UNITED STATES OF AMERICA 120 FERC ¶ 63,018
FEDERAL ENERGY REGULATORY COMMISSION

BP Pipelines (Alaska) Inc. Docket No. OR06-10-000
ConocoPhillips Transportation Alaska, Inc.
ExxonMobil Pipeline Company
Koch Alaska Pipeline Company
Unocal Pipeline Company

STATE OF ALASKA
REGULATORY COMMISSION OF ALASKA

BP Pipelines (Alaska) Inc. Docket No. P-06-10
ConocoPhillips Transportation Alaska, Inc.
ExxonMobil Pipeline Company
Koch Alaska Pipeline Company
Unocal Pipeline Company

INITIAL DECISION

(Issued September 7, 2007)

APPEARANCES

Carlyn D. Bishop, Esq., Bradford G. Keithley, Esq. and *Melissa Maxwell, Esq.* on behalf of BP Exploration Alaska, Inc. and BP Oil Supply (BP)

John E. Kennedy, Esq., Daniel W. Sanborn, Esq. and *Louis R. Veerman, Esq.* on behalf of BP Pipelines (Alaska), Inc., ConocoPhillips Transportation Alaska, Inc., ExxonMobil Pipeline Company and UnoCal Pipeline Company (TAPS Carriers)

John W. Griggs, Esq. on behalf of Chevron USA, Inc. and Union Oil Company of California (Chevron)

John A. Donovan, Esq. and *Matthew W.S. Estes, Esq.* on behalf of ConocoPhillips Alaska, Inc. (CPAI)

James F. Bendernagel, Jr., Esq., Eugene R. Elrod, Esq. and *Kurt Jacobs, Esq.* on behalf of ExxonMobil Corporation (subsumed under EMT)

James M. Armstrong, Esq., Randolph L. Jones, Jr., Esq., Kerri E. Kobbeman, Esq., Kory Parkhurst, Esq. and *Travis A. Pearson, Esq.* on behalf of Flint Hills Resources, Alaska, LLC (Flint Hills)

John B. Rudolph, Esq. on behalf of Koch Alaska Pipeline Company, LLC

Richard A. Curtin, Esq. and *Patricia Godley, Esq.* on behalf of Petro Star, Inc. (Petro Star)

Bruce J. Barnard, Esq. and *Alan Birnbaum, Esq.* on behalf of the State of Alaska (SOA)

Jeffrey G. Disciullo, Esq. and *David S. Shaffer, Esq.* on behalf of Tesoro Alaska Company (subsumed under EMT)

DEBRA J. BRANDWEIN, Presiding Administrative Law Judge, Regulatory Commission of Alaska

H. PETER YOUNG, Presiding Administrative Law Judge, Federal Energy Regulatory Commission

TABLE OF CONTENTS

I. JOINT STATEMENT OF THE CASE[1]

A. The Trans-Alaska Pipeline System (TAPS)

1. TAPS is a crude oil pipeline running approximately 800 miles from Pump Station No. 1 on Alaska's North Slope to the Marine Terminal located in Valdez, Alaska. At the height of North Slope production, TAPS transported over two million barrels of Alaska North Slope (ANS) crude oil per day. As production from the North Slope fields has declined, the volume of ANS transported by TAPS also has declined. In June 2006, TAPS transported about 791,500 barrels of ANS per day.

2. Crude oil produced on the North Slope is tendered to TAPS from gathering lines and pipelines at Pump Station No. 1 for transportation to market, thereby forming the "ANS common stream." There are also three additional delivery points along TAPS: (1) the Golden Valley Electrical Association (GVEA) Connection, where petroleum from the ANS common stream is taken from TAPS and processed by two refineries; (2) the Petro Star Valdez Refinery (PSVR) Connection, where petroleum from the ANS common stream is processed by one refinery; and (3) the Valdez Marine Terminal, where the ANS common stream is loaded on tankers for delivery to markets in either Alaska or the U.S. West Coast. A map of Alaska showing the TAPS system, Pump Station No. 1 and the delivery points is attached as Exhibit JS-4.

Pump Station No. 1

3. Five separate gathering lines and/or pipelines tender North Slope crude to TAPS at Pump Station No. 1: (1) the Prudhoe Bay gathering line delivers crude from the Prudhoe Bay field (referred to in some TAPS tariffs as "Sadlerochit" crude); (2) the Kuparuk pipeline delivers crude from the Kuparuk River, Milne Point and Alpine (also referred to as "Colville River") fields; (3) the Endicott pipeline delivers crude from the Endicott (also referred to as Duck Island) and Badami fields[2]; (4) the Lisburne gathering line

[1] The Joint Statement of the Case was prepared and submitted by the participants. It was accepted into the record as a joint stipulation (Exhibit JS-3) on July 9, 2007 for incorporation into this Initial Decision without substantive modification (minor stylistic changes have been made—some [bracketed]).

[2] In addition, in recent months the Endicott Pipeline has been used to transport some Prudhoe Bay production while a portion of the Prudhoe Bay pipeline has been shut down temporarily for repairs.

delivers crude from the Greater Pt. McIntyre Area[3]; and (5) the Northstar pipeline delivers crude from the Northstar field, which began production in November 2001. Exhibit JS-5 contains two schematics identifying the various fields from which the North Slope crude is delivered to Pump Station No. 1. The first page identifies the five pipelines that deliver crude to Pump Station No. 1, the amounts of crude delivered by each pipeline in June 2006, and the parties' relative ownership interests in those crude streams at that time. The second page shows the various fields that are served by the Kuparuk and Endicott pipelines, the amounts of crude oil delivered from each of those fields in June 2006, and the parties' relative interests in those fields at that time.

The Refinery Connections

4. The three refineries along TAPS process petroleum extracted from the ANS common stream and return unused portions of the stream to TAPS. Exhibit JS-6 is a schematic which depicts the parties who own these refineries, the volumes of petroleum delivered for processing to each of the refineries in June 2006 (the “offtake stream”), the volumes retained by the refineries, and the volumes of petroleum that are returned for further shipment on TAPS (the “return stream”). As noted on the schematic and further explained below, the shippers of the refinery return streams make Quality Bank payments based upon the differences between the quality of the petroleum delivered to them in the intake stream and the quality of the petroleum that makes up the return stream.

B. History of the Quality Bank

Need for the Quality Bank

5. Crude oil is a mixture of different hydrocarbon molecules, some of which are more valuable to refiners than others. In general, the types of molecules that refiners use to produce gasoline, diesel fuel and jet fuel are the most valuable. Each of the crude oil fields on the North Slope has its own unique mixture of hydrocarbon molecules. Because these crudes all have different qualities (i.e. different proportions of the various types of hydrocarbon molecules), they all have different values to refiners.

6. None of the North Slope crudes is bought or sold separately on the North Slope. Instead, all of the North Slope crudes tendered at Pump Station No. 1 are blended together and transported on TAPS as a single commingled common stream (i.e. the ANS common stream). The quality of the ANS common stream is also affected by the operations of the refineries connected to TAPS. As a result of crude oil processing at those refineries, the qualities of the refinery return streams differ from the quality of the

[3] In addition, some of the production from the Greater Pt. McIntyre Area is delivered to Pump Station No. 1 through the Prudhoe Bay pipeline.

offtake streams at those locations which, in turn, affects the quality of the ANS common stream delivered to the Valdez Terminal. At the Valdez Marine Terminal, all shippers receive the identical blend of petroleum regardless of the quality of the crude oil that they tendered to TAPS at Pump Station No. 1 or at one of the refinery connections.

7. The TAPS Quality Bank was designed to compensate shippers for differences in the values of the crude oils which they tender to TAPS as compared to the value of the commingled ANS common stream. Shippers of crude oils that have a lower value than the ANS common stream are required to make payments into the Quality Bank, while shippers of crude oils with a value higher than the ANS common stream receive payments from the Quality Bank. Because of the large volumes of ANS shipped on TAPS, small differences in quality can result in significant Quality Bank payments. As a consequence, the Quality Bank has been the subject of litigation almost from its very inception.

The Gravity-Based Quality Bank Methodology

8. TAPS began operations in 1977 with a single crude oil stream from the Prudhoe Bay field. The TAPS Quality Bank was instituted shortly thereafter as a result of the addition of a second crude oil stream from the Kuparuk pipeline and the start-up of operations of a refinery at the GVEA connection. The first TAPS Quality Bank proceeding was commenced in 1979. That proceeding resulted in a settlement in 1984 pursuant to which a gravity-based methodology was used to compensate shippers for differences in crude qualities. *Trans Alaska Pipeline System*, 29 FERC ¶ 61,123 (1984).

9. The "gravity" methodology determined the relative values of the crude oils transported by TAPS based on their API gravities as compared to the API gravity of the ANS common stream. API gravity is a measure of the density of a crude oil. Crude oils with high API gravities are lighter and typically are worth more than crude oils with lower API gravities. Thus, in the gravity-based TAPS Quality Bank, shippers of crude oils with API gravities higher than the API gravity of the ANS common stream received payments from the Quality Bank, while shippers of crude oils with API gravities lower than the ANS common stream made payments into the Quality Bank. The gravity method assumed a direct, linear relationship between API gravity and the values of the different crude oils tendered to TAPS, all of which fell within a relatively narrow range of API gravities.

Implementation of the Distillation Quality Bank Methodology

10. In addition to crude oil, there are significant reserves of natural gas on the North Slope. Natural gas, like crude oil, is a mixture of hydrocarbons, albeit very small, light hydrocarbon molecules. Beginning in 1986, significant volumes of Natural Gas Liquids (NGLs) began to be extracted from the natural gas produced from the Prudhoe Bay field

and blended into Prudhoe Bay crude oil for transportation to market over TAPS. NGLs have a very high API gravity (about 90° API versus 30° API for ANS), but are typically viewed as having a lower market value than crude oil. When blended with crude oil, volumes of NGLs can significantly increase the API gravity of the blended stream.

11. In 1989, two producers and an Alaska refiner filed complaints asserting that the gravity-based TAPS Quality Bank methodology no longer was just and reasonable as a result of NGL blending at Prudhoe Bay and increasing refinery operations along TAPS. After extended litigation and settlement negotiations and the resulting contested offer of settlement utilizing a distillation methodology, the Commissions in December 1993 replaced the gravity-based TAPS Quality Bank methodology with a distillation methodology. *Trans Alaska Pipeline System*, 65 FERC ¶ 61,277 (1993); Order No. P-89-1 (64) (APUC Dec. 1, 1993).[4] The distillation methodology adopted by the Commissions was based on the contested settlement with certain Commission imposed changes.

The Distillation Methodology

12. The distillation methodology imposed by the Commissions was based on the premise that crude oils are valued in the market based on the products that can be refined from them. As an initial step in the refining process, crude oil is separated into different components or "cuts." In very simplified terms, the crude oil is heated until it starts to boil, and the different cuts boil out of the crude oil at different temperatures, with the lightest cuts boiling out at lower temperatures and the heaviest cuts boiling out at considerably higher temperatures. This process is known as distillation, and the cuts produced by distillation are defined by the temperature range at which each cut boils out of the crude oil. For example, in the TAPS Quality Bank, the Heavy Distillate cut is defined as the material that boils out of the crude oil at temperatures between 450° and 650° Fahrenheit. Some of the Quality Bank cuts can be sold without further processing, while other cuts including the Heavy Distillate cut (sometimes referred to as “intermediate feedstocks”) are subjected to further processing and then sold as finished petroleum products. Exhibit JS-7 is a simple schematic of the distillation process showing the nine TAPS Quality Bank cuts,[5] the resulting intermediate feedstocks, and examples of the finished products made from each such feedstock.

---

[4] The distillation methodology is used at Pump Station No. 1, the GVEA Connection and the PSVR Connection. The gravity-based methodology is still used at the Valdez Marine Terminal.

[5] The nine cuts, from lightest to heaviest, are: (1) Propane; (2) Isobutane; (3) Normal Butane; (4) Light Straight Run (LSR); (5) Naphtha; (6) Light Distillate; (7) Heavy Distillate; (8) Vacuum Gas Oil (VGO); and (9) Resid. The first four of these cuts include the NGLs that are blended into certain of the North Slope crude oil streams along with NGLs which occur naturally in crude oil.

13. The TAPS Quality Bank distillation methodology determines the percentage of each Quality Bank cut contained in each of the petroleum streams tendered to TAPS and calculates the percentage of each in the ANS common stream. The methodology then develops a value for each cut, multiplies that value by the percentage of the cut contained in each petroleum stream, and sums the resulting values to develop a total value for each petroleum stream transported by TAPS. These values are then used to determine the Quality Bank payments. Shippers of petroleum streams with values that are higher than the value of the ANS common stream receive payments from the Quality Bank, while shippers of petroleum streams with values lower than the ANS common stream make payments into the Quality Bank. The Quality Bank is a "zero-sum" operation in that it ultimately pays to shippers of relatively higher-value streams all the money paid into the Quality Bank by shippers of relatively lower-value streams, less the expense incurred by the TAPS Carriers to administer the program.

Subsequent Litigation

14. FERC's 1993 decision implementing the distillation methodology was appealed to the D.C. Circuit, which issued its ruling in August 1995. *OXY U.S.A. Inc. v. FERC*, 64 F.3d 679 (D.C. Cir. 1995). Although the court upheld FERC's finding that the gravity methodology should be replaced by the distillation methodology, it remanded to FERC issues regarding the valuation of the Resid, Heavy Distillate and Light Distillate cuts.

15. In 1997, the Commissions approved another contested settlement that established new values for the remanded cuts. *Trans Alaska Pipeline System*, 81 FERC ¶ 61,319 (1997); Order No. P-89-1(87)(APUC Jan. 13, 1997). The FERC's decision was again appealed. On July 13, 1999, the D.C. Circuit issued its decision in *Exxon Company, U.S.A. v. FERC*, 182 F.3d 30 (D.C. Cir. 1999), approving the Heavy Distillate and Light Distillate values set forth in the 1997 Settlement, but remanding two issues to FERC for further consideration: (1) how the Resid cut should be valued; and (2) whether changes in the distillation methodology should be applied retroactively to December 1993 when that methodology was first implemented.

16. In a related proceeding, FERC issued decisions in 1999 denying complaints filed by Exxon Corporation and Tesoro Alaska Petroleum Company regarding the distillation methodology in general and the values of the Naphtha and VGO cuts in particular. *Exxon Co., U.S.A. v. Amerada Hess Pipeline Corp.*, 87 FERC ¶ 61,133 (1999); *Tesoro Alaska Petroleum Co. v. Amerada Hess Pipeline Corp.*, 87 FERC ¶ 61,132 (1999). Those decisions also were appealed to the D.C. Circuit, which issued a decision in 2000 remanding the methodological and Naphtha and VGO valuation issues for further consideration. *Tesoro Alaska Petroleum Co. v. FERC*, 234 F.3d 1286 (D.C. Cir. 2000).

17. In November 1999, the TAPS Quality Bank Administrator (QBA) notified the

Commissions of a radical change in the published prices used to determine the value of the West Coast Heavy Distillate cut. Under the 1997 Settlement, the price for Heavy Distillate on the West Coast had been set based on the Platts Oilgram Price Report (Platts) quotation for the price of West Coast High Sulfur (0.5 percent) Waterborne Gasoil less a processing cost adjustment of 1 cent per gallon. Platts announced that effective November 1, 1999, it would no longer assess US West Coast Waterborne Gasoil reflecting a sulfur content of 0.5 percent sulfur. Platts' elimination of the price assessment for this product required the use of a new proxy product to value the West Coast Heavy Distillate cut.

18. In February of 2000, FERC issued an order that accepted the parties' proposal to use Platts West Coast LA Pipeline LS No. 2 (0.05 percent sulfur) as the proxy for the West Coast Heavy Distillate cut, but referred to a settlement judge the issue of the processing cost adjustment required to reduce the sulfur content of the West Coast Heavy Distillate cut to the sulfur content of the proxy product. *Trans Alaska Pipeline System*, 90 FERC ¶ 61,123 (2000).

19. In November 2001, the Commissions issued orders setting for hearing the issues remanded by the D.C. Circuit in the *Exxon* and *Tesoro* decisions. *Trans Alaska Pipeline System*, 97 FERC ¶ 61,150 (2001); Order No. P-89-1 (90) (RCA Nov. 28, 2001). In addition, because no settlement could be achieved regarding the processing cost adjustment for the West Coast Heavy Distillate cut, that matter also was set for hearing.

20. After a lengthy hearing in 2002 and 2003, the Commissions issued a decision in 2005 that resolved all of the issues that had been set for hearing in the 2001 orders. *Trans Alaska Pipeline System*, 113 FERC ¶ 61,062 (2005) (Opinion No. 481); Order No. P-89-1 (104) (RCA Oct. 20, 2005). Included in the decision was a ruling on the processing cost adjustment to be used in valuing the West Coast Heavy Distillate cut. In their decisions on rehearing, the Commissions made certain changes to their 2005 decisions. *Trans Alaska Pipeline System*, 114 FERC ¶ 61,323 (2006) (Opinion 481-A); Order No. P-89-1 (109) (RCA Mar. 31, 2006). However, none of those changes related to valuation of the West Coast Heavy Distillate cut.[6] The Commissions' orders are currently on appeal. *BP Exploration (Alaska) Inc.*, *et al*., D.C. Circuit Docket Nos. 06-1153, *et al*. (consolidated); *Exxon Mobil Corp. v. RCA*, Superior Court of the State of Alaska Docket Nos. 3AN-05-13261 CI, *et al.* (consolidated).

---

[6] Subsequent rehearing orders likewise did not change the rulings regarding the processing cost adjustment for the West Coast Heavy Distillate cut. *Trans Alaska Pipeline System*, 115 FERC ¶ 61,287 (June 1, 2006); Order No. P-89-1 (111) (RCA June 12, 2006).

C. The Current Proceeding

21. On July 28, 2006, the [Quality Bank Administrator (QBA)] filed a notice of Radical Alteration in Basis for West Coast Heavy Distillate Price Quotation and Recommended Replacement Price (QBA Notice). As noted above, Opinion No. 481 and the RCA Order adopting it established the reference price to be used to value the West Coast Heavy Distillate cut. That reference price was the Platts West Coast spot quotation for Los Angeles Pipeline LS (EPA) Diesel (LSD), which had a sulfur content of 500 parts per million (ppm). Opinion No. 481 also established $0.0502 cents per gallon (in Year 2000 dollars) as the appropriate processing cost adjustment to be deducted from the Platts LSD reference price.[7] Effective June 1, 2006, Platts discontinued the LSD reference price and replaced it with a price quotation for LA Pipeline ULS (EPA) Diesel (ULSD), which is an ultra low sulfur diesel fuel that has a sulfur content of 8 ppm.

22. The QBA Notice stated that the change in the sulfur specification was a radical alteration within the meaning of the TAPS Quality Bank tariffs, and that more costly processing would be required to meet the lower sulfur specification of the proposed new ULSD proxy product. The QBA recommended the use of Platts ULSD price quotation less a processing cost adjustment of 10.4549 cents per gallon, which the QBA noted was approximately 4 cents per gallon more (in 2006 dollars) than the processing cost adjustment approved by the Commissions in their 2005 decision.

23. In response to the QBA Notice, several parties filed comments on the QBA proposal. Although there was general agreement among the parties on the use of the ULSD price to value the Heavy Distillate cut, the parties disagreed with the QBA proposal regarding the level of the proposed processing cost adjustment.

24. On September 26, 2006, the Commissions issued an order setting the Heavy Distillate processing cost adjustment issues for a concurrent hearing before both agencies. *BP Pipelines (Alaska) Inc.*, 116 FERC ¶ 61,291 (2006); Order No. P-06-10 (2) (RCA Sept. 26, 2006) [(September 26 Order)]. In its order, the FERC defined the scope of the proceeding as follows:

> The hearing should be governed, to the extent possible, by the results of prior Quality Bank rulings in Opinion Nos. 481 and 481-A. Thus, only issues as to cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate should be determined in this proceeding.

[7] This processing cost adjustment was adjusted annually in February by the QBA using the Nelson-Farrar Index prescribed in the tariffs.

116 FERC ¶ 61,291, at P 10.

[The following SUPPLEMENTAL PROCEDURAL HISTORY/SUMMARY BACKGROUND has been substituted for the final paragraph of Exhibit JS-3 exclusively for stylistic purposes. That paragraph remains a part of Exhibit JS-3 and of the official record in these proceedings.]

II. SUPPLEMENTAL PROCEDURAL HISTORY/SUMMARY BACKGROUND

Supplemental Procedural History

25. H. Peter Young was designated Presiding Administrative Law Judge in Docket No. OR06-10-000 by order of the Chief Judge issued October 3, 2006. Judge Young conducted a prehearing conference on October 25, 2006 in which a procedural schedule for Docket No. OR06-10-000 was adopted.

26. RCA appointed Debra J. Brandwein as Presiding Administrative Law Judge and designated the full RCA as the commission panel in Docket No. P-06-10 by order issued August 16, 2006.[8] That order adopted the September 26 Order and directed the parties to request the RCA to hold concurrent hearings with FERC if they so desired.[9]

27. CPAI filed an unopposed motion on October 2, 2006 requesting FERC and RCA to conduct concurrent hearings in FERC Docket No. OR06-10-000 and RCA Docket No. P-06-10. FERC and RCA issued orders establishing concurrent hearings on November 21, 2006 and November 24, 2006, respectively.[10] The Presiding Judges held a prehearing conference in the concurrent proceedings on December 6, 2006, and issued an order adopting an expedited procedural schedule for those proceedings on December 7, 2006.

28. The Joint Statement of Contested Issues submitted by the parties on May 1, 2007 questioned the scope of the hearing under the September 26 Order. Accordingly, the Presiding Judges issued a notice and order on May 5, 2007 which directed the parties to

---

[8] Order Designating Commission Panel and Appointing Administrative Law Judge, Order No. P-06-10 (1) (RCA Aug. 16, 2006). RCA issued an order reducing the panel from five to three Commissioners on April 4, 2007. Order P-06-10 (5).

[9] Order Adopting Federal Energy Regulatory Commission Decision and Directing Quality Bank Administrator to Use Proposed Replacement Price Subject to Refund, Order No. P-06-10 (2) (RCA Sept. 26, 2006).

[10] *BP Pipelines (Alaska) Inc.*, 117 FERC ¶61,215 (2006), Order Granting Motion and Establishing Concurrent Hearings, Order P-06-10 (4) (RCA Nov. 24, 2006).

file briefs addressing the issue on or before May 11, 2007. The Presiding Judges issued a Determination and Order on Scope of Hearing on May 18, 2007 (May 18 Determination) construing the September 26 Order to restrict the issues to be resolved at hearing to "cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate."[11] The May 18 Determination expressly deferred for more thorough exploration at hearing any alleged deviation(s) from prior rulings in Opinion Nos. 481 and 481-A, specifically prohibiting motions to strike testimony or other exhibits on that basis.

29. The hearing was conducted at the RCA in Anchorage, Alaska from July 9, 2007 through July 18, 2007. RCA Chairman Anthony A. Price and RCA Commissioners Janis W. Wilson and Kate Giard presided along with Judges Brandwein and Young. Reply Briefs (Reply Br.) were filed on August 3, 2007.[12] The evidentiary record closed August 14, 2007. Briefs on Exceptions to this Initial Decision are due September 21, 2007; Briefs Opposing Exceptions are due October 2, 2007.

30. Section 4412 (c) of the Motor Carrier Safety Reauthorization Act of 2005, Public Law No. 109-59 (enacted August 10, 2005), provides that FERC "shall issue a final order" with respect to any "claim relating to a quality bank under this section" no later than "15 months after the date on which [the] claim is filed. . . ." This language could be construed to require FERC to issue a final order concerning this Initial Decision as early as October 28, 2007.[13]

Summary Background

31. As previously explained, varying quality crude oil streams tendered at Pump Station No. 1 are commingled and transported on TAPS as a common stream of uniform blended quality. The blended stream quality is subsequently affected by refineries

---

[11] The quoted language was taken *verbatim* from the September 26 Order.

[12] The expedited nature of the proceedings required Initial Briefs (Initial Br.) to be filed *prior* to hearing commencement (June 5, 2007). Accordingly, post-hearing corrections to Initial Briefs were permitted.

[13] Section 4412 neither defines the term "claim" nor specifies when a claim is deemed filed. The earliest date on which a claim conceivably could be deemed filed in this proceeding is the date of the QBA Notice—July 28, 2006. Although the Presiding Judges deem it unlikely that the July 28, 2006 notice reasonably could be deemed a claim filed under the statute, the October 28, 2007 deadline is calculated from that date. The Presiding Judges self-imposed the September 7, 2007 Initial Decision issuance date to afford FERC the maximum possible time in which to issue its order.

connected at various points along the pipeline. The quality of the stream each refinery returns to TAPS differs from the quality of the commingled stream the refinery takes off the pipeline. The quality of the common stream TAPS ultimately delivers to the Valdez Terminal therefore is a complex not only of the various crude streams originally tendered at Pump Station No. 1, but also of the partially-refined streams returned to TAPS by the various refineries connected to the pipeline between Pump Station No. 1 and the Valdez Terminal. Nevertheless, each TAPS shipper receives an identical common stream blend of petroleum at Valdez Terminal irrespective of the quality of the crude oil it tendered at Pump Station No. 1 or any intermediary refining. The TAPS Quality Bank is intended to compensate each TAPS shipper for the difference in value between the crude stream it tenders at Pump Station No. 1 and the commingled/partially-refined stream it receives at Valdez Terminal. Shippers who receive a higher value stream than they tender must pay the differential *into* the Quality Bank. Shippers who receive a lower value stream than they tender are paid the differential *out of* the Quality Bank.

32. The Quality Bank's distillation valuation model assumes the market prices of crude oil streams are determined by the products that can be refined from them. The model derives the value of any crude stream in accordance with the proportions and market values of all products that can be distilled from the stream. The composite value of all such products—less their distillation costs—determines the underlying crude stream's presumed market value. For Quality Bank modeling purposes, then, the cost of distilling each component product is an integral factor in determining the overall value of the crude stream from which they are distilled. The higher the composite processing cost, the lower the crude's economic value to the shipper.[14]

33. The Quality Bank valuation methodology is problematic in a key respect: no actual refining takes place because it is a purely economic model. Rather, the model "constructs" and "operates" typical—but entirely hypothetical—refining facilities in order to estimate the capital investment and operating costs that should be imputed to producing each of the component petroleum products from which the composite crude oil stream market values are extrapolated. Each component product's imputed processing cost is then deducted from a published market reference price for the *refined* product in order to derive its Quality Bank value. Summed, these adjusted values comprise the Quality Bank value for any particular crude stream.[15]

34. The instant proceedings are concerned with the processing costs to be imputed to a single component product—Heavy Distillate—which boils out of crude oil at temperatures between 450 and 650 degrees Fahrenheit. Specifically, we must determine

[14] Shippers therefore have an interest in imputing the lowest possible processing cost. The converse holds true for pipeline refiners.

[15] Presuming the stream's initial relative quality has been taken into account.

the cost to be imputed to processing Heavy Distillate down to ULSD (8 ppm sulfur content)[16] in accordance with the QBA Notice and September 26 Order. It is uncontested among the parties that such processing requires the Quality Bank model to incorporate a pressurized steam & catalyst unit commonly known as a hydrotreater. Where the parties principally disagree is with respect to whether Opinion Nos. 481/481-A, interpreted in conjunction with the underlying Initial Decision (UID)[17] and the September 26 Order, require the model to incorporate a completely new hydrotreater hypothetically constructed in the 2005 timeframe for the specific purpose of satisfying the new 8 ppm ULSD sulfur specification.

III. ISSUE ANALYSES

A. Hearing Scope

1. What is the scope of this proceeding under the Commission's September 26, 2006 Order setting this proceeding for hearing and how does the Commission's Order affect establishing the processing cost adjustment to the Platts ULS (EPA) Diesel (8 ppm) reference price for valuing the West Coast Heavy Distillate cut? What base year(s) should be used for establishing that processing cost adjustment?

Participant Positions

TAPS Carriers/QBA[18]

35. TAPS Carriers/QBA take the position that the May 18 Determination is conclusive insofar as the proceedings' scope is concerned. They rely on the facts that the determination construed Paragraph 10 of the September 26 Order to require the hearing to be governed by the prior rulings in Opinion Nos. 481 and 481-A to the extent possible,

---

[16] The new reference product/price for Heavy Distillate.

[17] *Trans Alaska Pipeline System*, 108 FERC ¶ 63,030 (2004). Opinion No. 481 adopted significant portions of the UID by reference and without substantive discussion. It therefore will be necessary to analyze and rely on the UID in this Initial Decision—a somewhat unusual circumstance.

[18] TAPS Carriers consist of BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska, Inc., ExxonMobil Pipeline Company, Koch Alaska Pipeline Company, LLC and Unocal Pipeline Company. They endorse the recommendations of the QBA, whose testimony and exhibits they sponsored in these proceedings. Neither TAPS Carriers nor the QBA has any financial stake in the outcome here. Their only interests lie in the overall administrative feasibility of the Quality Bank model/ methodology.

and interpreted that paragraph to require the Presiding Judges to abide by any discernible rulings reflected in those opinions. TAPS Carriers/QBA also underscore the Presiding Judges' conclusions that Paragraph 10 unequivocally restricted these proceedings to issues concerning cost elements that increased or changed as a result of the more severe processing required to meet the new 8 ppm ULSD standard and, accordingly, they lacked jurisdiction to consider issues beyond those parameters. Turning to base year, TAPS Carriers/QBA maintain the UID directed the QBA to use a 2000 base year and Opinion No. 481 adopted this direction without discussion. They argue that this prior ruling must be adopted here pursuant to Paragraph 10 of the September 26 Order.

CPAI

36. CPAI submits that all proposals made in these proceedings—except the one from Flint Hills—properly interpreted Paragraph 10 of the September 26 Order to mean what it states on its face: the issues here are confined to cost elements that increased or changed as a result of the more severe processing required to meet the new 8 ppm ULSD specification. CPAI criticizes as tortured the Flint Hills/Petro Star contention that the "to the extent possible" qualifier reflected in Paragraph 10 also reopened to question the continuing reasonableness of prior Opinion Nos. 481/481-A rulings on cost elements not related to the more severe processing requirement. CPAI similarly criticizes Flint Hills' contention that 2005 is the appropriate base year to use in these proceedings as patently inconsistent with Opinion No. 481, circular in reasoning and a backdoor attempt to revisit/hyper-inflate previously approved costs unrelated to the more severe processing requirement by substituting year 2005 costs. On CPAI's account, it is undisputed that Opinion No. 481 adopted a 2000 base year for both the Heavy Distillate and Resid cuts, and nothing attributable to more severe Heavy Distillate processing requires it to be changed. CPAI adds that adopting anything but a 2000 base year for Heavy Distillate processing would inject inconsistency into the model because Resid would continue to be valued using the 2000 base year adopted in Opinion No. 481.

37. CPAI also disagrees with EMT's contention that 2005 should be used as the base year for two specific costs attributable to the more severe processing requirement: capital costs associated with necessary hydrotreater enhancements and costs associated with new and more active catalysts—both of which would be required to meet the new 8 ppm sulfur specification. CPAI emphasizes that the UID and Opinion No. 481 adopted a 2000 base year with explicit disregard for whether equipment required to meet the then effective 500 ppm sulfur specification actually existed in year 2000. CPAI argues that Opinion No. 481 mandates a similar disregard here.

EMT

38. EMT distill this issue into two simple questions: (1) whether the costs to be determined in these proceedings should be strictly limited to the specific cost elements

that increased or changed as a result of the more severe processing required to meet the new 8 ppm sulfur specification for the ULSD proxy product used to value Heavy Distillate for Quality Bank purposes; and (2) what specific base year should be used to establish the new processing cost adjustment? EMT emphasize that the September 26 Order expressly limited the scope of these proceedings to "cost elements that increase or change as a result of the more severe processing required" to meet the new 8 ppm sulfur specification. They maintain strict and literal enforcement of that limitation is essential to avoid a general reopening of the comprehensive Quality Bank proceeding which produced the UID and Opinion Nos. 481, 481-A and 481-B—particularly with respect to the processing cost calculation for the Resid cut. Moreover, they note that all parties except Flint Hills and Petro Star abided by the limitation in developing their proposed cost adjustments, the obvious implication being that it would be unfair, as well as impermissible, to consider broader/additional issues.

39. EMT cast the scope of issues as (i) the incremental capital costs associated with the additional equipment that would be required to achieve the 8 ppm sulfur specification; (ii) the costs associated with the new high-activity catalysts that would be required to meet the specification; (iii) the costs associated with increased hydrogen and power (i.e. electricity) consumption levels; and (iv) the increased maintenance and taxes/insurance costs that would result from applying the 4% and 1% factors adopted in Opinion No. 481 to the incremental ISBL[19] costs associated with the more severe processing requirement. They assert that neither Flint Hills nor Petro Star presented any credible evidence that any other cost associated with processing Heavy Distillate would increase as a result of the more severe sulfur processing requirement. EMT dismiss the Flint Hills/Petro Star contention that because any costs associated with the more severe processing requirement would be incurred in 2005, the base year for the entire processing cost adjustment must be 2005 as well, which would require updating *all* cost elements associated with processing Heavy Distillate to 2005. EMT maintain this contention cannot be squared with Paragraph 10 of the September 26 Order and events which allegedly precipitated its inclusion. According to EMT, CPAI comments addressing the QBA Notice and a related Flint Hills proposal to modify the indexing approach adopted in Opinion No. 481 cautioned that a failure to limit the scope of these proceedings to cost elements that increased or changed as a result of the more severe processing requirement could result in a general reopening of the entire Quality Bank proceeding, potentially undermining principles that the parties, FERC and RCA had just expended enormous time and resources to establish. CPAI therefore specifically requested FERC and RCA to

[19] Relevant capital costs fall into two general categories. ISBL (Inside the Battery Limits) costs consist of on-site plant investments such as hydrotreater unit components, pumps, compressors, heat exchangers and pipes. OSBL (Outside the Battery Limits) costs consist of off-site plant investments such as utility systems and storage tanks and are modeled as a percentage of ISBL costs. Combined, these categories comprise the Total Capital Investment used in the Quality Bank model.

"rule that any hearing that it [sic] initiates . . . be governed, to the extent possible, by the results of its prior Quality Bank rulings" and encouraged the Commissions to limit "the scope of the hearing to those cost elements that increase[d] or change[d] as a result of the more severe processing required to meet the sulfur specifications associated with the [ULSD] price used to value Heavy Distillate. All other aspects of the cost calculation should be governed by the Quality Bank rulings." EMT claims Paragraph 10 of the September 26 Order was a near-*verbatim* adoption of this request, and any Flint Hills/Petro Star contention that the base year question presented in these limited proceedings requires or permits revisiting UID/Opinion No. 481 cost determinations not directly impacted by the new, more severe Heavy Distillate processing requirement must therefore be rejected.

40. Although EMT apparently support the 2000 base year adopted in the UID and Opinion No. 481 for cost elements that are not directly impacted by the more severe sulfur processing requirement, they also support using a 2005 base year for the cost elements they concede would increase or change as a result of the more severe requirement. EMT reason such costs necessarily would have been incurred by the Quality Bank refinery in 2005, and therefore should be based on the most current available data instead of year 2000 data adjusted to 2005 using the Nelson-Farrar Refinery Operating Cost Index (NFOCI)[20] as the UID and Opinion No. 481 would suggest. They defend the apparent disconnect as being fully consistent with the Commissions' prior orders and sound economics in that the approach (i) is applied only to costs that increase or change as a result of the more severe sulfur processing requirement; (ii) uses the most recent available data; (iii) ostensibly uses the appropriate cost index (the Nelson-Farrar Refinery Construction Cost Index (NFCCI));[21] and (iv) ostensibly comports with a UID/Opinion No. 481 determination that a single base year need not be established for all processing cost adjustments. EMT contend this approach also is consistent with the UID/Opinion No. 481 because the 2000 base year adopted in those opinions for LSD Heavy Distillate and Resid processing costs reflected when those costs actually were introduced into the Quality Bank refinery. Similar treatment of costs associated with the new ULSD processing requirement supports a 2005 base year on

[20] The NFOCI is published monthly in the *Oil & Gas Journal*. It is a true index [ed. roughly analogous to the consumer price index] which tracks, compares and reflects overall refinery operating costs rather than those costs' individual components. It is regularly corrected for the productivity of labor, changes in the amounts of fuel used, productivity in the design and construction of refineries and the amounts of chemicals and catalysts employed. *See* Gerald L. Farrar, *How Nelson Cost Indexes are Compiled, Oil & Gas J.,* December 30, 1985 at 145.

[21] The NFCCI is also published monthly in the *Oil & Gas Journal*. While not a true index, it is used to calculate inflation during the time required to construct a refinery or process unit. *Id.*

EMT's account because the Quality Bank refinery wouldn't have incurred any such costs before 2005. The same holds true for the new high-activity catalysts that would be required to meet the 8 ppm ULSD specification because they simply did not exist in the year 2000 timeframe.

BP

41. BP takes the position that Opinion Nos. 481/481-A and the September 26 Order should be strictly applied and any non-compliance with their prescriptions should be rejected. BP also emphasizes the May 18 Determination, arguing that the Presiding Judges should not depart from it by permitting new elements to be introduced into any cost calculation falling beyond the scope of proceedings established by the Commissions. BP complains that all parties except Flint Hills abided by September 26 Order limitations in developing their cases/cost adjustments, and allowing Flint Hills to flaunt those limitations not only would be unfair to those who abided by them, but would produce an unjust and unreasonable result as well. BP specifically cites the fact that its witness testified he would have considered alternative approaches to the processing cost adjustment had the proceedings not expressly been restricted to costs that increased or changed as a result of the more severe processing requirement.

42. BP argues that using any base year except 2000 violates the September 26 Order, reasoning that the order requires a threshold question to be posed for each cost element: Does removing more sulfur *cause* an increase or change in the cost element? If the answer is no, then there is no causal relationship between the incremental sulfur removal and the cost element in question and the element falls outside the scope of the September 26 Order as a consequence. In BP's view, any other conclusion renders the order's scope prescription meaningless and permits collateral attack on prior rulings made in Opinion Nos. 481/481-A. BP characterizes the base year is one such element. It maintains the incremental sulfur removal does not require/cause the base year to be changed because the associated incremental costs can be calculated just as well by indexing the 2000 base year as by using any other. BP dismisses any contention that 2005 should be established as the appropriate base year because ULSD is a new reference product which the Quality Bank refinery would/could not have built the hydrotreater to produce until 2005, stressing the UID/Opinion No. 481 ruling that the existence or non-existence of certain equipment should not be considered in making any calculations presuming a 2000 base year.

SOA

43. SOA maintains the September 26 Order expressly limits the scope of these proceedings to cost elements that changed or increased due to the more severe processing requirement. It criticizes Flint Hills for making adjustments which admittedly are not attributable to that requirement, including adjustments to natural gas unit costs and consumption levels for fuel, water and steam. SOA emphasizes that while the total

amount of natural gas required to process Heavy Distillate from a 500 ppm sulfur content down to 8 ppm might increase, the gas cost per unit (Mcf) would not change. Natural gas costs the same amount per Mcf regardless of whether it is used to process Heavy Distillate down to a 500 ppm sulfur content or to an 8 ppm content. The incremental processing requirement therefore does not impact the cost of natural gas on a per unit basis. Additionally, SOA faults Flint Hills for proposing to change the consumption levels for fuel, water and steam approved in Opinion No. 481. SOA underscores that Flint Hills claims these changes are necessary to correct inadvertent errors in the consumption levels used for the Opinion No. 481 processing cost calculation. This claim exhibits three fatal flaws on SOA's account: (1) the proposed changes indisputably are not attributable to the more severe processing requirement—in contravention of the September 26 Order; (2) the proposed changes constitute an impermissible collateral attack on Opinion No. 481 because Flint Hills neither sought rehearing nor appealed the consumption levels approved in that order; and (3) the record in the instant proceedings confirms the consumption levels approved in Opinion No. 481 are not based on any inadvertent errors. Based on these criticisms, SOA submits that Flint Hills' proposed adjustments to natural gas unit costs, and to fuel, water and steam consumption levels, should be rejected as exceeding the prescribed scope of the proceedings SOA asserts that entertaining these proposals would reopen key elements of the processing cost methodology adopted in the UID and Opinion Nos. 481/481-A—particularly with respect to the Resid cut.

44. SOA similarly maintains the choice of base year is not dependent on the more severe processing requirement referenced in the September 26 Order. It notes that 2000 indisputably was determined to be the appropriate base year for determining Heavy Distillate and Resid processing costs in the UID and Opinion No. 481. SOA disputes Flint Hills' allegation that SOA and others actually rely on a 1996 base year, explaining that the UID and Opinion No. 481 established base year 2000 costs for processing both Heavy Distillate and Resid by indexing year 1996 cost bases to 2000. In contrast, SOA challenges as unsupported Flint Hills' assertion that it is imperative in the instant proceedings for the base year to match the year in which the Quality Bank refinery must install the hydrotreater required to produce the ULSD reference product in order to reflect the actual cost of doing so. SOA also dismisses Flint Hills' allegation that 2005 must be adopted as the base year because the NFOCI has not kept pace with the actual rise in individual component costs (such as natural gas) between 2000 and 2005, noting that the NFOCI is intended to reflect the overall composite of refinery operating costs rather than any individual component built into the index.

Chevron

45. Chevron relies on the May 18 Determination as the "law of the case" with respect to proceeding scope. It construes the determination as an absolute bar to Flint Hills' proposals to reconsider/change various cost elements and the base year established in the

UID and Opinion Nos. 481/481-A. Chevron contends the May 18 Determination, read in conjunction with the September 26 Order, requires the new Heavy Distillate processing cost adjustment to be made by adding any incremental costs incurred due to the more severe processing requirement to the existing adjustment. The only cost elements that increase as a result of the more severe requirement according to Chevron are power, catalyst/chemicals, hydrogen and capital recovery. Insofar as the base year is concerned, Chevron acknowledges the May 18 Determination is silent but interprets the fact that the determination rejected Flint Hills' contentions that the September 26 Order (i) did not in any way restrict the issues to be addressed at hearing and (ii) intended all related issues to be addressed as conclusive that 2000 must be used as the base year in these proceedings. Focusing on the UID and Opinion No. 481, Chevron emphasizes those decisions established 2000 as the appropriate base year for both the Heavy Distillate and Resid cuts, and irrespective of whether the requisite processing equipment existed at that time. Chevron also notes that in contrast to Flint Hills' proposal to establish 2005 as the base year using 2005 costs alone, the 2000 base year costs established in the UID/Opinion No. 481 were adjusted from 1996 using the NFCCI.

Petro Star

46. Although Petro Star initially states the scope of the proceedings were established in the May 18 Order,[22] it revisits the issue's importance and appropriate resolution almost immediately in a subsequent discussion and on Reply Brief.[23] Petro Star states the September 26 Order initiated the hearing in these proceedings "to examine the issues raised" by comments the QBA Notice. It then focuses on Paragraph 10 of the September 26 Order—specifically, the Commissions' directive that "[t]he hearing should be governed, *to the extent possible*, by the results of prior Quality Bank rulings in Opinion Nos. 481 and 481-A."[24] Petro Star asserts the "to the extent possible" qualifier forestalls the balance of the order from eliminating issues that must be decided to determine a just and reasonable value for the Heavy Distillate cut in these proceedings. It vigorously challenges any suggestion that the September 26 Order precludes parties from raising issues implicating increased processing costs unless those costs narrowly relate to the desulfurization process. In Petro Star's view, that interpretation preordains a Heavy Distillate processing cost adjustment that not only would violate the requirement for consistency among Quality Bank valuations, but also the Commissions' established policies and practices of attempting to ensure valuations that are as accurate and reasonable as possible.

---

[22] *See* Petro Star Initial Br. 4.

[23] *Id.* at 4-6; Petro Star Reply Br. 4-5.

[24] Petro Star RB at 4 (quoting September 26 Order, P 10 (emphasis added)).

47. Petro Star emphasizes that the Quality Bank "refinery" does not exist in the real world. It is an economic construct (i.e. model) intended to assist in establishing values for ANS crude cuts for which actual market prices are unavailable. Those values are established by subtracting Quality Bank "refinery" processing costs derived through the model from published reference prices for refined products in order to estimate what each cut's value would be in its unrefined state. Petro Star maintains that while the Quality Bank's model "refinery" is much simpler in design due to its hypothetical nature than any real world refinery could be, the model is intended to replicate a typical real world refinery and its capabilities. Accordingly, Quality Bank processing adjustments should reflect typical processing costs. This was the goal in the Opinion No. 481 proceedings, and it should be the goal here as well on Petro Star's account**.**

48. Petro Star advocates 2005 or some other "contemporary" base year, arguing this will produce a processing cost adjustment approximating the actual cost of producing ULSD in a real world refinery. Petro Star notes that 2005 provides the last full year of data prior to the June 2006 implementation date for the 8 ppm ULSD specification adopted for the Quality Bank, adding that most real world refineries brought their ULSD processes on line in 2006. According to Petro Star, retaining a 2000 base year freezes many costs at 1996 levels which fail to reflect what refiners actually must spend to produce ULSD. Petro Star cites what it characterizes as unequivocal record evidence indicating the NFOCI has not kept pace with actual fuel or power prices to bolster this contention. In addition, Petro Star asserts that nothing in Opinion No. 481 compels or even favors using 2000 as the base year in the instant proceedings, and neither Opinion No 481 nor any other Commission policy or precedent requires base year consistency among processing cost adjustments.

Flint Hills

49. Flint Hills places great emphasis on the fact that the new ULSD reference price was implemented as of June 1, 2006. Because that real world reference price necessarily is impacted by real world costs, Flint Hills deems it crucial that the base year bears a direct relationship to when the market reference product/price were implemented. Flint Hills underscores that real world refineries incurred the capital costs associated with upgrading their processing facilities to satisfy the new 8 ppm ULSD specification in the time period immediately prior to 2006 so they would be prepared to satisfy the new specification as of its June 1, 2006 implementation date. Flint Hills argues 2005 should be adopted as the base year in these proceedings because it provides the last full year of actual cost data prior to the new specification's implementation date. Moreover, Flint Hills contends that adopting a 2005 base year is not precluded by prior Commission orders. As Flint Hills frames it, only the *basic structure* for calculating the Heavy Distillate processing cost adjustment possibly could have been established in the UID/Opinion Nos. 481/481-A because those decisions were issued under the rubric of a 500 ppm LSD specification/reference price. The 8 ppm ULSD specification/ Heavy

Distillate reference price precipitating the instant proceedings simply did not exist when the UID and Opinion Nos. 481/481-A were decided.

50. Flint Hills stresses that the Heavy Distillate hydrotreater "built" into the Quality Bank refinery model in the UID/Opinion No. 481 indisputably was incapable of "producing" 8 ppm ULSD. As a consequence, the model's hydrotreater either had to be modified (i.e. revamped) or replaced by a completely new unit specifically designed and "built" for the purpose of producing 8 ppm ULSD (i.e. purpose-built).[25] Flint Hills therefore concludes that any costs associated with the need to revamp or completely replace the 500 ppm LSD hydrotreater built into the Quality Bank model clearly fall within the September 26 Order prescription concerning cost elements that increased or changed as a result of the more severe processing required to meet the 8 ppm ULSD specification. Flint Hills also concludes the revamp or replacement must be considered a 2006 event under the September 26 Order because the order specifically acknowledges the 8 ppm specification's June 1, 2006 effective date. It follows in Flint Hills' view that using year 2005 cost data to establish the base year in these proceedings is entirely consistent with the September 26 Order. Flint Hills defends adopting a 2005 base year in these proceedings as completely consistent with the UID and Opinion No. 481 as well, arguing that the 2000 base year adopted in those opinions reflected the most current cost data available in the record there. Similar treatment is essential here on Flint Hills account, particularly in light of evidence which suggests indexing year 2000 prices for fuel, power, steam and hydrogen using the NFOCI fails to reflect the actual 2005 prices for those processing components by significant margins.

51. Flint Hills strenuously argues Opinion Nos. 481/481-A and the September 26 Order cannot be construed/applied literally for several reasons. Because Opinion Nos. 481 and 481-A predate the 8 ppm ULSD specification's implementation date, they address the prior 500 ppm LSD Heavy Distillate reference product/price. Likewise, Opinion Nos. 481 and 481-A would not have (i) mandated a base year for the yet to be implemented 8 ppm ULSD reference product/price or (ii) specified whether the Quality Bank's 500 ppm LSD Heavy Distillate model hydrotreater should be revamped or replaced by modeling a new unit specifically designed and "built" to produce 8 ppm ULSD. Flint Hills ties these circumstances directly to Paragraph 10 of the September 26 Order—specifically, to the prescription that the hearing should be governed, to the extent possible, by the prior rulings in Opinion Nos. 481/481-A. Flint Hills essentially argues it is not reasonably *possible* for the instant proceedings to be strictly governed by prior rulings in the UID and Opinion Nos. 481/481-A because those opinions were confined to

[25] Flint Hills initially endorsed a revamp approach here because it construed the September 26 Order as indicating a preference for that approach. Flint Hills now advocates the purpose-built replacement approach as more consistent with its 2005 base year proposal.

the then-effective 500 ppm LSD reference product/price.[26] More particularly, it is not reasonably possible to adopt in these proceedings the component cost bases or base year established for the 500 ppm LSD reference product in the UID and Opinion Nos. 481/481-A because they are inapplicable to the new 8 ppm ULSD reference product.

Discussion/Analysis

52. The September 26 Order prescribes at Paragraph 10:

> The hearing should be governed, to the extent possible, by the results of prior Quality Bank rulings in Opinion Nos. 481 and 481-A. Thus, only issues as to cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate should be determined in this proceeding.

116 FERC ¶ 61,291, P 10 (2006). As noted at Paragraph 28, *supra*, the Joint Statement of Contested Issues submitted by the parties on May 1, 2007 first questioned the scope of these proceedings under the September 26 Order. We determined it made no sense to defer this threshold issue until the very hearing whose parameters were at issue. We therefore issued a notice and order directing the parties to file briefs addressing the issue by May 11, 2007. After considering the briefs, we issued the May 18 Determination. In it, we rejected Flint Hills' contentions on brief that the September 26 Order (i) did not in any way restrict the issues to be addressed at the hearing in these proceedings and (ii) intended that all related issues be addressed. We found those contentions patently at odds with Paragraphs 9 and 10 of the order, ruling:

> Paragraph 9 references only two (2) issues: what proxy product to use and what costs are involved in the more severe processing to meet the new sulfur specifications. Those are the only matters implicated for hearing in paragraph 9. Paragraph 10, moreover, pointedly requires the hearing to be governed, to the extent possible, by the prior rulings in Opinion Nos. 481 and 481-A. We interpret this language to require us to abide by any discernible ruling(s) contained in those opinions. In accordance with this guidance, paragraph 10 unequivocally restricts us to resolving in these proceedings "only issues as to cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate. . . ." We lack jurisdiction to do anything more.

May 18 Determination at P 9. This ruling notwithstanding, we explicitly refrained from making any ruling with respect to alleged deviations from prior rulings in Opinion Nos. 481/481-A at that time, stating "[s]uch matters are better left to more thorough

[26] Flint Hills never explicitly distills its argument down to this.

exploration at hearing. Accordingly, we will entertain no motion(s) to strike testimony or other exhibits at this time." *Id.* at P 10.

53. The May 18 Determination was issued to provide the parties with our understanding of the proceedings' parameters under the September 26 Order as far in advance of the hearing as possible. It was not intended to be construed as prohibiting any party from making the case it chose to make at hearing—nor could it plausibly be interpreted as doing so. This is clear from the facts that Paragraph 10 expressly: (1) declined to make any rulings with respect to alleged deviations from prior rulings in Opinion Nos. 481/481-A; (2) deferred such matters to more thorough exploration at hearing; and (3) prohibited motions to strike testimony or other exhibits on that basis. That being said, the May 18 Determination *was* intended as guidance to the parties—and as a caveat that exceeding the substantive parameters prescribed in the September 26 Order could have adverse consequences or raise jurisdictional obstacles.

54. We find and conclude as a threshold matter that the May 18 Determination neither constitutes the law of the case nor establishes an absolute bar to any proposal to reconsider or change cost elements or the base year established in the UID/Opinion Nos. 481/481-A. Whether and to what extent Paragraph 10 of the September 26 Order might bar changes to cost elements and the base year established in those opinions remains an open question.

55. We also find and conclude as a threshold matter we should not consider EMT's interpretation of the September 26 Order to the extent it relies on CPAI comments addressing the QBA Notice and related Flint Hills proposal. The order does not attribute Paragraph 10's wording to those comments, and it is unclear to us whether the Commissions made any of the comments referenced in the order part of the official record(s) in the instant dockets. Further, the comments were not proffered at hearing nor was any motion made to take official notice of them. We also deem it inappropriate in light of 18 C.F.R. § 385.508(d)(1), (2) (2007) to take official notice of them *sua sponte* at this time. We therefore will disregard (without prejudice) EMT's interpretation of the September 26 Order insofar as it relies on the CPAI comments.

56. Turning back to the September 26 Order itself, the parties' interpretations fall into two distinct camps—those advocating a more literal/strict construction of Paragraph 10 and those advocating a more liberal construction based on the "to the extent possible" qualifier. TAPS Carriers/QBA, CPAI, EMT, BP, SOA and Chevron fall into the former camp; Petro Star and Flint Hills, the latter.

57. The plain language of Paragraph 10 compels us to find and conclude the Commissions clearly intended to limit the issues to be resolved in these proceedings quite narrowly to "*only* issues as to cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new

Ultra Low Sulfur Diesel price used to value Heavy Distillate. . . ." 116 FERC ¶ 61,291, at P 10 (2006) (emphasis added). The prefatory word "only" cannot reasonably be construed as anything other than an intentional limitation. That limitation expressly confines the issues to "cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate. . . ." *Id.* As we previously ruled in the May 18 Determination, Paragraph 10 unequivocally restricts us to resolving in these proceedings only issues as to cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new ULSD reference product/price. We lack jurisdiction to do anything more. No evidence presented at hearing or argument made on brief supports a different conclusion.

58. The "to the extent possible" qualifier is somewhat more problematic—particularly in light of the subtleties of Flint Hills' arguments concerning it. As a general matter, we find and conclude the qualifier was intended to preserve as many of the prior rulings made in the UID and Opinion Nos. 481/481-A as reasonably possible. That is the most plausible interpretation of the phrase read in context with the rest of Paragraph 10. Moreover, failing expressly to preserve as many prior rulings as possible not only would have invited collateral attacks on them, but also could have facilitated a broader reopening of the Opinion No. 481 proceeding here—particularly with respect to the Resid cut—potentially undermining principles the parties and Commissions had just expended vast time and resources to establish.[27] It strains credibility to suppose the Commissions would not anticipate and take steps to preclude this scenario. Indeed, that is precisely what the first sentence in Paragraph 10 achieves.

59. Any reasonable reading of Paragraph 10 compels us to reject Petro Star's contention that the September 26 Order does not preclude issues concerning increased processing costs unless those costs narrowly relate to the more stringent ULSD sulfur specification. And as discussed *infra,* this interpretation does not preordain (or produce) a Heavy Distillate processing cost adjustment that violates the consistency requirement for Quality Bank valuations as Petro Star and Flint Hills claim. Neither does it violate the Commission policy/practice of attempting to ensure accurate and reasonable valuations.

60. Flint Hills' more subtle arguments cannot be so easily dismissed. As we understand the first of them, it literally is not reasonably *possible* for the instant proceedings to be governed by prior Heavy Distillate rulings in the UID and Opinion

[27] For example, the proceeding before Judge Silverstein consumed more than 100 actual hearing days over an eight month period, producing a record comprised of approximately 15,000 transcript pages and 1,500 exhibits. The massive UID consists of 3,084 paragraphs and 909 supplemental footnotes. Opinion No. 481 required an additional fourteen months to complete.

Nos. 481/481-A because those opinions addressed a completely different reference product/price: the 500 ppm LSD reference product/price in effect when the UID and Opinion Nos. 481/481-A were issued in 2004, 2005 and early 2006. By extension, it is not possible to adopt in these proceedings the component cost bases or base year established for the 500 ppm LSD reference product in the UID and Opinion Nos. 481/481-A because they bear no relation whatsoever to the new 8 ppm ULSD reference product/price implemented June 1, 2006. Since the UID and Opinion Nos. 481/481-A predate the 8 ppm ULSD specification's implementation date by approximately twenty-one, eight and two months respectively, they only address the prior 500 ppm LSD Heavy Distillate reference product/price. The UID and Opinion Nos. 481/481-A therefore would not have specified either a base year for the yet to be implemented 8 ppm ULSD reference product/price or whether the 500 ppm LSD Heavy Distillate hydrotreater built into the Quality Bank model in those opinions should be revamped or supplanted by a completely new unit specifically modeled to satisfy the 8 ppm ULSD specification in 2006. It follows in Flint Hills' view that the September 26 Order does not require adherence to prior UID/Opinion Nos. 481 and 481-A rulings inasmuch as those rulings are tied to the superseded 500 ppm LSD reference product/price.

61. Flint Hills' logic is intriguing, but uncompelling. The UID and Opinion Nos. 481/481-A indisputably address the Heavy Distillate cut cost adjustment only in the context of the 500 ppm LSD reference product/price in effect when the opinions were issued. The 8 ppm ULSD reference product/price has now supplanted the 500 ppm LSD reference product/price. It does not necessarily follow from this circumstance, however, that the prior UID/Opinion Nos. 481 and 481-A rulings are wholly inapplicable to the new reference product/price, as Flint Hills concludes. That might be the case if the new 8 ppm ULSD reference product/price bore no identifiable relationship to the old 500 ppm LSD reference product/price, but this clearly is not so. The old 500 ppm LSD reference product was produced from the Heavy Distillate cut. The same holds true for the new 8 ppm ULSD reference product. Moreover, the record confirms each product was/is used for the same purpose—highway diesel fuel. Exh. BPX-6 at 6-8; Tr. 1371, 1386-87. The only difference is the intervening imposition of a more strict specification for highway diesel fuel: 8 ppm sulfur content. It follows that the 8 ppm ULSD reference product is nothing more than an incremental enhancement—albeit significant—of the 500 ppm LSD reference product. It follows in turn that it is in fact possible to abide by prior UID/Opinion Nos. 481 and 481-A rulings in the instant proceedings insofar as those rulings are reasonably adaptable to the new 8 ppm ULSD reference product/price.

62. Paragraph 10 of the September 26 Order supports these conclusions. In reaction to the QBA Notice concerning Platts' replacement of the 500 ppm LSD reference product/price with the 8 ppm ULSD reference product/price, the Commissions confined the parameters of the instant proceedings to "issues as to cost elements that *increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new [ULSD] price* used to value Heavy Distillate. . . ."

116 FERC ¶ 61,291, at P 10 (2006) (emphasis added). This language confirms the Commissions intended the instant proceedings to determine only the *incremental* Heavy Distillate processing costs attributable to the enhanced 8 ppm ULSD specification.

Base Year

63. Petro Star, Flint Hills and EMT are the only parties arguing for a base year other than 2000. All three support 2005 as the appropriate base year.[28]

64. Petro Star criticizes adopting a 2000 base year on four grounds: (1) nothing in Opinion No. 481 compels or favors using 2000 as the base year in the instant proceedings, and neither Opinion No. 481 nor any other Commission policy or precedent requires base year consistency among processing cost adjustments; (2) a 2000 base year freezes many costs at 1996 levels which fail to reflect what refiners actually must spend to produce ULSD; (3) a 2005 base year produces a processing cost adjustment approximating the actual cost of producing ULSD in a real world refinery; and (4) 2005 provides the last full year of data prior to the 2006 implementation date for the ULSD reference product/price and most real world refineries started producing ULSD in 2006. These criticisms are easily dismissed.

65. We find and conclude the UID/Opinion No. 481 adopted 2000 as the appropriate base year for both the Resid and Heavy distillate cuts. 108 FERC ¶ 63,030, at P 1258, 1450 (2004); 113 FERC ¶ 61,061 (2005).[29] We further find and conclude the September 26 Order requires us to use 2000 as the base year in the instant proceedings to the extent possible—i.e. to the extent it is reasonably adaptable to the new 8 ppm ULSD reference product. We also reject the claim that Commission policy and precedent does not require base year consistency among Quality Bank processing adjustments to the extent such consistency can be achieved. The UID/Opinion No. 481 clearly sought base year consistency between the Resid and Heavy Distillate cuts.[30] Moreover, *OXY USA, Inc. v. FERC*, 64 F.3d 679, 693 (D.C. Cir. 1995) (*OXY*), defines the Quality Bank valuation methodology's "goal" as assigning accurate relative values to the crude streams delivered to TAPS—specifically including their component cuts. Failing to maintain base year consistency between the Resid and Heavy Distillate cuts to the extent possible would undermine this goal.

---

[28] EMT confine their support strictly to cost elements they concede would increase or change as a result of the more severe processing requirement.

[29] No party filed exceptions to the UID base year rulings.

[30] While the UID/Opinion No. 481 did not establish a 2000 base year for the Light Distillate cut as well, this circumstance is explained by the fact Light Distillate was not addressed in that proceeding.

66. In addition, we find and conclude a 2000 base year does not freeze costs at 1996 levels which fail to reflect what refiners actually must spend to produce ULSD. Both the UID and the record before us in the instant proceedings are conclusive that any 1996 Heavy Distillate processing cost bases used to establish 2000 base year costs were indexed to 2000 using either the NFCCI or NFOCI, as appropriate. 108 FERC ¶ 63,030, at P 1257-58, 1405-06 (2004); Tr. 152-53, 156-57, 359-62; 1415-18; Exh. TC-4 at 14-16; Exh. TC-15 at 7-8. Base year 2000 costs would be indexed forward to the present/future using the NFOCI alone. 108 FERC ¶ 63,030, at P 1407, 1450 (2004); Exh. TC-4 at 14; Exh. TC-15 at 7; Tr. 158-59, 359. It therefore cannot persuasively be argued that a 2000 base year freezes costs at 1996 levels. Nor can it persuasively be argued that it is inappropriate to use a 2000 base year here because NFOCI indexing to the present/future fails to reflect the processing costs real world refiners actually incurred/ incur to produce ULSD. We note first that such costs are only incidentally material in any event. Petro Star itself highlights the reason: the Quality Bank "refinery" does not exist in the real world. It is a purely economic model designed to assist in establishing values for ANS crude cuts for which actual market prices are unavailable. The model extrapolates proxy values for those cuts by subtracting *typical* processing costs derived *through the model* from published reference prices for refined products in order to estimate what each cut's value theoretically *should* be in its unrefined state. Petro Star concedes the model is much simpler due to its hypothetical nature than any real world refinery ever could be, yet essentially proposes to reify the model's Heavy Distillate processing component by substituting real world year 2005 ULSD processing costs for those the model specifically was designed to derive through NFOCI indexing. This would skew the output at least two ways: (1) it would replace the "typical" Heavy Distillate processing costs the model was designed to derive through indexing with real world refinery-specific ones; and (2) it would do so based exclusively on actual year 2005 inputs. This not only is inconsistent with the manner in which the model values Resid, violating *OXY* once again, but builds into the model going forward fuel, power and hydrogen costs which the record suggests are unrepresentatively high.[31] Finally, Petro Star's claim that the NFOCI demonstrably has not kept pace with actual fuel/power prices from 1996 through 2005 draws a false comparison. The NFOCI tracks *overall* refinery operating costs rather than any of those costs' individual components. *See* fn. 20, *supra*. The NFOCI therefore cannot reasonably be expected to match actual cost variations in any individual cost element

[31] The record indicates natural gas costs spiked in 2005 as a result of hurricane activity in the Gulf of Mexico. *See* Exh. SOA-7 at 6. The record also indicates natural gas prices receded in 2006. *Id.*; Exh. CPA-10 at 2.

contributing to the composite index. *Compare* Exh. FHR-6, Exh. FHR-12 *and* Exh. FHR-34 *with* Exh. SOA-7 at 5-7.[32]

67. On first impression, Flint Hills' arguments opposing a 2000 base year/favoring 2005 seem basically the same as Petro Star's. To the degree they are, they are dismissed for the preceding reasons. Closer examination, however, suggests subtleties associated with Flint Hills' 2005 base year arguments which cannot be dismissed without further consideration.

68. Flint Hills argues the UID/Opinion Nos. 481/481-A should be interpreted as establishing only the *basic structure* for calculating the Heavy Distillate processing cost adjustment. The 2000 base year adopted in those opinions is not part of that basic structure on Flint Hills' account. Instead, it was adopted because it reflected the most current cost data available in the record there. The most current cost data available here is from 2005. Compliance with prior rulings in the UID/Opinion Nos. 481/481-A therefore not only permits changing the base year to 2005, it requires it. In addition, the Heavy Distillate hydrotreater built into the Quality Bank model in the UID/Opinion No. 481 indisputably was incapable of producing ULSD. The model hydrotreater therefore either has to be revamped or replaced in these proceedings by a completely new unit capable of producing ULSD. Flint Hills argues as a consequence that any costs associated with the hydrotreater revamp/replacement expressly fall within the September 26 Order prescription concerning cost elements that increase or change as a result of the more severe processing required to meet the ULSD specification. Flint Hills also argues the revamp/replacement must be considered a 2006 event under the September 26 Order because the order specifically acknowledges the new specification's June 1, 2006 effective date. And because the most recent available yearly data for a 2006 event would be year 2005 data, Flint Hills concludes the base year must be 2005 to accord with the September 26 Order.

69. We once again find Flint Hills' arguments intriguing but uncompelling. Accepting for the sake of argument that the UID/Opinion Nos. 481/481-A only establish a basic structure for calculating the Heavy Distillate processing cost adjustment here, there is no reason to conclude the 2000 base year is not part of that structure. First, the 2000 base year was adopted for both Heavy Distillate *and* Resid. This suggests a structural consistency was intended, and the UID's actual wording supports that conclusion. *Compare* 108 FERC ¶ 63,030, at P 1254-58 (2004) *with* 108 FERC ¶ 63,030, at P 1449-50 (2004). Moreover, while year 2000 costs might have been the most recent costs in the Opinion No. 481 proceeding record, both the UID and the record before us are conclusive that the 2000 base year costs were derived by indexing 1996 cost bases using either the

[32] The record suggests a more legitimate fuel cost comparison might be based on the fuel index subsumed within the NFOCI, but even this would not be entirely accurate. *See* Exh. SOA-7 at 6

NFCCI or NFOCI. *Id.* at P 1257-58, 1405-06; Tr. 152-53, 156-57, 359-62; 1415-18; Exh. TC-4 at 14-16; Exh. TC-15 at 7-8. Since they were not year 2000 actual costs, they provide no support for Flint Hills' proposal to use actual year 2005 costs here. Instead, consistency with prior UID/Opinion Nos. 481/481-A rulings would require the base year 2000 costs adopted in those opinions to be indexed to 2005 or 2006 using the NFOCI. 108 FERC ¶ 63,030, at P 1407, 1450 (2004); Exh. TC-4 at 14; Exh. TC-15 at 7; Tr. 158-59, 359. We find and conclude there is no impediment to doing so in the instant proceedings, and any Flint Hills contention that prior UID/Opinion Nos. 481/481-A rulings require changing the base year to 2005 must be rejected as a consequence.

70. No party disputes the Heavy Distillate hydrotreater built into the Quality Bank model in the UID/Opinion No. 481 was/is incapable of satisfying the 8 ppm ULSD specification. Nor does any party dispute the model hydrotreater either has to be revamped or replaced in this case by a completely new unit specifically modeled to satisfy the specification. And we agree that any costs associated with the revamped/replacement model hydrotreater expressly fall within the September 26 Order prescription concerning cost elements that increase or change as a result of the more severe processing required to meet the ULSD specification. We also agree the revamp/replacement should be deemed a 2006 event—*precisely* because the September 26 Order accepts the new specification's June 1, 2006 effective date without discussion. In fact, we find and conclude the revamp/ replacement should be deemed a June 1, 2006 event. Unlike real world refineries, the Quality Bank model's adaptability is not constrained by considerations like hydrotreater construction lead times or natural gas supply contracting requirements.[33] These factors are taken into account through the NFOCI. Accordingly, while year 2005 (and five months of year 2006) costs should be taken into account for hydrotreater revamp/ replacement cost modeling purposes in this case, those costs must be calculated using year 2000 cost bases indexed to June 1, 2006 via the NFOCI. What real world refineries actually may have spent to revamp their LSD hydrotreaters or to construct new ones for the specific purpose of producing ULSD—and, more pertinent, *when* they may have done so—is simply immaterial to the task at hand.[34]

---

[33] We infer this is at least one rationale behind Judge Silverstein's UID rulings that the existence or non-existence of certain equipment in year 2000 should not be considered in making the Heavy Distillate and Resid cut base year calculations in that proceeding. *See* 108 FERC ¶ 63,030, at P 1258, 1450 (2004).

[34] To be perfectly clear, we do not mean to imply that the Heavy Distillate processing costs developed through the model should/do not accurately reflect real world costs—only that the model achieves this through the NFOCI, which subsumes a complex of processing cost inputs and which is regularly corrected for real world changes to those inputs. *See* fn. 20, *supra*.

71. Based on the preceding analysis, we reject the remaining Flint Hills and EMT arguments in support of using either actual year 2005 costs or a 2005 base year to determine the appropriate processing cost adjustment—incremental or otherwise—associated with the more severe processing required to meet the ULSD specification.

B. Operating Costs

1. Unit Costs – Should the unit costs adopted in Order Nos. 481 and 481-A continue to be used to develop the processing cost adjustment for the Heavy Distillate cut?

Participant Positions

TAPS Carriers/QBA

72. TAPS Carriers/QBA argue that the unit costs for fuel, power, steam, water, hydrogen, labor and labor burdens and benefits do not change as a result of the more severe processing requirement. Thus, TAPS Carriers/QBA contend the 1996 unit costs that were approved by the Commissions in Opinion Nos. 481/481-A, as reflected in Exhibits JS-1 and JS-2, must be used to calculate the processing cost adjustment in this case. TAPS Carriers/QBA state these previously-approved unit costs should be escalated in the same manner as has been done by the QBA in implementing Opinion 481. They argue that other party (Flint Hills, Petro Star and, to some degree, EMT) proposals to use current unit costs should be rejected as inconsistent with the method used to determine the processing cost adjustment for the Resid and Light Distillate components, inconsistent with *OXY*, and because reconsideration of these previously-approved unit costs is outside the scope of the instant proceedings.

CPAI

73. CPAI argues all the unit costs approved in Opinion Nos. 481 and 481-A, with the exception of catalyst, should be used to develop the processing cost adjustment for the Heavy Distillate cut in these proceedings. CPAI maintains new catalysts have been developed, at least in part, to meet the more stringent ULSD specification and, thus, the change in cost resulting from the use of new catalyst(s) is within the scope of the proceedings here. CPAI argues that the other unit cost adjustments Flint Hills proposes are unrelated to the more severe processing requirement and should be rejected. It contends Flint Hills has admitted (i) its proposed changes to the unit costs adopted in Opinion Nos. 481/481-A were not related to the more severe processing requirement; (ii) that absent its proposal for a change in base year, the increase in the severity of the processing would not cause the unit costs to increase; and (iii) the price paid by refiners for the utilities used in processing are not dependent on the date on which a refiner purchased its equipment.

EMT

74. EMT argue all the unit costs approved in Opinion Nos. 481 and 481-A, except catalyst cost, should be used to develop the Heavy Distillate cut processing cost adjustment in this case. EMT assert the only unit cost that changes as a result of the more severe processing is the unit cost for the high activity catalyst(s) required to meet the new ULSD sulfur specification. EMT state that, with the exception of Flint Hills, all parties agree the unit costs—except for high activity catalyst—do not change as a result of the more severe processing requirement. EMT note that Flint Hills seeks to use 2005 costs for fuel, power, steam, hydrogen and labor for reasons unrelated to any change or increase resulting from the more severe processing—a circumstance Flint Hills does not dispute. Further, EMT argue Flint Hills' witness admitted that without his recommended change in base year, the increase in processing severity would not impact the unit costs for fuel, power, hydrogen and labor. EMT also point out that Flint Hills argues the Commissions' adjustment methodology (using 1996 costs adjusted by the NFOCI) does not keep up with inflation and, thus, produces unfair results. EMT urge us to reject the Flint Hills proposal as outside the scope of these proceedings and constituting an impermissible collateral attack on Opinion Nos. 481/481-A. Further, EMT state the Flint Hills proposal would create inconsistency in the Quality Bank methodology which contravenes *OXY* and it is inconsistent with the method pursuant to which the original unit costs were determined and were approved in Opinion Nos. 481/481-A.[35]

BP

75. BP argues the unit costs for steam, fuel, power, hydrogen, catalyst and labor do not increase or change as a result of the more severe processing requirement. Thus, the unit costs adopted in Opinion Nos. 481/481-A must be used to develop the processing cost adjustment in this proceeding. BP states that, with the exception of catalyst cost, no party asserts the unit costs change as a result of more severe processing. BP argues Flint Hills' proposal to change the previously-approved unit costs should be rejected because it is not based on any change resulting from the more severe processing requirement; rather it is based primarily on Flint Hills' argument that the base year should be changed and on Flint Hills' assertion that there were deficiencies in certain processes adopted in Opinion Nos. 481/481-A, such as reliance on the NFOCI.

---

[35] EMT also note Petro Star's claim that the actual 2005 cost data is required to be used because of "consistency" requirements by the D.C. Circuit court rulings is without merit, characterizing this argument as a collateral attack on the Commissions' approved use of the NFOCI.

SOA

76. SOA argues all the unit costs approved in Opinion Nos. 481/481-A and are reflected in Exhibit JS-2, except the unit cost for catalyst/chemicals, should continue to be used because those costs do not change as a result of the more severe processing requirement. SOA contends the UID/Opinion No. 481 mandate that any Exhibit JS-2 costs that do not change as a result of the more severe processing be brought forward to 2006 using the NFOCI. SOA asserts any deviation from this method results in Heavy Distillate being valued in a manner inconsistent with other Quality Bank cuts. SOA argues that Flint Hills' proposal to use 2005 costs is beyond these proceedings' scope and should be rejected because Flint Hills admits its proposal is not based on the more severe processing requirement.[36]

Chevron

77. Chevron argues all unit costs previously adopted in Opinion Nos. 481/481-A, except the cost for catalyst, should continue to be used to develop the processing cost adjustment for the Heavy Distillate cut. Chevron asserts that only the unit cost for catalyst changes due to the more severe processing requirement. It states Flint Hills' argument that 2005 unit costs must be used in this proceeding should be rejected. Contrary to Flint Hills' assertion that most refineries incurred costs related to ULSD production in 2005, Chevron contends refineries did not actually incur such costs until 2006. Chevron further asserts Flint Hills uses 2005 costs to take advantage of anomalously high 2005 natural gas prices which impact the price of hydrogen and fuel, thereby inflating the processing cost adjustment/lowering Heavy Distillate value—an economic benefit to Flint Hills. Chevron also claims Flint Hills distorts the impact of high natural gas prices by using the 2005 unit costs. Additionally, Chevron asserts Flint Hills inconsistently uses the NFOCI to increase the 2005 costs to escalate the natural gas prices used to value fuel and hydrogen for 2006. Finally, Chevron asserts accepting the Flint Hills proposal would cause the Heavy Distillate cut be valued differently from other Quality Bank cuts, contravening *OXY*.

[36] SOA also addresses other arguments raised by Flint Hills as justification for adopting a 2005 base year for unit costs, particularly those relating to natural gas costs. Those arguments are addressed elsewhere in this Initial Decision and will not be reiterated here. In addition, SOA addresses Flint Hills' assertion that SOA's proposal deviates from the Commissions' orders and Opinion Nos. 481/481-A. *See* SOA Reply Br. 17–20. Because we have rejected Flint Hills' arguments concerning its use of 2005 costs, and have ruled only costs that increase or change as a result of the more severe ULSD processing requirement will be considered, we need not discuss SOA's positions here.

78. Chevron points out what it perceives to be additional flaws in Flint Hills' position on Reply Brief. It asserts Flint Hills takes inconsistent positions with respect to the applicability of the unit costs adopted in Opinion Nos. 481/481-A. Chevron notes Flint Hills takes the position Opinion Nos. 481/481-A do not address any costs specifically associated with a ULSD distillate hydrotreater so Flint Hills can challenge all unit costs regardless of whether they change as a result of the more severe processing requirement. Conversely, Flint Hills agrees Opinion Nos. 481/481-A are controlling on six of eight cost issues that are either uncontested or benefit Flint Hills. Chevron charges Flint Hills with failing to provide a legitimate rationale for binding itself to certain unit costs but not others, instead accusing other parties of adopting inconsistent positions. Chevron argues the other party deviations from Opinion Nos. 481/481-A rulings are within the scope of the proceedings as defined in the May 18 Determination and September 26 Order because those deviations relate specifically to costs that increase or change as a result of the more severe processing requirement.

79. Chevron also challenges Flint Hills' contention that the year 2005 rise in natural gas prices was a "sea change," noting testimony in this case demonstrates natural gas prices are volatile and only one small component of the fuel costs reflected in the NFOCI—comprising a mere 9% of the index. Finally, Chevron emphasizes the fact that increased processing severity may require additional hydrogen consumption does not imply the unit cost of natural gas changes as a result of the more severe processing.

Petro Star

80. Petro Star argues each of the unit costs must be evaluated using data from a 2005 or 2006 base year. Petro Star states it generally agrees that the QBA recommendations should be adopted in this proceeding, but the current costs recommended by Flint Hills should be used as well. It argues using the NFOCI to escalate unit costs for individual commodities is inappropriate, noting the NFOCI will neither accurately track increases in fuel costs nor replicate actual fuel costs. Petro Star acknowledges the volatility of fuel prices and suggests the Commissions may wish to require the mean of several yearly prices to be incorporated into the calculation in order to determine a processing cost adjustment that is more representative of current costs.[37]

Flint Hills

81. Flint Hills asserts unit costs must be consistent with the base year and, therefore, the unit costs adopted in Opinion Nos. 481/481-A must be changed to 2005. Flint Hills argues none of the 1996 costs for fuel, power, steam, hydrogen and labor, adjusted using the NFOCI, is equal to actual 2005 prices for those items. It contends the most

[37] Petro Star's arguments regarding use of a 2005 or 2006 base year have previously been discussed and will not be reiterated here.

significant operating cost factor in the processing cost adjustment is the cost of natural gas, noting natural gas is used to value both fuel and hydrogen which, together with catalyst, are the three most important operating cost components of a Heavy Distillate hydrotreater capable of satisfying the 8 ppm ULSD specification. Flint Hills complains using the current methodology locks in an unreasonably low natural gas price, resulting in Heavy Distillate overvaluation. It suggests that if the 2005 natural gas price is not adopted, a 2000-2006 average natural gas price should be adopted rather than the 1992–1999 average. On Reply Brief, Flint Hills claims a "sea change" in natural gas prices occurred around 2000. As a consequence, Flint Hills contends using pre-2000 costs—particularly natural gas costs—results in an unjust and unreasonable processing cost adjustment.

Discussion/Analysis

82. We ruled in Paragraph 57, *supra*, that the Commissions clearly intended to limit the issues to be resolved in these proceedings to "only issues as to cost elements that increase or change as a result of the more severe processing required…." Thus, we must determine here whether the unit costs adopted in Order Nos. 481/481-A change or increase as a result of the more severe processing required to satisfy the 8 ppm ULSD sulfur specification.

83. The various cost elements at issue in this proceeding are set forth in Exhibits JS-1 and JS-2.[38] These include fixed costs,[39] variable costs[40] and capital recovery costs.[41] All of these cost elements were approved in the UID and adopted in Opinion Nos. 481/481-A**.** The fixed percentage costs (maintenance and taxes and insurance) and the capital recovery costs are addressed in Section III-C-1 and Sections III-D-1 & 2, *infra*. Both the unit cost and the consumption level for catalyst are addressed in Section III-B-3-e, *infra*.

---

[38] Exhibit JS-2 is identical to Exhibit JS-1, except that Exhibit JS-2 incorporates the 1.27 West Coast location factor. The location factor is not at issue in this case.

[39] The fixed costs are labor, maintenance, and tax and insurance. Maintenance cost is calculated at 4% of ISBL capital cost; tax and insurance is calculated at 1% of ISBL capital cost.

[40] The variable costs are fuel, power, steam, water, catalyst/chemicals and hydrogen.

[41] Total capital recovery is calculated as 20% of the total capital investment. The 20% figure is not at issue in this case.

Here, we address only the unit costs for fuel, power, steam, water, hydrogen, labor, labor burdens and benefits, and utilization.[42]

84. No party contests the previously-approved unit cost for labor burdens and benefits or the utilization rate. We therefore find and conclude the labor burdens and benefits cost and the utilization rate set forth in Exhibits JS-1 and JS-2 should continue to be used to calculate the processing cost adjustment.

85. All parties except Flint Hills and Petro Star agree the previously-approved unit costs for fuel, power, steam, water, hydrogen and labor should continue to be used as well. Flint Hills and Petro Star argue year 2005 unit costs should be used. Flint Hills acknowledges, however, that its proposed unit cost changes are tied to its recommended change in base year,[43] not to changes in processing mechanics related to the more stringent ULSD specification. Tr. 632-636. *See also* Exh. CPA-10 at 9-10; Exh. CPA 11 at 3-4. The record conclusively establishes the unit costs for fuel, power, steam, water, hydrogen and labor do not increase or change as a result of the more severe processing required to satisfy the 8 ppm sulfur specification. Exh. EMT-1 at 20-21; Exh. TC-4 at 15-17; Exh. CPA-1 at 14-20; Exh. BPX-19 at 73-77; Exh. SOA-1 at 10. We therefore find and conclude the previously-approved unit costs for fuel, power, steam, water, hydrogen and labor, as set forth in Exhibits JS-1 and JS-2 should continue to be used to develop the Heavy Distillate processing cost adjustment.

2. Base Consumption Levels – Should the consumption levels for fuel, steam and water that were adopted in Order Nos. 481 and 481-A continue to be used to develop the processing cost adjustment for the Heavy Distillate cut?

Participant Positions

Taps Carriers/QBA

86. TAPS Carriers/QBA initially recommended that the base consumption levels for fuel, power, steam and water be changed from those adopted in Opinion Nos. 481/481-A due to the QBA perception there had been an error in the selection of those consumption levels. Based on the May 18 Determination and September 26 Orders, however, the QBA determined the previously-approved consumption levels should continue to be used

[42] Also included in the processing cost adjustment is a cost component for labor burdens and benefits, which is a percentage of the labor hourly rate, and a utilization rate, which is reflected as a percentage of calendar days the hydrotreater is operating.

[43] We previously rejected Flint Hills' and Petro Star's arguments that 2005 is the appropriate base year for this proceeding. Thus, we reject Flint Hills'/Petro Star's assertions that unit costs must be 2005 unit costs.

because those levels do not change as a result of the more severe processing requirement. TAPS Carriers/QBA also state that in determining the consumption levels should not be changed, the QBA noted CPAI witness O'Brien's rebuttal testimony explanation for his selection of the base consumption levels adopted in the Opinion no. 481 proceeding.

CPAI

87. CPAI argues that because the base consumption levels for fuel, steam and water do not change as a result of the more severe processing requirement, the base consumption levels adopted in Opinion Nos. 481/481-A should continue to be used. CPAI refutes Flint Hills' claim that the previously-adopted base consumption levels reflect inadvertent errors, asserting those consumption levels were intentionally selected. CPAI argues Flint Hills' position also must be rejected because it (i) is not based on an increase or change in consumption as a result of the more severe processing requirement; (ii) is beyond the scope of these proceedings; and (iii) constitutes an impermissible collateral attack on Opinion Nos. 481/481-A. CPAI notes the QBA withdrew his original proposal to modify the consumption levels because such modifications were beyond the scope of these proceedings.

EMT

88. EMT argue the consumption levels for fuel, steam and water adopted in Opinion Nos. 481/481-A should continue to be used to develop the processing cost adjustment in this case. EMT underscore that all parties except Flint Hills agree with this position. They note all parties—including Flint Hills—agree that the consumption levels for fuel, steam and water do not change as a result of the more severe processing requirement. EMT argue the Flint Hills position that the consumption levels must be changed because they were erroneous when adopted should be rejected because that issue falls outside these proceedings' scope and constitutes an impermissible collateral attack on Opinion Nos. 481/481-A. Further, EMT assert the evidence demonstrates the consumption levels adopted in Opinion Nos. 481/481-A were purposely selected.

BP

89. BP argues the base consumption levels for fuel, steam and water approved in Opinion Nos. 481/481-A do not change or increase due to the more severe processing requirement, and thus those base consumption levels should continue to be used here. BP asserts no party disputes the fact that there is no increase in these consumption levels as a result of the more severe processing requirement, stressing Flint Hills' position is that the base consumption levels are based on inadvertent error and should be changed as a consequence. BP states Flint Hills' position must be rejected as a violation of prior Commission orders.

SOA

90. SOA argues the base consumption levels for fuel, water and steam adopted in Opinion Nos. 481/481-A do not change or increase as a result of the more severe processing requirement; therefore, these levels should continue to be used to develop the processing cost adjustment in this case. SOA notes all parties, including Flint Hills, acknowledge the consumption levels do not increase or change as a result of the more severe processing requirement. Contrary to Flint Hills' assertion that the consumption levels were erroneously adopted in Opinion Nos. 481/481-A, SOA argues the evidence indicates those levels were purposely selected. SOA also contends Flint Hills' attempt to challenge the previously-approved consumption levels at this time constitutes an impermissible collateral attack on Opinion Nos. 481/481-A.

Chevron

91. Chevron argues the base consumption levels adopted in Opinion Nos. 481/481-A should continue to be used to develop the processing cost adjustment. Chevron challenges Flint Hills' contention that the consumption levels for fuel, steam and water (and power) must be changed here because the Commissions approved incorrect costs in Opinion No. 481. Chevron asserts that this issue is beyond the scope of, and cannot be re-litigated in, the instant proceedings. Chevron further contends that even if the issue of the base consumption levels were open to reconsideration here, the utility consumption rates approved in Opinion Nos. 481/481-A were purposely selected. Additionally, Chevron emphasizes evidence demonstrates, and all other parties agree, that the consumption levels for fuel, steam and water do not change as a result of the more severe processing requirement. Chevron also notes the QBA modified his position at hearing and now supports the position taken by all parties except Flint Hills.

Petro Star

92. Petro Star argues the consumption levels for fuel, steam and water should be based on a 2005 or 2006 base year and expressed in 2005 or 2006 dollars. Petro Star submits the QBA should not have been constrained from arguing the consumption levels for fuel, steam, water and power were erroneously adopted because the September 26 Order does not require the use of inappropriate cost factors just because they were adopted in Opinion No. 481. Petro Star adds the QBA's testimony proves his position despite CPAI witness O'Brien's testimony to the contrary, claiming the QBA still believes the consumption levels were selected in error and would have continued to recommend a change in the base consumption levels for those four elements but for the May 18 Determination and September 26 Orders. Petro Star therefore recommends that the "corrected" consumption levels for fuel, steam and water, as originally proposed by the QBA in Exhibit TC-4, be adopted in this proceeding.

Flint Hills

93. Flint Hills claims the base consumption levels for power, fuel, steam and water were erroneously selected by CPAI witness O'Brien in the Opinion No. 481 proceeding, and those consumption levels were erroneously adopted in Opinion No. 481 as a consequence. Flint Hills contends Mr. O'Brien selected his consumption levels from a textbook curve based on a naptha hydrotreater rather than a curve in the same text based on a distillate hydrotreater. Flint Hills faults that selection because a naptha hydrotreater would not be capable of producing the 500 ppm LSD reference product used to value Heavy Distillate at that time—a fact Mr. O'Brien admitted in this case according to Flint Hills. Flint Hills maintains naphtha hydrotreater consumption levels understate water and power consumption, understating the processing cost adjustment. It also asserts increasing the utility consumptions to those based on the distillate hydrotreater curve would be directionally consistent with the increase in processing severity. Flint Hills claims it used the appropriate power and water consumption levels and corrected the fuel and steam consumption levels to ensure that all utility consumption figures are based on the distillate hydrotreater. Flint Hills also claims the QBA's testimony supports its position, noting the QBA testified he would have continued to support the same changes advocated by Flint Hills but for the May 18 Determination and September 26 Order.

Discussion/Analysis

94. As discussed in Paragraphs 57 and 82, *supra*, we have ruled the Commissions clearly intended to limit the issues to be resolved in these proceedings to "only issues as to cost elements that increase or change as a result of the more severe processing required…." Once again, we are limited to determining whether the consumption levels for fuel, steam and water adopted in Order Nos. 481/481-A change or increase as a result of the more severe processing required to meet the new ULSD specification.

95. Only Flint Hills[44] asserts the base consumption levels for fuel, steam and water should be changed from those adopted in Opinion Nos. 481/481-A. The primary ground for its argument is that the consumption levels in for fuel, water and steam (and power) were erroneously selected by Mr. O'Brien, and thus were erroneously adopted in Opinion Nos. 481/481-A.[45] However, Flint Hills itself acknowledges the consumption levels for

[44] Petro Star takes the same position as Flint Hills but did not present any testimony in this case.

[45] At hearing, Flint Hills witness Sanderson testified that the distillate hydrotreater consumption levels he relied on were more representative of the increased processing severity. Tr. 650-61. No matter how phrased, however, Flint Hills' position that the consumption levels should be changed is inarguably based on its assertion that the previously-approved levels were selected in error. Flint Hills did not demonstrate there

fuel, steam and water do not change as a result of the more severe processing requirement. Exh. FHR-10 at 42–47; Exh. FHR-19 at 45-49; Exh. TC-15 at 15; Exh. CPA-10 at 21–22; Exh. CPA-11 at 3-8; Exh. BPX-20 at 152-57. More important, the record overwhelmingly establishes that the consumption levels for fuel, steam and water do not change as a result of the requirement. Exh. TC-15 at 16-17; Tr. 109, 142; Exh. EMT-5 at 11; Exh. CPA-1 at 15-16; Exh. BPX-1 at 83; Exh. SOA-3 at 1; Exh. FHR-10 at 43. We find and conclude the consumption levels for fuel, steam and water adopted in Opinion Nos. 481/481-A should continue to be used to calculate the processing cost in this case.[46]

3. Specific Costs Per Barrel – What cost per barrel of Heavy Distillate should be used for Quality Bank purposes for each of the following operating cost elements?

96. The cost per barrel of Heavy Distillate for each operating cost element depends on two variables: (i) the unit cost/barrel of Heavy Distillate for each element; and (ii) the consumption rate/barrel of Heavy Distillate for the element. The specific cost/barrel for each operating cost element is calculated by multiplying its unit cost by its consumption rate.

a. Fuel ($ per barrel of Heavy Distillate)

Participant Positions

TAPS Carriers/QBA

97. TAPS Carriers/QBA assert the unit costs approved in Opinion Nos. 481 and 481-A should continue to be used for all cost elements other than catalyst/chemicals. Because there is no change in the previously-approved base consumption level for fuel, TAPS Carriers/QBA propose the previously-approved cost for fuel of $0.190 per barrel of Heavy Distillate (in 1996 dollars) should be used. They note the cost should continue to be escalated to the relevant year using the NFOCI, as the QBA has done in implementing Opinion No. 481.

---

would be any change in the consumption levels as a result of the more severe processing. *See* Tr. 655; Exh. CPA-14 at 5-6.

[46] Although we need not address Flint Hills' argument that the base consumption levels were erroneously selected/adopted in Opinion No. 481, we note that Mr. O'Brien's testimony in this case establishes his consumption level selections in the Opinion No. 481 proceeding were intentional. *See* Exh. CPA-10 at 23-24; Tr. 138, 267-68, 799-803, 1168-69.

CPAI

98. CPAI states all parties agree there is no change in fuel consumption as a result of the more severe processing requirement. CPAI underscores that only Flint Hills proposes a change to the cost and consumption level for fuel, but that proposal is not based on an increase in processing severity, and therefore falls outside the scope of these proceedings. CPAI also charges the Flint Hills proposal has no record support. CPAI therefore concludes the previously-approved fuel cost/barrel should continue to be used.

EMT

99. EMT state all parties agree that neither the consumption level nor the unit cost for fuel change as a result of the more severe processing requirement. EMT assert Flint Hills' proposals to substitute a 2005 cost and change the consumption level based on a perceived error is outside the scope of these proceedings and constitutes an impermissible collateral attack on Opinion No. 481. Further, EMT contend adopting Flint Hills' position undermines the previously-approved methodology since it would result in inconsistent treatment between the Heavy Distillate and Resid cuts. EMT also assert that using 2005 costs would deviate from the fuel cost methodology established in the Opinion No. 481 proceeding, and adjusting those 2005 costs by the NFOCI in future years would distort the cost of fuel and hydrogen in those future years.

BP

100. BP argues that neither the volume nor the cost of fuel changes as a result of the more severe processing requirement. BP states no party has proposed a change in fuel consumption on that ground, noting the only proposed changes to fuel cost and volume were made by Flint Hills based on its assertions that 2005 costs should be used and that there was an error in the adoption of the fuel consumption level in the Opinion No. 481 proceeding. BP contends the previously-approved fuel cost of $0.190/barrel of Heavy Distillate (in 1996 dollars), should continue to be used as the fuel component cost.

SOA

101. Noting that there is no change in fuel consumption as a result of the more severe processing requirement, SOA asserts the cost per barrel Heavy Distillate for fuel reflected in Exhibit JS-2 should continue to be used.

Chevron

102. Chevron states the cost for fuel does not change as a result of the more severe processing requirement, noting that all parties except Flint Hills agree. Chevron asserts

that Flint Hills' position regarding utilization of 2005 costs and its purported correction of the previously adopted consumption rate for fuel are outside the scope of these proceedings. Thus, Chevron submits the fuel cost reflected in Exhibit JS-2 should continue to be used.

Petro Star

103. Petro Star asserts that cost per barrel for each of the specified operating cost elements should be based on 2005 or 2006 costs. Petro Star does not offer a specific proposed cost per barrel for fuel, but notes it is computed directly from the unit cost and consumption rate.[47]

Flint Hills

104. Flint Hills' recommended fuel cost is based on its assertions that the appropriate base year is 2005 and that the consumption level for fuel adopted in Opinion Nos. 481/481-A was erroneous.[48] Adjusting for these, Flint Hills proposes a fuel cost of $1.153/barrel of Heavy Distillate.

Discussion/Analysis

105. We previously determined that neither the unit cost nor the consumption level for fuel adopted in Opinion Nos. 481/481-A, as set forth in Exhibits JS-1 and JS-2, changed as a result of the more severe processing requirement. As a consequence, we find and conclude the specific fuel cost per barrel[49] adopted in those opinions should continue to be used to calculate the processing cost adjustment in this case.

b. Power ($ per barrel of Heavy Distillate)

Participant Positions

TAPS Carriers/QBA

106. TAPS Carriers/QBA assert power consumption increases by approximately 40% due to the more severe processing requirement. The increased power consumption

---

[47] Petro Star's position regarding changes to unit costs/consumption levels previously has been addressed and rejected.

[48] Flint Hills' rationale for these assertions previously has been addressed and rejected.

[49] Exhibits JS-1 and JS-2 list the specific cost per barrel Heavy Distillate for fuel as $0.190/barrel (in 1996 dollars).

results from an increased need for electricity to run the pumps and compressors associated with the model hydrotreater. The QBA bases his recommendation on information contained in the same professional study on which he relied to estimate the cost to revamp the base model hydrotreater. TAPS Carriers/QBA state the study pertains to a 50,000 barrel per day distillate hydrotreater processing straight run feed to produce 500 ppm LSD being revamped to produce 7 ppm sulfur diesel. TAPS Carriers/QBA argue the situation reflected in the study is virtually identical to the one presented here. Increasing the previously-approved power by 40%, the QBA recommends a power cost totaling $0.140/barrel (in 1996 dollars).

CPAI

107. CPAI argues power consumption increases as a result of the more severe processing requirement. CPAI contends that once Flint Hills' proposal is corrected to reflect the previously-approved base consumption level for power, the difference between all the party power cost proposals is less than $0.05/barrel (in 2000 dollars). CPAI maintains its proposal of $0.126/barrel, which is taken from a study examining the costs associated with the ULSD requirements, should be adopted here because it falls near the midpoint of the range of all party estimates, is reasonable and is based on straight run Heavy Distillate feed stock processed by an 800 psi ULSD hydrotreater.

EMT

108. EMT note all parties except Flint Hills and Petro Star agree that the previously-approved unit cost for power should continue to be used in this case. EMT add that all parties agree power consumption increases as a result of the more severe processing requirement, but disagree as to the amount of the increase. EMT point out the increase results from an increased amount of electricity needed to run the hydrotreater pumps and compressors.[50] EMT state the range of estimates runs between 4% (BP) and 40% (TAPS Carriers/QBA).[51] EMT estimate a 14% increase in power consumption (an increase from 2.00 Kwh to 2.28 Kwh) based on (i) adding a recycle scrubber, containing an amine booster pump, as part of its proposed revamp of the hydrotreater and (ii) an increase in compressor capacity to accommodate additional hydrogen needed for the desulfurization

[50] Specifically, EMT state that its revamp of the hydrotreater requires the addition of an amine booster pump to the recycle gas scrubber and that the need for more hydrogen requires greater compressor capacity, both of which increase the amount of electricity required.

[51] The parties present their estimates in terms of percentages as well as in kilowatt hours per barrel (Kwh/barrel). The range of estimates in percentages (4% to 40%) is equivalent to a range of 2.08 to 2.80 Kwh/barrel. Flint Hills did not propose an incremental increase in power, but asserts the new consumption level should be 3.00 Kwh/barrel—apparently based on its proposed change to the power consumption level.

process. EMT contend Flint Hills' proposal should be rejected because it relies on an impermissible adjustment to the previously-approved consumption rate for power and improperly uses 2005 price data. EMT argue that the TAPS Carriers/QBA proposal should be rejected because the QBA relied on outdated two-stage hydrotreating technology which unnecessarily increases power consumption. EMT acknowledge SOA's estimated power consumption increase of 17% is closer to the EMT estimate and lower than the QBA's, but argue the SOA estimate relies on the same outmoded technology as the QBA does.[52] EMT similarly argue that CPAI relied on outmoded technology to derive its estimate, which is virtually identical to the SOA figure. EMT maintain the BP estimate is unrealistically low, likely due to its omission of an amine scrubbing tower. They assert they have properly estimated the increase in power consumption by calculating the increased horsepower needed to operate the amine booster pump and the additional recycle hydrogen compressor. EMT therefore propose to combine the unit cost for power approved in Opinion No. 481 with the increased consumption rate for power, resulting in a total cost of $0.38/per gallon in 2006 dollars.

BP

109. BP explains the only increase in power resulting from the more severe processing requirement is an increase in the amount of electricity needed to run the hydrotreater's compressors. BP contends Flint Hills' proposed changes to power consumption are not based on more severe processing and should be rejected as a consequence. BP also contends the TAPS Carriers/QBA proposal to increase the power consumption figure by 40% is based on a report assuming a two-stage design processing non-virgin feed stock. BP argues the 40% TAPS Carriers/QBA power consumption figure is significantly overstated because they did not adjust it to reflect a single-stage hydrotreater processing straight-run feed stock. BP's proposed 4% power consumption increase produces a total cost per barrel of $0.104 (in 1996 dollars).

SOA

110. SOA maintains power consumption increases by 17% due to the more severe processing requirement. SOA explains this increase results from two requirements: an increase in power needed to re-circulate hydrogen in the hydrotreater and an increase in power related to "make-up" hydrogen compression. SOA states its estimate is reasonable because it is comparable to the CPAI, EMT and BP estimates. Increasing the 2.00 Kwh/barrel consumption rate in Exhibit JS-2 by 17% results in a consumption rate of 2.34 Kwh/barrel on SOA's account. Multiplying this number by the Exhibit JS-2 unit cost (escalated to 2000) produces a total power cost of $0.126/barrel.

[52] EMT also claim SOA overstates the need for power by assuming a reciprocating compressor instead of a centrifugal compressor.

Chevron

111. Chevron argues there is no change in power consumption due to the more severe processing requirement. It alleges both the Flint Hills and TAPS Carriers/QBA proposals are grossly overstated—the Flint Hills proposal because it changes the previously-approved consumption rate/uses 2005 costs, the TAPS Carriers/QBA proposal because it is based on an outdated approach. Chevron notes all other parties advocate small incremental changes. Chevron primarily proposes to use the Exhibit JS-2 value for power, adjusted to 2006 using the NFOCI and producing a power cost of $0.138/barrel. In the alternative, Chevron suggests that the Commissions average the Chevron, BP, CPAI, EMT and SOA proposals, which results in an incremental cost of $0.017/barrel.

Petro Star

112. Petro Star asserts the specific cost per barrel for power should be based on 2005 or 2006 costs and that the original QBA estimate for power consumption reflected in Exhibit TC-4 should be used in these proceedings. Petro Star does not offer a specific proposed cost per barrel for power, but notes it is computed directly from the unit cost and consumption rate.

Flint Hills

113. Consistent with its position on fuel costs, Flint Hills' recommended power cost is based on its assertions that the appropriate base year is 2005 and the consumption level for power adopted in Opinion No. 481 was erroneous. Adjusting for these, Flint Hills proposes a power consumption cost of $0.251/barrel.

Discussion/Analysis

114. The record is conclusive that the consumption level for power increases due to the more severe processing requirement. Exh. EMT-1 at 20-21; Exh. EMT-15 at 24; Exh. BPX-1 at 73; Exh. TC-4 at 17; Exh. SOA-1 at 9; Exh. CPA-1 at 15-16. The increased cost of power results from the incremental increase in electricity needed to run the pumps and compressors associated with the hydrotreater. In Section III-D-1, *infra*, we adopt EMT's proposed hydrotreater model revamp. Among other things, that revamp includes the addition of a recycle gas scrubber/amine booster pump and an increase in make-up hydrogen compressor capacity. The addition of this equipment results in increased power consumption. EMT estimate this additional equipment increases the previously-approved power consumption by 14%. Exh. EMT-1 at 21. No party disputes this estimate. We therefore adopt a 14% power consumption increase. We previously determined that the unit cost for power approved in Opinion Nos. 481/481-A did not change as a result of the more severe processing requirement. We therefore find and conclude the incremental increase in the specific power cost per barrel should be determined in this case by

multiplying the previously-approved unit cost for power by the increased power consumption rate of 2.28 Kwh.

c. Steam ($ per barrel of Heavy Distillate)

Participant Positions

TAPS Carriers/QBA

115. TAPS Carriers/QBA assert that the unit cost for steam does not increase as a result of the more severe processing requirement. Thus, the cost approved in Opinion Nos. 481 and 481-A ($0.040 per barrel of heavy distillate, in 1996 dollars) should continue to be used in this proceeding.

CPAI

116. CPAI notes that all parties, except Flint Hills, agree that the previously-approved costs and consumption levels for steam should continue to be used in this proceeding. CPAI states that Flint Hills' position should be rejected as outside the scope of this hearing and not supported by the record. CPAI asserts that using the previously approved unit costs and consumption levels for the steam results in a cost of $0.043 per barrel of Heavy Distillate in year 2000 dollars.

EMT

117. EMT assert that neither the consumption level nor the unit cost for steam changes as a result of the more severe processing. EMT argue that Flint Hills' position that the steam consumption rate adopted in Opinion No. 481 was erroneous is improper and constitutes an impermissible collateral attack on Opinion No. 481. Therefore, EMT state that the cost of steam per barrel approved in Opinion Nos. 481 and 481-A should continue to be used in this proceeding. According to EMT, adjusting the approved cost for steam using the NFOCI, results in steam cost of 0.14 cents/gallon in 2006 dollars.

BP

118. BP states that there is no change in the steam requirements as a result of the more severe processing. BP notes that no party has argued otherwise. BP asserts that Flint Hills' position that year 2005 costs should be used and that the previously approved consumption level for steam needs to be adjusted is outside the scope of this proceeding. BP recommends that the previously approved steam cost per barrel of $0.040 (in 1996 dollars) continue to be used in this proceeding.

SOA

119. SOA argues that there is no change in steam consumption per barrel and, therefore, the specific cost per barrel, as set forth in Exhibit JS-2, should be used in this proceeding. SOA asserts that adjusting the Exhibit JS-2 steam specific cost per barrel to year 2000 results in a cost of $0.043/barrel.

Chevron

120. Chevron argues that the cost of steam does not change as a result of the more severe processing requirement. Chevron asserts that Flint Hills' position is outside the scope of this proceeding. Chevron states that using the NFOCI to adjust the Exhibit JS-2 cost for steam to 2006, results in a $0.055 cost per barrel for steam.

Petro Star

121. Petro Star asserts that cost per barrel for each of the specified operating cost elements should be based on 2005 or 2006 costs. Petro Star does not offer a proposed cost per barrel for steam, but notes that it is computed directly from the unit cost and consumption rate.

Flint Hills

122. Flint Hills' recommended cost per barrel Heavy Distillate for steam is based on its assertions that the appropriate base year is 2005 and that the consumption level for steam adopted in Opinion Nos. 481 and 481-A was erroneous. Correcting for these items, Flint Hills proposes a specific cost per barrel for steam of $0.076 per barrel of Heavy Distillate.

Discussion/Analysis

123. We found and concluded in Paragraphs 88 and 98, *supra,* that neither the unit cost nor the consumption level for steam, that were approved in Opinion Nos. 481 and 481-A, and are set forth in Exhibits JS-1 and JS-2, changed as a result of the more severe processing requirement. Therefore, we find and conclude that the previously-approved specific cost per barrel Heavy Distillate for steam[53] shall continue to be used to calculate the processing cost adjustment in this proceeding.

[53] Exhibits JS-1 and JS-2 list the specific cost per barrel Heavy Distillate for steam as $0.040/barrel (in 1996 dollars).

d. Water ($ per barrel of Heavy Distillate)

Participant Positions

TAPS Carriers

124. TAPS Carriers assert that the unit cost for water does not increase as a result of the more severe processing requirement. Thus, the costs approved in Opinions 481 and 481-A should continue to be used in this proceeding. That cost is $0.008 per barrel of Heavy Distillate, in 1996 dollars.

CPAI

125. CPAI states that all parties agree that there is no change in the water cost as a result of the more severe processing requirement. CPAI states that Flint Hills' position that the previously-approved consumption level was erroneous should be rejected as outside the scope of this hearing and not supported by the record. Thus, CPAI asserts that the previously approved unit costs and consumption levels for water of $0.008 per barrel of Heavy Distillate in year 2000 dollars, should be used in this proceeding

EMT

126. EMT state that there is no change in water consumption or unit cost as a result of the more severe processing. EMT assert that Flint Hills' position that the previously-approved water consumption rate was erroneous should be rejected as an impermissible collateral attack on Opinion No. 481, as outside the scope of this proceeding and because it undermines the integrity of the approved methodology. EMT assert that the cost of water per barrel Heavy Distillate approved in Opinion Nos. 481 and 481-A should be used in this proceeding. EMT state that the 2006 cost for water is 0.02 cents/gallon.

BP

127. BP states that cost of water does not change as a result of the more severe processing requirement. BP notes that no party disagrees with this position. BP asserts that Flint Hills' position that the base consumption level for water requires correction is outside this scope of this proceeding. BP recommends that the previously approved cost for water, $0.008 per barrel (in 1996 dollars), be used in this proceeding.

SOA

128. SOA states that there is no change in water consumption per barrel and, therefore, the cost per barrel, as set forth in Exhibit JS-2, should continue to be used in this

proceeding. SOA asserts that adjusting the Exhibit JS-2 water specific cost per barrel to year 2000 results in a cost of $0.008/barrel.

Chevron

129. Chevron argues that the cost of water does not change as a result of the more severe processing requirement. Chevron notes that no party disagrees with its position. Chevron states that Flint Hills' argument that 2005 costs should be used and that the previously approved consumption level for water was erroneous are beyond the scope of this proceeding. Chevron recommends that the cost for water approved in Opinion No. 481, as set forth in Exhibit JS-2, should be used in this proceeding. According to Chevron, adjusting that cost to 2006, using the NFOCI, results in a water cost of $0.010 per barrel.

Petro Star

130. Petro Star asserts that cost per barrel for each of the specified operating cost elements should be based on 2005 or 2006 costs. Petro Star does not offer a proposed cost per barrel for water, but notes that it is computed directly from the unit cost and consumption rate.

Flint Hills

131. Flint Hills asserts that the appropriate base year is 2005. However, because it did not have 2005 cost data available for water, it used the previously-approved 1996 unit cost for water and escalated it to 2005 using the NFOCI to determine the unit cost for its calculation of the specific cost of water per barrel Heavy Distillate. As discussed above, Flint Hills asserts that the consumption level for water adopted in Opinion Nos. 481 and 481-A was erroneous. With its correction to the consumption level, Flint Hills proposes a cost for water of $0.013 per barrel of Heavy Distillate.

Discussion/Analysis

132. We found and concluded in Paragraphs 85 and 95, *supra*, that neither the unit cost nor the consumption level for water, that were approved in Opinion Nos. 481 and 481-A, and are set forth in Exhibits JS-1 and JS-2, changed as a result of the more severe processing requirement. Therefore, we find and conclude that the previously-approved specific cost per barrel heavy Distillate for water[54] shall continue to be used to calculate the processing cost adjustment in this proceeding.

[54] Exhibits JS-1 and JS-2 list the specific cost per barrel Heavy Distillate for water as $0.008/barrel (in 1996 dollars).

e. Catalyst/Chemicals ($ per barrel of Heavy Distillate)

TAPS Carriers/QBA

133. TAPS Carriers/QBA emphasize it is difficult to obtain actual information on catalyst costs, basing their catalyst cost estimate on a study prepared by professional consultants instead. They note catalyst cost is dependent on hydrotreater design and feedstock type. TAPS Carriers/QBA acknowledge the study on which they relied may have included cracked stock in its calculations, and that processing cracked stock likely would increase catalyst cost, but contend their $0.15/barrel estimate is reasonable nonetheless.

CPAI

134. CPAI maintains it is difficult to develop a catalyst cost estimate because the costs depend on catalyst type and hydrotreater configuration, as well as the fact reliable catalyst price information is not publicly available. It proposes a catalyst cost of $0.122 per barrel (in 2000 dollars), noting the other party estimates are within 10 cents per barrel of one another. CPAI contends the Flint Hills, EMT and SOA estimates are too high because all three were based on a study that analyzed a hydrotreater processing both straight run and cracked stock feeds. The estimates are overstated according to CPAI because more catalyst is required to process cracked stock. CPAI also argues the TAPS Carriers/QBA estimate is too high because it relied on a study the QBA acknowledged was likely to include cracked stock. CPAI asserts its catalyst consumption estimate constitutes the best record evidence because it is based on a refiner processing ANS Heavy Distillate.

EMT

135. EMT state all parties agree the cost of catalyst changes as a result of the more severe processing, and the figure depends on the volume, life and the cost per pound of the catalyst used. According to EMT, the model revamp at issue here can be achieved by doubling existing catalyst volume. They propose a catalyst cost of $0.38/gallon (in 2006 dollars), noting this estimate is almost identical to those of CPAI and SOA. EMT base their estimate on an existing hydrotreater revamp study presuming a 30 month catalyst life. They state their cost estimate is based on a real world refiner's actual 2005 expenditure for high-activity catalyst, stating in addition the catalyst price was the result of competitive bidding and is generally consistent with 2005 catalyst costs. They emphasize no other party bases its estimate on actual costs. EMT argue the wide range between other party estimates indicates it is unreliable to use 1996 and 2000 prices. They critique BP's estimate as too low because it fails to reflect changes in technology and subsumes calculation errors. EMT characterize the TAPS Carriers/QBA and Flint Hills estimates as based on unreliable data, and Chevron's estimate as of limited utility because

it averages costs from a combination of high-activity catalysts Chevron employed in a single refinery revamp.[55] EMT claim their estimate constitutes the best evidence of appropriate catalyst costs in this case because it is based on actual 2005 costs for a single-stage ULSD hydrotreater revamp.

BP

136. BP argues catalyst cost per barrel depends on the cost, volume, density and cycle life of the catalyst, as well as hydrotreater capacity and utilization. BP asserts evaluating catalyst cost components is difficult because not all parties here analyzed all of the various inputs, emphasizing the range in catalyst proposals here runs from \$0.203 to \$0.009 per barrel as a consequence. BP states the cost differentials are attributable to the year chosen and the type of catalyst used, claiming there is substantial evidence the Cobalt Molybdenum (CoMo) catalyst used to produce LSD remains effective for processing ULSD—a fact the QBA confirms on BP's account. BP therefore concludes there is no increase in the unit cost for catalyst as a result of the more severe processing requirement, proposing a \$0.047/barrel increase in the composite catalyst/chemical cost for a total of \$0.067/barrel.

SOA

137. SOA argues both the unit cost and consumption level of catalyst change as a result of the more severe processing requirement. According to SOA, new high-activity catalysts which are both denser and more expensive than CoMo must be used. SOA argues catalyst volume must double at the same time projected catalyst life decreases from 3 years to 2. Based on these conclusions, SOA estimates total catalyst cost will increase by approximately 6.3 times over the current figure. SOA defends this estimate as reasonable because it is similar to other party recommendations (citing CPAI at 6.1 times current cost, BPX at 3.4 times current cost and EMT at 7.5 times current cost). SOA proposes the catalyst/chemicals cost per barrel reflected in Exhibit JS-2 be multiplied by 6.3 and adjusted to 2000, producing a catalyst cost of \$0.135/barrel in this case.

Chevron

138. Relying on experience at its El Segundo and Richmond refineries, Chevron also argues the cost of catalyst/chemicals increases as a result of the more severe processing requirement. Chevron states its incremental increase in catalyst cost at El Segundo was \$0.117 per barrel, reflecting an increase in unit cost from \$9.00 per pound to \$11.80 per

[55] EMT also criticize Chevron because it not only devoted significant capital to its revamps, but purchased expensive catalysts as well—behavior no actual refiner would exhibit in EMT's opinion.

catalyst pound and a reduction in cycle time from three years to 18 months. According to Chevron, adding the incremental amount to the previously-approved cost per barrel of catalyst, reflected in JS-2 and updated to 2006 using the NFOCI, results in a catalyst cost of $0.144 per barrel. Chevron also notes its proposed catalyst cost is comparable to that of CPAI, BPX and EMT.

Petro Star

139. Petro Star endorses the QBA's $0.15/barrel cost estimate for catalyst as accurate and consistent with the overall QBA approach.

Flint Hills

140. Flint Hills asserts both the catalyst unit cost and consumption level change as a result of the more severe processing requirement. It emphasizes that catalyst costs depend on catalyst life, noting its cost estimate is based on a 24-month catalyst life whereas other parties assume a 36-month life cycle. Flint Hills relies on a 2001 study for its catalyst cost proposal, arguing that it adopted the $10/pound cost from the study and adjusted it to 2005 using the NFOCI, producing a catalyst cost estimate of $11/pound. Flint Hills notes this estimate is less than Chevron's, only slightly higher than the 2006 figure proposed by TAPS Carriers/QBA and relatively close to CPAI once the 24/36-month useful life differential between the two is taken into account—arguing as a consequence its proposed cost is reasonable. The resulting catalyst/chemicals cost is $0.203/barrel.

Discussion/Analysis

141. This issue is substantially resolved in Section III-D-1, *infra*. In Paragraph 202, we rely on UID Paragraph 1450 to find and conclude it is appropriate in this case to incorporate high activity catalyst(s) which did not exist in year 2000 into the model hydrotreater revamp. We also find and conclude at Paragraph 202 that the per-unit cost associated with such catalyst(s) should be determined as of June 1, 2006 and indexed to the 2000 base year. In addition, we find and conclude at Paragraph 206 that the hydrotreater revamp should be achieved primarily by: (1) installing a second reactor unit; (2) doubling the catalyst volume; and (3) replacing the CoMo catalyst currently employed in the model with high-activity catalyst(s) – all in accordance with Exh. EMT-6 and Exh. EMT-7 at 2. Any issues concerning catalyst volume or type are resolved in accordance with those rulings. *Accord* Exh. EMT-6 at 8-17; Exh. SOA-10 at 75-76.

142. On the record before us, we also find and conclude it is most reasonable to adopt a 30 month catalyst effective life in this case. Although the record indicates the new high activity catalysts have effective lives ranging anywhere from six to sixty months (*see, e.g.*, Exh. TC-13 at 72), it is inconclusive with respect to a precise number—most likely

due to the impacts of multiple design variables on catalyst life expectancies. In addition, the parties come down fairly well-divided between a 24 month life cycle and a 36 month life cycle. Thirty months would be the average. Finally, the study on which a substantial portion of the revamp proposal adopted at Section III-D-1 is based supports 30 months as the appropriate catalyst life to assume for that revamp scenario. Exh. EMT-15 at 22; Exh. EMT-6.

143. Insofar as catalyst unit cost is concerned, we find and conclude EMT provides the most appropriate base figure. The record establishes actual cost data for the new catalysts are exceedingly difficult to obtain. *See*, *e.g.*, Exh. CPA-1 at 16-17; Tr. 248. The EMT figure is based on an actual year 2005 purchase of high activity catalyst for use by a single-stage hydrotreater revamped to satisfy the ULSD specification. Exh. EMT-1 at 21; Exh. EMT-15 at 10. Moreover, it falls in the middle of the range proposed by the parties in this case. *See* Exh. EMT-26. Nevertheless, EMT's $0.38/gallon total catalyst cost figure is stated in 2006 dollars brought forward from 2005 using the NFOCI. The 2005 cost figure first should have been adjusted to a 2000 base year, then brought forward using the NFOCI in accordance with the UID/Opinion No. 481.

f. Hydrogen ($ per barrel of Heavy Distillate)

<u>Participant Positions</u>

TAPS Carriers/QBA

144. TAPS Carriers/QBA note that all parties, except Flint Hills, take the position that the unit cost for hydrogen should be the same as that approved in Opinion No. 481. Further, all parties agree that hydrogen consumption increases as a result of the more severe processing requirement. The QBA estimates, based on parties' suggestions and on a variety of published materials, that hydrogen consumption would increase from the previously-approved 250 standard cubic feet ("scf") per barrel to 350 scf per barrel. TAPS Carriers/QBA state that three of the other six witnesses have proposed the same estimate, noting that the range of estimates is from 300 to 350 scfs per barrel. TAPS Carriers assert that BP's recommendation that the rate of hydrogen consumption should be determined by ordering tests be conducted in a pilot plant should be rejected as infeasible and unnecessary.[56]

CPAI

[56] TAPS Carriers further assert that, in addition to the fact that no parameters have been agreed to for such a test, the performance of such test would delay the decision in this proceeding which is on a expedited schedule to comply with the deadline prescribed in Section 4412(c) of the Motor Carrier Safety Reauthorization Act of 2005.

145. CPAI notes that the estimates for increased hydrogen consumption fall within a close range.[57] CPAI asserts that all parties rely on published information in arriving at their estimates. CPAI argues that the higher estimates are based on studies assuming the inclusion of cracked stocks in the feedstock blend because it takes more hydrogen to process a cracked stock than a straight run feed, such as ANS Heavy Distillate. For this reason, CPAI asserts that its estimate of 325 scf per barrel is the most reasonable. CPAI notes that its estimate is almost identical to that of SOA (330 scf) and that it falls at the midpoint of all estimates. CPAI proposes a specific cost for hydrogen of 61.1 cents per barrel, in 2000 dollars.

EMT

146. EMT note that all parties, except Flint Hills and Petro Star have asserted that the unit cost for hydrogen does not change as a result of the more severe processing requirement. EMT further point out that all parties agree that hydrogen consumption increases with the more severe processing. EMT assert that its consumption rate estimate of 350 scf per barrel is supported by substantial evidence in the record. Specifically, EMT state that the study upon which it relied indicated that a revamp of a hydrotreater to meet the new sulfur specification would result in a 40% increase in hydrogen consumption. EMT also note that the QBA, in arriving at the same incremental increase as EMT, based his estimate on his review and analysis of numerous published sources. EMT contend that BP's and Chevron's proposals of 300 scf should be rejected because those estimates (i) assume a lower sulfur starting point than 500 ppm, (ii) they fail to consider the additional purge gas required to maintain the purity of the recycle hydrogen stream, and (iii) neither begins with the previously-approved base consumption level of 250 scf as required by Opinion No. 481. EMT argue that CPAI's and SOA's proposals are too low because they fail to consider the need for additional purge gas. According to EMT, the need for purge gas increases the hydrogen requirement by 44 scf per barrel. Finally, EMT argue that BP's proposal for a pilot plant study should be rejected as not administratively feasible. EMT state that using its recommended 350 scf per barrel Heavy Distillate and the previously-approved unit cost for hydrogen, adjusted to 2006, results in a specific cost per barrel Heavy Distillate for hydrogen of 2.00 cents per gallon.

BP

147. BP contends that the best method of determining the increase in hydrogen consumption is to perform a pilot test. Nevertheless, BP proposes in the alternative, an estimated incremental increase in hydrogen consumption of 50 scf. BP argues that the parties asserting higher incremental increases rely on hydrogen consumption levels for non-virgin feeds. BP states that only estimates relying on virgin feeds should be used to

---

[57] CPAI states that once Flint Hills' proposed 2005 unit cost is changed to reflect the unit cost approved in Opinion No. 481, its specific cost estimate is close to the others.

determine the hydrogen consumption level in this proceeding. BP acknowledges that it started its analysis with a Heavy Distillate sulfur content of 350 ppm, rather than 500 ppm and states that if 500 ppm is the appropriate starting point, its hydrogen consumption level estimate increases to 53 scf per barrel. BP proposes an incremental specific cost for hydrogen of $0.088/barrel, in 1996 dollars.

SOA

148. SOA asserts that hydrogen consumption changes due to the more severe processing requirement. SOA recommends an increase from the previously-approved 250 scf per barrel to 330 scf per barrel, relying on one study analyzing the scope and costs of revamping two hydrotreaters to meet the ultra low sulfur requirement. SOA states that its estimate is reasonable because CPAI, BP, EMT, Flint Hills and TAPS Carriers provide similar recommendations. SOA proposes that the previously-approved specific cost per barrel for hydrogen, as set forth in Exhibit JS-2 continue to be used. According to SOA, adjusting that cost to 2000, results in a hydrogen cost of $0.620/barrel.

Chevron

149. Chevron argues that its actual experience at its El Segundo refinery is what should be relied on in this proceeding. Chevron states that it experienced a 51 scf per barrel incremental increase in hydrogen consumption at that refinery. Chevron notes that this is the same incremental increase proposed by BP. Chevron indicates its agreement with other parties' criticism of the TAPS Carriers/QBA's and Flint Hills' proposals of 350 scf as too high, stating that the studies relied on by those parties included cracked stock. Chevron proposes an incremental hydrogen cost of $0.205, in 2006 dollars. According to Chevron, adjusting the hydrogen cost reflected in JS-2 to 2006 using NFOCI results in a hydrogen cost per barrel Heavy Distillate of $0.603.

Petro Star

150. Petro Star asserts that the QBA considered a wide rage of information in arriving at his hydrogen consumption estimate of 350 scf per barrel and that such estimate is accurate and consistent with the QBA's overall approach. Noting that this estimate matches those of EMT and Flint Hills, Petro Star recommends its adoption for use in this proceeding.

Flint Hills

151. Flint Hills asserts that hydrogen consumption increases from 250 to 350 scf per barrel as a result of the more severe processing requirement. Flint Hills notes that its estimate is supported by the testimony of EMT's witness, who asserted that hydrogen

consumption would increase by 40% and by the QBA who based his estimate on research of a number of public sources. Flint Hills asserts that its witness considered the literature supporting the estimates of CPAI – 325 scf and the SOA – 330 scf and concluded that those estimates are too low. Flint Hills contends that BP's estimate of 300 scf per barrel is too low and should be rejected because it is based on a starting point of less than 500 ppm sulfur. Further, Flint Hills argues that BP's suggestion that a pilot study should be undertaken to evaluate hydrogen consumption should be rejected as administratively infeasible and because, as even BP's witness admits, such study may not result in an accurate estimate. Using the 350 scf per barrel and its proposed 2005 costs for hydrogen, Flint Hills recommends a hydrogen cost of $1.288 per barrel of Heavy Distillate.

Discussion/Analysis

152. All parties agree that there is an increase in hydrogen consumption as a result of the more severe processing required. The parties disagree as to the magnitude of that increase. At the outset, we summarily reject BP's proposal that a pilot study be conducted. None of the parameters that would have to be specified to perform such a study have been agreed to by the parties, nor would they likely be agreed to. We agree that such study would be administratively infeasible and would impermissibly delay the resolution of this proceeding. Further, we note that even BP's witness, McGovern, acknowledges that there is no guarantee that such study would result in an accurate prediction. *See, e.g.*, Exh. TC-15 at 21; Exh. TC-21at 2 (Exh. FHR-30 at 3); Exh. FHR-10 at 52.

153. We also reject BP's and Chevron's respective proposals because they assume a starting point of less than 500 ppm sulfur.[58] As discussed in detail in Section III.D.1., *infra*, we have adopted as a starting point for this proceeding, a pre-existing high pressure hydrotreater unit that processes Heavy Distillate to a low sulfur diesel with a sulfur content of *exactly* 500 ppm.

154. Three parties (EMT, Flint Hills, and the TAPS Carriers/QBA) estimate that hydrogen consumption increases 100 scf per barrel, from 250 to 350 scf per barrel. Petro Star asserts that we should adopt the TAPS Carriers/QBA proposal of 350 scf per barrel. CPAI and SOA estimate incremental increase of 75 scf and 80 scf (from 250 to 325 and 330 scf per barrel), respectively. CPAI asserts that after reviewing a variety of sources, its witness, O'Brien, determined that the incremental increase in hydrogen would be in

[58] BP witness McGovern acknowledged that he started at 350 ppm sulfur and one paper upon which he relied for his estimate started at 200 ppm. *See* Tr. 1332; Exh. BPX-8. *See also* Tr. 1328–1330. Chevron's witness, Engibous, acknowledged that Chevron's El Segundo Refinery started at 300 ppm sulfur (Tr. 1620) and that its Richmond Refinery started at 30-50 ppm sulfur (Tr. 1620).

the range of 20% - 40% (50 – 100 scf per barrel) and he selected the midpoint of that range, or 75 scf per barrel as his estimate. Exh. CPA-1 at 19. SOA relied upon the MathPro Inc. report[59] for its estimate. SOA and CPAI assert that the other parties' higher estimates are flawed because they rely on studies that assume some cracked stock in the feedstock, resulting in higher estimates of hydrogen consumption. BP makes a similar argument. We agree that the testimony in the record supports a conclusion that cracked stock is more difficult to process than virgin feed and that processing cracked stock would increase the hydrogen consumption. However, we do not believe that such conclusion requires disregarding the recommendations of either the QBA or EMT.

155. EMT witness, Schneider, testified that in concluding that there should be a 40% increase in hydrogen consumption, he did not rely solely on the Mustang Study,[60] which did include cracked stock. Rather, Schneider testified that he considered the information in the Mustang Study and used his experience to determine that a 40% increase in the base hydrogen amount approved in Opinion No. 481 should be applied in this proceeding. Tr. 1544-1545. *See also* Exh. EMT-1 at 20. The QBA relied on several published sources for his estimated increase in hydrogen consumption. *See* Exh. TC-4 at 15-16.[61] He testified that he considered some estimates in the literature that were much higher than his proposed 350 scf per barrel. Exh. TC-15 at 18. In discussing the various reports he analyzed, the QBA states that the estimates he reviewed were based on surveys of numerous technology vendors, as opposed to considering information from only one source. Exh. TC-4 at 16. In addition, the QBA reviewed and considered information in a 2003 Turner and Mason Study[62] which states that the revamping of existing low sulfur diesel units to produce ultra low sulfur diesel, will, in almost all instances "require additional make-up hydrogen capacity on the order of 50%." Tr. 531-32; quoting Exh.

[59] MathPro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards* (West Bethesda, MD, October 1999) (MathPro Study). *See* Exh. TC-7. The QBA also reviewed and considered the MathPro Study. *See* Exh. TC-4 at 16, referencing Exh. TC-7 at 24.

[60] Palmer, R.E. and others. *Revamp Your Hydrotreater to Manufacture Ultra Low Sulfur Diesel Fuel*, NPRA 2001 Annual Meeting, AM-04-27 (Mustang Study).

[61] The sources relied upon by the QBA that he describes in Exhibit TC-4 at p. 16, are exhibits in this proceeding. The respective discussions regarding increases in hydrogen consumption contained in those sources are found at Exh. TC-5 at 27, Exh. TC-8 at 2, Exh. TC-11 at 13, Exh. TC-7 at 24, and Exh. TC-13 at 251.

[62] Turner, Mason & Company, *Ultra Low Sulfur Diesel Multi-Client Study Phase I Report* (August 2003). The Turner and Mason Study analyzed responses to questionnaires relating the status of ULS diesel plans of refiners comprising approximately two-thirds of the total U.S. refining capacity.

SOA-10 at 75. As the QBA pointed out, a 50% increase in the previously-approved 250 scf/barrel base starting level results in an increase of 125 scf/barrel. Tr. 531. Flint Hills' witness Sanderson testified that he relied on the same source as the QBA and that the 350 scf estimate is supported by a number of other studies. Exh. FHR-10 at 50. We find the position taken by the TAPS Carriers/QBA to be comprehensive and well-reasoned. The QBA's estimate also is supported by the conclusions of EMT's expert and Flint Hill's expert, and, as acknowledged by both CPAI and SOA, it is close to their estimates. We find and conclude that the record evidence supports an incremental increase in hydrogen consumption of 100 scf as a result of the more severe processing.

156. We found and concluded in Paragraph 88, *supra*, that the unit cost for hydrogen that was approved in Opinion Nos. 481 and 481-A did not change as a result of the more severe processing requirement. Therefore, we find and conclude that for purposes of this proceeding, the incremental increase in the specific cost per barrel Heavy Distillate for hydrogen is determined by multiplying the previously-approved unit cost for hydrogen by the increased hydrogen consumption rate of 100 scf per barrel.

g. Labor ($ per barrel of Heavy Distillate)

<u>Participant Positions</u>

TAPS Carriers

157. TAPS Carriers assert that there is no change in the cost for labor as a result of the more severe processing. Therefore, TAPS Carriers state that the specific cost for labor approved in Opinion Nos. 481 and 481-A should continue to be used in this proceeding. That cost is $0.014 per barrel in 1996 dollars.

CPAI

158. CPAI states that all parties agree that the consumption level for labor does not change as a result of the more severe processing and that only Flint Hills asserts that the cost of labor should be changed. CPAI asserts that Flint Hills' position should be rejected because it is outside the scope of the hearing and is not supported by the record. CPAI recommends using the previously approved unit costs and consumption levels for the labor. According to CPAI, this results in a labor cost of $0.015 per barrel of Heavy Distillate in year 2000 dollars.

EMT

159. EMT state that neither the unit cost nor the consumption rate for labor changes as a result of the more severe processing. According to EMT, all parties agree with this position. EMT argue that Flint Hills' position that the 2005 West Coast labor rate should be used instead of that approved in Opinion No. 481 is outside the scope of this

proceeding, constitutes an impermissible collateral attack on Opinion No. 481 and creates an inconsistency that undermines the integrity of the approved methodology. Thus, EMT assert that the cost of labor approved in Opinion Nos. 481 and 481-A should continue to be used in this proceeding. EMT adjusts that to 2006 and proposes a cost of labor of 0.05 cents per gallon.

BP

160. BP states that neither the amount nor the cost of labor changes as a result of the more severe processing requirement. BP notes that all parties, except Flint Hills, agree with this position. BP argues that Flint Hills' assertion that the cost of labor should be changed to 2005 labor rates is outside the scope of this proceeding. BP proposes that the previously-approved labor cost per barrel of $0.014, in 1996 dollars, continue to be used in this proceeding.

SOA

161. SOA asserts that there is no change in the cost of labor as a result of the more severe processing requirement. Thus, SOA proposes that the previously approved labor cost as set forth in Exhibit JS-2 be used in this processing. SOA states that adjusting that cost to 2000, results in a labor cost of $0.015/Bbl.

Chevron

162. Chevron states that the cost of labor does not change as a result of the more severe processing requirement. Chevron notes that all parties, except Flint Hills, agree with this position and that Flint Hills' proposed usage of 2005 labor costs should be rejected as outside the scope of this proceeding. Chevron asserts that the previously-approved labor cost, as reflected in Exhibit JS-2, should be used in this proceeding. According to Chevron, adjusting that value to 2006, using NFOCI, results in a labor cost of $0.019.

Petro Star

163. Petro Star asserts that cost per barrel for each of the specified operating cost elements should be based on 2005 or 2006 costs. Petro Star does not offer a specific proposed cost per barrel for labor, but notes that it is computed directly from the unit cost and consumption rate.

Flint Hills

164. Flint Hills asserts that 2005 costs should be used for labor. Thus, Flint Hills proposes a labor cost of $0.020 per barrel of Heavy Distillate.

Discussion/Analysis

165. We found and concluded in Paragraphs 85 and 95, *supra*, that neither the unit cost nor the consumption level for labor, that were approved in Opinion Nos. 481 and 481-A, and are reflected in Exhibits JS-1 and JS-2, changed as a result of the more severe processing requirement. Therefore, we find and conclude that the previously-approved specific cost per barrel heavy Distillate for labor[63] shall continue to be used to calculate the processing cost adjustment in this proceeding.

C. Fixed Percentage Operating Costs

1. Do the fixed percentage maintenance, taxes, and insurance cost factors established under FERC Opinions Nos. 481 and 481-A change as a result of the more severe processing required to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate? What are the costs for maintenance, taxes and insurance?

166. The fixed percentage maintenance and tax and insurance cost factors that were approved in Opinion Nos. 481 and 481-A are 4% ISBL capital cost for maintenance and 1% ISBL capital cost for the combined tax and insurance costs. Those cost factors are reflected in Exhibits JS-1 and JS-2. Once the ISBL capital cost is determined, the maintenance and tax and insurance costs are easily calculated. The question to be answered here is whether the fixed percentage cost factors change as a result of the more severe processing required.

Participant Positions

TAPS Carrier/QBA

167. TAPS Carriers/QBA state that all parties agree that there is no change in the fixed percentages for maintenance and tax and insurance approved in Opinion Nos. 481 and 481-A as a result of the more severe processing and, therefore, those percentages should continue to be used in this proceeding.

CPAI

168. CPAI argues that the percentages approved in Opinion Nos. 481 and 481-A should continue to be used in this proceeding.

[63] Exhibits JS-1 and JS-2 list the specific cost per barrel Heavy Distillate for labor as $0.014/barrel (in 1996 dollars).

EMT

169. EMT argue that the fixed percentages approved in Opinion Nos. 481 and 481-A should be used for the calculation of maintenance and tax and insurance costs in this proceeding. EMT state that all parties, except perhaps Chevron agree that there is no change in these fixed percentages as a result of the more severe processing. EMT note that Chevron stated that it did not object to using the previously-approved fixed percentages, but that it relied on actual cost data from its own refineries, rather than the fixed percentages, in preparing its proposal in this proceeding.

BP

170. BP asserts that all parties agree that the fixed percentages approved in Opinion Nos. 481 and 481-A do not change as a result of the more severe processing requirement.

SOA

171. SOA argues that there should be no change made to the fixed percentage cost factors approved in Opinion Nos. 481 and 481-A.

Chevron

172. Chevron asserts that it does not object to using the percentages approved in Opinion Nos. 481 and 481-A for the maintenance and tax and insurance costs, and that those cost factors do not change as a result of the more severe processing. However, Chevron states that it used its actual maintenance costs in developing its processing cost adjustment proposal, because it experienced higher maintenance costs at its El Segundo and Richmond refineries than that reflected by using the fixed percentage cost.

Petro Star

173. Petro Star argues that the fixed percentage cost factors established under Opinion Nos. 481 and 481-A should continue to be used in this proceeding.

Flint Hills

174. Flint Hills asserts that there is no change to the fixed percentages for maintenance and tax and insurance that were established in Opinion Nos. 481 and 481-A as a result of the more severe processing required.

Discussion/Analysis

175. All parties agree that there should be no change made to the fixed percentage approved in Opinion Nos. 481 and 481-A for tax and insurance. All parties, except Chevron, unequivocally agree that the fixed percentage for maintenance approved in Opinion Nos. 481 and 481-A should continue to be used in this proceeding. *See* Exh. EMT-1 at 11, 19; Exh. SOA-1 at 11; Exh. BPX -1 at 73; Exh. CPA-1 at 21; Exh. FHR-1 at 22; Exh. TC-1 at 13, Exh. TC-4 at 11. Although Chevron takes the position that the previously-approved fixed percentage for maintenance did not adequately reflect its actual maintenance costs at its revamped refineries, Chevron states that the difference is not significant and it does not oppose the continued use of the fixed percentage cost for maintenance that was approved in Opinion Nos. 481 and 481-A. *See* Chevron Initial Br. 25. Based on the evidence in the record, including Chevron's acknowledgement that any change in its actual maintenance costs was insignificant, we find that the fixed cost percentages for maintenance and tax and insurance do not change as a result of the more severe processing. Therefore, we find and conclude that the fixed percentage cost for maintenance (4% ISBL capital cost) and the fixed percentage cost for taxes and insurance (1% ISBL capital cost) that were approved in Opinion Nos. 481 and 481-A should continue to be used to determine the processing cost adjustment in this proceeding.

176. Now that we have adopted the previously-approved percentage costs for maintenance and for taxes and insurance, we must determine the cost of maintenance and the cost of taxes and insurance. In Section III.D.1., *infra*, we adopted EMT's revamp proposal. We found and concluded, however, that EMT's ISBL cost estimate of $18.49 million on an NFCCI-adjusted West Coast basis must be appropriately adjusted to a 2000 base year. Once such adjustment is made, the appropriate ISBL cost will be determined and can be incorporated into the equation for purposes of calculating the costs for maintenance and taxes and insurance to be included in the processing cost adjustment.

D. Capital Costs

1. ISBL Costs – What is the ISBL capital cost for a 50,000 barrel per stream day Heavy Distillate hydrotreater capable of processing Heavy Distillate to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate?

177. We acknowledged at Paragraph 70, *supra*, that no party disputes the Heavy Distillate hydrotreater built into the Quality Bank model in the UID/Opinion No. 481 is incapable of satisfying the 8 ppm ULSD specification. We also acknowledged that no party disputes the model hydrotreater either has to be revamped or replaced in the instant proceedings by a completely new unit specifically modeled to satisfy the specification. In addition, we found and concluded that: (1) any costs associated with the revamped/

replacement model hydrotreater expressly fall within the September 28 Order prescription concerning cost elements that increase or change as a result of the more severe processing required to meet the ULSD specification; and (2) the revamp/ replacement should be deemed a June 1, 2006 event. We must now determine whether the model should be modified in accordance with the revamp approach or the replacement approach. We also must determine the capital costs associated with the indicated approach so those costs can be incorporated into the Heavy Distillate processing cost adjustment.

Participant Positions

TAPS Carriers/QBA

178. TAPS Carriers/QBA argue the revamp approach must be adopted. They state the costs associated with the hypothetical Heavy Distillate hydrotreater approved in Opinion No. 481 evidently were estimated based on a modern high pressure unit suitable for modification to meet more stringent sulfur specifications. The also contend the revamp approach is more reasonable than replacement because that approach was adopted by most real world refineries. Accordingly, TAPS Carriers/QBA propose to establish the ISBL cost component in this case by adding the indicated revamp capital costs to the capital costs imputed to the Heavy Distillate hydrotreater in the Opinion No. 481 proceeding. This would total $100.97 million on a 1996 West Coast basis.

179. TAPS Carriers/QBA maintain both the capital costs and all other costs used to calculate the Heavy Distillate processing cost adjustment in Opinion No. 481 were based on the assumption the processing required was from 5,000 ppm sulfur content to 500 ppm. They challenge the validity of any claim that the processing costs approved in Opinion No. 481 included costs attributable to incremental sulfur processing capability down to 350 or 300 ppm in anticipation of a more stringent future sulfur specification, adding any such presumption necessarily would fail to account for that increment in the instant proceedings.

CPAI

180. CPAI insists the replacement approach must be adopted, arguing at the outset it would only be appropriate to adopt a revamp approach if the combined costs of the hypothetical hydrotreater adopted in Opinion No. 481 and its revamp were lower than those associated with building a brand new unit for modeling purposes. On CPAI's account, this is because the Commissions' replacement cost methodology assumes processing equipment is newly constructed the same year the processing cost is calculated. It contends this requires any revamp approach to assume the base model hydrotreater adopted in Opinion No. 481 is reconstructed in 2006 and the revamp enhancement is made immediately thereafter. It contrasts this methodology with real

world refinery practice on the ground no actual refiner would decide whether to revamp or replace an existing hyrotreater this way. Real world costs associated with an existing hydrotreater are already sunk, so any decision with respect to the revamp/replacement choice would be made by comparing incremental revamp costs to whole unit replacement costs. It therefore is not surprising in CPAI's view that most real world refiners would favor the revamp option. Viewed from the replacement cost methodology perspective, however, no real world refiner would satisfy the 8 ppm ULSD specification by first building a 500 ppm hydrotreater and then immediately upgrading it unless that course were cheaper than building a hydrotreater specifically designed to satisfy the 8 ppm specification in the first instance. CPAI advocates the replacement approach because its calculations indicate replacement is slightly cheaper than base+revamp ($79.88 million vs. $81.3 million).

EMT

181. EMT assert the revamp approach should be adopted for several reasons: (1) it mimics what real world refineries did; (2) it costs less than replacement; and (3) the UID/Opinion No. 481 anticipated more stringent future sulfur specifications would be satisfied by revamping the model hydrotreater adopted in those opinions. EMT also maintain the revamp approach is mandated by the September 26 Order because the high pressure model hydrotreater approved in Opinion No. 481 indisputably can be modified to satisfy the 8 ppm ULSD specification.[64] They dismiss any claim that the Quality Bank employs a replacement cost methodology, acknowledging the processing cost adjustment is updated annually through the NFOCI, but stressing that *individual* cost elements—including capital costs—are not updated to reflect current costs in calculating the annual adjustment. They similarly discount any claim there is insufficient information concerning the previously-approved model hydrotreater to estimate the cost of revamping it, citing record evidence inconsistent with such claims. EMT maintain substantial record evidence supports adopting their revamp cost estimate of $18.49 million on an NFCCI-adjusted 2005 West Coast basis, which assumes the revamp is accomplished by (i) doubling the catalyst volume by installing a second reactor; (ii) employing a new, high-activity catalyst; (iii) adding additional make-up hydrogen compressor capacity; and (iv) installing a recycle hydrogen gas amine scrubber. They criticize other parties' reliance on real world revamp cost data as unreliable and inconsistent with the Quality Bank methodology to the extent it ignores the model's simplifying assumptions.

[64] EMT do not make the corollary argument that the revamp starting point consequently should be less than 500 ppm, as some other parties citing this rationale do.

BP

182. BP states as a preliminary matter that "confusion" exists concerning the amount of desulfurization at issue in this case. According to BP, retail pump sulfur specifications have been conflated with pipeline specifications, thereby obfuscating the true costs associated with the more stringent 8 ppm ULSD specification**.** It states the EPA sulfur specifications—which are maximum retail pump specifications—are 500 ppm for LSD and 15 ppm for ULSD. To ensure delivery of sulfur-compliant diesel at the retail pump, however, pipelines require refiners to deliver even lower sulfur content diesels to the pipelines. According to BP, while actual pipeline specifications vary, the average sulfur content for diesel actually produced and delivered to pipelines has been 350 ppm for LSD and the current pipeline specification for ULSD is 8 ppm. BP therefore contends the amount of desulfurization at issue in this case is the difference between 350 ppm and 8 ppm, or 342 ppm. Any [revamp][65] proposal predicated on Heavy Distillate processing from 500 ppm to 8 ppm sulfur content severely overstates the amount of processing required/double-counts the 500 to 350 ppm processing cost increment on BP's account.

183. BP contends design technology—specifically, single-stage versus two-stage hydrotreater design—accounts for a significant portion of the ISBL capital cost disparity among the various party proposals here despite the fact that two-stage designs reflect outdated technology. It states that in the late 1990s/early 2000s many industry experts believed a two-stage design would be required to produce ULSD, but recent data and actual unit revamps reflect single-stage designs. Since two-stage hydrotreaters are more expensive to build than single-stage units, revamp proposals reflecting two-stage units overstate ISBL capital costs. Moreover, although the UID/Opinion No. 481 does not specify whether the 50,000 barrel/day high pressure hydrotreater incorporated into the Quality Bank model was a single-stage or two-stage unit, two-stage units were not required in order to produce the LSD reference product at issue there. Thus, it is logical to conclude the previously-approved hydrotreater was a single-stage unit in BP's view. And since (i) most real world refiners revamped their hydrotreaters instead of building new ones to produce ULSD, and (ii) a revamp approach isolates only those costs that increase or change as a result of the more severe processing required to satisfy the ULSD specification, BP premises its ISBL capital cost proposal on a single-stage unit revamped by incorporating a second reactor to meet the 8 ppm sulfur specification. BP sets the attending ISBL capital costs at $12.7 million on a 1996 West Coast basis.

[65] The sulfur processing increment is only relevant to a revamp scenario.

SOA

184. SOA contends nothing in the UID, Opinion Nos. 481/481-A or the September 26 Order directly addresses whether a revamp or replacement approach should be adopted in this case. Nevertheless, those orders define the replacement cost methodology used to establish the processing cost calculation's ISBL capital cost component. On SOA's account, the Quality Bank methodology diverges from real world practice in that it calculates capital costs on an annual basis—literally building a brand new unit each year based on current costs. The revamp/replacement distinction is essentially meaningless for Quality Bank modeling purposes because the model will construct a new unit either way. The only difference will be whether it (i) constructs a unit specifically designed to satisfy the 8 ppm ULSD specification in the first instance or (ii) constructs a new unit designed to satisfy the 500 ppm LSD specification and immediately revamps it to satisfy the 8 ppm ULSD specification. The choice comes down to which hypothetical procedure models lower capital costs. SOA maintains constructing a unit specifically designed to satisfy the 8 ppm ULSD specification in the first instance models lower costs and is both logical/conceptually more consistent with the replacement cost methodology.

185. SOA criticizes any reliance on Paragraph 10 of the September 26 Order to support adopting the hydrotreater contemplated in the UID/Opinion No. 481 and enhancing it here as conflating the Quality Bank model with the real world. SOA asserts the model—unlike real world refineries—retains no "existing" facilities from year to year, instead annually modeling a brand new refinery based on current cost data. SOA therefore concludes the simple, logical and economically efficient way to calculate the capital cost element change attributable to the more stringent 8 ppm sulfur specification in this case is to replace the LSD hydrotreater the UID and Opinion No. 481 built into the model with a completely new ULSD unit. The attending capital cost should be derived by applying simple 1999-1996 NFCCI and Chemical Engineering (CE) index averages instead of the NFOCI in SOA's view due to the fact the NFOCI is a composite index not designed to track changes in individual cost components. SOA applies this methodology to derive a 1996 West Coast basis totaling $106.3 million for a replacement unit.

Chevron

186. Chevron takes the position the September 26 Order requires a revamp approach. It interprets the order's express limitation of issues here to "only cost elements that increase or change as a result of the more severe processing required to meet the sulfur specifications associated with the new [ULSD] price" as clear indication that the Commissions intended to retain the previously-established processing cost adjustment to the extent possible, adding only the incremental costs associated with satisfying the more stringent sulfur specification. Replacing the previously-approved model hydrotreater

with a completely new unit specifically designed to satisfy the 8 ppm ULSD specification is inconsistent with that intent, would require a wholly new processing cost adjustment and potentially would call into question all the cost elements and hydrotreater model assumptions established in Opinion No. 481 as Chevron sees it.

187. Chevron advocates a revamp approach based on a combination of the model hydrotreater's previously-established characteristics and cost data from actual refinery revamps. Chevron first emphasizes the hydrotreater's hypothetical nature, explaining it is a purely economic model used solely to derive the processing cost adjustment used to value Heavy Distillate. It then details the current model hydrotreater's presumed characteristics, submitting these characteristics are integral to estimating the capital costs attributable to the more stringent ULSD specification. Chief among these is the assumption the current model represents an 800 psi unit capable of being modified instead of replaced to satisfy the ULSD specification. Chevron claims recent improvements in catalyst technology enable actual units in this general pressure range to be revamped to produce ULSD at relatively modest capital costs, citing various real world examples to substantiate this claim. Chevron maintains the evidence shows roughly 80% of actual LSD refiners revamped their existing hydrotreaters to produce ULSD rather than replacing them. It attributes this circumstance to more active catalysts[66] and reactor vessel design changes which in combination permit refiners to adapt existing single-stage hydrotreaters instead of adding more expensive second-stage reactors to produce ULSD.

188. Although Chevron estimates the appropriate ISBL capital costs for its revamp proposal at $6.0 million on a 2005 West Coast basis in consideration of actual costs incurred at its El Segundo and Richmond refineries,[67] it states any processing cost adjustment adopted in this case also should "take account of the BP and EMT proposals." Chevron Reply Br. 34. Chevron appears to advocate averaging its own estimate with the others to produce a $13.49 million 2005 West Coast basis ISBL capital cost adjustment.[68]

189. Chevron's position regarding the amount of desulfurization at issue in this case/its importance is unclear. On the one hand, Chevron highlights that its ISBL capital cost estimate relies on real world refineries that actually produced LSD in the 340 ppm range

[66] Nickel/Molybdenum (NiMo) catalysts instead of Cobalt/Molybdenum (CoMo) ones.

[67] Chevron attributes a processing capacity of 35,000 barrels/day to El Segundo and a processing capacity of 30,000 barrels/day to Richmond. Exh. CVX-2 at n. 1.

[68] Chevron adjusts BP's $12.7 million 1996 West Coast basis capital cost adjustment to $18.49 million on a 2005 West Coast basis for this purpose.

to satisfy the 500 ppm specification, claiming the model hydrotreater adopted in Opinion No. 481 also "is fully capable of producing [LSD] with 350 ppm sulfur" content. On the other, Chevron dismisses the 500/340 ppm differential as nothing more than a measuring error allowance and characterizes the incremental cost of reducing sulfur content from 500 to 350 ppm as "very small."

Petro Star

190. Petro Star believes ISBL capital costs should be determined as of 2005 or 2006, be expressed in 2005/2006 dollars, and be based on a revamp of the LSD hydrotreater approved in Opinion Nos. 481/481-A. It therefore endorses the TAPS Carriers/QBA proposal with one exception: the QBA should not have de-escalated the 1999 capital costs he used to 1996 and then re-escalated them to 2006. Consistent with its 2005 base year proposal, Petro Star advocates escalating year 1999 costs in a straightforward manner to 2005 for use in a 2005 base year processing cost adjustment. Petro Star agrees adopting a revamp approach is consistent with both actual industry practice and the design characteristics imputed to the model LSD hydrotreater in the UID/Opinion No. 481.

191. Petro Star contends the desulfurzation starting point in this case should be 500 ppm. It emphasizes the UID/Opinion No. 481 proceeding specifically addressed a 0.05% [500 ppm] sulfur specification, and no party in that proceeding suggested any additional desulfurization was at issue or accounted for in the processing cost adjustment adopted there. Presuming otherwise here would leave uncompensated the processing increment between 500 and 350 ppm, translating into an unfairly low processing cost adjustment in Petro Star's view.

Flint Hills

192. Flint Hills advocates the replacement approach.[69] It first states the broad criticism that a revamp approach is inconsistent with the Quality Bank's general replacement cost methodology. It then focuses on the UID/Opinion NO. 481 model hydrotreater's imputed design, underscoring a difference between the "two-stage" unit Flint Hills models and the two-stage design parameters presumed by other parties. Flint Hills models a two-stage hydrotreater as a single high pressure reactor vessel incorporating two discrete catalysts/ catalyst beds to achieve the requisite processing. Other parties, in contrast, presume a two-stage hydrotreater incorporates two discrete reactors with an interstage stripper or

[69] The record indicates that while Flint Hills always believed a replacement approach was more appropriate, it initially endorsed a revamp in this case because it construed the September 26 Order as indicating a preference for that approach. Flint Hills now advocates a replacement approach as more consistent with its overall 2005 base year proposal.

amine scrubber between them. Flint Hills characterizes any emphasis on the difference as overblown and diversionary in any event, asserting the record proves the cost differential to be nominal—especially if realistic (i.e. year 2005) capital costs are used as the starting point. Flint Hills adds it is difficult to see how whatever ULSD model hydrotreater is adopted in this case could cost significantly more as a two reactor unit than a single reactor one, highlighting the circumstance that CPAI witness O'Brien modeled the hydrotreater adopted in the UID/Opinion No. 481, but even he could not confirm whether it incorporated one reactor or two.

193. As stated under Issue I, *supra*, Flint Hills emphasizes the Heavy Distillate hydrotreater modeled in the UID/Opinion No. 481 indisputably was incapable of satisfying the 8 ppm ULSD specification. Any ISBL capital costs associated with the need to replace that hydrotreater with a completely new unit specifically modeled to satisfy the more stringent sulfur specification therefore fall within the September 26 Order prescription concerning cost elements that increased or changed as a result of the more severe processing requirement. In addition, the replacement must be considered a 2006 event in Flint Hills' view because the September 26 Order specifically acknowledges the 8 ppm specification's June 1, 2006 effective date. Since real world refineries incurred the capital costs associated with upgrading their processing facilities to satisfy the 8 ppm ULSD specification in the time period immediately prior to June 1, 2006, and since 2005 provides the last full year of actual cost data prior to that date, it follows on Flint Hill's account that using year 2005 cost data to establish the replacement unit's ISBL capital costs in this case is entirely consistent with the September 26 Order. Flint Hills sets the ISBL capital costs cost associated with a replacement ULSD hydrotreater at $114.3 million on a 2005 West Coast basis.

Discussion/Analysis

194. We find and conclude at the outset that the UID/Opinion Nos. 481/481-A adopted a high-pressure[70] hydrotreater unit with a Heavy Distillate processing capacity of 50,000 barrels/day as typical of hydrotreaters used to produce the 500 ppm LSD reference product. 108 FERC ¶ 63,030, at P 1420-23, 1428 & n. 570 (2004). We also find and conclude the UID/Opinion Nos. 481/481-A ruled the ISBL capital costs associated with processing Heavy Distillate for Quality Bank purposes should be calculated on the basis of a hydrotreater unit with those characteristics. *Id.* at P 1428.

195. We ruled at Paragraph 58, *supra*, that the "to the extent possible" qualifier reflected in Paragraph 10 of the September 26 Order generally was intended to preserve as many of the prior rulings made in the UID/Opinion Nos. 481/481-A as reasonably possible. We ruled at Paragraph 61, *supra*, that the only difference between the prior 500

[70] The UID defines "high pressure" as 800 pounds per square inch (psi) or higher.

ppm LSD Heavy Distillate reference product and the 8 ppm ULSD reference product implemented June 1, 2006 was the intervening imposition of a lower sulfur specification for highway diesel fuel. We therefore concluded the ULSD reference product was nothing more than a significant *incremental enhancement* of the 500 ppm LSD reference product. We ruled at Paragraphs 61 and 65, *supra*, that the "to the extent possible" qualifier reflected in Paragraph 10 of the September 26 Order required us to abide by prior rulings made in the UID/Opinion Nos. 481/481-A to the extent they were reasonably adaptable to the ULSD reference product. Consistent with all those rulings, we find and conclude the UID and Opinion Nos. 481/481-A require us to adopt as starting points in the instant proceedings: (1) a pre-existing high pressure hydrotreater unit with a Heavy Distillate processing capacity of 50,000 barrels/day; and (2) ISBL capital costs associated with such a unit processing Heavy Distillate down to LSD with a sulfur content of *exactly* 500 ppm.

196. Here again, the Quality Bank's *model* hydrotreater is not constrained by real world considerations such as whether actual refinery hydrotreaters built to produce LSD were/ are capable of processing Heavy Distillate marginally below the 500 ppm sulfur specification. Such real world variables are simply immaterial because the Quality Bank model hydrotreater is, by virtue of its hypothetical nature, capable of simplifying assumptions/precision unachievable in any real world refinery. These include the ability to process Heavy Distillate precisely to either a 500 ppm or 8 ppm sulfur content—and the concomitant processing cost adjustment precision that goes with it. There was/is absolutely no need or legitimate reason to build excess processing capability into the Quality Bank's Heavy Distillate model hydrotreater. Nothing in the UID or Opinion Nos. 481/481-A indicates a different conclusion is warranted.[71]

197. The overwhelming weight of evidence before us confirms this conclusion. Most pertinent, the Heavy Distillate reference product/price addressed in the UID/Opinion No. 481 inarguably was 0.05 % (or 500 ppm) sulfur content LSD. 108 FERC ¶ 63,030, at P

[71] The UID does cite the fact that a study published in 2000 stated many refiners constructing hydrotreaters to meet the 500 ppm LSD specification had constructed units of at least 800 psi instead of lower pressure units because the incremental costs were "small" and "protected their investment" in the event the specification was lowered in the future. *See* 108 FERC ¶ 63,030, at P 1422 (2004). The UID neither quantifies the incremental costs/processing capabilities nor explains why or to what degree such investment protected the investments. Nor does the UID state what weight it accorded the study among the various factors it cites in support of adopting a high pressure hydrotreater. Our reading of the UID suggests it endorsed a high pressure 50,000 barrel/day unit primarily because it typified hydrotreater units commonly employed by refiners to process Heavy Distillate to a 500 ppm sulfur specification. *Id.* at P 1420-21, 1426 & n. 570.

1415 & n. 567 (2004). There is no suggestion whatsoever in either opinion that a more stringent specification had to be accounted for in that proceeding. The QBA Notice and September 26 Order confirm this. Each specifically and exclusively cites 500 ppm LSD as the obsolete Heavy Distillate reference product/price. Ex. TC-4 at 2; 116 FERC ¶ 61,291, at P 5 (2006). We do not presume the QBA and the Commissions to be in error in this regard[72]—particularly when the September 26 Order defines the limits of our jurisdiction. In addition, the record reveals the varying lower pipeline specifications for what they were/are: real world marginal safeguards to ensure delivery of 500 ppm maximum sulfur content diesel at the retail pump. Exh. BPX-1 at 31-35; Tr. 1371-72. Such safeguards are unnecessary for economic modeling purposes; the reference product is by definition sulfur-compliant.[73] *Accord* Tr. 542-43, 550.

198. Our Paragraph 195 conclusion that the UID and Opinion Nos. 481/481-A require us to adopt a pre-existing high pressure hydrotreater unit with a Heavy Distillate processing capacity of 50,000 barrels per day as a starting point also dictates that the model be modified here in accordance with the revamp approach. It would be logically inconsistent with our prior rulings to do otherwise. Accordingly, we must reject any proposal predicated on a replacement approach.

199. Since the Quality Bank's model hydrotreater is not constrained by real world considerations, one might argue its capacity for simplifying assumptions just as easily should permit us to supplant the 500 ppm LSD hydrotreater built into the model in the UID and Opinion Nos. 481/481-A with an entirely new unit specifically modeled to satisfy the 8 ppm ULSD specification. This argument would fail for a number of reasons. Foremost among them is it violates the September 26 Order's prescription that prior UID

---

[72] Neither do we presume the QBA, Commissions and Exh. JS-3 at ¶ 21 to be in error with respect to the 8 ppm ULSD specification. Nevertheless, the record suggests the actual (EPA) ULSD pump specification supplanting the 500 ppm LSD pump specification on June 1, 2006 was 15 ppm rather than 8 ppm. *See generally* Exh. TC-13. *See also* Exh. BPX-1 at 31-34. By our own reasoning, then, the incremental desulfurization at issue in this case properly would range from 500 ppm to 15 ppm instead of 8 ppm. Whether any party's proposed processing cost adjustment is based on this increment is unknown. We observe, however, that incremental sulfur processing costs are greater at the low sulfur content end of the range than they are at the high end due to a higher concentration of sterically-hindered compounds. *See, e.g.,* Tr. 402, 424-25.

[73] In addition, we find no evidence quantifying the incremental processing costs for the 500-350/340 ppm band in the UID, and virtually none here. This strongly suggests the attending costs would be stranded if a desulfurization starting point below 500 ppm were adopted. *See also* Tr. 542-43, 550.

and Opinion Nos. 481/481-A rulings should be preserved to the extent possible. Modifying the 500 ppm LSD model hydrotreater adopted in the UID and Opinion Nos. 481/481-A to satisfy the 8 ppm ULSD specification is indisputably possible here; the only question would be which revamp approach to adopt. In addition, a revamp approach is conceptually more consistent with the Commissions' clear intention to address only *incremental* costs in these proceedings. Incremental costs logically must relate to previously-established base costs—in this case, those associated with the 500 ppm LSD model hydrotreater adopted in the UID and Opinion Nos. 481/481-A.[74] Finally, the only possible rationales for replacing the 500 ppm LSD model hydrotreater with an entirely different unit specifically modeled to satisfy the 8 ppm ULSD specification would be because the replacement model either (i) was superior to the revamp model in some functional way or (ii) that it produced a lower ISBL capital cost adjustment. The first rationale is meaningless in the context of our competing hypothetical models; the replacement/revamp alternatives must be equivalent in both production capacity (50,000 barrels/day) and quality (8 ppm ULSD product). The second rationale is belied by the record. *See* Exh. EMT-1 at 16; Exh. EMT-5; Exh. EMT-9; Exh. EMT-11 at 12-13; Exh. EMT-25 at 25; Exh. BPX-1 at 67-69; Exh. CVX-1 at 8-12; Exh. CVX-2.

200. CPAI, SOA and Flint Hills maintain the replacement cost methodology compels us to adopt the hydrotreater replacement approach here. We disagree. First, CPAI, SOA and Flint Hills construe the replacement cost methodology as assuming all processing equipment is newly constructed each year the processing cost is calculated—i.e. every year. This cannot be the case. The 500 ppm LSD Heavy Distillate hydrotreater was incorporated into the Quality Bank model employing 1996 capital cost bases indexed to a 2000 base year using both the NFOCI *and* NFCCI. 108 FERC ¶ 63,030, at P 1257-58 (2004); Tr. 360-61. Thereafter, the imputed base year 2000 capital costs could be indexed forward *only* through the NFOCI. 108 FERC ¶ 63,030, at P 1450 (2004); Exh. TC-4 at 14; Exh. TC-15 at 7; Tr. 358-60. But we already have established the NFOCI does not annually update any individual cost elements, including capital costs. The Quality Bank model consequently cannot legitimately be characterized as constructing a brand new Heavy Distillate hydrotreater (i.e. replacing it) every year—even in the most abstract sense. The model merely escalates the hydrotreater's original imputed capital costs in conjunction with every other individual cost element on an annual basis through the NFOCI. Moreover, the September 26 Order expressly intends to preserve the model hydrotreater adopted in the UID/Opinion No. 481 to the extent possible.[75] Replacing it

[74] We find the extensive record evidence indicating most real world refiners adopted a revamp approach comforting but immaterial. Having stressed the hypothetical nature of the model hydrotreater throughout, it would be disingenuous for us to rely on real world supporting data at this juncture.

[75] We reject SOA's contention that relying on Paragraph 10 of the September 26 Order to support retaining the hydrotreater contemplated in the UID/Opinion No. 481 and

with a completely new model hydrotreater even once, let alone annually, is patently inconsistent with that intent. It is similarly inconsistent with the September 26 Order's obvious intent to limit this case to incremental costs. We therefore find and conclude the ISBL cost component should be determined in this case by adding the indicated revamp capital costs to the $62.865 million 1996 West Coast basis capital costs imputed to the Heavy Distillate hydrotreater in the Opinion No. 481 proceeding.[76]

201. Turning to the more complicated matter of specific base hydrotreater design parameters for revamp purposes, we note at the outset that hydrotreater design is inextricably linked to the catalyst(s) employed. The record is conclusive that hydrotreater capital costs are impacted by the quantity and effectiveness of the catalyst(s) used in the reactor vessel(s). Exh. EMT-1 at 21; Exh. EMT-6 at 8; Exh. EMT-15 at 22; Exh. SOA-1 at 10; Exh. SOA-10 at 1992-93; Exh. BPX-19 at 31-45, 76-77; Exh. TC-13 at 70-73; Exh. CVX-1 at 9-10; Tr. 855-56, 1073-74. To be precise, catalyst and capital costs are covariant—the more the model relies on more/better catalyst(s), the less it must rely on additional capital components such as additional reactors, pumps, compressors, etc. With the exception of BP, however, every party to these proceedings premised its ISBL capital and catalyst cost positions on the assumption that catalysts which did not exist until at least 2003 would be used in the revamped (or replacement) Heavy Distillate hydrotreater built into the model here. This presents somewhat of a dilemma. Consistent with our prior rulings, we could simply adopt BP's position as the only one complying with the 1996/2000 base year principle. Alternately, we could deviate from that principle to avoid the harsh result of having to disregard all other capital cost/catalyst proposals, and in doing so apparently violate the prior ruling consistency principle we have embraced throughout. The first alternative is troubling because we are not persuaded by the record before us that interim advances in single-stage high pressure hydrotreater design enable the 8 ppm ULSD specification to be satisfied using the less active catalyst contemplated in the Opinion No. 481 proceeding. The second alternative is troubling because we would have to incorporate into the Heavy Distillate hydrotreater model new high activity catalyst(s) that cannot be priced using 1996 or 2000 cost bases indexed forward using the NFOCI because there are no 1996 or 2000 cost bases to index for the new catalyst(s).

---

enhancing it here conflates the Quality Bank model with the real world. To the contrary, it simply preserves the basic structure/elements of the model itself, adding the minimum indicated enhancements to hypothetically satisfy the ULSD specification.

[76] The total capital costs imputed to the Heavy Distillate hydrotreater in the Opinion No. 481 proceeding was $49.5 million on a Gulf Coast basis. Applying the Commission-approved location factor of 1.27 (*see* 108 FERC ¶ 63,030, at P 1437 (2004)) produces a base hydrotreater capital cost component totaling $62.865 million on a 1996 West Coast basis.

202. The UID and September 26 Order suggest two potential solutions. The UID expressly states "the existence or non-existence of certain equipment [as of base year 2000] should not be considered in making any [Heavy Distillate processing cost] calculations." 108 FERC ¶ 63,030, at P 1450 (2004). Incorporating new high activity catalyst(s) into the Heavy Distillate hydrotreater revamp model in this case therefore would remain consistent with/governed by prior Quality Bank rulings in the UID and Opinion Nos. 481/481-A. In addition, the September 26 Order prescribes the instant proceedings should be governed by prior UID/Opinion Nos. 481/481-A rulings only "to the extent possible." We therefore might conclude it is not reasonably possible to avoid incorporating high activity catalyst(s) into the model hydrotreater revamp because we are unconvinced the less active catalyst contemplated in prior UID/Opinion No. 481 rulings is capable of satisfying the 8 ppm ULSD specification under any circumstances.[77] We rely on UID Paragraph 1450 to find and conclude it is appropriate in this case to incorporate high activity catalyst(s) which did not exist in year 2000 into the model hydrotreater revamp. The per-unit cost associated with such catalyst(s) should be determined as of June 1, 2006 and indexed to the 2000 base year using the NFOCI.

203. Having determined it is appropriate to incorporate high activity catalyst(s), we may now also determine what capital equipment is required/appropriate to incorporate into the Heavy Distillate hydrotreater model revamp unit. We first find and conclude the base unit model hydrotreater adopted in the UID/Opinion No. 481 was a single-stage high pressure unit. Although the UID does not specify—or apparently even consider—this design parameter, the evidence before us is conclusive that a typical 800 psi hydrotreater with a Heavy Distillate processing capacity of 50,000 barrels/day would require only one reactor vessel to produce 500 ppm LSD using a CoMo catalyst. Exh. BPX-1 at 35-36, 54; Exh. BPX-19 at 36-37; Exh. BPX-22 at 92; Exh. TC-13 at 65; Tr. 335-38, 1209-10, 1292-93. Here again, there was no reason or legitimate basis to build excess processing capacity (in this context, a second stage reactor/inter-stage stripper) into the Opinion No. 481 model hydrotreater.

204. The competing revamp proposals involve either adapting the current base unit's single-stage configuration to incorporate recent technological advances (Chevron, BP[78])

---

[77] We are compelled to reject this conclusion. While the record may be unconvincing that advances in *single*-stage high pressure hydrotreater design enable such units to satisfy the 8 ppm ULSD specification using the less active catalyst(s), it appears uncontested that a two-stage unit could do so—although at significant incremental capital cost.

[78] BP distinguishes single-stage configurations from single-reactor configurations. In BP's view, a two-reactor configuration constitutes a single-stage unit if there is no intermediary/additional processing equipment required. *See* Exh. BPX-1 at 56. EMT appear to agree insofar as an inter-stage stripper is implicated.

or adding a second-stage reactor vessel/ancillary equipment (TAPS Carriers/QBA, EMT, Petro Star).[79] The Chevron and BP proposals are both the simplest and cheapest. These virtues favor adopting one of the proposals if feasible—that is, if the proposed design enhancements are not merely speculative and demonstrably would be capable of processing 50,000 barrels/day of Heavy Distillate to the 8 ppm ULSD specification. We find and conclude neither proposal satisfies these criteria. The record confirms Chevron's proposal is based primarily on its own Richmond and El Segundo refinery revamps. Exh. CVX-1 at 8-12; Exh. CVX-2. Those refineries, however, have Heavy Distillate processing capacities of only 30,000 and 35,000 barrels/day respectively. Exh. CVX-2 at n. 1. There is scant record support for Chevron's conclusion that the approach adopted at either Richmond or El Segundo is realistically scalable to 50,000 barrels/day. Neither is there what we consider adequate record support for the capital costs Chevron attributes to the processing capability increment, which it apparently calculates in simple direct proportion to the increase in processing volume.[80] Similarly, there is not what we consider adequate record support for BP's contention that the only piece of additional equipment required for the base unit model hydrotreater to satisfy the 8 ppm ULSD specification is a second reactor vessel. We observe first that this contention is premised to some indeterminate degree on the 340/350 ppm desulfurization starting point BP advocates. *See, e.g.*, BP Reply Br. 31-32. This contention was discredited at Paragraphs 196-99, supr*a*. More important, the actual revamp evidence on which BP relies does not confirm the additional reactor vessel BP proposes would, by itself, be sufficient—either in raw processing capability or additional catalyst capacity. *See generally* Exh. BPX-12 *and* Exh. BPX-23. To the contrary, the evidence affirmatively suggests additional equipment would be required—particularly since the BP proposal retains CoMo catalyst.

205. Turning to the two-stage/ancillary equipment proposals, the record confirms the TAPS Carriers/QBA proposal is fundamentally flawed in that it presumes a medium pressure (i.e. 650 psi) base unit as the revamp starting point. *Compare* Exh. TC-4 at 15 *and* Tr. 382 *with* Exh. SOA-4 at 105. Further, it relies on a two-stage process incorporating inter-stage stripping which the record indicates is outmoded. *See, e.g.*, Exh. TC-6 at 33, 104-05; Tr. 378-79; Exh. BPX-22 at 92. In addition, the record suggests the actual project revamp evidence cited by TAPS Carriers/QBA to support their proposal is inadequate and also may be unreliable. *See, e.g.*, TC Reply Br. 18, 20; Exh. TC-15 at 10; Exh. TC-17; Tr. 428-31. Finally, the TAPS Carriers/QBA revamp proposal reflects

---

[79] Petro Star endorses the TAPS Carriers/QBA approach. We do not consider revamp "alternatives" discussed by parties advocating a replacement approach.

[80] *See* Chevron Initial Br. 28-29 & n. 10. Chevron itself appears to acknowledge these deficiencies when it concedes El Segundo may not be representative and therefore states "the processing cost adjustment . . . should take account of the [BP] and EMT proposals." Chevron Reply Br. 34.

both a significant increase in capital costs and a significant increase in catalyst costs. This is inconsistent with the covariant relationship between the two.

206. The EMT proposal exhibits none of the deficiencies cited in the preceding analysis. On the record before us, we find and conclude the Heavy Distillate model hydrotreater revamp should be achieved by: (1) installing a second reactor unit; (2) doubling the catalyst volume; (3) replacing the CoMo catalyst currently employed in the model with high-activity catalyst(s); (4) adding make-up hydrogen compressor capacity; and (5) installing a recycle hydrogen gas amine scrubber. *See generally* Exh. EMT-6. *See also* Exh. EMT-7 at 2. *Accord* Exh. BPX-23; Exh. SOA-10 at 75-76. The preceding ruling notwithstanding, we also find and conclude EMT's revamp cost estimate of $18.49 million on an NFCCI-adjusted 2005 West Coast basis must be appropriately adjusted to a 2000 base year using the NFOCI in accordance with the UID/Opinion No. 481.

2. OSBL Costs – What is the OSBL capital cost for a 50,000 barrel per stream day Heavy Distillate hydrotreater capable of processing Heavy Distillate to meet the sulfur specifications associated with the new Ultra Low Sulfur Diesel price used to value Heavy Distillate?

207. OSBL costs consist of off-site plant investments such as utility systems and storage tanks and are modeled as a percentage of ISBL costs. The UID and Opinion Nos. 481/481-A set the Heavy Distillate OSBL cost component at 29%. 108 FERC ¶ 63,030, at P 1434 (2004). All parties agree the ISBL cost component associated with the Heavy Distillate hydrotreater model revamp (or replacement) also should be set at a percentage of the ISBL cost component, but they disagree what the percentage should be in this case.

<u>Participant Positions</u>

TAPS Carriers/QBA

208. TAPS Carriers/QBA initially endorsed the 29% figure adopted in the UID and Opinion Nos. 481/481-A. After considering the BP and EMT arguments in favor of a lower percentage, however, TAPS Carriers/QBA concluded there was some validity in reducing the 29% figure in this case because any incremental OSBL costs attributable to the model hydrotreater revamp logically would be less than those attributable to the base unit modeled in the Opinion No. 481 proceeding. TAPS Carriers/QBA state the study on which they based their ISBL capital cost estimate applies a two-thirds OSBL multiplier to revamp scenarios, translating to roughly 19% here. They note this figure matches the SOA proposal. And while TAPS Carriers/QBA appear to consider EMT's 10% proposal equally acceptable, they reject BP's zero percent position as unreasonable.

CPAI

209. Although CPAI states 29% is the appropriate OSBL multiplier for a hydrotreater replacement approach, it would not object to a lower figure being applied in a revamp scenario—provided the figure has adequate record support.

EMT

210. EMT advocate 10%. They maintain OSBL costs imputed to a revamp should be significantly less than those imputed to a new (or replacement) unit. EMT assert the UID/Opinion No. 481 acknowledge OSBL costs vary by processing unit and that such costs should reflect those likely to be incurred by the unit in question. They further assert the evidence is clear that OSBL costs attributable to a revamp are considerably less than those attributable to a new/replacement unit—typically ranging from 5% to no more than 20% of ISBL costs. EMT note that no party advocating a 29% OSBL factor has identified the specific OSBL items contributing to that figure. EMT similarly criticize the TAPS Carriers/QBA and SOA 19% OSBL factors as unreasonable, claiming they are based exclusively on an unrepresentative study. EMT contrast this with their 10% proposal, which they emphasize is based on a calculation of the specific costs associated with revamping the Opinion No. 481 model hydrotreater in accordance with their ISBL capital cost proposal. EMT dismiss any complaint that the 10% figure fails to account for additional storage tanks, noting the assumption that the model hydrotreater renders only one hypothetical product both before and after the revamp obviates the need for additional tanks. They similarly dismiss any claimed need for “off-spec” storage.

BP

211. BP argues the OSBL factor should be zero in this case because the revamped hydrotreater requires no incremental OSBL facilities to satisfy the 8 ppm ULSD specification. BP characterizes any 29% OSBL proposal as merely a robotic application of the OSBL factor adopted in the UID/Opinion No. 481, noting the QBA withdrew his original support for the 29% figure in recognition of this. BP contends the same OSBL facilities modeled to support the base LSD hydrotreater can support the revamped ULSD unit equally well because only one reference product is implicated in either scenario. And since a single-stage unit revamp requires (i) only an additional reactor vessel and a minimal increase in power for compression, (ii) no additional sulfur recovery facilities, and (iii) no additional plot space because the model base unit was over-sized in anticipation of the ULSD specification on BP’s account, no incremental OSBL facilities are required to satisfy the ULSD specification.

SOA

212. SOA supports a 29% OSBL multiplier for its recommended hydrotreater replacement approach, but states it agrees with the QBA's reasoning insofar as a revamp approach is concerned. Accordingly, SOA recommends a 19% OSBL factor.

Chevron

213. Chevron states any OSBL factor adopted for a revamp in this case should not exceed 10% because no storage tanks or other major off-site facilities were added in conjunction with Chevron's revamp proposal. In addition, any OSBL allowance should be justified through identification of the specific OSBL facilities attributable to the revamp in Chevron's view.

Petro Star

214. Petro Star endorses the 19% QBA alternative because it is consistent with other aspects of the TAPS Carriers/QBA approach and will yield more accurate results than a 10% OSBL factor. Petro Star notes the study on which the QBA based his ISBL capital cost and power consumption estimates applied a two-thirds multiplier to derive the appropriate OSBL factor, and applying the same methodology here results in 19%.

Flint Hills

215. Flint Hills supports a 29% OSBL multiplier for its recommended hydrotreater replacement approach. It alternately submits the absolute minimum OSBL factor should be 19% if the QBA revamp proposal is adopted. Flint Hills roundly criticizes the EMT and BP proposals as unconscionable, particularly when applied to what Flint Hills characterizes as unrealistically low ISBL capital costs.

Discussion/Analysis

216. We find and conclude as a preliminary matter it is not reasonably possible in this instance to adhere to prior UID/Opinion Nos. 481/481-A rulings. The 29% OSBL factor adopted in those opinions was predicated on the completely new 500 ppm LSD Heavy Distillate base hydrotreater incorporated into the Quality Bank model in the Opinion No. 481 proceeding. While it would be entirely appropriate—compulsory, in fact—to adopt the 29% OSBL factor here had we endorsed an ISBL replacement approach, that factor cannot rationally be applied to any model revamp.

217. We next reject BP's contention that the OSBL factor should be zero in this case because the revamped hydrotreater requires no incremental OSBL facilities to satisfy the

8 ppm ULSD specification. We agree with BP's conclusion that the OSBL facilities modeled to support base LSD hydrotreater operations in the UID/Opinion Nos. 481/481-A should be presumed capable of supporting the revamped ULSD model unit as well because only one reference product is implicated in either scenario. The base model hydrotreater was presumed capable of processing 50,000 barrels/day of Heavy Distillate to satisfy the 500 ppm LSD specification; the revamped model hydrotreater is presumed capable of processing 50,000 barrels/day of Heavy Distillate to satisfy the 8 ppm ULSD specification. No additional storage tanks, pipes, etc. logically should be required because those facilities are of identical utility insofar as either of the two model hydrotreaters and their respective reference products are concerned. Moreover, the record indicates no additional tankage/piping is required for "off-spec" purposes because one of each model's simplifying assumptions is that the Heavy Distillate hydrotreater satisfies the relevant specification 100% of the time. Tr. 458-60. It does not follow from these conclusions, however, that the revamped model hydrotreater requires no incremental OSBL facilities whatsoever to satisfy the 8 ppm ULSD specification.

218. We adopted the model hydrotreater revamp ISBL design parameters proposed by EMT. The record reflects substantial credible evidence that the EMT revamp proposal would require incremental OSBL facilities to supply power (i.e. electricity) to the new amine booster pump and the additional make-up hydrogen compressor. Exh. EMT-1 at 17. EMT calculated the incremental power requirement attributable to those components using their indicated horsepowers. *Id*. It then estimated the Gulf Coast OSBL cost of the structures and equipment needed to transfer the incremental power using a standard estimating factor and adjusting the cost by the 1.27 location factor approved in the Opinion No. 481 proceeding. *Id*. This produced an OSBL cost totaling $1.1 million (translating to approximately 5.5% of EMT's ISBL figure) on a 2005 West Coast basis. *Id*. The $1.1 million figure was increased to $1.85 million (10% of EMT's ISBL figure) to reflect minor mechanical modifications to account for small increases in off-site amine and sour water stripping capacities, sulfur recovery capacity and enhancing the hydrogen supply system to the revamped hydrotreater. *Id*. We find and conclude this evidence supports adopting a 10% OSBL factor—adjusted, as appropriate, to a 2000 base year using the NFOCI in accordance with the UID/Opinion No. 481.[81]

[81] This ruling obviates the need to discuss the 19% proposal, except to observe it is necessarily overstated in light of the 10% ruling, as well as the fact it is premised on the discredited need for additional storage tanks. *See* Exh. TC-15 at 13.

E. Total Processing Costs

1. What is the total processing cost for the ANS Heavy Distillate cut that should be adopted (on a June 2006 basis). What is the justification for this cost and how should it be adjusted thereafter?

219. This issue is resolved in accordance with all prior rulings.

IV. MATTERS NOT DISCUSSED

220. This Initial Decision's failure to discuss any matter raised/argument made by the parties, or any portion of the record, does not indicate it has not been considered. Rather, any such matter(s), argument(s) or portion(s) of the record has/have been determined to be irrelevant, immaterial or meritless. Arguments made on brief which were otherwise unsupported by record evidence or legal precedent have been accorded no weight.

V. ORDER

221. Wherefore, it is ordered, subject to review by the Commission on exceptions or on its own motion, as provided by Commission Rules of Practice and Procedure, that within thirty (30) days of the issuance of the final Commission order in this proceeding, the QBA, TAPS Carriers and all other parties shall comply with the findings and conclusions reflected in this Initial Decision, as adopted or modified by the Commission.

Debra J. Brandwein
Presiding Administrative Law Judge
Regulatory Commission of Alaska

H. Peter Young
Presiding Administrative Law Judge
Federal Energy Regulatory Commission