses. *Id.* Alaska argues that this is meaningless, because one could just as easily criticize the analyses for producing too low a price by dropping the contracts of a company whose data are below the average. *Id.* The point of the analyses, according to Alaska, is to use all the data available and not to eliminate data that runs counter to a party's interests. *Id.* It also argues that Williams overstates the significance of Company 31's data on the outcome of the analysis. *Id.* While Williams states that the percentage of purchases attributed to Company 31 went from 23.6% in 1999 to 83.3% in 2001, Alaska explains, the average West Coast Naphtha contract price was 12.7¢/gallon above the Gulf Coast Naphtha price in 1999, and 14.1¢/gallon above the Gulf Coast price in 2001. *Id.* at pp. 17-18. Further, notes Alaska, in 2000, when Company 31's percentage of purchase was only about half the 2001 percentage, the difference was 14.3¢/gallon, slightly higher than the 2001 figure. *Id.* at p. 18.

4. BP

1886. In order for the Quality Bank to properly compensate those shippers injecting higher-quality crude into TAPS and to properly debit those shippers injecting lower-quality crude into TAPS, BP asserts that the Quality Bank methodology must remain internally consistent. BP Initial Brief at p. 7. BP points out that the Circuit Court has said that the "[Commission] must accurately value all cuts -- not merely some or most of them -- or it must overvalue or undervalue all cuts to approximately the same degree." *Id.* at pp. 7-8 (quoting *OXY*, 64 F.3d at p. 693). In other words, states BP, internal consistency is an essential goal of the Quality Bank. *Id.* at p. 8. Therefore, it is BP's position that the development of a West Coast Naphtha methodology must be guided by this consistency principle. *Id.*

1887. According to BP, witnesses and parties who consider the West Coast contracts useful suggested that their only practical use is as a yardstick to determine the validity of a proposed West Coast methodology for valuing Naphtha on the West Coast. *Id.*; BP Reply Brief at p. 7. In BP's view, the only way that the West Coast Naphtha contracts could properly play such a role is if they were consistent with the other prices used in the Quality Bank. BP Initial Brief at p. 8. In other words, explains BP, values derived from West Coast contracts must bear sufficient similarity to the prices that are used to measure the value of the other Quality Bank cuts for them to be useful in judging the validity of the proposed West Coast naphtha valuations. *Id.* It argues that the evidence presented in this case conclusively shows that the contracts and the values that the witnesses have assigned to them are not consistent with reported prices, and that, therefore, the contracts are not a useful yardstick for considering the merits of the West Coast Naphtha valuation proposals. *Id.*

1888. The preferred method of valuing the Quality Bank cuts, states BP, is through the use of prices that are reported by either Platts or OPIS, two price-reporting services.[647] *Id.* at p. 9. It explains that both Platts and OPIS survey the markets that they are trying to assess to determine the value of a particular product in the particular market at a particular moment. *Id.* BP states that the Platts and OPIS independent, unbiased assessments are the foundation of the Quality Bank methodology and notes that these reporting services provide a valuable role in the industry because their unbiased assessments allow industry participants to consider pricing information when planning their business, including their contracting decisions. *Id.* According to BP, these services attempt to provide the industry with price transparency. *Id.* at pp. 9-10. It notes that Ross agreed with Platts assessment of the important role that published prices play in the market. *Id.* at p. 10.

[647] BP cites Transcript at pp. 9740-41; Exhibit Nos. PAI-33 at p. 3, WAP-1 at pp. 4-5 in support. BP Initial Brief at p. 9, n.6.

1889. BP states that the EIA also has discussed the importance of publicly available prices in ensuring an appropriate supply/demand balance in oil markets. *Id.* It notes that spot market prices are relatively transparent and provide a clear signal about supply and demand characteristics of a market. *Id.* Further, explains BP, the EIA has recognized the importance that published prices play in market activity, stating that they enhance a market participant's ability to assess the market price level. *Id.* at pp. 10-11. BP states that, in its view, Exxon, Phillips and Alaska underestimate the importance that transparency plays in the petroleum market. BP Reply Brief at p. 10.

1890. According to BP, the editors for Platts and OPIS exercise editorial discretion in assessing the prices that they report. BP Initial Brief at p. 11. For example, continues BP, Platts does not adhere blindly to the use of weighted average prices to determine reported prices even in liquid markets and believes there is an important role for independent, analytical scrutiny, rather than simple volume weighted calculation, especially in thinly traded markets which can be subject to manipulation. *Id.* It asserts that the Naphtha market on the West Coast meets anyone's definition of thinly traded. *Id.*

1891. BP states that component cuts for ANS are valued based on published prices determined from markets characterized by transparency. BP Reply Brief at p. 11. By contrast, it points out that the West Coast Naphtha contracts were entered into in a market that lacks published prices and is opaque. *Id.* It asserts that this significant difference is fatal to the use of the Naphtha contracts as a yardstick for evaluating any methodology. *Id.*

1892. Reported prices play an important role in developing an efficient, well-functioning energy market and Platts is a significant contributor to the operation of the energy market, BP claims. BP Initial Brief at p. 12. It notes that Toof testified that the classic definition of a transparent market is one where all participants have perfect knowledge of information relevant to the transaction at hand. *Id.* (citing Transcript at pp. 6362-63). By contrast, notes BP, in an opaque market, the parties to a transaction would have little or no information. *Id.* at pp. 12-13. It points out that Toof and Ross agreed that the Gulf Coast Naphtha market, with its reported prices, is closer to being transparent than the West Coast Naphtha market, which lacks reported prices. *Id.* at p. 13.

1893. Phillips and Alaska, BP states, attempt to undermine the importance of transparency in the Naphtha market by claiming that enough information is available to the Naphtha contract participants for the contract prices to be a useful yardstick for evaluating the naphtha methodologies. BP Reply Brief at p. 13. It points out that this information, such as their own internal production value, their own negotiated Naphtha contracts, and a Gulf Coast Naphtha price, fails to provide market participants with information equivalent to that available in a transparent market with published prices. *Id.* at pp. 13-14. BP considers this information to be an incomplete subset of all Naphtha contracts and prices that falls far short of published price information. *Id.* at p. 14. It states that the information that refiners can glean from their computer models cannot replace published prices and only reveals a maximum price and notes that it tells the refiners nothing about the best price they should be able to achieve. *Id.*

1894. According to BP, the West Coast Naphtha contract prices were formed in an environment that lacked supply availability information, supply sources information, and complete price information. BP Initial Brief at p. 15. Because of that, asserts BP, there are few potential market participants who actually participate in the market and they do so only sporadically to meet emergent Naphtha supply needs. *Id.*

1895. BP states that Platts and OPIS survey the market to develop their price assessments, exercise editorial discretion, and are independent. *Id.* at p. 18. Further, explains BP, they look at spot transactions and not long-term contracts. *Id.* It asserts that Pulliam's, Tallett's, and O'Brien's Naphtha contract analyses are different. *Id.* BP points out that Pulliam acknowledged that one difference is that, although his contract analysis looks strictly at the terms of the contracts, Platts surveys the market and ordinarily does not look at individual contracts. *Id.* at pp. 18-19. It explains that this prevents individual deals from taking on a disproportionate value if only one player is in the market at a specific time. *Id.* at p. 19. Other players may value Naphtha at a lower value or not have a need for Naphtha at the time, notes BP, but would purchase at a lower price, if transparency permitted the potential buyer to determine that additional quantities would be available at that price. *Id.* Surveying the price level at which a transaction would occur, argues BP, rather than valuing the product based on one particular transaction, helps prevent overvaluation. *Id.*

1896. Another difference between the price-reporting service values and the contract values, according to BP, is the impact of long-term transactions. *Id.* BP notes that all of the contract analyses included long-term transactions. *Id.* It states that Platts does not look at long-term transactions generally and bases its values on the immediate estimated value. *Id.* For any West Coast Naphtha contracts analysis to be comparable to the reported prices, BP asserts, the analysis should have considered only spot assessments and excluded term contracts. *Id.* at p. 20. Otherwise, explains BP, formula values negotiated at a specific point in time will continue to affect the valuation at later points in time when market conditions may have changed. *Id.*

1897. Moreover, states BP, the data in the contracts analyzed by Pulliam have not been filtered to isolate them to a particular jurisdiction. *Id.* Unlike Platts, BP notes, neither Pulliam's, Tallett's, nor O'Brien's analysis adjusted prices to ensure consistency of location. *Id.* Further, BP explains, none of the analysts made the same adjustments that Platts would have made. *Id.* For example, continues BP, Platts makes various adjustments to values determined for its product prices according to industry knowledge, experience, and current market conditions and none of the West Coast contract analyses do anything like that. *Id.* Instead, according to BP, each simply reflects a compilation of particular transactions made with imperfect knowledge in an opaque market. *Id.* It argues that this provides one more indication that the contract analyses are not comparable to the price reporting services's product price assessments that underlie the Quality Bank. *Id.*

1898. BP notes that at least two techniques can measure the variation on a monthly basis in a product's price. *Id.* at p. 21. One measure, according to it, compares the absolute highest and lowest values in a month for the product; and the other compares the difference in the product's average high and average low prices for the month, the measure that Ross defined as monthly price variability. *Id.* The second measure, according to BP, is the appropriate tool to use to compare the reported prices to Pulliam's contract analysis. *Id.*

1899. Pulliam priced out the Naphtha contracts, BP states, using monthly average prices instead of trying to determine an exact contract price on a given day because he lacked data to make exact determinations for all of the contracts. *Id.* Further, explains BP, many of the Naphtha contracts's pricing terms were based on the reported price of gasoline minus a constant and were referenced to the delivery date for the Naphtha. *Id.* Therefore, states BP, instead of trying to price each contract out to match the delivery date using daily gasoline prices, Pulliam used the monthly average gasoline price. *Id.* at pp. 21-22. To appropriately compare those contract prices with the Platts and OPIS reported prices used in the Quality Bank, explains BP, Ross developed charts that describe what he called the price variability for the reported prices and then compared the range of the average high prices and average low prices with the range of the average high and average low prices that Pulliam developed in his contract analysis. *Id.* at p. 22.

1900. BP comments that the contract monthly price variability is well out of proportion to the published price series monthly price variability. *Id.* at p. 24. It notes that even Pulliam recognized that, were West Coast prices for Naphtha published, the range of Naphtha values for published price assessments "would be narrower" than what Pulliam's contract analysis yielded. *Id.* (citing Transcript at p. 7510). BP's conclusion is that the contract values are simply not comparable to the published price series, cannot be trusted as a reliable indicator of the value of Naphtha on the West Coast, and are not a useful yardstick. *Id.* It views any conclusions drawn from the contract data set as flawed. *Id.*

1901. As support for the proposition that the contract analyses provide a good yardstick for appraising the Naphtha valuation proposals, BP notes, the contract supporters point to the claimed similar values that each analysis produces and argue that, therefore, the methodologies must be sound and useful. BP Reply Brief at p. 19. BP disagrees with this conclusion for four reasons: (1) the results should be similar, (2) the contracts are still an inappropriate yardstick to use to evaluate Naphtha valuation methodologies, (3) neither participant diversity nor volumes transacted resolves the problems of an opaque market, and (4) the techniques used in the contract analyses are different than the techniques used by the reporting services. *Id.*

1902. First, BP asserts, it is not surprising that the analysts's results are similar as analyses of the same contracts should produce similar, if not identical, results. *Id.* It believes that this establishes only the similarity of the methodologies and the precision of the calculations, not the appropriateness or usefulness of the calculations. *Id.*

1903. Second, BP argues, even if one assumes that the contracts were formed in a market that is comparable to the markets that underlie the other Quality Bank cuts's reference prices the contract analyses would still be an inappropriate yardstick for judging methodological suitability. *Id.* Despite the contract supporters's claims of consistency among contract analyses's results, BP maintains, there are noticeable variations between the analyses's end results. *Id.* BP point out that, for the 1994-2001 period, the contract analyses range from 6.1¢/gallon above the Gulf Coast Naphtha price for the Pulliam contract analysis to 9.93¢/gallon above the Gulf Coast Naphtha price for the Culberson contract analysis. *Id.* at p. 20. It explains that both the Tallett and O'Brien methodologies produce results that surpass the Gulf Coast Naphtha price by 9¢/gallon during that period. *Id.* BP further notes that the data indicate that the contract analyses themselves are subjective in calculating the Naphtha contract values, as they vary widely depending on the criteria chosen for each analysis. *Id.* It states that every contract analysis used a different subset of the contracts based on the witnesses's personal choices about what to include. *Id.* BP maintains that, contrary to the contract supporters's argument that a comparison of the various contract analysis results supports their use as a measuring tool, a comparison of the resulting values cuts squarely against the contract analyses's reliability and appropriateness. *Id.*

1904. Third, BP points out, the contract supporters argue that the contracts represent transactions from a variety of sources with all of the major West Coast players represented. *Id.* It notes that the supporters claim that participant diversity and the supposedly substantial volumes transacted prove that the contracts are representative of the West Coast value of Naphtha. *Id.* BP argues that neither of those factors resolves the problems of an opaque market and argues that regardless of participant numbers or volumes transacted all of the Naphtha contracts were formed under conditions that are not comparable to the market conditions that underlie the Quality Bank reference prices. *Id.* In BP's view, because their underlying data source does not represent Naphtha prices that would be found in a transparent market, their reliability is weakened. *Id.* at p. 21.

1905. Fourth, BP states, the techniques used in the contract analyses are different than the techniques used by the reporting services. *Id.* It notes that the reporting services exercise editorial discretion, look at spot transactions only, and do not use contracts. *Id.* BP explains that price is influenced by other contractual terms including the contract's length. *Id.* In contrast, BP notes, the contract analyses look at long-term contracts and make valuation determinations from the individual contracts and points out that the contract analyses did not filter the data to ensure consistent pricing location in keeping with the reporting services techniques. *Id*.

1906. Moreover, BP maintains, drawing conclusions from the contract data is dangerous because the data set in this case is incomplete. *Id.*; BP Initial Brief at p 24. BP notes that Pulliam admitted that Platts picks up transactions between traders, while the contract analyses performed in this case would not pick up those types of transactions. BP Initial Brief at p 24. Without these transactions, claims BP, the contract analyses data set is only a subset of those transactions that should be considered. *Id.* at pp. 24-25. This fact coupled with the many differences in the techniques used to generate the Naphtha values reflected in the contract analyses means, according to BP, that the contract analyses are generating values that are not consistent with – and likely substantially different from – the values that would be generated by a reported pricing series. *Id.* at p. 25.

1907. BP notes that the contract supporters (Exxon, Phillips and Alaska) claim that the contracts's pricing mechanisms were not formed in a dysfunctional market, and explain that the contract supports assert that 1999-2001 did not produce anomalous gasoline prices, that anomalies were not distorting the contract values during this period, and that the data from that period is relevant. BP Reply Brief at p. 23. As to this claim, BP states:

> They base this assertion on several flawed arguments. First, they assert that since the contract values produce results similar to various formulas' results, this similarity indicates that the contract values are reliable for 1999-2001. For example, they argue that the contract values are similar to: (1) 1993 settlement values produced; (2) Mr. Kutola's rule of thumb; (3) Mr. Ross' analysis of contract data when adjusted for quality and volume weighting; and (4) the values generated as a function of crude oil and gasoline prices. Second, they argue that gasoline price spikes in 1999-2001 were matched by price spikes in other products. They also assert that price differentials for all products existed for the entire 1994-2001 period, not just 1999-2001, indicating that it is not anomalous for [the] West Coast to have greater differentials than the Gulf Coast and that the intermediate products' prices followed gasoline price spikes.

Id. at pp. 23-24, n.5 (citations omitted).

1908. Further, BP asserts, the supporters believe that the market characteristics that were present in 1999-2001 are likely to continue and cannot be considered anomalous. *Id.* at pp. 23-24. It argues that these assertions ignore the evidence establishing that the 1999-2001 period was characterized by large price swings, related to gasoline price anomalies, that hadn't happened in earlier periods. *Id.* at p. 24. BP suggests that the unstressed 1994-1998 contracts are more likely to be representative of West Coast naphtha values in a transparent market. *Id.*

1909. According to Ross, BP claims, there was greater gasoline price stability and fewer gasoline price anomalies on the West Coast during the 1994-1998 period than during the 1999-2001 period. BP Initial Brief at p. 25. According to it, this is important when considering whether the Naphtha contracts offer any value as a predictor of West Coast Naphtha values because, explains BP, the Naphtha contract prices are linked to gasoline prices, so that some of the contract prices went up starting in 1999. *Id.* BP points out that, according to Ross, this would not have happened in a transparent market. *Id.* It also notes that the Stillwater report, Exhibit No. EMT-385, chronicles the dysfunctional market conditions that were present in 1999-2001, and explains that the report indicates the market conditions in 1999-2001 were very different from those in 1994-1998 and that the gasoline market on the West Coast suffered from supply-demand imbalances in the later period. BP Reply Brief at p. 24. Thus, BP concludes, the contracts during the 1999-2001 period are corrupted by gasoline price irregularities and are less reliable as an indicator of Naphtha value on the West Coast.[648] BP Initial Brief at p. 26.

1910. BP notes that Ross further testified that it is problematic to look at the "contract line" over the entire 1994-2001 period because "it's distorted by the events of 1999 through 2001." *Id.* (citing Transcript at p. 9667). These events indicate that if any of the contracts or contract analyses are to be considered, according to BP, the contract data and analyses related to the 1994-1998 period would be closer to a Naphtha value in a transparent market than contract data and analyses related to the 1999-2001 period. *Id.* BP asserts that including the data from the 1999-2001 period in an analysis would result in values that are less likely to be representative of naphtha in a transparent market. *Id.*

1911. Ross acknowledged, according to BP, that Naphtha and VGO would not move in sync all the time, but claimed that, on average, they would show similar patterns. *Id.* at p. 28. The 1999-2001 contracts deviate from the VGO values and the values of the other intermediate products, explains BP. *Id.* Further, BP states, even if the 1999-2001 period characteristics continue, the contracts still would not represent the West Coast value of Naphtha in a transparent market. BP Reply Brief at p. 27. In a transparent market, it argues, the West Coast Naphtha value would not track the elevated gasoline prices because many of the disruptions that have led to higher gasoline prices would not affect intermediate feedstock (such as Naphtha) values. *Id.*

1912. The record shows, in BP's view, that the anomalous conditions during 1999-2001 corrupted the contracts and elevated their values in lockstep with gasoline, when the intermediate product values would not have been affected. *Id.* at pp. 27-28. It argues that

[648] BP also cites Exhibit No. WAP-199, a report to the California Attorney General that Pulliam co-authored, as further evidence that there were pricing irregularities on the West Coast which became more severe in 1999. BP Reply Brief at p. 25.

this relationship further undermines the appropriateness of using the contracts as a yardstick for the Naphtha valuation proposals. *Id.* at p. 28. Nevertheless, asserts BP, if the contracts are used as a yardstick, the 1994-1998 data is more reliable than the 1999-2001 data, because the 1994-1998 period did not suffer from the extreme price spikes that plagued the later period. BP Initial Brief at p. 28.

5. Unocal/OXY

1913. Unocal/OXY's position is that the Naphtha contracts analyzed in this proceeding provide some relevant and useful information about West Coast Naphtha, but that they do not provide a basis for determining West Coast Naphtha values. Unocal/OXY Initial Brief at p. 31. Further, Unocal/OXY believe, Exxon, Phillips and Alaska place too great an emphasis on the value of the contracts because it is in their economic interest to do so. Unocal/OXY Reply Brief at pp. 68-69.

1914. The contract data, Unocal/OXY state, validate the continued use of Gulf Coast pricing if consideration of the contract data is limited to the period of 1992-1998, as even Pulliam conceded. *Id.* at p. 69. They also point out that the contract pricing during the anomalous period shows evidence of various market defects that render the data unreliable. *Id.* Therefore, Unocal/OXY conclude, the contracts do not provide a basis for refuting the continued use of Gulf Coast pricing. *Id.*

1915. Unocal/OXY assert that the private contracts relating to West Coast Naphtha sales do not provide reliable evidence of the West Coast value of Naphtha for several reasons. *Id.* First, they state, the number of contracts is too small, comprising less than two percent of West Coast Naphtha volumes. Unocal/OXY Initial Brief at p. 31. Second, continues Unocal/OXY, the small sample of contracts was dominated by no more than four large participants. *Id.* at pp. 31-32 (citing Exhibit Nos. WAP-200, WAP-202, SOA-34, SOA-35, SOA-36, SOA-37).

1916. In addition, Unocal/OXY note, the sample of contracts is heavily weighted for the period 1999 through 2001, a period of extremely high volatility in California gasoline prices, characterized by anomalous conditions described earlier. *Id.* at p. 32. While the contracts spanned the period from 1988 through March of 2002, Unocal/OXY point out, 61% of the volumes included were in the 1999-2001 period. *Id.* Accordingly, Unocal/OXY claim, the entire sample was heavily influenced by a single large buyer who entered the market in 1998 and dominated the market in 2001. *Id.* They concede, in their reply brief, that a small sample size does not by itself render the data unusable, but claim that a small sample is more susceptible to distortion, manipulation and anticompetitive effects. Unocal/OXY Reply Brief at p. 76. Unocal/OXY assert that the pre-1999 contract data has not been tainted in this manner and is usable, but that the post-1999 data is tainted and thus is unusable. *Id.*

1917. Unocal/OXY also assert that there are other indications that the market in the West Coast was not competitive during the period 1999-2001 as indicated by several "red flags." Unocal/OXY Reply Brief at p. 73. They point out that a 1999 report to the California Attorney General cautions that the gasoline market has become more concentrated, that in-state refiners have been the primary beneficiaries of California's higher prices, and that the market is characterized by a relative lack of competition. *Id.* Also, they note, Ross has characterized the West Coast Naphtha market as opaque, which prevents the exchange of information on price and quality, and that Culberson has characterized the West Coast gasoline market as not workably competitive. *Id.* at p. 74. Finally, they point out that the Stillwater report describes the California gasoline market as increasingly unstable and subject to extreme volatility. *Id.* (citing Exhibit No. EMT-385 at p. 15).

1918. Because of the above problems on the West Coast, Unocal/OXY contend, the Commission should be careful not to base its decision on evidence that has been distorted by these non-competitive considerations. *Id.* Specifically, they assert that the pricing evidence from the 1999-2001 contracts should be disregarded. *Id.* at pp. 74-75. They also argue that the degree of sophistication attributed to the parties to the contracts does not obviate that possibility of market manipulation. *Id.* at p. 75.

1919. In addition, state Unocal/OXY, the contracts were often ambiguous with respect to the terms describing the quality of the material traded. Unocal/OXY Initial Brief at p. 32. Approximately 30 different terms were used to describe the Naphtha being sold, which, Unocal/OXY assert, created ambiguity as to whether the Naphtha described in the contracts was comparable to Quality Bank Naphtha. *Id.* (citing Exhibit No. UNO-7 at pp. 38-39). They claim that, as there is no precise definition of Naphtha commonly used in the industry, deciding whether a particular contract dealt with Quality Bank Naphtha or something else involved a large degree of subjective judgment. *Id.* Consequently, explain Unocal/OXY, each of the experts who analyzed the contracts did not analyze exactly the same set of contracts. *Id.* at pp. 32-33 (citing Exhibit Nos. EMT-133, PAI-154, PAI-224, SOA-1). Unocal/OXY continue, there were also a large number of very small volume transactions produced by Phillips, representing 200 barrel truck sales that Unocal/OXY's witness Culberson excluded, because they did not represent a true market value. *Id.* at p. 33.

1920. Unocal/OXY also claim that, not only were the quality terms ambiguous, but the pricing terms also were uncertain in most of the contracts, as the prices specified some deduction from a published price for a delivery date that was not specified in the contracts. *Id.* at p. 34. Typically, explain Unocal/OXY, the price is a three or five day average of published prices before and after delivery, less a deduction. *Id.* Rather than use these prices, Unocal/OXY state, O'Brien and Pulliam used monthly average prices for all such contracts, whether they had delivery data or not, and Tallett only used monthly average prices in the absence of delivery date information. *Id.* Prices for West Coast gasoline, the most frequently used pricing reference, continue Unocal/OXY, fluctuate widely during any given month. *Id.* Therefore, Unocal/OXY agree with Culberson that use of monthly average prices as a substitute for 3-day or 5-day averages could cause serious price distortion and that they should be excluded for that reason. *Id.*

1921. Because the contracts do not reflect the market value of Naphtha on the West Coast, they provide, in Unocal/OXY's view, no compelling evidence that West Coast Naphtha should be valued higher than Gulf Coast Naphtha. *Id.* They explain that, focusing on the 1999-2001 period, which represent a majority of the volumes in the studies, one dominant purchaser consistently paid materially higher prices than other purchasers, one paid consistently lower prices, and others were in the middle. *Id.* at pp. 34-35. Further, state Unocal/OXY, the largest purchasers rarely bought at the same time, meaning that there was no or very little competition to set prices. *Id.* at p. 35. The monthly prices paid by buyers reflected average differences of 15.6¢/gallon, and, therefore, state Unocal/OXY, there was no market clearing price during those months. *Id.* Unocal/OXY conclude that this means that the market was far from transparent. *Id.*

1922. Although the contracts do not provide evidence of the market value of West Coast Naphtha, Unocal/OXY contend, they provide isolated or anecdotal evidence respecting West Coast Naphtha transactions, particularly for the pre-1999 time period. *Id.* They assert that the evidence introduced by O'Brien, Pulliam, Tallett, and Culberson validates the continued use of Gulf Coast pricing. *Id.* (citing Exhibit Nos. EMT-380, EMT-381, PAI-154, PAI-224, SOA-15, SOA-16). For the period prior to 1999, Unocal/OXY state, three of these studies (Pulliam's, Tallett's, and Culberson's) show that the unadjusted average price of the Naphtha contracts is no more than two cents above the average Gulf Coast price for the period. *Id.* at pp. 35-36 (citing Exhibit Nos. SOA-25, EMT-380, UNO-20). They also maintain that, in light of the fact that Platts does not even include contracts such as those included in these studies when it develops a price assessment, differences of this magnitude are inconsequential. *Id.* at p. 36. Furthermore, Unocal/OXY point out, Culberson testified that, when contracts for Naphtha are made on the Gulf Coast, they often include a price that includes an adjustment of a penny or two from the referenced Platts price. *Id.* The much larger differentials between the contract prices and Gulf Coast prices shown for the 1999-2001 period, in their view, should be ignored because the contract sample is dominated by a very small number of purchasers operating in a non-transparent market during an aberrational period of extreme gasoline price volatility. *Id.* By contrast, explain Unocal/OXY, the pre-1999 period is not compromised by these features, and the data are therefore more reliable. *Id.*

1923. In addition, Unocal/OXY assert, problems with nomenclature cause counter-intuitive results that call into question the validity of the contract data. *Id.* at p. 37. They note that Ross testified that Full Range Naphtha should command a lower price than Heavy Naphtha. *Id.* Yet, Unocal/OXY note, when Tallett's Heavy Naphtha study is compared to his All Accepted Contracts study some interesting results are evident. *Id.*

(citing Exhibit Nos. EMT-380, EMT-381). According to Unocal/OXY, the straight average of contract prices for the All Contracts set is higher than the straight average for the Heavy Naphtha set. *Id.* Unocal/OXY explain that the pricing anomaly occurs in individual contracts as well: Ross identified three specific contracts that priced both Heavy Naphtha and Full Range Naphtha in the same contract, and set the prices equal. *Id.* Based on the foregoing, it is Unocal/OXY's position that the contracts for West Coast Naphtha transactions do not provide credible evidence that West Coast Naphtha has a higher value than Gulf Coast Naphtha. *Id.*

1924. Moreover, Unocal/OXY assert that the results of the contract analysis are inconsistent. Unocal/OXY Reply Brief at p. 77. They state that Pulliam testified that Exhibits Nos. SOA-24 and SOA-28 support the O'Brien methodology because "it came closer to the contract prices than any of the Gulf Coast based methodologies." *Id.* at pp. 77-78 (quoting Transcript at p. 7449). However, Unocal/OXY note, Pulliam eventually conceded that the Sanderson/Culberson method was closest for 1994-1998 and Tallett's method came closest if the whole period was considered. *Id.* at p. 78. Further, Unocal/OXY state, Pulliam ultimately agreed that the O'Brien method only produced the closest match during the 1999-2001 period, a period which Unocal/OXY calls "anomalous." *Id.* They note that Pulliam continued to defend the O'Brien method at the hearing, even though he acknowledged that the 1999-2001 period was characterized by refinery outages, supply constraints, elevated gasoline prices, and a relatively less competitive market. *Id.*

1925. Unocal/OXY state that, as the contract analyses are more or less consistent in terms of their overall pricing averages, all pose the same problem that Pulliam confronted. *Id.* They note that all the proposed methodologies plus the existing valuation method can claim some legitimacy from some part of the contract analyses. *Id.* Unocal/OXY argue that the contract analyses do not, however, all support a single consistent methodology throughout the period and assert that, because they don't, they are not robust and the contract analyses is of only questionable utility in this proceeding. *Id.*

6. Williams

1926. Williams asserts that no party to this proceeding considered any West Coast Naphtha contracts relevant to this proceeding or likely to provide any probative evidence in its pre-filed direct testimony. Williams Initial Brief at p. 44. It suggests that the subsequent attempts by proponents of a change to the valuation method for West Coast Naphtha to use these contracts to show their proposals are sound are misguided and argues that the hearing record reflects that the Naphtha contracts do not serve any such purpose nor do they provide any relevant or probative evidence going to the value of Naphtha on the West Coast. *Id.*

1927. According to Williams, O'Brien, Pulliam, and Tallett attempted to coordinate their testimony to show the extreme subjectivity of this analysis and to indicate the potential for manipulation of the limited West Coast Naphtha contract data. *Id.* at p. 45. It cites Exhibit Nos. PAI-82, PAI-156, and PAI-157 as proof that the three analysts were constantly changing their testimony so that eventually they would all use the same set of contracts, noting that O'Brien's data points kept changing as contracts were removed from his Heavy Naphtha contract analysis, and others were added in.[649] *Id.* Williams argues that this was particularly true of O'Brien's attempt to align his data points with those of Pulliam because they both supported the Phillips's proposal. *Id.* at pp. 45-46.

1928. Williams suggests that a problem with Pulliam's analysis is that he elected to ignore the actual pricing contained in a number of the West Coast Naphtha contracts; instead using a monthly average price. *Id.* at p. 47. They note that, even though Pulliam presented various rationalizations for doing this, he had to agree that this approach skewed the results.[650] *Id.* Williams points out that Pulliam admitted that Exhibit No. WAP-194, which graphs the variations in Pulliam's Naphtha contract values from month-to-month, shows that the actual monthly average is not at a consistent point in the monthly range. *Id.* Pulliam's answer was that it is volume-weighted, according to Williams, so it reflects the average price paid for all the transactions in the month. *Id.* at pp. 47-48.

1929. The other specific difference in contract interpretations and their impacts, Williams contends, is shown on Exhibit No. WAP-195, involving a contract between Company 32 and Phillips that both O'Brien and Pulliam included in their equivalent contract analyses. *Id.* at p. 48. It claims that Pulliam used 40,000 barrels because he said it was the volume specified in the contract, while O'Brien used 50,895 barrels which Pulliam understood to be the number of barrels that was actually delivered under that

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[649] In Williams's opinion, Pulliam's changes were the result of his not being sufficiently trained to do such contract analyses. Williams Initial Brief at p. 45, n.33. Further, Williams notes, Tallett, through a series of changes to his contract analysis, brought his contract analysis closer to his, as well as O'Brien's, calculated Naphtha values. Williams Initial Brief at p. 45, n.34.

[650] Williams notes that Pulliam attempts "to wiggle off the hook" by explaining that he ran some sensitivity tests "that allegedly show how little things would change if actual contract pricing was used." Williams Initial Brief at p. 47, n.37 (referring to Exhibit No. SOA-23). It asserts that the problem with the sensitivities is the same fundamental flaw with Pulliam's entire contract analyses, i.e., his failure to analyze the contracts correctly and accurately in the first instance results in his conclusions being suspect. *Id.*

contract for that month.[651] *Id.* Thus, notes Williams, there was a variation, for this particular transaction, of 20 to 25% in volume. *Id.* Therefore, Williams notes that, as Pulliam testified, O'Brien will have a higher average price in this case than he would. *Id.* Williams explains that this difference underscored another problem with the contract analyses: the persons performing them did not have the actual volumes delivered under all the contracts. *Id.* Consequently, it contends, Pulliam conceded that, because his analysis is volume weighted, as the volume of the contract varies, his answer would also vary. *Id.* at pp. 48-49.

1930. The other area of concern where questions arise with respect to the contracts, according to Williams, is the impact on the contract pricing results which a single company can potentially have. *Id.* at p. 49 (citing Exhibit No. WAP-200). It explains that this Exhibit shows that, from 1999-2001, a single company which started purchasing Naphtha in 1998 became the dominant purchaser; going from 23.6% of the contract purchases in 1999 to a staggering 83.3% of the contract purchases in 2001. *Id.* While Pulliam testified that he did not think there was any special significance to this, the issue as to the impact is magnified because that same company (Company 31) was one of two companies that paid the highest prices for Naphtha during this period. *Id.* at pp. 49-50 (citing Exhibit Nos. WAP-8, WAP-141, WAP-230, WAP-231). Yet, Williams notes, Pulliam placed no significance on Company 31's suddenly dominant role in Naphtha purchases. *Id.* at p. 50.

1931. In reply, Williams states, the underlying bases of the analyses of the Naphtha contracts produced in this proceeding renders any conclusions dubious. Williams Reply Brief at p. 50. It notes that Phillips points to the congruence of the results as its reason for arguing that criticism of the contract analysis is without merit. *Id.* However, Williams points out, part of the similarity of the results was derived by O'Brien and Pulliam to a greater extent, and Tallett (with the assistance of Toof) to a lesser extent, because of their attempts at reconciliation of the results so that the contracts relied upon and the results there from were in closer harmony. *Id.*

1932. Sanderson testified, Williams claims, that companies such as Platts who report price assessments limit their assessments to cash spot transactions. Williams Initial Brief at p. 50. According to Williams, this renders Pulliam's contract analysis, as well as those of O'Brien and Tallett, inconsistent with other Quality Bank price assessments. *Id.* at pp. 50-51. It states that the consequence of this is shown in Exhibit No. WAP-230 which, it claims, shows that, for the period 1994-2001, the total average daily volume of Heavy Naphtha contracts (according to Tallett's contracts analysis) is 1,100 barrels/day and for

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[651] Williams notes that Pulliam admitted that he made a data entry error with respect to the contract volume that he used for this particular contract. Williams Initial Brief at p. 48, n.38.

the period 1999-2001 it is only slightly higher, 1,260 barrels/day. *Id.* at p. 51. Williams calls this volume "a drop in the bucket," amounting to no more than 0.4% of the Naphtha throughput, when compared to the overall throughput of 337,000 barrels/day of straight run Naphtha in reformers. *Id.* Williams states that, also as shown on Exhibit No. WAP-230, the spot volumes for these two periods are reduced by approximately 25% and 33%, respectively, or below 1,000 barrels/day in both instances, when Company 31's volumes are removed. *Id.* Thus, on the basis used by Platts and other independent reporters of petroleum intermediate feedstock prices (spot transactions), it states, this almost non-existent volume renders the Naphtha contracts virtually meaningless with respect to a meaningful indication of the value of Quality Bank West Coast Naphtha. *Id.*

1933. In Williams's view, the fact that these small volumes have no relevance is buttressed by O'Brien's deposition testimony (incorporated into Sanderson's pre-filed rebuttal testimony) concerning the subject, in which he stated that these contracts do not represent a market price, because they make up only a very small portion of the total Naphtha processed through West Coast refineries. *Id.* at pp. 51-52. At his deposition regarding his answering testimony, Williams notes that O'Brien quantified substantial contract volume, stating he would consider substantial volumes to be 40-50,000 barrels/day and that to establish a market you would need that kind of daily trade. *Id.* at p. 52. Thus, even if one disregards this small volume of spot contracts, which is all that Platts would have to rely on in giving an assessment, Williams states, the highest total daily volume of all the Heavy Naphtha contracts for the most recent three years (1999-2001), is 1,260 barrels/day, which does not even come close to O'Brien's threshold to establish a market price. *Id.*

1934. Williams asserts that Exxon improperly references the Naphtha contracts as demonstrating "that Naphtha sellers have been able to extract a substantial portion of any higher West Coast refining margin." Williams Reply Brief at p. 49. In doing so, Williams notes, Exxon relied upon incomplete Sanderson testimony. *Id.* at pp. 49-50 (citing Transcript at pp. 11224, 11230). It argues that, if one looks at the complete Sanderson testimony, it is clear that that Exxon's assumption applies at best to no more than 1% of the Naphtha volume on the West Coast (the volume represented by the Naphtha contracts) and not to the other 99% of the West Coast Naphtha. *Id.* at p. 50.

1935. In Williams's opinion, the West Coast Naphtha contracts that were used in the various analyses show five points that are not subject to subjective adjustment or interpretation: (1) the West Coast Naphtha market is not robust, which is consistent with the West Coast Naphtha supply/demand being in balance; (2) most recent cargoes ported are more of a Full Range Naphtha cut tailored to meet CARB gasoline specifications; (3) the largest volume contract, "the Contract that Ross relies on," contains ANS + $4.00/barrel in the pricing formula; (4) only one contract has any N+A adjustment, and that was a penalty provision; and (5) the spot contract volume is minuscule. Williams Initial Brief at p. 53.

1936. Williams notes that Exxon states that "the reasonableness of the West Coast Naphtha values determined by [Tallett's] methodology is strongly confirmed by the fact that [Tallett's] West Coast Naphtha values are very close to the actual West Coast Naphtha prices found in the West Coast Naphtha contracts." Williams Reply Brief at p. 55 (quoting Exxon Initial Brief at p. 263). It asserts that the fallacy in Exxon's argument is that those contracts reflect how Naphtha is priced for small volume sales and thus do not reflect its value. *Id.* Williams argues that pricing Naphtha at a discount to unleaded regular gasoline is the mechanism buyers and sellers use to price small volume purchases and ensure that the price of Naphtha is indexed to other petroleum commodities to reduce the financial risk to both buyer and seller of a price change in Naphtha. *Id.* at pp. 55-56. It maintains however, that the fact that contract Naphtha prices are related to gasoline prices through a price discount to gasoline does not have a bearing on the valuation methodology. *Id.* at p. 56. Williams notes that Sanderson explained that the ability to hedge

> can be built into the transaction. For instance, if you sell naphtha based on a discount to unleaded gasoline or to CARB gasoline, you can hedge in that way. Because then if the gasoline price falls, the naphtha value falls, so the refiner gets that advantage or the receiver gets that advantage. The producer does not.

Id. (quoting Transcript at pp. 9200-01).

7. Petro Star

1937. According to Petro Star, Phillips, Exxon and Alaska assert that the West Coast Naphtha contracts examined by O'Brien, Tallett, and Pulliam corroborate the methodologies proposed by O'Brien and Tallett and repudiate the fairness of the current methodology. Petro Star Initial Brief at p. 3. It argues that the contracts accomplish none of those objectives. *Id.* In particular, Petro Star states, there is little, if any, reason to believe that the prices reflected by the contract transactions fairly represent the value of the vast bulk of Naphtha produced in or imported to the West Coast.[652] *Id.*

1938. Petro Star states that the proponents of higher West Coast Naphtha valuations

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[652] Petro Star states that the issues concerning the Naphtha contracts break down into questions concerning whether the contracts are likely to shed light on the value of Naphtha as it is produced and used on the West Coast and those concerning precisely what the contract data show, assuming that they are useful. Petro Star Initial Brief at p. 3, n.4. It notes that its brief focuses only on the former question and does not duplicate the detailed criticisms of the contract analyses presented by Williams and Unocal/OXY. *Id.*

proffer a number of arguments why the Naphtha contracts are representative of Naphtha generally, but none of those arguments changes the fact that the contracts represent only a tiny fraction of the West Coast Naphtha volume. Petro Star Reply Brief at p. 3. It asserts that, most importantly, none of them surmount the fact that Naphtha typically is not bought and sold as a commodity on the West Coast. *Id.*

1939. Explains Petro Star, almost all Naphtha that is used on the West Coast is distilled from crude oil by the refineries that use it to manufacture gasoline and/or jet fuel. Petro Star Initial Brief at p. 4. According to it, Naphtha is, therefore, typically neither bought nor sold as such, and the cost of Naphtha to the refiner is the cost of crude oil plus the cost to distill the crude. *Id.* Petro Star states that the "typical" West Coast Naphtha barrel thus arrives at the refinery gate as a crude oil component, whether from California, Alaska or elsewhere. *Id.* It points out that the refinery distills crude oil, further processes most of the Naphtha to produce gasoline blendstocks, and uses most of the remainder to manufacture jet fuel. *Id.* The refinery sells finished gasoline and jet fuel, not Naphtha states Petro Star *Id.*

1940. Further, according to Petro Star, a typical catalytic reformer on the West Coast processes from 30,000 to 40,000 barrels of Naphtha per day. *Id.* at p. 5. It states that refiners buy crude oil to distill the Naphtha they need to fill their reformers or make jet fuel. *Id.* Notes Petro Star, approximately 337,000 barrels/day of Naphtha typically are distilled from crude oil on the West Coast and used according to the general pattern described above. *Id.*

1941. By contrast, according to Petro Star, refiners buy Naphtha, as opposed to crude oil, very occasionally, and in small quantities. *Id.* at p. 5. For example, notes Petro Star, Pulliam's combined contract (i.e., both "Spec" and "Potential" Naphtha) indicated that annual Naphtha contract volumes for the period 1994 through 2001 ranged from a low of 1260 barrels/day in 1998 to a high of 7190 barrels/day in 2000. *Id.* In other words, states Petro Star, even if a single refiner operating a typical 30,000-40,000 barrel/day catalytic reformer had purchased all of the Naphtha sold under the contracts in 2000, it still would have refined three-fourths of its Naphtha feed from crude oil. *Id.* In fact, points out Petro Star, the largest Naphtha purchaser in 2000 bought 30.3% of the total, or approximately 2200 barrels/day.[653] *Id.*

[653] Petro Star states that it focuses on Pulliam's contract analysis because he testified most extensively about the issue of whether the contract data were representative of Naphtha purchased as crude oil and refined internally. Petro Star Initial Brief at p. 5, n.5. It explains that the contract analyses performed by Tallett and O'Brien did not involve sample sizes that were materially different from Pulliam's. *Id.* Consequently, in Petro Star's view, the arguments it makes regarding the contracts analyzed by Pulliam apply equally well to Tallett's and O'Brien's analyses. *Id.*

1942. These small volumes of Naphtha represent a very limited number of transactions, in Petro Star's opinion. *Id.* For the entire West Coast, notes Petro Star, Pulliam's combined contract database includes 175 contracts over the entire period 1994 through 2001, somewhat less than two per month on average. *Id.* Even during the more recent period 1999 through 2001, Petro Star states, there are only 94 contracts, or fewer than three per month. *Id.* Petro Star argues the Naphtha contracts do not represent a large enough sample to accurately reflect all of Naphtha refined on the West Coast. *Id.* More importantly, states Petro Star, the vast bulk of West Coast Naphtha is not involved in the same kind of transaction as the Naphtha traded under the contracts. *Id.* at p. 6.

1943. Pulliam acknowledged, Petro Star suggests, that a random sample must be representative of the population from which it is drawn to be valid. *Id.* However, states Petro Star, he opined that Naphtha contract prices are representative of the value of Naphtha that was purchased as crude oil and refined rather than sold. *Id.* Petro Star explains that Pulliam looked to the stock market to explain why, claiming that the value of a stock to the owner who does not sell on any given day is represented by the value (selling price) of the one percent that is traded on a given day. *Id.* Pulliam explained, continues Petro Star, that he believes that a refiner that uses Naphtha internally only does so after deciding not to sell it. *Id.*

1944. In fact, asserts Petro Star, once Pulliam's implicit assumptions are tested against the realities of refining economics, the stock market analogy better illustrates why the contracts are not representative of the value of West Coast Naphtha. *Id.* at p. 7. It indicates that Pulliam's theory is that 99% of the Naphtha that does not trade is valued at the same price as the 1% that was sold, according to Petro Star, because any one of the non-selling shareholders could have sold his or her stock at that same price. *Id.* Petro Star states that Pulliam assumes that the reverse, if any refiner wanted to sell, it could find a buyer for its Naphtha at or near the prices in the contracts analyzed by Pulliam, also is true. *Id.*

1945. According to Petro Star, this is unlikely to be the case, because the Naphtha market essentially is in balance on the West Coast. *Id.* Consequently, according to Petro Star, refiners have a choice: they can either buy Naphtha or they can buy crude oil. *Id.* There is no dispute that refiners typically build their refineries to process crude oil, and the one thing that the contract data unequivocally show, states Petro Star, is that demand for purchased Naphtha is very limited. *Id.* Indeed, asserts Petro Star, none of the reasons that O'Brien recounted for why large refiners might trade Naphtha back and forth are routine. *Id.* Moreover, notes Petro Star, Tallett testified that, if you imported a cargo of gasoline into California, you would hope to sell it for a reasonable price, but if you imported Naphtha you might or might not find people that would pay a reasonable price. *Id.* at pp. 7-8. Petro Star states that O'Brien similarly testified that a few isolated California refiners sell Naphtha outside California because there is no local market. *Id.*

Finally, notes Petro Star, each of the small refiners that Pulliam reported closed in spite of being fully capable of producing Naphtha. *Id.* (citing Exhibit WAP-199 at p. 22.)

1946. At best, asserts Petro Star, the most that the price of the 1% can indicate is the value of the small volume of Naphtha that is traded as a commodity rather than purchased as crude oil. Petro Star Reply Brief at p. 4. According to Petro Star, the contract proponents's arguments that the Naphtha contracts are broadly representative rests on the mistaken assumption that all of the Naphtha on the West Coast is constantly in play in a vibrant Naphtha market. *Id.* Thus, states Petro Star, Baumol tacitly assumes that the prices contained in the Naphtha contracts are indeed widely available when he testified that, if a refinery uses Naphtha internally that could be sold at a price higher than its internal value, then the refiner could be subject to a shareholder derivative suit. *Id.* Moreover, notes Petro Star, Baumol's hypothetical rests on the high prices being persistent. *Id.* If in fact there were persistent high prices available for Naphtha, Petro Star argues, there would be imports of Naphtha into the West Coast and it states that Baumol testified he also believed that would be true. *Id.* However, asserts Petro Star, deals for Naphtha sales are struck so infrequently that it would be rash to assume that because Company A got a high price for Naphtha, Company B could get the same high price. *Id.* at p. 5.

1947. Further, notes Petro Star, Alaska argues that "specific knowledge about the refining industry" indicates that the contract data accurately reflects the value of West Coast Naphtha that is not bought and sold as a commodity. *Id.* at p. 6 (quoting Alaska Initial Brief at pp. 8-9). It notes that Alaska contends that constant refinery optimization essentially means that refineries always make the choice whether to refine Naphtha from crude and use it themselves, or to buy and sell it as a commodity. *Id.* at pp. 6-7.

1948. Petro Star also claims that Alaska cites Culberson's testimony concerning a refiners options to change the crude slate, the boiling ranges, the cut points, import VGO, and make decisions as to how to satisfy its Naphtha demand, as an example. *Id.* at p. 7. According to Alaska, notes Petro Star, these examples provide the linkage between the contract prices and the value of internally used Naphtha. *Id.* In fact, asserts Petro Star, they merely confirm that refineries buy or sell only very small volumes of Naphtha. *Id.* It states that the Alaska conceded that Sanderson's remarks only pertained to those instances where the refinery actually made Naphtha purchasing decisions when it was more economical to buy from an outside source. *Id.* Moreover, asserts Petro Star, except for VGO importing, the routine optimization decisions that Culberson described all illustrate how a refinery in the ordinary course of business trims its Naphtha supply by adjusting how it processes crude oil – not by purchasing commodity Naphtha. *Id.* at pp. 7-8. Therefore, concludes Petro Star, the knowledge relied upon by Alaska shows that Naphtha volumes sold under contract are small, precisely because almost all West Coast Naphtha is purchased and used according to a different pattern. *Id.* at p. 8.

1949. None of the contract proponents's arguments, Petro Star contends, designed to show that the small sample reflected in the Naphtha contracts is either adequate or representative have merit. *Id.* While 1% might comprise an adequate sample size under some circumstances, Petro Star maintains it doesn't in this case. *Id.* It explains that when using small samples, it is necessary to design them carefully so that they are representative of the large group of data you are sampling and not just one segment. *Id.* In the case of the Naphtha contracts, states Petro Star, just one segment of the population is picked. *Id.* Virtually none of the Naphtha used on the West Coast is traded as a commodity, notes Petro Star, but all of the data come from the one or two percent that is. *Id.*

1950. Petro Star suggests that the argument that the pricing services rely on a small number of transactions to derive their quotations to be equally unpersuasive for three reasons. *Id.* First, states Petro Star, the pricing services themselves do not believe that there is sufficient information available to support quotations for West Coast Naphtha. *Id.* Second, states Petro Star, and contrary to the premise of the argument, the pricing services do not simply extrapolate from transactional data to arrive at their prices. *Id.* For example, Platts quotes are its assessment of where Naphtha could be traded. *Id.* at pp. 9-10. If, instead of relying on contacts and exercising judgment, the pricing services had to rely on the Naphtha contracts, Petro Star argues that they frequently would have to accept the price for one or a very few individual, and frequently stale, contracts as the prevailing Naphtha price. *Id.* at p. 10. Finally, the bulk of the Naphtha contracts are term contracts, notes Petro Star, which the pricing services find to be unreliable as price indicators because they may not reflect the current market. *Id.*

1951. Market realities thus, according to Petro Star, contradict Pulliam's assumption that a refiner could find a buyer for its Naphtha at or near the prices in the contracts that Pulliam examined.[654] Petro Star Initial Brief at p. 8. There is no evidence, according to Petro Star, that any West Coast refiner uses purchased Naphtha as more than a small fraction of its reformer feed. *Id.* at p. 9. Further, states Petro Star, there is no evidence that the prices contained in the Naphtha contracts are representative of the value of

[654] Petro Star asserts that there is an additional reason why the prices in many of the contracts that Pulliam analyzed may not be representative. Petro Star Initial Brief at p. 8, n.6. It explains that term contracts, as opposed to spot contracts, may no longer reflect market prices when delivery occurs. *Id.* For this reason, states Petro Star, Platts uses spot, not term contracts, and avoids contracts where the Naphtha price is set up as a function of gasoline minus a differential and the differential doesn't change with the market on a day-to-day basis. *Id.* Petro Star points out that the majority of the contracts analyzed by Pulliam price Naphtha in this manner. *Id.* Similarly, concludes Petro Star, fewer than half of the "Heavy Naphtha" contracts analyzed by Tallett during the crucial 1999-2001 period were spot contracts. *Id.*