129 FERC ¶ 61,240
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

Kern River Gas Transmission Company   Docket Nos. RP04-274-015
RP04-274-016
RP04-274-017
RP04-274-018
RP04-274-019
RP04-274-008

OPINION NO. 486-C

ORDER ON REHEARING AND COMPLIANCE AND ESTABLISHING SETTLEMENT JUDGE PROCEDURES AND A HEARING

(Issued December 17, 2009)

TABLE OF CONTENTS

1. On January 15, 2009, the Commission issued Opinion No. 486-B,[1] which addressed the reasonableness of Kern River Gas Transmission Company's (Kern River) proposed rates. The Commission held that Kern River's return on equity (ROE) should be 11.55 percent, rejected a pending settlement filed by Kern River, denied rehearing requests of Opinion No. 486-A,[2] and required Kern River to make a revised compliance filing, including revised rates.

2. This order addresses the requests for rehearing of Opinion No. 486-B, as well as the protests to the revised compliance filings and revised tariff sheets filed by Kern River on March 2, 2009, March 27, 2009, and September 22, 2009.[3] The Commission denies the requests for rehearing of Opinion No. 486-B, accepts the revised compliance filing as it applies to Kern River's Period One Rates, subject to conditions. The Commission also finds that Kern River must offer levelized Period Two Rates, sets other issues regarding the Period Two Rates for hearing, and holds the hearing in abeyance for settlement judge procedures. The Period One Rates for the Locked-in Period[4] will be effective as of the dates stated in the tariff sheets, while the prospective Period One Rates will be effective the date of the issuance of this order. The Commission directs Kern River to file revised tariff sheets for the Period One, as discussed below, within 45 days of the date of this order. Kern River is also directed to file *pro forma* tariff sheets for Period Two consistent with the discussion in the this order.

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[1] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034 (2009) (Opinion No. 486-B).

[2] *Kern River Gas Transmission Co.*, 123 FERC ¶ 61,056 (2008) (Opinion No. 486-A).

[3] On March 2, 2009, Kern River submitted a revised compliance filing in accordance with Opinion No. 486-B. On March 27, 2009, Kern River submitted a supplemental compliance filing in Docket No. RP04-274-018 to correct the pagination of two tariff sheets in its March 2, 2009 compliance filing. On September 22, 2009, Kern River filed additional corrections to its March 2, 2009 compliance filing in Docket No. RP04-274-019. *See* Appendix A, B, C, and D for a list of the revised tariff sheets.

[4] The Locked-in Period in this proceeding begins on November 1, 2004 and continues through the date of this order, when the prospective Period One Rates become effective.

I. Background

3. The background of this proceeding is described in detail in Opinion No. 486,[5] Opinion No. 486-A,[6] and Opinion No. 486-B.[7] To summarize, when the Commission authorized Kern River to construct its Original System[8] in 1990, the Commission approved initial rates based on, among other things, a levelized cost of service and a 25-year depreciation life (Original Certificate Proceeding).[9] The Commission also accepted Kern River's proposal for separate levelized rates for three different periods: (1) the 15-year term of the firm shippers' initial contracts (Period One); (2) the period from the expiration of those contracts to the end of Kern River's depreciable life (Period Two); and (3) the period thereafter (Period Three). The levelized rates for Period One (Period One Rates) were designed to permit Kern River to recover approximately 70 percent of its original investment, an amount about equal to the portion of its invested capital funded through debt.[10] Since the Period One Rates would allow Kern River to recover more invested capital during Period One than Kern River would under ordinary straight-line depreciation for the depreciable life of the project, the rates for the second two periods (the Period Two Rates and Period Three Rates) were lower than the Period One Rates.

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[5] *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077, at P 4-18 (2006) (Opinion No. 486).

[6] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 2-17.

[7] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 2-22.

[8] Kern River's Original System constitutes the system of transmission facilities that Kern River constructed in 1991-1992 under the optional certificate issued in Docket No. CP89-2048-000. Kern River's transmission facilities are divided into five segments: the Original System and the 2002 Expansion (which together constitute the Rolled-in System), and three incremental facilities – the 2003 Expansion, the Big Horn lateral in Nevada, and the High Desert lateral in California.

[9] *Kern River Gas Transmission Co.*, 50 FERC ¶ 61,069, at 61,150 (1990) (Original Certificate Order), *order on reh'g*, 51 FERC ¶ 61,195 (1990) (Original Certificate Rehearing Order); *Kern River Gas Transmission Co.*, 58 FERC ¶ 61,073, at 61,242-44 (1992) (Amended Original Certificate Order), *order on reh'g*, 60 FERC ¶ 61,123, at 61,437 (1992) (Amended Original Certificate Rehearing Order), *aff'd sub nom. Pacific Gas Transmission Co. v. FERC*, 998 F.2d 1303 (5th Cir. 1993).

[10] *See* Original Certificate Order, 50 FERC ¶ 61,069, at 61,144 (1990).

4. In May 2000, Kern River proposed to lower its rates by refinancing its debt and providing for longer debt recovery periods by extending the terms of its firm contracts. The Commission accepted a settlement containing this proposal (the Extended Term (ET) Settlement).[11] As a result of the ET Settlement, all of Kern River's firm shippers extended their contracts. One group of customers extended their contract terms by five years and entered into revised contracts with ten-year terms (October 1, 2001 to 2011), while the other group extended their contract terms by 10 years and entered into revised contracts with 15-year terms (October 1, 2001 to 2016). The ET Settlement provided that the firm shippers' rates under these contracts would be designed consistent with the principles stated in the Original Certificate Order, permitting Kern River to recover 70 percent of the costs of the plant being depreciated by the end of the new repayment periods.[12]

5. In May 2002, Kern River completed an expansion project by adding additional compression to its system (2002 Expansion).[13] The costs associated with the 2002 Expansion were rolled into the Original System costs, creating the Rolled-in System. As before, the 2002 Expansion shippers were permitted to choose 10-year or 15-year terms for this additional capacity. In May 2003, Kern River completed another expansion project (2003 Expansion).[14] Kern River priced these services on an incremental basis and again permitted shippers to choose either 10-year or 15-year firm contracts. Therefore, after the 2003 Expansion, there were six groups of levelized rate contracts, and the shippers under all those contracts are still paying Period One Rates.[15]

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[11] *Kern River Gas Transmission Co.*, 92 FERC ¶ 61,061 (2000), *order on reh'g*, 94 FERC ¶ 61,115 (2001).

[12] *Id.* at 61,059

[13] *Kern River Gas Transmission Co.*, 96 FERC ¶ 61,137 (2001) (2002 Expansion Certificate Order).

[14] *Kern River Gas Transmission Co.*, 100 FERC ¶ 61,056 (2002) (2003 Expansion Certificate Order), *order on reh'g*, 101 FERC ¶ 61,042 (2002).

[15] The expiration dates of the various contracts are as follows:

> Original system – 10-year contracts (expires 2011); Original system – 15-year contracts (expires 2016); 2002 Expansion – 10-year contracts (expires 2012); 2002 Expansion – 15-year contracts (expires 2017); 2003 Expansion – 10-year contracts (expires 2013); 2003 Expansion – 15-year contracts (expires 2018); and Big Horn Lateral contracts (expires 2017).

(continued …)

II. The Instant Proceeding

6. On April 30, 2004, Kern River filed the instant general rate case under section 4 of the Natural Gas Act (NGA) (Original Rate Case Filing). Kern River proposed to continue using the rate levelization methodology and cost of service rate principles approved in the Original Certificate Order, the ET Settlement, the 2002 and 2003 Expansion Certificate Orders, and prior Kern River rate case settlements,[16] with certain modifications.[17] After a hearing, the Presiding Administrative Law Judge (ALJ) issued her Initial Decision (ID) on March 2, 2006, addressing numerous cost of service and rate design issues, including Kern River's continuation of its levelized rate methodology and its proposed ROE.[18]

7. On October 19, 2006, the Commission issued Opinion No. 486, affirming the ALJ's decision that Kern River's rates should continue to be designed based upon the levelized methodology.[19] The Commission recognized that the Period One Rates will result in Kern River recovering more depreciation expense than it will have depreciated on its books. As a result, at the end of Period One, Kern River's books would reflect a

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> Negotiated rate contracts pertaining to the High Desert Lateral under a traditional depreciation methodology expire in 2017. *See* Ex. KR-45 at 4, line 7-8.

Because Kern River's firm contracts expire on seven different dates, in its April 30, 2004 rate case filing, Kern River proposed different levelized rates for each of the seven groups of contracts. Thus, there are different proposed rates for (1) original firm shippers with 10-year contracts, (2) original firm shippers with 15-year contracts, (3) 2002 Expansion shippers with 10-year contracts, (4) 2002 Expansion shippers with 15-year contracts, (5) 2003 Expansion shippers with 10-year contracts, (6) 2003 Expansion shippers with 15-year contracts, and (7) Big Horn Lateral shippers. The rates of the first four groups of shippers are based on the rolled-in cost of service of the original system and the 2002 Expansion. The rates of the 2003 Expansion and Big Horn shippers are based on the incremental costs of their expansion projects.

[16] *Kern River Gas Transmission Co.*, 70 FERC ¶ 61,072 (1995); *Kern River Gas Transmission Co.*, 90 FERC ¶ 61,124, *order on reh'g*, 91 FERC ¶ 61,103 (2000).

[17] *See* Opinion No. 486, 117 FERC ¶ 61,077 at P 4-17 (providing a detailed history of recent regulatory proceedings regarding Kern River's system).

[18] *Kern River Gas Transmission Co.*, 114 FERC ¶ 63,031 (2006).

[19] Opinion No. 486, 117 FERC ¶ 61,077 at P 37.

regulatory liability, which will serve to lower its Period Two Rates. In order to increase the assurance that Kern River's shippers will obtain the benefit of the lower Period Two Rates if they continue service beyond the terms of their existing contracts, the Commission directed Kern River to include in its tariff the expected Period Two Rates that would take effect when the firm shippers' existing contracts expire.[20]

8. Opinion No. 486 reversed the ALJ's determination that the proper ROE for Kern River was 9.34 percent. The Commission found that the ALJ erred in her findings concerning the proxy group used to determine a range of reasonable returns for setting Kern River's ROE. Opinion No. 486 adopted a four-company proxy group and determined that Kern River's risk in relation to the members of the proxy group was high. Opinion No. 486, therefore, added 50 basis points to the median ROE of the proxy group, resulting in an ROE of 11.2 percent for Kern River.[21]

9. While requests for rehearing of Opinion No. 486 were pending, the Commission concluded that its policy regarding ROE proxy groups for gas and oil pipelines should be reexamined. As a result, on April 17, 2008, the Commission issued a *Policy Statement* concerning the composition of the proxy groups used to determine gas and oil pipelines' ROEs under the Discounted Cash Flow (DCF) model.[22]

10. On April 18, 2008, the Commission issued Opinion No. 486-A. In that order, the Commission denied all requests for rehearing of Opinion No. 486, with the exception of those related to Kern River's ROE. Recognizing that the Kern River record did not address all of the ROE issues needing examination in light of the *Policy Statement*, Opinion No. 486-A reopened the record for a paper hearing to give all parties an opportunity to submit additional evidence.

11. BP Energy Company (BP) filed a request for rehearing of Opinion No. 486-A, focusing primarily on the ROE issue but also requesting clarification on certain levelized rate issues. On September 30, 2008, Kern River filed a settlement proposal (Settlement), together with revised tariff sheets to implement the Settlement rates for the settling

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[20] On December 18, 2006, Kern River submitted a compliance filing in Docket No. RP04-274-008 in accordance with Opinion No. 486. The Commission did not act on this filing because it was superseded by the revised compliance filing Kern River submitted on March 2, 2009. The compliance filing in Docket No. RP04-274-008 is therefore rejected as moot.

[21] *Id.* P 2.

[22] *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048 (2008) (*Policy Statement*).

parties on an interim basis effective October 1, 2008. The Settlement also required Kern River to refund to the settling parties the amounts it had collected in excess of the Settlement rates since November 1, 2004. Most parties to the proceeding supported the Settlement, but it was opposed by Commission Trial Staff (Trial Staff), BP, and Southwest Gas Corporation (Southwest). On October 28, 2008, the Commission accepted the tariff sheets implementing the reduced Settlement rates on an interim basis, subject to the Commission's decision on the merits of the Settlement.[23]

12. On January 15, 2009, the Commission issued Opinion No. 486-B. Based on the record in the paper hearing, Opinion No. 486-B held that Kern River's ROE should be 11.55 percent, and the Commission therefore rejected the Settlement on the ground that its 12.5 percent ROE was too high.[24] The Commission also directed Kern River to cancel the interim rates filed with the Settlement and recapture the refunds made under the Settlement as soon as was practical. Opinion No. 486-B required Kern River to submit a compliance filing by March 2, 2009 revising its rates consistent with the Commission's merits findings in Opinion Nos. 486, 486-A, and 486-B.[25] Opinion No. 486-B also denied BP's request for rehearing of Opinion No. 486-A.

13. Several parties requested rehearing of Opinion No. 486-B.[26] In addition, on January 30, March 2, March 27, and September 22, 2009, Kern River submitted filings to comply with the directives of Opinion No. 486-B. These filings are described in detail in the subsequent sections of this order.

14. In the first portion of this order, the Commission denies the requests for rehearing of Opinion No. 486-B. The second portion of this order addresses the compliance filings submitted by Kern River. Specifically, the Commission accepts the tariff sheets listed in Appendix C establishing the rates for Period One, subject to conditions. The tariff sheets establishing the Period One Rates for the Locked-in Period will be effective as of the dates stated in the tariff sheets. The tariff sheets establishing the prospective Period One Rates will be effective the date of the issuance of this order. The Commission rejects the tariff sheets listed in Appendix D concerning the Period Two Rates. The Commission finds that Kern River must offer levelized rates in Period Two, requires Kern River to file

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[23] *Kern River Gas Transmission Co.*, 125 FERC ¶ 61,108 (2008).

[24] *Id.* P 23-28, 154-166.

[25] *Id.* P 167-191.

[26] BP filed a request for clarification or rehearing of Opinion No. 486-B in Docket No. RP04-274-015. The Rolled-In Customer Group (RCG) filed a request for rehearing of Opinion No. 486-B in Docket Nos. RP04-274-016 and RP00-157-015.

pro forma Period Two tariff sheets, and establishes settlement judge procedures and a hearing on the remaining issues.

III. Requests for Rehearing of Opinion No. 486-B

15. BP and RCG[27] filed requests for rehearing of Opinion No. 486-B. These rehearing requests focus on the determination of the appropriate ROE for Kern River. Specifically, BP and RCG object to the Commission's inclusion or exclusion of particular firms from the proxy group used to determine Kern River's ROE, and the determination of Kern River's relative risk within the proxy group. BP also raises some secondary procedural concerns.

A. Background of the Requests for Rehearing

16. Most natural gas pipelines are wholly-owned subsidiaries and their common stock is not publicly traded. Therefore, the Commission performs a DCF analysis of publicly-traded proxy firms to determine the return that equity markets require a pipeline to give its investors in order for them to invest their capital in the pipeline. The DCF model is based on the premise that "a stock's price is equal to the present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk."[28] With simplifying assumptions, the DCF model results in the investor using the following formula to determine share price: $P = D/ (r-g)$, where P is the price of the stock at the relevant time, D is the current dividend, r is the discount rate or rate of return, and g is the expected constant growth in dividend income to be reflected in capital appreciation.[29]

17. Unlike investors, the Commission uses the DCF model to determine the ROE (the "r" component) to be included in the pipeline's rates, rather than to estimate a stock's value. Therefore, the Commission solves the DCF formula for the discount rate, which represents the rate of return that an investor requires in order to invest in a firm. Under

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[27] RCG consists of Area Energy LLC, Anadarko E&P Company, Anadarko Petroleum Corporation, Chevron U.S.A. Inc. (on its own behalf and on the behalf of Nevada Cogeneration Associates #1 and #2), Shell Energy North America (US), LP (formerly Coral Energy Resources LP), Occidental Energy Marketing Inc., and SWEPI LP (formerly Shell Rocky Mountain Production LLC).

[28] *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001) (*CAPP v. FERC*).

[29] *National Fuel Gas Supply Corp*., 51 FERC ¶ 61,122, at 61,337, n.68 (1990); *Ozark Gas Transmission Sys.*, 68 FERC ¶ 61,032, at 61,104, n.16. (1994).

the resulting DCF formula, ROE equals current dividend yield (dividends divided by share price) plus the projected future growth rate of dividends:

$$R = D/P + g$$

18. The Commission uses a two-step procedure for determining the constant growth of dividends: averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group (discussed below), as published by Institutional Brokers Estimated System (IBES), are used for determining growth for the short term; long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in the Gross Domestic Product (GDP).[30] The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[31]

19. In deciding the ROE issue in this case, the primary issue has been developing a representative proxy group used to determine a range of reasonable returns for setting Kern River's ROE. Historically, the Commission required that each company included in the proxy group satisfy the following three standards: (1) the company's stock must be publicly traded; (2) the company must be recognized as a natural gas company and its stock must be recognized and tracked by an investment information service, such as the Value Line Investment Survey; and (3) pipeline operations must constitute a high proportion of the company's business.[32] This last standard could only be satisfied if a company's pipeline business accounted for, on average, at least 50 percent of a company's assets or operating income over the most recent three-year period.[33] However, in a July 2003 order in the *Williston II* proceeding,[34] the Commission found that, because of mergers, acquisitions, and other changes in the natural gas industry, only

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[30] *Northwest Pipeline Co.*, 79 FERC ¶ 61,309, at 62,383 (1997) (Opinion No. 396-B). *Williston Basin Interstate Pipeline Co.*, 79 FERC ¶ 61,311, at 62,389 (1997) (*Williston I*), *aff'd in relevant part, Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999).

[31] *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶ 61,084 at 61,423-4 (Opinion No. 414-A), *reh'g denied*, 85 FERC ¶ 61,323, at 62,266-70 (1998) (Opinion No. 414-B).

[32] *Williston Basin Interstate Pipeline Co.,* 104 FERC ¶ 61,036, at P 34-43 (2003) (*Williston II*).

[33] *Williston II*, 104 FERC ¶ 61,036 at P 35 n.46.

[34] *Id.*

three corporations remained that satisfied the Commission's historical proxy group standards.

20. In Opinion No. 486, the Commission adopted the same solution to this problem as it had in *Williston II* and *HIOS*,[35] and relaxed the requirement that natural gas business account for at least 50 percent of the corporation's assets or operating income. Instead, the Commission approved the pipeline's proposal to use a proxy group based on the corporations in the Value Line Investment Survey's list of corporations in the "Natural Gas (Diversified) Industry"[36] that own Commission-regulated natural gas pipelines, without regard to what portion of the company's business comprises pipeline operations. Therefore, the Commission adopted a four-company proxy group consisting of Kinder Morgan Inc. (KMI), Equitable Resources, Inc. (Equitable), National Fuel Gas Co. (National Fuel), and Questar Corporation (Questar).[37] Finding that this proxy group included firms of lower risk than Kern River, the Commission added 50 basis points to the median return of the selected proxy group for an ROE of 11.2 percent.[38] The Commission also rejected Kern River's proposal to include master limited partnerships (MLPs) in the proxy group.

21. While the requests for rehearing of Opinion No. 486 were pending, the Commission concluded that its policy on ROE proxy groups for gas and oil pipelines should be reexamined in light of the fact that there were so few oil and natural gas corporations available for inclusion in the ROE proxy group. Thus, on July 17, 2007, the Commission issued a proposed policy statement concerning the composition of the proxy groups used to determine gas and oil pipeline ROEs. The Commission proposed to permit inclusion of MLPs in a ROE proxy group, subject to certain conditions.

22. On August 7, 2007, the U.S. Court of Appeals for the D.C. Circuit issued an opinion in *Petal Gas v. FERC*,[39] reversing the Commission's earlier ROE determinations

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[35] *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043, *reh'g denied*, 112 FERC ¶ 61,050 (2005) (*HIOS*).

[36] *See* Ex. S-3 at 7.

[37] The Commission excluded Williams Gas Marketing, Inc. (Williams) and El Paso Corporation (El Paso) from the proxy group on the grounds that their financial difficulties lowered their ROEs to a level that made them unrepresentative. Opinion No. 486, 117 FERC ¶ 61,077 at P 140-41.

[38] *Id.* P 2.

[39] *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695 (D.C. Cir. 2007) (*Petal Gas v. FERC*).

in *HIOS* and *Petal*.[40] Both of these appeals turned explicitly on the issue of the relative risk of the proxy group members selected to determine the ROE. The court emphasized that the Commission's "proxy group arrangements must be risk-appropriate."[41] The court explained that this means that firms included in the proxy group should face similar risks to the pipeline whose ROE is being determined, and any differences in risk should be recognized in determining where to place the pipeline in the proxy group range of reasonable returns.

23. The court held that the Commission had not shown that the proxy group arrangements it approved in *Petal* and *HIOS* were risk-appropriate. The court pointed out that the Commission had rejected the inclusion of MLPs in the proxy group on the ground that MLP distributions, unlike dividends, might provide returns *of* equity as well as returns *on* equity. While stating that this proposition is not "self-evident," the court accepted it for the sake of argument. Nonetheless, the court stated that nothing in the Commission's decision explained why the companies selected by the Commission for inclusion in the proxy group, including companies with substantial local distribution business, were risk-comparable to HIOS. The court stated that when the goal is a proxy group of comparable companies, it is not clear that natural gas companies with highly different risk profiles should be regarded as comparable.[42]

24. Subsequently, on April 17, 2008, the Commission issued its *Policy Statement* concerning the composition of the proxy groups used to determine jurisdictional gas and oil pipelines' ROE under the DCF model.[43] The Commission concluded: (1) MLPs could be included in the ROE proxy group for both oil and gas pipelines; (2) there should be no cap on the level of distributions included in the Commission's current DCF methodology; (3) the IBES forecasts would remain the basis for the short-term growth forecast used in the DCF calculation; (4) there should be an adjustment to the long-term growth rate used to calculate the equity cost of capital for an MLP; and (5) there would be no modification to the current respective two-thirds and one-third weightings of the short- and long-term growth factors. The Commission stated that the *Policy Statement* made no findings as to which particular corporations and/or MLPs should be included in

[40] *Petal Gas Storage, L.L.C.*, 97 FERC ¶ 61,097 (2001), *reh'g granted in part and denied in part*, 106 FERC ¶ 61,325 (2004) (*Petal*).

[41] *Petal Gas v. FERC*, 496 F.3d at 699 (quoting *CAPP v. FERC*, 254 F.3d 289 (D.C. Cir. 2001)).

[42] *Id.* at 700.

[43] *Policy Statement*, 123 FERC ¶ 61,048 (2008).

the gas or oil proxy groups. The Commission left that determination to each individual rate case.

25. Contemporaneously with the *Policy Statement*, the Commission issued Opinion No. 486-A, which denied all requests for rehearing except for those related to the ROE.[44] On the ROE issues, Opinion No. 486-A granted rehearing to permit the inclusion of MLPs in the proxy group, but denied the Shipper Parties' request to include Williams and El Paso in the proxy group.[45] Opinion No. 486-A reiterated the *Policy Statement*'s conclusions that: (1) MLPs are appropriately included in the proxy group;[46] (2) there should be no cap on the distributions to be included in the DCF model;[47] and (3) long-term growth should be limited to 50 percent of GDP.[48] Opinion No. 486-A also concluded that there should be no adjustment to the results of the DCF model to reflect depreciation, use of external funds, or the income tax advantages of MLPs.[49]

26. Recognizing that the record in this proceeding did not fully address all of the issues requiring examination in light of the *Policy Statement*, Opinion No. 486-A reopened the record for a paper hearing to give all participants an opportunity to submit additional evidence as to (1) which specific MLPs should be included in the proxy group consistent with the *Policy Statement*, (2) the appropriate DCF analysis of each entity proposed for inclusion in the proxy group, and (3) where Kern River's ROE should be set in the resulting range of reasonable returns.

27. In Opinion No. 486-B, the Commission held, based on the record of the paper hearing, that Kern River's ROE should be 11.55 percent. Opinion No. 486-B found that the proxy group should be determined based on proxy company data for the 2004 test period upon which Kern River's rates in this rate case are based.[50] Using that data, Opinion No. 486-B adopted a five member proxy group that included three MLPs and two corporations.[51] The MLPs were Northern Border Partners, L.P. (Northern Border),

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[44] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 1.

[45] *Id.* P 188-89.

[46] *Id.* P 167-173.

[47] *Id.* P 174, 178-180.

[48] *Id.* P 181-183.

[49] *Id.* P 184-187.

[50] *Id.* P 57.

[51] *Id.* P 35-44.

TC Pipelines, L.P. (TC Pipelines), and Kinder Morgan Energy Partners (KMEP), and the corporations were KMI and National Fuel.[52] The Commission determined the ROEs of each corporation and MLP in the proxy group, using the DCF methodology in the *Proxy Group Policy Statement.*[53] Finally, the Commission held that Kern River's risk was within a broad range of average risk, and therefore set Kern River's ROE at the 11.55 percent median of the range of proxy group ROEs.[54]

28. As noted, BP and RCG filed requests for rehearing of Opinion No. 486-B. Both rehearing requests focus on the Commission's holdings concerning the composition of the proxy group and Kern River's placement within the range of reasonable returns. BP contends that the Commission should have included three additional corporations in the proxy group: Equitable, Questar, and NiSource, Inc. (NiSource). It does not ask that any of the five entities the Commission included in the proxy group be excluded. RCG, by contrast, contends that the Commission erred in including KMEP in the proxy group, and it does not seek to add any entities to the proxy group. Both BP and RCG contend that the Commission should have found that Kern River has lower than average risk, and therefore its ROE should be set at less than the median of reasonable returns. Finally, BP contends that the Commission should have lowered the ROE embedded in Kern River's proposed Period Two Rates to reflect the lower risk that would occur in that period.[55]

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[52] *Id.* P 59, 61, and 105.

[53] *Id.* P 106-131.

[54] *Id.* P 132-153.

[55] BP also requested clarification that Opinion No. 486-B did not decide any of the issues it had raised in its comments on Kern River's December 6, 2006 filing to comply with Opinion No. 486. BP noted that its comments to that earlier compliance filing were pending when Opinion No. 486-B issued and that Opinion No. 486-B neither acknowledged nor addressed any of those comments. Because Opinion No. 486-B required Kern River to make a revised compliance filing, the Commission did not address the issues that had been raised with respect to Kern River's earlier compliance filing. In later sections of this order, the Commission addresses all issues which have been raised with respect to Kern River's latest filings to comply with Opinion Nos. 486, 486-A, and 486-B. BP also requested the Commission to clarify that Kern River should make available an electronic copy of all the rate models and work papers underlying any revised compliance filing. This request is moot as the materials were provided as part of the revised compliance filing.

29. Below, we first discuss the issues raised on rehearing with respect to the composition of the proxy group. We then turn to the issues concerning Kern River's placement in the range of reasonable returns.

B. Composition of the Proxy Group

30. As the court explained in *Petal Gas v. FERC*, the purpose of the proxy group is to "provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. Market-determined stock figures reflect a company's risk level and when combined with dividend values, permit calculation of the 'risk-adjusted expected rate of return sufficient to attract investors.'"[56] It is thus crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined. In other words, as the court emphasized in *Petal Gas v. FERC*, the proxy group must be "risk-appropriate."[57]

31. In Opinion No. 486-B, the Commission found that the firms the parties proposed to include in the proxy group fell into three categories. These are (1) corporations satisfying the historic requirement that a proxy firm's pipeline business account for, on average, at least 50 percent of the firm's assets or operating income; (2) MLPs owning natural gas transmission companies; and (3) diversified natural gas companies with some interstate natural gas transmission business but with a majority of the business in other natural gas activities such as distribution and exploration and production. The Commission found that only one corporation in the first category could be included in the proxy group. That was KMI, whose pipeline business accounts for over 60 percent of its assets. Neither BP nor RCG question this ruling. We thus turn to a discussion of the second two categories.

1. MLPs Owning Transmission Companies

32. Opinion No. 486-B included three MLPs in the proxy group, Northern Border, TC Pipelines, and KMEP. The first two MLPs more than satisfied the Commission's historic requirement that a firm's natural gas pipeline business account for at least 50 percent of its assets or operating income. During 2004, 91 percent of Northern Border's operating income came from interstate natural gas pipeline operations. TC Pipelines is an investment partnership, which in 2004 owned a 30 percent interest in Northern Border and 49.1 percent interest in Tuscarora Gas Transmission Company. All of TC Pipelines'

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[56] *Petal Gas v. FERC*, 496 F.3d 695, 697 (D.C. Cir. 2007) (quoting *CAPP v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001)).

[57] *Id.*

2004 revenue came from dividends paid by those two pipelines. The rehearing applicants do not object to the inclusion of either of these MLPs in the proxy group.

33. Opinion No. 486-B also included KMEP in the proxy group. In 2004, KMEP owned 100 percent interests in two interstate natural gas pipelines, Kinder Morgan Interstate Transmission, Inc., and Trailblazer Pipeline Company (Trailblazer).[58] In addition, KMI transferred its 100 percent ownership interest in TransColorado Gas Transmission Company (TransColorado) to KMEP effective November 1, 2004.[59] The Commission found that KMEP's operations and assets in 2004 were about 35 percent gas pipeline business, 35 percent oil pipeline business, and 30 percent CO2 pipeline and terminal operations.[60] KMEP was not involved in any gas distribution, exploration and production, or trading and marketing activities during 2004.

34. While KMEP did not satisfy the historic standard that natural gas pipeline operations account for at least 50 percent of its business, the Commission nevertheless included KMEP in the proxy group, because its combined gas and oil transmission business substantially exceeded 50 percent and the gas transmission business was at least as great as the oil transmission business. Opinion No. 486-B pointed out that Value Line recently stated:

> The Oil/Gas Distribution Industry is unusually homogeneous in its operations as members do little besides distribute hydrocarbons, mostly by pipeline.[61]

35. Therefore, while the Commission continued to view the oil pipeline component of a diversified natural gas company as somewhat riskier than the gas pipeline component, the Commission concluded that KMEP's risks were sufficiently comparable to Kern River's for it to be included in the proxy group.

36. Opinion No. 486-B also rejected RCG's contention that KMEP should be excluded from the proxy group because KMI is its general partner, and therefore inclusion of KMEP duplicates the inclusion of KMI in the proxy group. The Commission found that KMI and KMEP represent sufficiently separate investments that both may be included in the proxy group. Among other things, the Commission stated that KMI's investment in KMEP represented less than one quarter of its assets, and a

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[58] Ex. BP-178.

[59] Ex. S-3 at 33.

[60] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 67, 71.

[61] March 14, 2008 Issue; Ex. S-3 at 127.

substantial part of its gas transmission business, including its ownership interest in Natural Gas Pipeline Company of America (Natural), is unrelated to KMEP. KMI and KMEP are separately traded public securities. Given that KMI's business operations include substantial natural gas transmission and other business activities in which KMEP is not involved, the two stocks do not represent investments in the same business.

37. Only RCG seeks rehearing of Opinion No. 486-B's inclusion of KMEP in the proxy group. While BP challenges Opinion No. 486-B's statement that oil pipelines have somewhat higher risk than natural gas pipelines, it does not contest the inclusion of KMEP in the proxy group, which it advocated during the paper hearing.

38. In its rehearing request, RCG again argues that KMI and KMEP should not both be included in the proxy group. It asserts that because KMI is KMEP's general partner, inclusion of both firms in the proxy group would double count the same company data and overweight the proxy group toward the equity cost of capital of those two firms. It points to a statement in Opinion No. 486-B that acknowledges that to some extent KMEP's risk would be reflected in its corporate parent's as supporting its conclusions. RCG does not contest Opinion No. 486-B's finding that KMEP is reasonably comparable to Kern River.

39. The Commission denies RCG's request for rehearing. The Commission continues to find that KMI and KMEP represent sufficiently separate investments that both may be included in the proxy group. KMI and KMEP are separately traded public securities, with substantially different asset profiles as discussed below. That the investment community views the two stocks as separate and distinct investments is demonstrated by the fact that security analysts surveyed by IBES in 2004 projected significantly greater growth for KMI than for KMEP.[62] In addition, KMEP's dividend yield during 2004 was significantly higher than KMI's. Finally, KMI had an investment credit rating of BBB and KMEP an investment credit rating of BBB+, suggesting that KMEP may have a slightly lower risk profile. Both had a business profile rating of 5 on a scale of 10, which suggests that they have similar risks in terms of their earning prospects and returns.[63]

40. RCG suggests that the two firms have a 64 percent overlap in their natural gas pipeline facilities and therefore investors would view an investment in either of the two firms as an investment in essentially the same pipeline business. RCG arrives at its asserted 64 percent overlap as follows. It points out that 35 percent of KMEP's assets are

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[62] As displayed in Ex. BP-126, the security analysts' five-year projected growth rate for KMEP is 8 percent and is 11.70 percent for KMI.

[63] In fact, their 2004 DCF calculations are similar: 13 percent for KMI and 12.99 percent for KMEP. *See* Opinion No. 486-B, 126 FERC ¶ 61,034 at P 131.

natural gas pipelines, and 55 percent of KMI's assets are natural gas pipelines. It then asserts that KMI's 55 percent natural gas transmission operations "include the KMEP gas transmission operations."[64] Finally it states that "the 64 percent overlap is determined by calculating what percentage of KMI's gas transmission operation is included in those of KMEP (i.e., dividing 35 percent by 55 percent)."[65]

41. RCG's assertion of a 64 percent overlap in the two firm's natural gas pipeline facilities is premised on a factual error – its assertion that the 55 percent of KMI's assets made up of natural gas pipeline facilities includes KMEP's gas transmission operations. That is not true. KMI's Form 10-K report to the Securities and Exchange Commission for 2004 shows that at the end of 2004 KMI had some 55 percent of its assets in Natural, 23 percent in its equity in KMEP, 5 percent in natural gas distribution, 4 percent in electric generation, 9 percent in goodwill, and 5 percent other.[66] KMEP's Form 10-K report shows that at the end of 2004, it had 35 percent of its assets in three interstate natural gas pipelines, Kinder Morgan Interstate Pipeline, Trailblazer, and TransColorado. KMEP's remaining assets were 35 percent in oil pipelines, 15 percent in terminals and 15 percent in CO2 pipelines. [67]

42. These facts demonstrate that the 55 percent of KMI's assets which RCG asserts include KMEP's gas transmission operations are, instead, made up entirely of the gas transmission facilities of Natural, which KMI owns directly. KMI's ownership interest in KMEP represents an additional 23 percent of KMI's assets over and above the 55 percent share of its assets represented by Natural. Because only 35 percent of KMEP's assets are made up of pipelines, the three pipelines owned by KMEP represent only 8.05 percent of KMI's total assets (23 percent of the 35 percent of KMEP's assets made up of gas pipelines). It follows that investments in KMI and KMEP represent significantly different investments in natural gas pipeline facilities. An investment in KMI is an investment in a firm with 55 percent of its assets in Natural and only about 8 percent of its assets in Kinder Morgan, Trailblazer and TransColorado. By contrast, an investment in KMEP is an investment in a firm with none of its assets in Natural and 35 percent of its assets in Kinder Morgan, Trailblazer, and TransColorado. Thus, there is relatively little overlap in the gas pipeline businesses of KMI and KMEP.

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[64] RCG rehearing request at 7.

[65] *Id.* at 7 n.14.

[66] Ex. S-3 at 31.

[67] Ex. S-3 at 31.

43. Moreover, there are significant differences in the two firms' involvement in non-gas pipeline business. With 63.05 percent of its assets related to natural gas transmission, KMI has only 36.95 percent of its assets in non-gas pipeline businesses. KMEP presents almost the exact opposite situation, with only 35 percent of its assets in the natural gas pipeline business and 65 percent of its assets in other businesses. Taking into account its 23 percent asset investment in KMEP, KMI's non-gas pipeline assets are 5 percent in natural gas distribution, 4 percent in electric generation, 8.05 percent oil pipeline, 3.45 percent terminals, 3.45 percent CO2 pipelines, 9 percent goodwill, and 5 percent other. By contrast, KMEP had no gas distribution or electric generation assets, but was substantially more heavily invested in oil pipelines (35 percent), terminals (15 percent), and CO2 pipelines (15 percent).

44. RCG also points out that the DCF results of KMI and KMEP are virtually the same, with a 13 percent ROE for KMI and 12.99 percent ROE for KMEP. RCG contends that this contradicts Opinion No. 486-B's statement that KMEP's greater investment in oil and other non-natural gas pipeline activities may give KMEP a somewhat higher overall risk than KMI. RCG argues that including both firms in the proxy group improperly increases the median of the proxy group ROEs by double counting essentially the same corporate entity data.

45. The fact that the DCF analysis of the two firms yields essentially the same return, with a slightly higher ROE for KMI, does not undercut our holding that the two firms represent separate investments, and thus both may be included in the proxy group. The analysis above demonstrates that, from an investor's point of view, the two firms are involved in substantially separate business activities, with KMI notably more heavily invested in gas pipelines than KMEP, and the two firms' gas pipeline assets differing to a significant extent. Moreover, while the end-results of the DCF analysis for each firm are nearly the same, the financial data used in the analysis of each firm is entirely different. Under the DCF formula used by the Commission, the ROE of a particular firm equals its current dividend yield (dividends divided by share price) plus the projected future growth rate of dividends. The projected growth rate is based on IBES five-year forecasts for the short-term growth factor for both corporations and MLPs, and one hundred percent of the forecasted long-term gross domestic product for corporations, but only one half of that forecast for MLPs. KMI and KMEP have separate share prices, and they pay different dividends/distributions to their separate groups of shareholders. Also, security analysts provide separate short-term, five-year growth projections to IBES for each firm. Therefore, all of the firm-specific data used in the DCF analyses of KMEP is different from that used for KMI. Moreover, the long-term growth projections of the two firms, while not based on firm-specific data, are also different, with KMI's equal to projected growth in GDP but KMEP's set at half that level. The end-results of the DCF analyses of

the two firms are only about the same, because KMI's significantly lower dividend yield is offset by its significantly higher growth projection.[68]

46. For these reasons, contrary to RCG's arguments, including both KMI and KMEP in the proxy group does not double count the same corporate data[69] or overweight the proxy group. In this regard, we note that RCG does not object to the inclusion of TC Pipelines in the proxy group, even though it received 30 percent of its income from Northern Border in 2004. Thus, there is an overlap in earnings between TC Pipelines and Northern Border comparable to the overlap between KMI and KMEP. If KMEP were excluded from the proxy group on the ground of its overlap with KMI, consistency would require that TC Pipelines also be excluded. This would leave the median in the same place as with the two firms included.

47. The Commission included KMEP in the proxy group, in part because there were only three firms available in 2004 (KMI, TC Pipelines, and Northern Border) that had natural gas pipeline assets or operating income in excess of the historic 50 percent standard and had no other disqualifying factor. The Commission held that KMEP,

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[68] Ex. BP-126.

[69] With respect to RCG's contention that the fact KMEP has a slightly lower ROE than KMI belies Opinion No. 486-B's statement that KMEP's oil pipeline activities give it somewhat higher risk, the Commission notes that the DCF analysis of a particular firm may not exactly track its relative risk. The application of the DCF model is relatively mechanical with the risk components reflected in inputs such as the security price, the dividend or distribution, and the projected growth rate. Measuring investor expectations is far from an exact science, and if the inputs to the model do not fully reflect investor perceptions, the results of the DCF model may not accurately reflect investor requirements. The possibility of such measurement errors is precisely why the Commission uses a proxy group to develop a reasonable range of returns. A broader range of factors must be examined in making any determination of the relative risk of firms proposed for inclusion in the proxy group. For example, as discussed in Opinion No. 486, the Commission excluded El Paso and Williams because they had unrealistically low DCF returns in relationship to their cost of debt, which reflected their financial problems. The Commission noted that the difficulties experienced by both firms were largely related to their production and energy trading activities, and the Commission concluded that those operations were much more volatile and risky than the firm's pipeline operations. Thus, the two firms with the highest risk profile of the potential proxy group had the lowest DCF returns of that group and were excluded as unrepresentative. This example demonstrates how one must evaluate the commercial environment in which the firm operates and any financial or market factors singular to the firm. Opinion No. 486, 117 FERC ¶ 61,077 at P 124, 140-41.

together with National Fuel, were the two other, most risk-appropriate firms to add to the proxy group in order to achieve a five-member group. In finding that KMEP was risk-appropriate, the Commission relied on a finding that, while KMEP's 35 percent oil pipeline component had a somewhat higher risk than its natural gas pipeline business, the relative risks of the oil pipeline business are closer to those of natural gas pipelines than any of the other business lines that may be owned by a diversified natural gas energy firms, including exploration and production of natural gas. In making this finding, Opinion No. 486-B relied in part on a Value Line publication concluding that oil and gas pipelines were part of a relatively homogenous group given their common characteristics as pipeline transporters of hydrocarbons.[70]

48. In its rehearing request, BP asserts that Opinion No. 486-B incorrectly concluded that oil and gas pipelines are homogenous and ignored the Commission's own historical statements that oil pipelines are riskier than gas pipelines. BP further argues that Opinion No. 486-B ignored BP's record evidence that oil pipelines are riskier than natural gas pipelines.[71] BP also objects to the Commission's reliance on a generic statement in a Value Line publication.

49. BP incorrectly seizes on one statement in Opinion No. 486-B to conclude that the Commission has reversed without reason its historical position that oil pipelines are more risky than gas pipelines. As discussed, Opinion No. 486-B only concluded that the risks of the oil pipeline business were closer to those of the natural gas pipeline business than the other product lines of a diversified natural gas company, because the natural gas and oil pipeline businesses involve the regulated transportation of hydrocarbons, and not the more risky unregulated exploration, production, and energy commodity marketing businesses. However, the Commission explicitly recognized that the oil pipeline component of a natural gas company will increase somewhat the firm's overall risk primarily due to the oil pipeline industry's overall greater exposure to competition.[72]

50. In any event, during the paper hearing in this case on the composition of proxy group, BP supported inclusion of KMEP, and it does not argue on rehearing that the Commission erred in including KMEP. Therefore, BP apparently believes that KMEP's overall risk is sufficiently comparable to Kern River's to allow its inclusion in the proxy group. Because the Commission has not included any other firm with oil pipeline business in the proxy group, BP's concern on this issue appears more theoretical, than real. Nevertheless, the Commission finds that Opinion No. 486-B's reliance on the Value

[70] *Id.* P 127.

[71] *See* BP's February 13, 2009 Request for Rehearing at 27-29.

[72] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 75.

Line statement concerning the relative risk of natural gas and oil pipelines to be appropriate. The Commission performs a DCF analysis of publicly-traded proxy firms to determine the return on equity that markets require a pipeline to give its investors in order for them to invest their capital in the pipeline.[73] Therefore, the Commission seeks proxy firms that investors view as having comparable risk. Because Value Line is a publication relied on by many investors, its statements concerning the relative risks of different energy-related investments is highly probative of the views of investors generally.

51. Finally, Opinion No. 486-B recognized that, as pointed out by BP, oil pipelines are subject to a somewhat different regulatory scheme than natural gas pipelines and that this makes oil pipelines somewhat more risky. However, it is worth noting that some of the factors pointed out by BP in its rehearing request could be viewed as reducing oil pipeline risk. For example, BP argues that the indexing methodology permitted for oil pipeline rates allows an oil pipelines to increase its rates independently of costs, and provided that the rate changes do not exceed the change in an annual index published by the Bureau of Labor Statistics, such rates are largely insulated from rate challenges by shippers except under specified narrow circumstances.[74]

2. <u>The Diversified Natural Gas Corporations</u>

52. The last group of proposed proxy group members the Commission considered were five diversified natural gas corporations with some interstate natural gas transmission business but that did not satisfy the Commission's historic requirement that natural gas pipeline operations account for at least 50 percent of their business. Before addressing the parties' contentions concerning specific corporations, Opinion No. 486-B first rejected Kern River's contention that all such corporations should be excluded from the proxy group, because the integrated, diversified, business profile of such a firm is not comparable to Kern River's midstream transmission-only operations. The Commission stated a preference that proxy firms satisfy the Commission's historical standard that 50 percent of their income, revenue, or assets be in the pipeline business.[75] Nevertheless, Opinion No. 486-B stated that, in order to achieve a proxy group of at least five firms, a diversified natural gas company not satisfying the historical standard could be considered

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[73] *Policy Statement*, 123 FERC ¶ 61,048 at P 48.

[74] *See BP West Coast Products v. SFPP, L.P.*, 121 FERC ¶ 61,243 (2007), *reh'g denied*, *BP West Coast Products v. SFPP, L.P.*, 123 FERC ¶ 61,121 (2008), *appeal sub nom. ExxonMobil Oil Corp. and BP West Coast Products LLC v. FERC*, Nos. 07-1163, *et al.* (consolidated) (D.C. Cir.).

[75] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 91.

for the proxy group, and the Commission set forth general guidelines for a case-by-case evaluation of such diversified natural gas corporations.

53. Opinion No. 486-B found that generally the LDC business is lower risk than the interstate natural gas pipeline business, but the Commission recognized that, depending upon the particular circumstances of an LDC, it could have as much risk as an interstate natural gas pipeline.[76] The Commission stated that the unregulated gathering, processing, exploration, production, and marketing businesses are always more risky than the pipeline business, because of the potential for price volatility in the gas commodity markets among other things.[77] Therefore, the Commission concluded if the firm has a total of more than 50 percent of its business devoted to the more risky market-oriented components, it should be excluded from the proxy group.[78] Similarly, Opinion No. 486-B stated that, if a diversified gas corporation has a lower risk distribution business which substantially outweighs its pipeline business, the corporation should be excluded from the proxy group.[79] However, the Commission stated that a particular diversified natural gas corporation can be included in the proxy group, if it is shown that (1) the corporation's LDC business has a similar risk to its pipeline business, or (2) the lower risk of the LDC business is offset by the higher risk of the market-oriented components and neither component substantially outweighs the pipeline business.[80]

54. Opinion No. 486-B found that National Fuel satisfied these standards for inclusion in the proxy group. The Commission stated that National Fuel's net income profile was approximately 28 percent distribution, 28 percent natural gas transportation, 32 percent exploration and production, 3 percent marketing and trading, and 8 percent other.[81] Based on these numbers, the Commission concluded that in 2004, National Fuel's transportation and distribution components, which exceeded 50 percent, were quite well balanced, and that the exploration and production and marketing and trading functions, which totaled 35 percent, were similar in proportion to the transportation and distribution components.

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[76] *Id.* P 89.

[77] *Id.* P 86.

[78] *Id.* P 92.

[79] *Id.*

[80] *Id.* P 89.

[81] Ex. S-2, Schedule No. 1.

55. As described in more detail in subsequent sections, Opinion No. 486-B held that none of the other diversified natural gas corporations satisfied the Commission's revised standards for inclusion in the proxy group. Among the corporations the Commission excluded from the proxy group were Equitable, Questar, and NiSource. BP seeks rehearing of the Commission's exclusion of each of those corporations. It also asserts that the Commission erred in some of its statements explaining its general guidelines for analyzing whether to include diversified natural gas corporations in the proxy group.

a. <u>Guidelines for Analyzing Diversified Natural Gas Corporations</u>

56. BP argues in its request for rehearing that Opinion No. 486-B unduly relied on generic analyses in developing its methodology for determining whether a particular firm is suitable for inclusion in a natural gas pipeline proxy group. It argues that the Commission thereby wrongly concluded that a natural gas distribution function is intrinsically less risky than a natural gas pipeline function, and in fact that in some instances the opposite is true. BP asserts that in relying on an assumption that natural gas pipelines have greater risk than diversified natural gas corporations, the Commission did not sufficiently evaluate certain diversified natural gas corporations with a local gas distribution component, but relied on generalizations for its conclusions.[82]

57. The Commission disagrees. Opinion No. 486-B established an analytical framework for evaluating whether firms proposed for the proxy group have comparable risk. As discussed below, that framework properly recognizes that all the non-pipeline business components of a diversified natural gas firm inevitably have different risks from the pipeline component. However, that framework also gives the Commission flexibility, in individual cases, to consider contentions that the local distribution business of a particular diversified natural gas firm has sufficiently comparable risk for that firm to be included in the proxy group.

58. Since Order No. 636, most pipelines, including Kern River, are no longer in the natural gas merchant business and thus do not derive significant revenues from sales of the gas commodity. Therefore, as the Commission explained in *Northwest Pipeline Corporation*,[83] "the goal in choosing proxy companies is to obtain a surrogate for the rate of return that investors in a pure transmission company would expect." Diversified natural gas corporations not only have gas transmission operations, but engage in other aspects of the natural gas business, including exploration and production, marketing and trading, and distribution to retail customers. These other business activities all derive

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[82] BP's February 13, 2009 Request for Rehearing at 24-27.

[83] Opinion No. 396-B, 79 FERC ¶ 61,309, at 62,381 (1997).

revenues at least in part from the sale of the natural gas commodity. Producers, marketers, and LDCs all make unbundled and/or bundled sales of the gas commodity. However, the Commission has found that there is no reason to believe that pricing and revenue data for the gas commodity would correlate with transmission prices and revenues.[84]

59. For these reasons, as the Commission also found in *Northwest Pipeline Corporation*, “The Commission . . . traditionally select[s] as the proxy group, companies in the natural gas business whose business (revenues and assets) is, as much as possible, related to transmission,” rather than to gas commodity sales.[85] Historically, the Commission implemented this policy by requiring that diversified natural gas corporations have at least 50 percent of their assets invested in their interstate gas pipeline operations, or derive at least 50 percent of their operating revenues from such operations. The Commission used these minimum thresholds as part of its effort to ensure that the proxy firms would serve as a reasonable “surrogate for the rate of return that investors in a pure transmission company would expect.” The 50 percent standard increased the likelihood that the firms included in a proxy group had comparable business and regulatory risks and reduced the need to make excessively refined judgments among firms with different business profiles.[86]

60. Opinion No. 486-B marked a deliberate return to the policy goals and regulatory standards embedded in the Commission’s traditional 50 percent threshold standards for including a firm in the proxy group.[87] A proxy group made up of firms with predominantly transmission-only business would more likely meet the comparability standards of *Petal Gas v. FERC*.

61. In developing its revised methodology, the Commission first concluded that there can be little disagreement that the gathering and processing, exploration and production, and trading and marketing activities of a diversified natural gas company are riskier than the gas transmission, oil transmission, or gas distribution components.[88] Opinion

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[84] *Id*. at 62,380. The Commission also pointed out that the ALJ in that case had found that growth in gas commodity prices may be inversely related to pipeline revenues in some circumstances, because a decrease in gas commodity prices relative to other fuels would likely cause an increase in pipeline transmission revenues.

[85] *Id*.

[86] *Cf. Policy Statement*, 123 FERC ¶ 61,048 at P 49-51.

[87] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 58-98.

[88] *Id.* P 86.

No. 486-B cited a report by Moody's Investors Service on how it assigns ratings to North American diversified natural gas transmission and distribution companies. That report describes both the gas pipeline and LDC businesses as relatively low risk because, among other things, "LDCs and pipelines earn regulated rates that lend predictability to their cash flows" and "employ relatively low-tech, long-lived assets and are characterized by low rates of technical innovation."[89] That report continued that, "Because these businesses are generally mature and offer limited growth, companies often diversify into other businesses that promise higher return, albeit at higher risk. Generally diversification is into a business within the gas value chain and related to the company's core regulated business. For example, exploration and production and gathering and processing are the most common areas of diversification."[90]

62. Opinion No. 486-B then addressed Kern River and BP's opposing contentions concerning the relative risks of a diversified natural gas corporation's pipeline and distribution businesses.[91] Upon review of a detailed record, Opinion No. 486-B held that BP and Staff had provided sound reasons why the LDC component of certain natural gas distribution companies might have at least as much business and regulatory risks as an interstate pipeline.[92] For that reason, Opinion No. 486-B found that diversified natural gas firms with local distribution business need not be automatically excluded from the proxy group, particularly if any lower risk of the distribution operations is offset by other higher risk activities.[93] However, the Commission also found that most LDCs continue to have lower risk than pipelines, because most LDCs remain local monopolies, entry remains difficult, and various other factors reduce their risk.[94] In reaching this conclusion, the Commission relied in part on the Moody's publication.[95]

63. On rehearing, BP contends the Commission improperly relied on general assertions about LDC operations in North America and failed to address BP's more

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[89] *E.g.*, Ex. S-3 at 76, *reproducing* Moody's Investors Service Rating Methodology, *North American Diversified Natural Gas Transmission and Distribution Companies*, March 2007 (Moody's *North American Diversified*).

[90] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 86.

[91] *Id.* P 84-93.

[92] *Id.* P 89.

[93] *Id.*

[94] *Id.* P 90.

[95] *Id.* P 86.

specific evidence, particularly about inter-LDC competition in Pennsylvania, where some of Equitable and NiSource's distribution operations are located. In the relevant part of Opinion No. 486-B, the Commission addressed various parties' contentions concerning the relative risk of LDC and pipeline businesses generally, as part of considering Kern River's argument that diversified natural gas companies with substantial distribution components should always be excluded from the proxy group.[96] By finding that BP had provided sound reasons why the LDC component of some gas distribution companies might have at least as much risk as an interstate pipeline, the Commission recognized that parties should be permitted to present evidence about specific LDCs in order to show that their risks are similar to pipelines, such as BP's evidence concerning Pennsylvania LDCs.[97] BP's specific evidence with respect to Equitable and NiSource will be considered in the later sections of this order addressing its contentions that the Commission should have included those firms in the proxy group.

64. However, BP also presented testimony asserting that the gas distribution business generally should be considered at least as risky as the pipeline business because LDCs have significant revenue volatility as a result of (1) the fact a large portion of their revenues are collected through volumetric rates, (2) revenue from winter heating is dependent on the weather, and (3) greater seasonal variations in demand.[98] BP also asserted that LDCs have declining usage per customer due to conservation, increased appliance efficiency, and price-elasticity.[99] BP also asserted that LDCs have a greater risk of bad consumer debt than pipelines. It explained that LDCs, unlike pipelines, directly serve individual retail consumers and, to the extent they provide bundled sales service, they are at risk for the cost of the natural gas commodity as well as distribution costs.[100]

65. It was this evidence Opinion No. 486-B was addressing when it found that BP "overstates the risk generally applicable to the LDC components of diversified natural gas companies."[101] While increased reliance on market-based supplies of gas and more volatile retail pricing may have increased the risk of traditional LDCs, this did not change

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[96] *Id.* P 84-93.

[97] *Id.* P 89, 92.

[98] *See, e.g.,* Ex. BP-94 at 13-14; Ex. BP-159 at 8-9.

[99] Ex. BP-94 at 14-15.

[100] Ex. BP-159 at 13-14.

[101] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 90.

the basic economic structure of the industry. Thus, the Commission concluded that most (but not all) LDC functions remain local monopolies and often control alternative supplies of gas that help mitigate their gas price risk. Entry remains difficult and the risk of fluctuating gas prices is balanced by the use of weighted average gas forms of pricing combined with pass through mechanisms which both shift the risk of changes to the consumer while evening out the worst fluctuations.[102] The Commission also pointed out that, while that natural gas demand by some customers may have declined due to conservation, gas remains the heating and industrial fuel of choice because of its overall lower BTU cost. In fact, the Commission noted that most of these factors advanced by BP are reflected in the evaluation of the relative risk of LDCs and natural gas pipelines by Moody's. Nevertheless, in making its evaluation, Moody's still concluded that LDCs generally have lower risk than natural gas pipelines, even as Moody's acknowledged that LDCs now face higher risks than when gas prices and entry were more strictly regulated and seasonal demand was more stable.[103]

66. On rehearing, BP states that the Commission improperly relied on Moody's assertions about the LDC business across America in a Moody's publication. Nevertheless, the Commission finds that Opinion No. 486-B's reliance on the Moody's statement concerning the relative risk of the distribution and pipeline businesses to be appropriate. As discussed above, the Commission performs a DCF analysis of publicly-traded proxy firms to determine the return on equity that markets require a pipeline to give its investors in order for them to invest their capital in the pipeline.[104] Therefore, the Commission seeks proxy firms that investors view as having comparable risk. Because Moody's is a publication relied on by many investors, its statements concerning the relative risks of different energy-related investments are probative of the views of investors generally.

67. For these reasons, the Commission reaffirms its conclusion in Opinion No. 486-B that the weight of evidence is that LDC operations are generally (but not necessarily always) less risky than interstate gas transmission operations and that a rational analysis starts from this point.

68. However, even if one were to conclude, as BP argues, that a gas distribution function is now riskier than an interstate natural gas pipeline function, this would not help BP's cause. As discussed above, the Commission's goal in choosing proxy companies is to obtain a surrogate for the rate of return that investors in a <u>pure</u> transmission company

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[102] *Id. See also* the discussion of Equitable and Questar, *infra*.

[103] Moody's *North American Diversified*, Ex. S-3 at 76-77.

[104] *Policy Statement*, 123 FERC ¶ 61,048 at P 48.

would expect. LDCs are not pure transmission companies. Unlike pipelines, they derive a large part of their revenues from sales of the natural gas commodity to industrial, residential and other gas users. This is illustrated by the evidence discussed below with respect to the distribution businesses of Equitable, Questar, and NiSource. It follows that an investor is likely to consider an investment in the LDC business as subject to different risks than an investment in a pure transmission company, whether it views the LDC business as less risky like Moody's, or it takes a similar view of LDC risk as BP. Indeed, BP's own analysis of the different risks of LDCs and pipelines supports this conclusion. Many of the risks of the local distribution business highlighted by BP arise in connection with LDCs' merchant business, for example LDCs' risk for their commodity gas purchase costs.

69. It follows that, the more a firm's business profile diverges from the minimum 50 percent gas transmission rule, the more the Commission will have "to make increasingly difficult determinations" as to whether investors might view the non-transmission components of the firm's business as having comparable risk to its transmission components.[105] As the court stated in *Petal*, when the goal is a proxy group of comparable companies, it is not clear that natural gas companies with substantial non-pipeline business operations should be regarded as comparable.[106] The court's statement is equally true whether the question is: (1) do some diversified natural gas firms have a local distribution function that is riskier than its natural gas pipeline function as BP urges, or (2) what is the relative weight of a less risky local gas distribution function and the riskier, more market-oriented components of such a firm?

70. The potential complexity of any such analysis is why Opinion No. 486-B returned to a preference for the historical standard of 50 percent of pipeline assets or income for inclusion in a gas pipeline proxy group.[107] This reflects the historical concern that the more the diversified natural gas firm consists of functions other than a natural gas transmission function, the more difficult it is to assure that any proxy group is risk appropriate under *Petal Gas v. FERC*. Therefore, the Commission again concludes that, while a diversified natural gas firm not satisfying the historical 50 percent standard may be considered for inclusion in the proxy group, such a firm should be excluded from the

[105] *Petal Gas v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007); *Williston II*, 104 FERC ¶ 61,036 at P 35 n.46 (2003).

[106] *Petal Gas v. FERC*, 496 F.3d at 700.

[107] Opinion No. 468-B, 126 FERC ¶ 61,034 at P 91.

proxy group if either of its less risky distribution or more risky market-oriented functions substantially outweighs its transmission functions or each other.[108]

71. As a general matter, in order to include such a firm in the proxy group, it must be shown that (1) the combined natural gas pipeline and distribution businesses of the firm make up at least 50 percent of its total business, (2) the natural gas pipeline business is at least equal to the distribution business, and (3) the firm's more risky exploration, production, and other market-oriented businesses are no greater than the less risky distribution business.[109] The proponent of including such a firm in the proxy group must make a convincing case that an investor would view such a firm as having comparable risk to a pipeline, either because the lower and higher risks of the various non-transmission components offset one another, or the firm's distribution business is not of lower risk because of such factors as those cited by BP.

b. <u>Equitable</u>

72. Opinion No. 486-B found that Equitable's distribution business accounted for 27 percent of its assets, while only 11 percent of its assets were in the natural gas transmission business. The Commission also found that 47 percent of Equitable's assets were in the gathering and production business.[110] Opinion No. 486-B accordingly concluded that Equitable's transmission component was relatively small compared to any of the remaining components, including the distribution component, and that the riskier functions predominated. The Commission stated that including Equitable in the proxy group would require the Commission to assign an appropriate weight to less risky and riskier components under circumstances where the latter far exceed the gas transmission function.[111] Thus, the Commission concluded that Equitable did not meet the Commission's current standards for inclusion in the proxy group.

73. In its rehearing request, BP asserts that Opinion No. 486-B improperly focused on Equitable's assets, even though it approved National Fuel's inclusion in the proxy group based on its net income profile. BP asserts that Opinion No. 486-B's focus on Equitable's assets but National Fuel's net income constituted an inappropriate "apples-to-

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[108] *Policy Statement*, 123 FERC ¶ 61,048 at P 51.

[109] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 91-92, 94, 97-99.

[110] Opinion No. 486-B described Equitable as having a "processing and gathering" business segment. The reference to processing should have been to production.

[111] *Petal Gas v. FERC*, 496 F.3d at 699; *Williston II*, 104 FERC ¶ 61,036 at P 35 n.46.

shoeboxes" comparison. BP also argues that the Commission improperly relied on generic arguments about the lower risks of the distribution business derived from the *Policy Statement* or general sources included in the record, rather than evaluating specific evidence in the record that Equitable is at least, and in fact more risky than Kern River due to competition in its distribution service territory, fluctuations in the price of natural gas, and the seasonal nature of its business. BP concludes that Equitable is not a predominately local distribution company and therefore it should be included in the Kern River proxy group.

74. In light of BP's contentions on rehearing, the Commission has further reviewed the specific evidence in the record concerning Equitable's operations, including its net operating revenues from its various business lines. Based on that review, the Commission reaffirms its exclusion of Equitable from the proxy group. Equitable's 2004 SEC Form 10-K report states that it has three business segments: Equitable Utilities, Equitable Supply, and NORESCO.[112] Equitable Utilities includes Equitable's natural gas distribution and interstate pipeline businesses, as well as its unregulated marketing business. In 2004, all three of Equitable Utilities' business lines accounted for only 36 percent of Equitable's net operating revenues.[113] Staff's analysis of Equitable's 2004 Form 10-K indicates that approximately 70 percent of Equitable Utilities' net operating income was derived from its gas distribution business (apparently including the marketing business), and only 30 percent from its gas pipeline business.[114] Using that ratio to allocate the 36 percent of Equitable net operating income derived from Equitable Utilities between its pipeline business and its distribution and marketing business, leads to a finding that 11 percent of Equitable's net operating income is derived from its pipeline business and 25 percent from its distribution business.[115]

75. Equitable's 2004 Form 10-K states that Equitable Supply generated approximately 58 percent of its net operating revenues and NORESCO provided approximately 6 percent. Equitable Supply has both production and gathering businesses. Its production business develops, produces and sells natural gas and, to a limited extent, crude oil and

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[112] Ex. S-3 at 21.

[113] *Id.*

[114] *Id*. at 27.

[115] Staff used the same methodology to determine the asset percentages used in Opinion No. 486-B. However, given BP's assertion that net income figures should be used, our discussion on rehearing will focus on the net operating revenue data in the record, which is the nearest equivalent to the net income figures used in Opinion No. 486-A's analysis of National Fuel.

associated byproducts, in the Appalachian region of the United States. Equitable states that gas wells in the Appalachian Basin are characterized by low drilling costs, high drilling completion rates, long-lived production, and proximity to natural gas markets. Equitable states that this has resulted in "a highly fragmented operating environment," with approximately 3,500 independent operators and 94,000 producing gas and oil wells.[116] Equitable Supply operates approximately 12,600 of those wells. Approximately half the throughput of Equitable Supply's gathering system is its own production. NORESCO provides various energy-related products designed to improve its customers' energy efficiency, including cogeneration, central plant, and private power generation facilities. Equitable states that NORESCO operates in a highly competitive market segment.[117]

76. The above information demonstrates that Equitable is not sufficiently comparable to Kern River to be included in the proxy group. Its 11 percent net operating revenues from its pipeline business do not come close to satisfying the Commission's historical standard that at least 50 percent of a proxy firm's net income or assets be derived from the pipeline business. Moreover, Equitable's percentage of revenues from the pipeline business is only slightly more than one-third the 28 percent of net income National Fuel derives from the interstate natural gas pipeline business. In addition, Equitable's combined pipeline and distribution activities account for only 36 percent of its net operating income. Thus, even treating Equitable's distribution business as being comparable to the pipeline business, as BP proposes, Equitable would not satisfy the 50 percent threshold. By contrast, the Commission permitted National Fuel to be included in the proxy group because its combined pipeline and distribution businesses account for 56 percent of it net income.

77. Moreover, the record here does not support BP's argument that Equitable's distribution operations as a whole are at least as risky as its pipeline operations. Equitable's distribution operations take place not only in southwestern Pennsylvania, but also in northern West Virginia and in eastern Kentucky.[118] Thus, Equitable's distribution operations are subject to regulation by state public service commissions in Pennsylvania, West Virginia, and Kentucky. While Pennsylvania permits direct retail competition in Equitable's service area in that state, Equitable states that it also operates in areas with "state utility Commission exclusively certificated areas."[119] Therefore, not all of

[116] Ex. S-3 at 25.

[117] *Id.*

[118] *Id*. at 21.

[119] *Id*.

Equitable's distribution service areas are subject to the Pennsylvania regulatory environment highlighted by BP in its rehearing request.

78. In addition, while the Form 10-K states that Pennsylvania is one of the few states that permit local distribution companies to compete for new and old customers, the Form 10-K also states that only the industrial market is highly competitive, and that fluctuations in this market do not have a significant impact on the company's financial results.[120] There is nothing to suggest that significant numbers of Equitable's local retail or residential customers, who use gas primarily for heating purposes, are requesting competitive retail deliveries in Equitable's service territory. Rather, the Form 10-K states that it is the pipeline component that is facing the expiration of some 95 percent of its contracts in the near future and this is the main competitive issue.[121] Thus, in this case, Equitable's Form 10-K indicates its greater risk is in the pipeline component, not the distribution component as BP argues.

79. In any event, because Equitable Supply provided 58 percent of Equitable's operating income in 2004, its exploration, production and gathering activities dominate for purposes of any risk analysis of the firm. The proxy group at issue here is not measuring the comparable risk of gas producing firms, but of gas transmission firms, which Equitable is not. While it appears from Equitable's Form 10-K that its production activities in the Appalachian Basin may have somewhat lower risk than production activities in other producing areas with higher drilling costs and lower drilling completion rates, nevertheless the risks of exploration and production are different from those of unbundled transportation of natural gas. As previously discussed, the profitability of the pipeline business is significantly less related to the commodity price of natural gas, than is the profitability of the exploration and production business. Producers earn revenues from the sale the natural gas commodity, but pipelines do not. It was for that reason that the Commission found in the *Northwest Pipeline Corporation* case discussed above that there had been no showing that commodity revenue is a good proxy for transmission revenues.[122]

80. Accordingly, the Commission reaffirms its conclusion that Equitable should be excluded from the proxy group, because it has not been shown that an investor would view Equitable as having comparable risk to an investment in a pure transmission company.

[120] *Id.* at 23.

[121] *Id.*

[122] *Northwest Pipeline Corp.*, 79 FERC ¶ 61,309, at 62,380-1 (1997).

c. **Questar**

81. Opinion No. 486-B found that Questar's distribution business accounted for 27 percent of its assets, while only 20 percent of its assets were in the natural gas transmission business. The Commission also found that 51 percent of Questar's assets were in the exploration and production business. Opinion No. 486-B accordingly excluded Questar from the proxy group on the same ground it excluded Equitable, finding that Questar's transmission component was relatively small compared to the remaining components of its business, including the distribution component, and that the riskier exploration and production functions predominated.

82. On rehearing, BP argues that Opinion No. 486-B erred by not including Questar in the Kern River proxy group. As with Equitable, it asserts that Opinion No. 486-B unduly relied on general analysis and did not make a sufficiently detailed analysis of Questar's functions. It also asserts that Opinion No. 486-B improperly focused on Questar's assets, even though it approved National Fuel's inclusion in the proxy group based on its net income profile. BP concludes that Questar is not a predominately local distribution company and therefore it should be included in the Kern River proxy group.

83. As with Equitable, the Commission has further reviewed the specific evidence in the record concerning Questar's operations, including its net operating revenues from its various business lines. Based on that review, the Commission reaffirms its exclusion of Questar from the proxy group. Questar's 2004 SEC Form 10-K report states that it has three main business lines, gas and oil exploration and development, interstate gas transmission, and retail gas distribution.[123] Table 1 replicates Trial Staff's analysis of how Questar's operating income and assets are divided among its business lines.[124]

Table 1

Analysis of Questar Corporation's Operating Income, Assets
And Net Assets By Major Function as of December 31, 2004
(In Thousands)

Function	Operating Income	Percent Total	Assets	Percent Total
Market Resources	$276,546	66.54%	$2,456,332	50.36%
Questar Pipeline	$66,033	15.89%	$1,055,030	21.63%
Questar Gas	$67,466	16.23%	$1,315,537	26.97%
Corporate and	$5,542	1.33%	$50,872	1.04%

[123] Ex. S-3 at 46.

[124] *See* Ex. S-2, Schedule No. 1; Ex. S-3 at 44.

Other				
Totals	$415,587	100.00%	$4,877,771	100.00%

Note 1 Market Resources includes exploration, production, related gathering and gas sales to affiliates and other parties.
Note 2 Source for Operating Income: Questar 2004 Form 10-K at p. 26, 33, 37, and 39 for each of the functions respectively.
Note 3 Assets are total investment and do not reflect accrued depreciation or amortization. Source: Questar 2004 Form 10-K at p. 61.

84. Table 1 shows that based on operating income the natural gas pipeline function was less than 16 percent of operating income and the gas distribution function was slightly more. In contrast, Market Resources (the exploration, production, and sales function), was 66.54 percent of operating income, or more than twice the other two functions combined. This information confirms that Questar is not sufficiently comparable to Kern River to be included in the proxy group. Its 16 percent net operating revenues from its pipeline business do not come close to satisfying the Commission's historical standard that at least 50 percent of a proxy firm's net income or assets be derived from the pipeline business. In addition, Questar's combined pipeline and distribution activities account for only about 32 percent of its net operating income. Thus, even treating Questar's distribution business as being comparable to the pipeline business, as BP proposes, Equitable would not satisfy the 50 percent threshold. By contrast, the Commission permitted National Fuel to be included in the proxy group because its combined pipeline and distribution businesses account for 56 percent of its net income.

85. Finally, BP has provided even less support for a finding that Questar's distribution business has as much or more risk than its pipeline business, than it did for Equitable. Questar has no distribution business in Pennsylvania. Therefore, BP's evidence concerning Pennsylvania's regulation of its LDCs is not relevant to Questar. Questar's Form 10-K notes that its distribution business faces the usual risks of all local distribution companies, including seasonal risks, but that it has systemic methods of mitigating these risks. The detailed financials indicate that customer base is growing and that operating income for two out of the three years 2002, 2003, and 2004 was in the range of $67 to $70 million.[125] Standard & Poor's describes Questar's exploration and production business as its principal growth driver.[126] Since Questar's operating income from exploration and production was some two thirds of its total income and is riskier than either the pipeline or the distribution function, Questar is not a risk appropriate member

[125] *Id.* at 14, 37.

[126] *Id.* at 42.

of the Kern River proxy group even if examined based on operating income from its different business lines.

d. NiSource

86. Opinion No. 486-B rejected BP's proposal to include NiSource in the proxy group for several reasons. First, the Commission pointed out that Value Line categorized NiSource as an electric utility in 2004, not a diversified natural gas company. Second, the Commission found that, while NiSource owned four interstate natural gas pipelines,[127] those pipelines represented only 18 percent of its assets in 2004. By contrast, its gas distribution facilities accounted for 37 percent of its assets. Opinion No. 486-B also stated that NiSource obtained only about 33 percent of its net operating income from gas pipeline operations, with over 40 percent from gas distribution and 29 percent from electric operations.[128] Thus, the Commission found, a total of 69 percent of NiSource's operating income was from lower risk distribution activities. Based on these facts, the Commission concluded that BP had failed to show that NiSource is sufficiently comparable to Kern River to be included in the proxy group.

87. BP asserts that Opinion No. 486-B improperly excluded NiSource from the proxy group. BP states that, while NiSource's pipelines represented only 18 percent of its assets, the total value of those assets was over $3 billion which is not a small investment. It also asserts that, using the net operating income measure the Commission applied to National Fuel, 34 percent of NiSource's net operating income was from pipeline business and 41 percent from natural gas distribution. BP states that therefore these two segments involving transportation of natural gas provided about 75 percent of NiSource's net operating income, were well balanced, and far outweighed its income from electric distribution. BP also contends that NiSource's natural gas distribution business is at least as risky as its pipeline business for the same reasons it relied on with respect to Equitable and Questar.

88. The Commission again concludes that NiSource should not be included in the Kern River proxy group. First, while Opinion No. 486-B did not address the point, NiSource cut its dividend in November 2003, which is within about six months of the beginning of the data period used for the DCF analysis of the firms in the proxy group. As Trial Staff's witness testified, "When companies cut dividends, their dividend yields and growth expectations immediate change. This can lead to ongoing instability in the

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[127] These were Columbia Gas Transmission Corporation, Columbia Gulf Transmission Corp., Crossroads Pipeline Co., and Granite State Gas Transmission, Inc.

[128] Opinion No. 486-B, 126 FERC ¶ 61,034, at P 99 (2009) (citing Ex. BP-124 at 3).

data inputs, which the DCF model requires to remain stable, thereby distorting DCF results."[129] Thus, the fact NiSource cut its dividend provides an independent ground requiring exclusion of NiSource from the proxy group, regardless of the sources of its net operating income.[130]

89. Moreover, a review of both NiSource's operating income and asset distribution in the 2004 base year continues to show that NiSource was less likely to be viewed by investors as of comparable risk to Kern River, than National Fuel. On rehearing, BP asserts, without citation to any exhibit, that 34 percent of NiSource's net operating income was from pipeline business and 41 percent from natural gas distribution,[131] and therefore these two business lines were well-balanced, as the Commission found with respect to National Fuel. However, BP's evidence in this case tells a different story. Its witness, Mr. Ives, testified that 27.25 percent of NiSource's 2004 net operating revenue was from its pipeline and storage business while 47.14 percent was from the gas distribution business.[132] Therefore, NiSource's net revenue from natural gas distribution was almost 75 percent greater than its net revenue from pipeline functions. This contrasts with National Fuel, who received approximately 28 percent of its net income from the pipeline business and an equal percentage from natural gas distribution. Thus, unlike National Fuel, NiSource's overall natural gas operations were heavily weighted toward distribution.[133]

[129] Ex. S-4 at 23.

[130] *See* Opinion No. 486, 117 FERC ¶ 61,077 at P 124, 138 (excluding El Paso and Williams from the proxy group in part on the ground that they had recently cut their dividends).

[131] In Ex. S-5 at 5, Trial Staff stated that 35.7 percent of NiSource's 2003 operating income was from gas pipelines, 24.8 percent was from electric distribution and, by subtraction, 39.5 percent was from gas distribution. However, the relevant time period for this case is 2004, not 2003.

[132] Ex. BP-94 at 59-60; Ex. BP-120.

[133] Trial Staff did not provide an asset distribution, but BP states that electric marketing assets were 18.33 percent, natural gas pipeline assets 17.97 percent, gas distribution 37.27 percent, and corporate and other 26.42 percent, in which case under BP's own numbers the gas distribution assets are twice those of the natural gas pipeline function. Ex. BP-114. Thus, the asset data is even more heavily weighted towards distribution, than the net operating income.

90. In addition, the third major component of NiSource's business was electric distribution, which accounted for 24.88 percent of its net operating revenue. By contrast, the third major component of National Fuel's business was exploration and production, which represented 32 percent of its net income. Opinion No. 486-B included National Fuel in the proxy group in part on the ground that investors would view its distribution business as having less risk than its pipeline business, but would view its exploration and production business as having higher risk. Thus, the two non-pipeline components would approximately offset each other. The same finding cannot be made with respect to NiSource, since investors would likely view both its non-pipeline business components as having lower risk than its pipeline business. Thus, the addition of the electric distribution component suggests even lower risk for that element than the mixture of gas functions involved with National Fuel.

91. At bottom, in 2004 NiSource was primarily a natural gas and electric distribution company, not a pipeline company. BP's estimate of the operating income from the two distribution operations was some 72.02 percent. As NiSource states in its 2004 SEC Form 10-K, NiSource "focuses its business strategy on its core, rate regulated asset-based businesses with virtually 100% of its operating income generated from the rate-regulated businesses."[134] A further indication that investors were not likely, in 2004, to view an investment in NiSource as an investment in the natural gas pipeline business is the fact that Value Line did not include NiSource in its list of diversified natural gas companies. Rather, Value Line only followed NiSource as an electric distribution company. As the Commission has previously pointed out, Value Line is a major publication used by investors and therefore is probative of the views of investors.

92. Moreover, the record here does not support a conclusion that NiSource's gas distribution operations are riskier that its natural gas pipeline component. A further review of NiSource's 2004 10-K discloses that most of its gas customer credit risk is recoverable through trackers, stranded cost or other recovery mechanisms and that it improved its recovery of bad debts in 2004.[135] It also stated that its commodity price risk resulting from non-trading activities at NiSource's rate regulated subsidiaries is limited and that it had disposed of its trading operations in 2002, thereby reducing its risk profile.[136] Seasonal considerations involve the usual cash management function rather than any underlying concerns about market volatility[137] and its market risk for the power

[134] *See* NiSource's SEC Form 10-K for the fiscal year ending December 31, 2004 (NiSource 2004 10-K) at 3.

[135] *Id*. at 29, 54-55.

[136] *Id.* at 41, 45.

[137] *Id.* at 31.

trading functions supporting its electric distribution operations is minimal.[138] The 2004 10-K does state that gas on gas competition is common in Ohio and Pennsylvania, but does not appear to consider this a matter of concern given the multi-state nature of NiSource's operations.[139] Also, while BP's evidence concerning retail competition focuses on Pennsylvania, NiSource's Form 10-K indicates that, together with its subsidiaries, it has major distribution operations in Indiana, Virginia, Kentucky, Maryland, Massachusetts, Maine, and New Hampshire, in addition to Pennsylvania and Ohio.

93. Therefore, Opinion No. 486-B properly excluded NiSource from the Kern River proxy group.

e. Reliance on *Policy Statement*

94. BP also asserts on rehearing that the Commission erred by relying on the *Policy Statement* in making conclusions about the risks involved in the distribution functions of a certain diversified natural gas pipeline corporation. It argues that Opinion No. 486-B appears to rely on the *Policy Statement* for the conclusion that the Commission would have "to make increasingly difficult determinations of relative risk" by assigning an appropriate weight to less risky distribution and the riskier, more market-oriented components without analyzing the specific firms involved. BP further argues that the Commission thus inappropriately relied on the *Policy Statement* in reaching its conclusions regarding the relative risk of Questar, Equitable, and NiSource, and thus the Commission should rely only on the record developed here and not on the *Policy Statement*.

95. BP's argument that the Commission relied on the *Policy Statement* in making determinations on the relative risk of Questar, Equitable, and NiSource is without merit. As discussed, the extensive analysis in Opinion No. 486-B of the risks of the different business lines of diversified gas corporations was based on the materials and analysis of each of the named diversified natural gas companies, as well as more generic information included in the record used to establish the Commission's overall methodology for evaluating such corporations. BP's concern appears to be that Opinion No. 486-B relied on the *Policy Statement* to conclude that a local gas distribution function always has a lower risk than interstate gas transmission and that this conclusion was applied to the review of the three diversified natural gas corporations with which BP is concerned.

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[138] *Id.* at 27.

[139] *Id.* at 33.

96. The *Policy Statement* did note *Petal Gas v. FERC* stands for the principle that LDCs generally have lower risk than interstate natural gas pipelines.[140] However, the *Policy Statement* took pains to state that diversified natural gas corporations would not be excluded from a proxy group simply based on that nomenclature.[141] Thus, the *Policy Statement* was relied upon primarily to support the policy conclusion that MLPs could be included in a pipeline proxy group,[142] which BP did not contest. Opinion No. 486-B also concluded that that there might be circumstances under which a diversified natural gas corporation had as much risk as an interstate gas company. This conclusion was not based on the *Policy Statement*. Rather, Opinion No. 486-B reviewed BP's and Trial Staff's arguments of the circumstances under which a diversified natural gas corporation with a natural gas distribution component might be as risky as a natural gas pipeline.[143] Moreover, the Commission reviews its prior determinations regarding the four firms used in the proxy group in detail below.

C. Kern River's Relative Risk

97. In Opinion No. 486-B, the Commission held that the ROEs of the five firms selected for the proxy group are as follows: KMI: 13.00 percent; KMEP: 12.99 percent; Northern Border: 11.55 percent; TC Pipelines: 10.35 percent; and National Fuel: 8.80 percent. Thus, the range of reasonable returns is 8.8 percent to 13 percent, and the median ROE is Northern Border's ROE of 11.55 percent.[144] In deciding where to place Kern River in the range of reasonable returns, the Commission applied its existing policy, under which pipelines are presumed to fall into a broad range of average risk, absent highly unusual circumstances that indicate anomalously high or low risk as compared to other pipelines.[145] The Commission held that, while there are differences among the proxy group firms, with three being somewhat more risky than Kern River, and two having about the same risk, all five proxy group members fall within broad range of average risk. There is no credible evidence in this record to support a finding that Kern River is of anomalously high or low risk compared the other members of the proxy

[140] *Policy Statement*, 123 FERC ¶ 61,048 at P 26.

[141] *Id.* P 51.

[142] *Id.* P 2, 49-51.

[143] Opinion No. 486-B, 126 FERC ¶ 61,034 at P 84-92.

[144] *Id.* P 131.

[145] *Transcontinental Gas Pipe Line*, 90 FERC ¶ 61,279, at 61,936 (2000).

group. The Commission thus concluded that Kern River is of a similar risk to the overall risk of the proxy group and set its ROE at the 11.55 percent median of the proxy group.

98. On rehearing, BP and RCG both assert that Opinion No. 486-B incorrectly concluded that Kern River was of average risk compared to the members of the proxy group. They argue that Kern River is substantially less risky than those members for several reasons. These include a lower dependence on interruptible throughput, lower shipper credit risk, a longer average contract term, strong growth in its California delivery market, increasing reserves and transportation demand in its production market, little risk of entry by other pipelines or from potential sources of liquefied natural gas, likely growth from the increased displacement of coal and oil by natural gas in the generating and industrial markets, demonstrated success in marketing turned-back capacity, particularly the so-called Mirant capacity that was returned in 2004 as part of Mirant's bankruptcy proceeding, and the rapid amortization of Kern River's rate base under its Phase One rates. BP also argues that Kern River has lower financial risk than the MLPs included in the proxy group because it has greater access to financial resources through its parent company and lacks the pressure to make distributions unlike publically traded MLPs. Given these factors, they conclude that Kern River's return should be reduced to reflect a lower risk. BP also argues that Opinion No. 486-B improperly concluded that Kern River and Northern Border have similar risks, and further that Opinion No. 486-B incorrectly stated BP's position on the issue of the reduced return. Finally, BP argues that it is irrational to argue that firms within the proxy group reflect a broad range of average risk since some must be above or below the average for one to exist.

99. Both BP and RCG introduced exhibits in support of their position. BP's evidence was extensive, but almost all of it was for the years 2006 through 2008 and was designed to show a significant improvement in Kern River's competitive position between 2004 and 2008.[146] Much of this might carry weight if the base year at issue was 2008, but it is not. The base year here is 2004 and the DCF calculation is based on that year. As was previously discussed, investors make decisions and determine the return required on a risk-adjusted basis. Thus, the investor's perceptions and decision-making framework is based on the information available for the twelve months of 2004. It would be inconsistent to base the DCF model on 2004 financial information, including 2004

[146] *See* Ex. BP-94, *passim*, Ex. BP-95 through Ex. BP-106, Ex. BP-108 through Ex. BP-111, Ex. BP-113, Ex. BP-117, and Ex. BP-119. *See also* Ex. BP-136, which uses primarily 2008 information although some is relevant to 2004, particularly at 14, 20, 23. The entire analysis of the risk of diversified natural gas companies is for 2008 or for reports after the test period (*Id.* at 24-38), as is the weather and regulatory risk analysis for such firms. *Id.* at 47-52.

dividend yield and IBES short-term growth projection, and then determine whether there should be a risk-based adjustment using data over an extended four year period. While BP correctly notes that Kern River also was relaxed about the base year on the issue of relative risk when it suited Kern River's purposes, two erroneous approaches do not cancel each other out. Thus, the Commission will not go outside the 2004 base period except where the argument advanced reflects a change to a specifically-identified anomalous condition that occurred shortly after the end of the base year.

100. The Commission has consistently held that it will not find that a firm has risk outside the broad range of average in which most pipelines fall, unless a party presents a very persuasive case to the contrary. BP's request for rehearing questions this standard by asserting that Opinion No. 486-B did not effectively answer BP's point that not all pipelines can be of average risk. Opinion No. 486-B's response to this argument was that the selection of the proxy group is designed to remove any outliers and thus assure that the members of the proxy group fell within the historical standard. As the Commission understands it, BP argues that this response is irrelevant because, under *Petal Gas v. FERC*, the standard for inclusion in the proxy group is comparability, not whether the firm falls within an average range. On that point, the court in *Petal Gas v. FERC* stated:

101. The Commission does address the issue of relative risk when it places HIOS in the middle of the proxy group in terms of return on equity. But in doing so, the Commission expressly relies on the "assumption that pipelines generally fall into a broad range of average risk . . . as compared to other pipelines" – an assumption that is decisive only if a given proxy group is composed of other pipelines (interior citations omitted).[147]The implication of this remark is that pipelines may be considered to fall within a broad range of average risk in part because their inherent characteristics are similar, provided that other aspects of their profiles are reasonably comparable so that their risks are generally comparable. In this case, the proxy group has three firms with pipeline business significantly in excess of the historic 50 percent standard, and the median is established by Northern Border, whose pipeline facilities account for 91 percent of its operating income.[148] In addition, while the proxy group includes two firms with less than 50 percent gas transmission business, one (KMEP) has an ROE above the median, while the other (National Fuel) has an ROE below the median. Thus, their presence in the proxy group does not either increase or decrease the median established by Northern

[147] *Petal Gas v. FERC*, 496 F.3d 695, 700 (D.C. Cir. 2007) (citing *HIOS*, 110 FERC ¶ 61,043, at P 154 (2005)).

[148] The other two firms are KMI and TC Pipelines. As discussed previously in this order, 63.05 percent of KMI's assets are related to natural gas pipelines, taking into account its ownership interest in KMEP. One hundred percent of TC Pipelines' income is from pipelines. Ex. S-2, Schedule 3.

Border's 11.55 percent ROE, and as discussed further below, the Commission has found them to be reasonably comparable. Thus, contrary to BP's argument, it is not illogical to start from the position that pipelines fall within a broad range of average risk.

102. Therefore, if the Commission is to award Kern River a lower or a higher return, there must be highly unusual circumstances that indicate anomalously high or low risk compared to other pipelines in order to conclude that its relative risk falls significantly outside the range of the proxy group as a whole. The Commission requires a very persuasive case in support of any adjustment precisely because of the difficulty of quantifying why a given firm's relative risk should be deemed to be significantly above or below that of the firms included in the proxy group.[149] Given its current approach to determining comparability, the Commission denies rehearing of BP's argument that the Commission's approach to relative risk is irrational.

103. The Commission will now turn to the three specific assertions raised by BP and RCG. The first two assertions are interrelated. One is that Opinion No. 486-B erred by setting Kern River's ROE at the median of the proxy group. The second asserts that Opinion No. 486-B erred in holding that Northern Border and Kern River have similar risk. In this regard, BP asserts that Northern Border lacks the base load Kern River has in California, and therefore, has a higher contract risk. BP argues that Kern River's base load status is reflected in the fact that it has a consistently higher load factor than Northern Border's 79.3 percent, and that Northern Border's load factor is 64 percent less than Kern River's given that the latter's load factor is well in excess of 100 percent. BP further asserts that if Northern Border's 79.3 percent load factor resulted in full cost recovery, this would be inconsistent with Commission policies that prohibit shifting excess capacity to a pipeline's shippers. BP also asserts that the lower risk is reflected in the fact that Northern Border has a Moody's credit rating that is two notches below Kern River's rating (Northern Border's Baa2 versus Kern River's A-3).

104. In addition, BP argues that Kern River has lower loss reserves than BP's proxy group, which reflects a more stable customer profile and the fact that Kern River now holds $79 million in letters of credit from its customers. It also argues that Kern River is owned by a Subchapter C corporation, and unlike a MLP, is not under pressure to pass through cash distributions in excess of its earnings. BP thus concludes that Kern River is more financially stable and can also obtain a lower borrowing cost based on the financial strength of its parent. It also argues that Northern Border lacks the advantage of accelerated depreciation, the environmental advantages of the California market, and Kern River's growth prospects. BP also asserts that Northern Border lacks the ability to recover the bulk of its investment through Period One rates and the competitive

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[149] Opinion No. 468-B, 126 FERC ¶ 61,034 at P 140; *See also Policy Statement*, 123 FERC ¶ 61,048 at P 7.

advantage that will come to Kern River when it implements its lower Period Two rates. Finally, even though BP makes the point that Northern Border has a lower credit rating, BP also asserts that Opinion No. 486-B unduly relied on credit ratings in evaluating the relative risk and that credit ratings do not accurately measure relative market or business risk.[150] BP therefore concludes that Northern Border has markedly greater risk than Kern River.[151]

105. BP's third assertion is that Opinion No. 486-B erred when it states that BP proposed to place Kern River's ROE at the point mid-way between the median and the low end of the DCF range. In fact, BP states, it would adjust the risk between Kern River the rest of the proxy group by comparing their subscribed capacities. In the testimony cited in BP's rehearing request, BP's witness asserted that Kern River's ROE should be 20 percent lower than the median of the proxy group, because its capacity subscription level of 107 percent is about 20 percent higher than the average capacity subscription level of the other proxy group pipelines.[152]

106. As noted, a major problem with BP's argument is that almost all of its evidence on Kern River's relative risk is based on the period 2006 through 2008, and as such, is clearly outside the test period. In fact, the only evidence comparing the two firms that is within the test period is the evidence on the difference in their credit ratings,[153] part of the arguments relating to relative credit exposure in the period 2004 through 2005,[154] the consistency of Kern River's throughput,[155] the growth in electric power and of natural

[150] It is unclear whether BP is requesting rehearing of Opinion No. 486-B's holding that investment credit ratings and business profile ratings are helpful in determining relative risk. If so, rehearing is denied for the reasons stated in *Kern River Gas Transmission Co*., 126 FERC ¶ 61,034, at P 133-37 (2009).

[151] BP's February 13, 2009 Request for Rehearing at 40-41.

[152] Ex. BP-121 at 15.

[153] Ex. BP-108 (which provides information both within and outside the test period).

[154] Ex. BP-112.

[155] Rebuttal Brief of BP Energy Company on Reopened Record Issues at 24-24 (citing Ex. BP-22).

gas consumers,[156] and indirectly certain information on access to dry natural gas proven reserves.[157]

107. In its rehearing request, BP asserts that in 2004, Kern River's mainline was more fully contracted than those of any of its proxy companies, citing its Exhibit BP-104.[158] That exhibit shows that Kern River's capacity was 107.2 percent subscribed in 2004, and the average capacity subscription percentage of the 34 pipelines owned by the nine firms BP proposed for inclusion in the proxy group was 89.2 percent as of January 1, 2008. It is the approximately 20 percent difference between these two percentages that forms the basis for BP's proposal to reduce Kern River's ROE 20 percent below the median of the proxy group. BP's reliance on this exhibit is fatally flawed by the facts the exhibit (1) uses capacity subscription data for the pipelines owned by all nine firms it proposed for the proxy group, four of which we rejected, and (2) the proxy firm data is from 2008, well after the end of the test period.

108. Because this exhibit forms the basis of BP's proposal to adjust Kern River's ROE 20 percent below the median, we have recalculated the average proxy firm capacity subscription percentage, excluding data for pipelines which were not owned in 2004 by the five firms we have included in the proxy group.[159] The average capacity subscription percentage for the pipelines that were owned by our proxy firms was 105.30 percent, nearly the same as Kern River's 2004 capacity subscription percentage of 107.2 percent. Moreover, the capacity subscription percentage for the pipelines owned by KMEP was 90.33 percent, for pipelines owned by Northern Border was 109.25 percent, and for pipelines owned by TC Pipelines was 118.68 percent. Thus, Kern River's capacity subscription percentage was almost the same as that of Northern Border, which establishes the median of our proxy group. Also, KMEP, whose DCF results are above the median, had a lower capacity subscription percentage than Kern River, while TC Pipelines, whose DCF results are below the median, had a higher capacity subscription

[156] Ex. BP-103 at 2.

[157] Ex. BP-98.

[158] BP's February 13, 2009 Request for Rehearing at 30.

[159] These pipelines include: (1) National Fuel; (2) three pipelines owned by KMEP: Kinder Morgan, Trailblazer, and TransColorado; (3) four pipelines owned by Northern Border Partners: Northern Border Pipeline Company (Northern Border Pipeline), Guardian Pipeline LLC, Midwestern Gas Transmission Company, and Viking Gas Company; and (4) the two pipelines in which TC Pipelines owned an interest: Northern Border and Tuscarora. BP's exhibit does not include capacity subscription data for Natural, owned by KMI in 2004.

percentage. Therefore, even if we were to agree with BP that 2008 capacity subscription data should be considered in determining Kern River's relative risk, which we do not, that data would not provide a basis for adjusting Kern River's ROE below the median.

109. BP also asserts that Kern River had an average contract duration that was well in excess of that of the proxy firms.[160] However, the exhibit BP cites only compares contract durations as of April 1, 2008 for both Kern River and the 34 comparison pipelines used in the capacity subscription exhibit discussed above. The exhibit thus contains no information relevant to the 2004 period at issue here.

110. BP's assertion that Kern River is the baseload pipeline serving southern California is based on an exhibit showing relative gas commodity prices in the various production basins attached to the pipelines serving southern California in 2007 and 2008, not in 2004.[161] Its assertion that Kern River projects that production from its Rocky Mountain production areas will outpace export pipeline capacity is based on statement Kern River made at an October 2006 customer meeting.[162] Moreover, BP's statement that California has adopted regulatory policies preventing new coal and oil-fired plants from serving California's electric load is based on a law California adopted in 2006, also after the test period in this case.[163]

111. In addition, BP makes a number of arguments asserting that Kern River is less risky than Northern Border. While it is reasonable to grant BP's point that the Chicago market, with nine natural gas pipelines, may be somewhat more competitive than southern California, even in the latter market there is competition among El Paso, Transwestern Pipeline, Mojave Pipeline, and Gas Transmission Northwest, at a minimum. BP provides no specific analysis of the two different markets in 2004, relative load factors, rate levels or returns, leaving its arguments at a more general level.

112. In its rehearing request, BP asserts that Northern Border Pipeline's 79.3 percent load factor "during the relevant period was only 64 percent of Kern River's."[164] However, the exhibit BP cites for this proposition clearly states that the comparison is

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[160] BP's February 13, 2009 Request for Rehearing at 30.

[161] *See* Ex. BP-100.

[162] BP's February 13, 2009 Request for Rehearing at 31-32 (citing Ex. BP-94 at 64).

[163] Ex. BP-94 at 31-32.

[164] BP's February 13, 2009 Request for Rehearing at 35 (citing Ex. BP-136 at 19-20)

based on the two pipelines' load factors during 2007, not 2004.[165] Similarly, BP relies on TC Pipelines' SEC Form 10-K for 2007 to suggest that Northern Border Pipeline could face capacity de-subscription of up to 37 percent at the beginning of the second quarter of 2008, and up to 48 percent by the end of 2008, because of upcoming contract expirations.[166] BP contends that the Commission policy would not permit Northern Border Pipeline to shift the costs of such unsubscribed capacity to its remaining customers.[167] This evidence also relates solely to events well after the test period. In any event, BP's Exhibit BP-104, discussed above, indicates a capacity subscription percentage for Northern Border Pipeline of 119.6 percent. The exhibit states that this percentage was calculated using Index of Customer data as of April 1, 2008, with expired contracts removed to the determine the volumes currently subscribed. This suggests that actual capacity turn back was not a significant problem.

113. BP also provides no detail on Northern Border Pipeline's current rate profiles or analysis of accommodations it may have reached with its shippers in rate cases relevant to the 2004 test year. For example, the protests to Kern River's June 1999 general rate increase do not appear to have mentioned the discounting issue.[168] BP's affiliate's protest to Northern Border Pipeline's November 2005 general rate filing mentions the issue only in passing,[169] and there is no mention of throughput or discounting issues in the settlement materials filed with the Commission in September 2006,[170] well before the 2007 year on which BP relies. There is thus nothing in the record to suggest that Northern Border Pipeline's rates as of the end of the test period in this rate case (or subsequently) reflected anything other than the Commission's standard policy of

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[165] *See* Ex. BP-136 at 19-20, 23.

[166] BP's February 13, 2009 Request for Rehearing at 36 (citing Ex. BP-136 at 22).

[167] *Id.* (citing*, e.g., Natural Gas Pipeline Co.*, 73 FERC ¶ 61,460 at 62,569 (2001)).

[168] *See Northern Border Pipeline Co.*, 87 FERC ¶ 61,380 (1999).

[169] *See Northern Border Pipeline Co.*, 113 FERC ¶ 61,230 (2005); *See* BP Canada Energy Marketing Corp.'s November 14, 2005 Motion to Intervene and Protest in Docket No. RP06-72-000 at 10.

[170] *See* Northern Border's September 18, 2006 Settlement Filing and Attachments in Docket No. RP06-72-000.

designing a pipeline's rates to permit full recovery of its cost of service, assuming it was required to continue offering the same discounts as during the test period.[171]

114. In keeping with such general assertions, while BP asserts that Northern Border lacks the accelerated depreciation, levelized rate structure, or the expansion prospects of Kern River, the only discernable quantification of these differences is the distinction in the Moody's credit ratings of the two pipelines in 2004, which BP argues is unreliable, while at the same time advancing it as a rationale.[172] Moreover, while Moody's gave Northern Border a credit rating two notches below that of Kern River, Standard & Poor's gave the two pipelines the same A- credit rating in 2004.[173] The upshot of this is while BP has presented some arguments to suggest Northern Border may be slightly riskier than Kern River, it has not presented a very persuasive case that there are highly unusual circumstances that indicate Kern River has anomalously high or low risk compared to Northern Border. The record does not support BP's argument that Kern River is markedly less risky than Northern Border or than the proxy group as a whole during the test period. The other arguments BP makes on the relative growth of the two firms' markets and the prospects that the gas from their supply areas will be transported over their respective systems are well outside the test period.[174]

115. BP and RCG were effective in rebutting Kern River's argument that Kern River is extraordinarily risky. For example, both BP and RCG established that the Mirant contract, which was terminated in Mirant's bankruptcy, posed no threat to Kern River's long-term position because Kern River was able to resell the capacity on an interruptible basis.[175] However, BP and RCG did not negate Kern River's assertions that in 2004 it

[171] *Williams Natural Gas Co.*, 77 FERC ¶ 61,277, at 62,205 (1996).

[172] BP does so even through one member of its proxy group, Questar, had a credit rating of A-3 in 2004, the same as Kern River. But as previously discussed, this could be because of factors that relate to business lines that are not pipelines. If the credit rating is the criteria, any firm with an A-3 credit rating would be comparable to Kern River.

[173] Ex. S-2, Schedule 2.

[174] Ex. BP-94 at 4-5, 20-22, 25-31; Ex. BP-95; Ex. BP-96.

[175] BP also asserts in its rehearing request that Mirant's bankruptcy has resulted in Kern River's service to electric generators producing returns in excess of the amounts cost-based rates would yield. However, that assertion is based on the fact that in 2006, Kern River received $107 million in the Mirant bankruptcy proceeding. *See* BP's February 13, 2009 Request for Rehearing at 30-31. Because the bankruptcy settlement occurred after the test period in this case, it is not relevant to a determination of Kern River's relative risk in this case.

was facing risk of entry by other pipelines in its supply markets, that it served fewer LDCs and more independent generating plants directly than some of its competitors in the California market, and its producers were at least somewhat less creditworthy than its competitors. Thus, even if one concedes that Kern River has somewhat lower risk than the five firms in the Commission's proxy group,[176] neither BP nor RCG has presented a persuasive case that Kern River's ROE should be placed lower than the median ROE of the proxy group. As Opinion No. 486-B stated, the instant debate is emblematic of why the Commission applies such a rigorous standard to arguments that a pipeline's ROE should be less or greater than the median ROE of an appropriate proxy group.[177]

116. Finally, BP's argument is premised on the fact that Kern River has a consistently high load factor and therefore lower risk than the members of the proxy group. While it is true that Kern River has a consistently high load factor, and we would add, relatively low rates, the record strongly suggests that this is a function of sound business planning. Kern River has carefully staged its expansions, offered its shippers attractive long term contracts, and used a levelized rate that enhances its competitive position compared to its older competitors. As such, BP's argument has a certain tenor that no sound business judgment should go unpunished. The Commission has encountered this circuitry before. In Opinion No. 414-A, the Commission first stated that its prior evaluations of risk tended to some extent give higher returns to less efficient, higher risk pipelines, thus giving them less incentive to become more efficient. It further noted that at the same time more efficient companies were awarded lower returns, which failed to recognize and reward their success. The Commission concluded that therefore, while it would continue to examine a pipeline's relative risk, it would not lower a pipeline's ROE if its lower risk was the result of its own efficiency. The Commission stated that it would focus on risks faced by the pipeline that are attributable to circumstances outside the control of the pipeline's management, such as the competitive environment. Of interest here is the Commission's observation that Transcontinental Gas Pipe Line Corporation's (Transco) positive market position was largely the result of its relatively low rates in its market area and its lengthy contract terms. Therefore the Commission declined to follow its earlier practice and did not lower Transco's return below the middle of the range of returns developed by the proxy group. Kern River's relative strength reflects its prudent expansion and low rates and it should not be penalized for its accomplishments by having

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[176] Opinion No. 486-B concluded that all of the other members were riskier than Kern River and that one was about the same risk based primarily on differences in business lines and their respective credit and business risks. Opinion No. 486-B, 126 FERC ¶ 61,034 at P 149-153.

[177] *Id.* P 146.

its ROE lowered below the median of the proxy group.[178] For the reasons stated, BP and RCG's requests for rehearing are denied.

D. The ROE for Kern River's Period Two Rates

117. BP asserts that the Commission erred in not modifying the ROE to be included in Kern River's Period Two Rates. BP argues that at the end of Period One Kern River will have depreciated rate base, and as such, will have much lower costs and risk in Period Two. BP therefore concludes that the rate of return on equity used to design the Period Two Rates should be lower than the proposed Period Two Rates included in Kern River's March 2, 2009 revised compliance filing. The Commission concludes that this particular rehearing request is premature for two reasons. First, BP has presented no metrics or quantification to date for determining what the lower ROE should be in Period Two as the record now stands. It simply argues that the ROE embedded in Period Two Rates should be lower. As previously noted, the Commission is establishing an additional hearing on Kern River's proposed Period Two Rates. Therefore rehearing is denied without prejudice to further consideration of the issue in the hearing on the Period Two rates established by this order.

IV. Compliance Filings

118. In order to implement the Commission's rejection of Kern River's Settlement proposal, Opinion No. 486-B directed Kern River to (1) cancel the interim rates filed with the Settlement effective October 1, 2008, and (2) recapture the interim refunds previously made under the Settlement at the earliest practical date. In order to implement its holding that Kern River's ROE should be 11.55 percent, the Commission directed that Kern River make a revised compliance filing on or before March 2, 2009 using the 11.55 percent ROE and following all the Commission's other merits holdings in this proceeding.

119. On January 30, 2009, Kern River submitted a filing to comply with Opinion No. 486-B's directives related to the rejection of the Settlement. On March 2, 2009, Kern River filed tariff sheets revising its rates to reflect an 11.55 percent ROE and the Commission's other merits holdings. On March 27, 2009 and September 22, 2009, Kern River made further compliance filings to correct the March 2, 2009 compliance filing.

120. As described below, on April 10, 2009, the Commission accepted Kern River's January 30, 2009 compliance filing.[179] In this order, the Commission accepts the March

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[178] Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,427 (1998).

[179] *Kern River Transmission Co.*, 127 FERC ¶ 61,033 (2009) (April 10, 2009 Order).

2, 2009 compliance filing, as revised on March 27, 2009 and September 22, 2009, with respect to the Period One Rates, subject to the conditions discussed below. The Commission rejects Kern River's tariff sheets setting forth its proposed Period Two rates, and requires Kern River to file revised *pro forma* Period Two tariff sheets offering levelized Period Two Rates. The Commission also establishes a hearing to consider issues concerning the Period Two rates as discussed below, and suspends that hearing for settlement judge procedures.

A. January 30, 2009 Compliance Filing

121. In its April 10, 2009 Order, the Commission found that Kern River's January 30, 2009 compliance filing reasonably implemented Opinion No. 486-B's rejection of the Settlement.[180] In the January 30, 2009 compliance filing, Kern River stated that, as required by the Settlement, it had refunded to the settling parties the amounts in excess of the Settlement rates which it had collected from November 1, 2004 until the October 1, 2008 interim implementation of the Settlement. While Opinion No. 486-B authorized Kern River to recapture all of those refunds, Kern River stated that it had given the settling parties the option to defer repayment of the refunds in order to allow the refund amount to be offset against any amount Kern River may be obligated to refund in accordance with the Commission's final order in this proceeding. The Commission found this to be reasonable, holding that it benefitted Kern River's settling customers by allowing them to delay the return of refunds and avoided the disruption of requiring customers to repay refunds which were then likely to be refunded back to the customers upon the conclusion of this case.[181]

122. Kern River also filed tariff sheets removing the interim Settlement rates effective October 1, 2008 and reinstating the higher motion rates in this proceeding on that date. However, Kern River proposed not to bill and collect from settling parties the difference between the Settlement rates and the motion rates for the period October 1 through December 31, 2008. Instead, Kern River stated that it would use such uncollected amounts to offset any additional refunds that it may be obligated to make to the settling parties as a result of collecting the reinstated motion rates after January 1, 2009. The Commission approved this offset procedure as benefitting Kern River's settling parties in the same manner as Kern River's proposed refund offset procedures for the period from November 1, 2004 through September 30, 2008.[182]

[180] *Id.* P 19.

[181] *Id.* P 20.

[182] *Id.* P 21.

123. Finally, in a February 5, 2009 letter to the Commission, Kern River stated that it would bill all customers at the motion rates in its February invoices for January 2009 business. Kern River further stated that its March 2, 2009 filing to comply with the other rulings of Opinion No. 486-B would show that the rates required by Opinion No. 486 for all customer classes, other than the 10-year shippers on the Rolled-in System, are lower than the rates in effect before Kern River made its April 30, 2004 NGA section 4 filing in this case. However, Kern River stated that, consistent with NGA section 5, the Commission cannot reduce the rates for the non-10-year Rolled-in System shippers below the rates in effect before this rate case, until the Commission approves the compliance filing thereby fixing the new just and reasonable rates to be applied prospectively. Kern River stated that this creates a "Locked-in Period" from November 1, 2004 through the date of the Commission's final order in this proceeding, when it states "the revised lower rates required by Opinion No. 486 will take effect," and it refers to the rates it will charge each of its customer classes during that period as the "Locked-in Period Rates." Accordingly, Kern River stated that, beginning with its March invoices for February 2009 business, it would bill the non-10-year Rolled-in System shippers Locked-in Period Rates equal to the rates in effect before this rate case. Kern River stated that, in the same invoices, it would begin billing the 10-year Rolled-in System shippers the revised rates in the compliance filing. Finally, Kern River stated that it would recalculate its billings to the settling parties for the period from October 1, 2008 through January 31, 2009 at the "locked in period rates," and would pay refunds or bill customers as appropriate to resolve any difference between the amount Kern River actually collected from each settling party for October-January services and the amount it would have collected at the Locked-in Period Rates.

124. In the April 10, 2009 Order, the Commission accepted this proposal, because it would result in an immediate rate reduction for all customers. The Commission also stated that all issues concerning Kern River's proposed rates in the March 2, 2009 compliance filing could be raised in comments or protests to that filing, and the Commission would address any concerns pertaining to Locked-in Period Rates, or the related refund implications, when it acts on that compliance filing. Therefore, the Commission stated that its approval of the interim billing of the 10-year Rolled-in System shippers would be subject to whatever adjustments the Commission might require in its review of Kern River's March 2, 2009 compliance filing in this proceeding.[183]

B. March 2, 2009 Compliance Filing

125. On March 2, 2009, Kern River submitted a revised compliance filing in Docket No. RP04-274-017 to comply with Opinion No. 486-B. In particular, as set forth below,

[183] *Id.* P 25.

Kern River states that it revised its cost of service and rate design in accordance with Opinion No. 486-B.

126. Kern River states that it used an ROE of 11.55 percent to calculate its cost of service. Kern River asserts that it calculated prospective rates for its Original System using reservation billing determinants equal to 100 percent of Kern River's design capacity and usage billing determinants equal to actual throughput over the last 12 months of the test period. Kern River calculated prospective rates for firm transportation services using a Straight Fixed-Variable (SFV) rate design. Kern River calculated rates for interruptible and authorized overrun service using the "blended rate" methodology required by Opinion No. 486.

127. Kern River states that it credited interruptible revenues for transportation on the High Desert Lateral to the cost of service for the High Desert Lateral. Kern River increased the market-oriented revenue (MOR) credit by $2.9 million, reflecting the elimination of Kern River's proposed decrease to its MOR credits due to the implementation of a blended fuel rate for interruptible and authorized overrun services. In addition, Kern River eliminated the three percent annual inflation adjustment to operation and maintenance (O&M) and general and administrative (G&A) costs from the calculation of the levelized annual cost of service. Kern River calculated its blended cost of debt using 8.455 percent as the cost of the Series A debt issue, resulting in a weighted average cost of debt of 6.214 percent. Kern River states that it included the depreciation of Mars turbine compressor engines and general plant in its levelization calculations. In addition, Kern River allocated Utah compressor fuel taxes to mainline services only. Kern River also adjusted its Account 928, Regulatory Commission Expense, to reflect a five-year amortization of the base and test period total for such costs.

128. Kern River states that it adjusted the proposed book depreciation rates to 1.95 percent for the Rolled-in System transmission plant, and 3.0 percent for the 2003 Expansion plant. Kern River also provides a net negative salvage rate of 0.12 percent applicable to transmission plant and a book depreciation rate of 9.92 percent for the Mars turbine compressor engines. Kern River also proposes to reflect a book depreciation rate of 1.95 percent for the Contribution in Aid of Construction related to the Blue Diamond delivery point.

129. Kern River's revised compliance filing includes rates for both Periods One and Two. The Period One rates are levelized, consistent with Opinion No. 486's approval of Kern River's proposal in this rate case to continue using the rate levelization methodology approved in its original certificate and subsequent proceedings. Kern River states that it calculated the rates for the Locked-in Period of Period One by taking the "higher of" the (1) rates calculated in accordance with Opinion Nos. 486, 486-A and 486-B; or (2) the last clean rate, which is the last rate approved by the Commission that is not subject to refund. Kern River submitted multiple tariff sheets applicable to different portions of the Locked-in Period. Kern River asserts that it calculated the prospective

rates applicable in Period One in accordance with Opinion Nos. 486, 486-A, and 486-B, to be effective on the date the Commission issues a final order in this proceeding.

130. As required by Opinion No. 486, Kern River also included in its filing proposed Period Two Rates to take effect when the contracts of Kern River's long-term, firm shippers expire. Despite the fact it proposed levelized rates for Period One in this rate case, Kern River proposes traditional rates for Period Two. In conjunction with these rates, Kern River also proposes a new section 30 of the General Terms and Conditions (GT&C) of its tariff. The new section 30 sets forth definitions for Periods One and Two and the qualifications necessary for a Shipper to be "eligible" for Period Two rates.[184] Section 30 also describes the conditions applicable to the eligible Period Two shippers[185] and when Period Two Rates will be available to the applicable shipper group.[186]

[184] Kern River defines an "eligible shipper" as a "Shipper (or its successor, assignee, or permanent replacement shipper) that has paid the maximum applicable levelized rate for a full 10-year or 15-year term." Proposed Original Sheet No. 230, Section 30.1(c).

[185] For example, Kern River proposes that an eligible shipper that wishes to retain its capacity at the end of Period One must enter into a new, standard form firm transportation service agreement under Rate Schedule KRF-1 and must notify Kern River in writing of its intent to enter into a Period Two transportation service agreement not less than 12 months prior to the expiration of its Period One transportation service agreement. Proposed Original Sheet No. 230, Section 30.2(a) and (b).

[186] Kern River states that this new section will describe the shippers that will be eligible for Period Two (Step-Down Rates) and when each Step-Down Rate will be available to the applicable shipper group. *See* Appendix B, Sheet Nos. 230 - 231. Kern River states that the Step-Down Rates will become effective as follows: (1) October 1, 2011, the 10-year, Rolled-in System Step-Down Rate is available to Original System shippers whose contracts expire on September 30, 2011; (2) May 1, 2012, 10-year, Rolled-in System Step-Down Rate is available to 2002 Expansion shippers whose contracts expire on April 30, 2012; (3) October 1, 2016, the 15-year, Rolled-in System Step-Down Rate is available to Original System shippers whose contracts expire on September 30, 2016; (4) May 1, 2017, 15-year, Rolled-in System Step-Down Rate is available to 2002 Expansion shippers whose contracts expire on April 30, 2017; (5) May 1, 2013, 10-year, 2003 Expansion Step-Down Rate is available to 2003 Expansion shippers whose contracts expire on April 30, 2013; (6) May 1, 2018, 15-year, 2003 Expansion Step-Down Rate is available to 2003 Expansion shippers whose contracts expire on April 30, 2018.

131. Finally, Kern River explains that pursuant to Section 2 of Article 5 of the Settlement, Kern River paid refunds to settling parties equal to the difference between the amounts collected from such parties for firm service from November 1, 2004 through August 31, 2008, and the amounts Kern River would have collected for those services under the Locked-in Period Rates. Kern River further explains that Opinion No. 486-B directed Kern River to recapture the interim refunds previously made at the earliest practical date. Kern River states that in compliance with Opinion No. 486-B, on January 22, 2009, Kern River mailed to each settling party a letter agreement addressing the repayment of refunds. In the letter, Kern River gave settling parties the option to either (1) postpone repayment of the early refund and use that amount to offset any additional refunds Kern River may be required to pay after a final order; or (2) repay the refund within 15 days of the receipt of the letter. Kern River states that no shippers opted to repay Kern River immediately.

C. March 27, 2009 Compliance Filing

132. On March 27, 2009, Kern River filed a supplemental compliance filing in Docket No. RP04-274-018 to (1) submit two tariff sheets that were inadvertently omitted from Kern River's January 30, 2009 filing; and (2) correct the pagination of two sheets filed in the March 2, 2009 compliance filing.

D. September 22, 2009 Compliance Filing

133. On September 22, 2009, Kern River submitted a filing to correct certain aspects of the March 2, 2009 compliance filing. Specifically, Kern River revised its Period One and Period Two Rates to reflect corrected costs of service for the corresponding periods. Kern River states that the corrections result in an overall reduction in Kern River's cost of service. Kern River explains that while the cost of service in Period One increases by $1.1 million, it is offset in Period Two by a reduction in cost of service of $14.1 million.[187]

134. Kern River states that errors were discovered during a detailed internal review of Kern River's treatment of regulatory vs. book depreciation, which then necessitated a comprehensive review of Kern River's levelization models. As a result, Kern River determined it has made certain calculation errors that impact the cost of service and rates presented in the March 2, 2009 compliance filing.

[187] Kern River also states, in its September 22, 2009, filing that to promote administrative efficiency, it also submits a complete restatement of its March 2, 2009 compliance filing in its entirety, including the March 2, 2009 Transmittal letter. *See* Kern River's September 22, 2009 Transmittal Letter at 5-6.

135. The first correction Kern River made was to apply the book depreciation rate for transportation plant to calculate book depreciation expense related to compressor engines and general plant, instead of the higher book depreciation rates approved in Opinion No. 486 for compressor engines and general plant.[188] Kern River states that because compressor engines and general plant are included in levelization in Period One, this error had no effect on the Period One cost of service and rates in the March 2, 2009 compliance filing. However, Kern River states that the traditional, Period Two costs of service presented in the March 2, 2009 compliance filing for all services should have been computed utilizing the prescribed book depreciation rates for each individual plant category to match the straight line book depreciation expense recorded for transmission plant, compressor engines, and general plant, respectively, during Period Two.

136. Second, Kern River states that in order to appropriately calculate Period Two rates, it must extrapolate the balance of the regulatory liability associated with levelized depreciation at the beginning of Period Two, using the difference between the accumulated book depreciation amounts and the cumulative levelized depreciation amounts collected in rates through the end of Period One. Kern River states that it incorrectly included a regulatory asset related to levelized depreciation for compressor engines and general plant, both separately and in the overall calculation of the regulatory liability. Kern River states that the double-count of these amounts caused the rate base for Period Two to be overstated.

137. Third, Kern River states that it failed to account for the fact that Period One for the 2002 Expansion rolled-in shippers ends seven months later than Period One for the Original System (vintage) shippers. Because of this, Kern River states that it incorrectly calculated the deferred taxes, the regulatory liability and the amortization period of the regulatory assets and liabilities for Period Two for rolled-in shippers.

138. Fourth, Kern River states that it incorrectly applied to general plant and compressor engines, as well as to transmission plant, the negative salvage rate approved in Opinion No. 486. Kern River states that this oversight caused the cost of service for the rolled-in shippers to be slightly overstated in Period One and slightly understated in Period Two, and caused the cost of service for 2003 Expansion shippers to be slightly understated in Period One and Period Two. Kern River states that the removal of the incorrect negative salvage expense related to compressor engines and general plant, as a result of levelization, increases rate base during both Period One and Period Two.

139. Fifth, Kern River states that it misapplied the remaining economic life adopted by the Commission in its calculations of amortization in Period Two of the regulatory liability arising from levelization in Period One. Kern River states that it has corrected

[188] Opinion No. 486, 117 FERC ¶ 61,077 at P 57.

the rates to reflect the application of the 35-year remaining economic life adopted by the Commission, measured from November 1, 2004.

140. Sixth, Kern River found two regulatory assets associated with restaged compressors and the South Georgia adjustment to be incorrectly included in the cost of service for the 15-year 2002 Expansion shippers. Kern River states that these assets will be fully amortized before Period Two for the 15-year 2002 Expansion shipper group commences. Kern River states that these regulatory assets should have been removed from rate base and the amortization removed from the Period Two cost of service for the 15-year 2002 Expansion shipper group to be effective May 1, 2017.

141. Seventh, Kern River states that the effective tax rate applied to the cumulative timing differences at October 31, 2004 in calculating the accumulated deferred income taxes was not consistent with the effective tax rate applied to the amortization of those cumulative timing differences. Kern River asserts that state limitations on utilization of net operating losses and bonus depreciation result in tax rates different from the overall blended income tax rate. Kern River states that it used an overall blended rate of 38.12 percent in the amortization of the cumulative timing differences, rather than the specific tax rates. Kern River states that this inconsistency resulted in an understated rate base calculation for Period One and Period Two. Kern River states that in addition, it made an adjustment to utilize the deferred tax asset related to the net operating loss for the Big Horn Lateral.

142. Eighth, Kern River states that its calculation of deferred income tax expense for the 15-year 2003 Expansion shippers incorrectly pro-rated the book depreciation expense for four months in the final year, even though it had already been pro-rated for those four months. Kern River states that this calculation error had the impact of doubling and thus overstating the deferred income tax liability, and thereby understating rate base during Period One and at the beginning of Period Two.

143. Kern River states that as a result of these corrections, for Period One, there is a net increase in Kern River's cost of service and a corresponding increase in rates for all shipper groups ranging from $0.0003 to $0.0029/dekatherm (dth). However, Kern River states that it proposes to continue to bill the interim rates currently in effect until a final order is issued, so there will be no immediate impact for shippers.

144. Kern River states that for Period Two, its corrections result in a net reduction in Kern River's proposed cost of service and a corresponding decrease in rates for three of the four shipper groups, ranging from $0.0092 to $0.0391/dth. Kern River states that there is an increase of $0.0011/dth for the 10-year 2003 Expansion shipper group. However, Kern River explains that this rate will not take effect until 2013.

E. <u>Notice</u>

145. Notice of Kern River's March 2, 2009 compliance filing in Docket No. RP04-274-017 was issued on March 10, 2009. Notice of Kern River's supplemental compliance filing in Docket No. RP04-274-018 was issued on March 31, 2009. Comments were due as provided in section 154.210 of the Commission's regulations, 18 C.F.R. § 154.210 (2009). BP, Calpine Energy Services, L.P. (Calpine), Nevada Power Company (Nevada), Questar, RCG, Southwest, and Williams filed protests. BP, Kern River, and RCG filed answers.

146. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2009), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We will accept the answers filed by BP, Kern River, and RCG because they have provided information that assisted us in our decision-making process.

147. Notice of Kern River's September 22, 2009 compliance filing in Docket No. RP04-274-019 was issued on September 25, 2009. On October 5, 2009, the Commission granted parties an extension for filing comments on Kern River's corrected compliance filing to October 15, 2009. BP filed a protest. Calpine, Nevada, Questar, and RCG filed comments requesting expedited action on the compliance filings in order to make the prospective rate reductions resulting from this rate case effective as soon as possible. On October 20, 2009, the Commission issued a notice providing parties with an opportunity to file answers by October 30, 2009. Kern River filed an answer to BP's protest.

F. <u>Discussion</u>

148. The Commission accepts Kern River's revised compliance filing as it applies to the Period One Rates, subject to conditions. The Period One Rates for the Locked-in Period are effective as of the dates stated in the tariff sheets and the prospective Period One Rates are effective the date of the issuance of this order.[189] Finally, the Commission holds that Kern River must offer its long-term firm shippers levelized Period Two Rates, and the Commission establishes a hearing to consider all other issues concerning the calculation of Period Two Rates and the terms and conditions which shippers must satisfy in order to be eligible for the levelized Period Two Rates. The Commission will, however, hold such hearing in abeyance for settlement judge procedures. Because Kern River has filed tariff sheets that are not based upon a levelized methodology for its Period Two Rates, the tariff sheets it has filed with respect to Period Two are rejected as

[189] *See* Appendix C.

discussed below,[190] and the Commission requires Kern River to file *pro forma* tariff sheets setting forth a revised Period Two rate proposal consistent with the discussion in this order.

1. Period One Rates

a. Effective Date of 95 Percent Load Factor Condition

149. When the Commission certificated Kern River's Original System under the optional expedited procedures adopted in Order No. 436, the Commission required Kern River to design its rates based on volumes equal to 95 percent of its design capacity.[191] This has been referred to as the 95 percent load factor condition. In the Original Certificate Proceeding, the Commission also required that Kern River make a filing three years after its in-service date either justifying its existing rates or proposing alternative rates, and that the filing "must use the same or greater throughput levels on which Kern River's initial rates have been predicated."[192]

150. Since at least 2002, Kern River has had firm contracts for 100 percent of the capacity of its Original System.[193] Nevertheless, in this case, Kern River proposed to design its rates for Original System firm shippers using reservation and usage billing determinants equal to 95 percent of the design capacity of its Original System, arguing that the 95 percent load factor condition capped its billing determinants at that level. In Opinion No. 486, the Commission rejected Kern River's proposal to design its Original System rate using billing determinants equal to 95 percent of its design capacity.[194] Instead, the Commission required Kern River to use reservation billing determinants equal to 100 percent of Kern River's design capacity and usage billing determinants equal to its actual throughput over the last 12 months of the test period. The Commission agreed that the 95 percent load factor condition imposed in the Original Certificate Proceeding was a part of the allocation of risks as between the pipeline, its customers and lenders approved by the Original Certificate Order, and therefore Kern River's rates for Original System shippers should be designed consistent with that condition. However, the Commission held that the condition is only a floor under Kern River's Original

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[190] *See* Appendix D.

[191] Original Certificate Order, 50 FERC ¶ 61,069, at 61,150 (1990).

[192] *Id.* at 61,151.

[193] Ex. S-27 at 18; S-22.

[194] Opinion No. 486, 117 FERC ¶ 61,077 at P 86.

System billing determinants, and not a ceiling. In reaching this conclusion, Opinion No. 486 relied in part on the fact that the Original Certificate Order also required Kern River to make a tariff filing three years after its in-service date using "the same *or greater* throughput levels on which Kern River's initial rates have been predicated."[195] Opinion No. 486-A reaffirmed this holding.

i. <u>Kern River's Compliance Filing</u>

151. In its March 2, 2009 compliance filing, Kern River proposes to implement Opinion No. 486's holding concerning the 95 percent load factor condition on a prospective only basis. Thus, it calculated refunds for the Locked-in Period based on billing determinants equal to only 95 percent of the design capacity of the Rolled-in System.

ii. <u>Protests</u>

152. BP and RCG argue that the elimination of the 95 percent load factor cap on the Rolled-in System billing determinants should be effective November 1, 2004, the date the proposed rates in this case were placed into effect. BP and RCG state that Kern River's prospective-only implementation of Opinion No. 486's holdings concerning the 95 percent load factor condition is inconsistent with section 4 of the NGA and Commission precedent.

153. BP and RCG explain the Commission has stated that "by filing [a] rate increase, a gas company assumes the risk of having to justify its entire rate structure… including integral provisions of that structure which the company does not propose to change."[196] BP and RCG assert that billing determinants are integral to Kern River's rate structure. The parties contend that Kern River failed to meet its NGA section 4 burden with respect to the proposed billing determinants, and therefore, the elimination of the 95 percent load factor adjustment should be applied retroactively to November 1, 2004.

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[195] Original Certificate Order, 50 FERC ¶ 61,069, at 61,151 (1990) (emphasis added).

[196] *Colorado Interstate Gas Co. v. FERC*, 791 F.2d 803, 807 (10th Cir. 1986), *cert. denied*, 479 U.S. 1043 (1987). *See also Tennessee Gas Pipeline Co.*, 94 FERC ¶ 61,117, at 61,447 (2001) (stating the pipeline has the burden of proof on the throughput used to design its rates).

iii. Kern River's Response

154. Kern River argues that it properly implemented the rate design changes prospectively in the March 2, 2009 compliance filing. Kern River contends that Opinion No. 486 abrogated the Commission's previous interpretation of the 95 percent load factor condition. Kern River argues that since it is not proposing in this rate case a change to its 95 percent load factor rate design approved in the Original Certificate Proceeding, the Commission's order in Opinion No. 486 may only be implemented in accordance with section 5(a) of the NGA. As such, Kern River argues that any rate design changes are to be applied on a prospective basis.

iv. Commission Determination

155. The Commission finds that Kern River's rates for the Locked-in Period, commencing November 1, 2004, must be designed based on projected units of service, as required by Opinion No. 486, subject only to the refund floor established by the rates in effect before this rate case.

156. When a pipeline files a rate increase under NGA section 4, the pipeline bears the burden of proving the justness and reasonableness of its proposed increase.[197] This includes proving that all of the cost and throughput components of the rate increase in the filing are just and reasonable under NGA section 4, even when the pipeline has not proposed to change certain of those components.[198] Whatever changes to the various rate components that are ultimately approved by the Commission will take effect retroactively to the date the filed rates were suspended and placed into service, subject to refund.

157. Kern River's assertion that, in this rate case, it proposed to continue to apply the same 95 percent load factor condition approved in the Original Certificate Proceeding is directly contrary to the Commission's holdings in Opinion Nos. 486 and 486-A. As the Commission found in those opinions, nothing in the Original Certificate Orders supports Kern River's assertion that the 95 percent load factor condition capped its rate design volumes.[199] In Kern River's Original Certificate Proceeding, the Commission stated that Kern River's next tariff filing "must use the same or greater throughput levels on which Kern River's initial rates have been predicted,"[200] indicating that the 95 percent load

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[197] *Dominion Transmission Inc.*, 93 FERC ¶ 61,272, at 61,881 (2000).

[198] *Northern Border Pipeline Co.*, 89 FERC ¶ 61,185, at 61,575 (1999). *See also Northwest Pipeline Corp.*, 92 FERC ¶ 61,287, at 62,012 (2000).

[199] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 75.

[200] Original Certificate Order, 50 FERC ¶ 61,069, at 61,150 (1990).

factor condition did not cap Kern River's rate design volumes at that time or subsequently. The Commission affirmed this interpretation in Opinion No. 486 when it rejected Kern River's assertion that the 95 percent load factor is a billing determinant ceiling.[201] Opinion No. 486 explained that the 95 percent load factor condition requires Kern River to calculate its Original System rates based upon *at least* 95 percent of its design capacity.[202] Opinion No. 486 further clarified that because the 95 percent load factor condition only established a floor on Kern River's rate design volumes, Kern River's rates should be derived "based on projected units of service."[203] Moreover, both of Kern River's rate cases immediately preceding this one settled, with the parties agreeing to design its rates using reservation billing determinants equal to 95 percent of the Original System's design capacity.[204]

158. Despite the Commission's determinations in the Original Certificate Proceeding and Opinion No. 486, and its use of somewhat higher billing determinants in the last rate case, Kern River proposed rates in its April 30, 2004 filing that were designed using billing determinants equal to 95 percent of the design capacity of its Original System. However, Kern River did not meet its burden to prove under NGA section 4 that the use of those billing determinants to design its rates was just and reasonable and not unduly discriminatory. Therefore, the Commission finds that Kern River's rates must be designed using projected units of service, as required by Opinion No. 486, commencing on November 1, 2004, the date the Commission accepted and suspended, subject to refund, the rates in this proceeding. However, this ruling is subject to the caveat that Kern River need not reduce its rates for any customer class for the period prior to the date of this order below those approved in the last rate case. The Commission directs Kern River to submit a compliance filing within 45 days of this order properly implementing this holding.

b. <u>Billing Determinants Used for Allocating Costs and Calculating Per-Unit Rates for the Rolled-in System</u>

i. <u>Opinion No. 486</u>

159. As described above, Opinion No. 486 rejected Kern River's proposal to design its rates for Rolled-in System firm shippers using reservation and usage billing determinants

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[201] Opinion No. 486, 117 FERC ¶ 61,077 at P 77.

[202] *Id.*

[203] *Id*. P 84.

[204] *Id*. P 82.

equal to 95 percent of the design capacity of its Original System facilities. The Commission stated that rates for the Rolled-in System should be designed based on projected units of service, consistent with the Commission's ordinary test period methodology, to the extent those projected units of service exceed the 95 percent load factor condition.[205] The Commission explained that rates for pipelines are based on actual data for a one-year base period, as adjusted to reflect known and measurable changes that will occur within the following nine months (adjustment period). The Commission stated that in the present case, Kern River conceded that during the test period it had firm contracts for 100 percent of its Original System capacity and that Kern River pointed to no known and measurable change that occurred during the test period that would justify reducing its projected units of service below that level.[206]

ii. <u>Kern River's Compliance Filing</u>

160. In the March 2, 2009 compliance filing, Kern River used actual reservation billing determinants of 639,570 dth to design the per-unit prospective rates for the 10-year and 15-year Rolled-in System shippers.[207] Kern River states that this amount equals the design capacity of the Rolled-in System, plus an amount equal to the annualized contract demand under three 15-year contracts for seasonal firm service utilizing the rolled-in facilities.[208]

161. However, when allocating costs of the rolled-in facilities between the 10-year and 15-year shippers, Kern River used projected units of service of 624,416 dth for the 15-year shippers. That amount includes the design capacity of the Rolled-in System, but excludes the contract demands of the three 15-year seasonal contracts.

iii. <u>Protests</u>

162. BP argues the Commission should direct Kern River to include the contract demand for the three 15-year seasonal firm contracts in the reservation billing determinants for both (a) allocating costs between the 10-year and 15-year Rolled-in System shippers, and (b) calculating the per-unit rates for the 10-year and 15-year Rolled-in System shippers. BP states that although prior to Opinion No. 486, Kern River's firm

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[205] Opinion No. 486, 117 FERC ¶ 61,077 at P 84.

[206] *Id.* (citing Ex. KR-86 at 12).

[207] Kern River's March 2, 2009 Compliance Filing, Statement I-3 at 2.

[208] *Id.* The annualized contract demand for the three 15-year contracts for seasonal firm service utilizing the rolled-in facilities that Kern River used is 15,154 dth.

transportation rates for the Rolled-in System were based on a 95 percent load factor, the Commission terminated the use of the 95 percent load factor condition as a billing determinant ceiling in Opinion No. 486, and held that Kern River's rates should be designed based on projected units of service. BP argues that the holding in Opinion No. 486 is consistent with the Commission's regulations.[209]

163. BP contends that the rates for each class of Rolled-in System shippers in Kern River's compliance filing are not consistent with Opinion No. 486 because Kern River failed to include the projected units of service associated with several 15-year seasonal contracts when Kern River allocated costs between 10-year and 15-year Rolled-in System shippers. BP asserts that the lower the level of 15-year billing determinants used to allocate costs between 10-year and 15-year Rolled-in System shippers, the lower the proportion of costs allocated to 15-year contracts, and therefore the higher the remaining proportion of costs allocated by default to 10-year contracts. BP argues that the 10-year Rolled-in System shippers' rates, which reflect an inflated share of costs based on an artificially decreased level of 15-year projected units of service, do not satisfy the requirement that the rates must reflect projected units of service.

iv. Kern River's Response

164. Kern River argues that it used the allocation factors and billing determinants approved by the Commission to calculate the rates for the Rolled-in System. Kern River acknowledges that Opinion No. 486 directed it to design its rates for rolled-in firm transportation service on the basis of reservation billing determinants of 639,570 dth.[210] However, Kern River argues that BP's assertion that Kern River should have made the same change in the reservation billing determinants it used to allocate the costs of rolled-in facilities between 10-year and 15-year shippers is without merit.

165. Kern River argues that by raising this issue, BP is improperly attempting to raise a new issue during the compliance stage of this proceeding. Kern River contends the record demonstrates that neither BP nor any other party contested Kern River's allocation factors for apportioning costs between 10-year and 15-year rolled-in services prior to the issuance of Opinion No. 486. Kern River further asserts that its position on the matter

[209] 18 C.F.R. § 284.10(b)(3) (2009); 18 C.F.R. § 284.10(c)(2) (2009).

[210] Kern River states that its proposed billing determinants represent 95 percent of the annual design capacity of its Original System facilities. Kern River asserts that the greater quantity prescribed by the Commission equals the design capacity of the Rolled-in System, plus an amount equal to the annualized contract demand under three 15-year contracts for seasonal firm service utilizing the rolled-in facilities. Kern River's April 14, 2009 Answer at 14 (citing Ex. KR-119, Datafile.xls, General Data Tab (Protected Materials)).

was well known prior to the March 2, 2009 compliance filing because the cost of service models included in that filing are the third set of working models that use billing determinants representing 95 percent of the annual design capacity of its Original System facilities. Kern River maintains that BP's argument constitutes an improper collateral attack on Opinion No. 486 that should have been raised on rehearing of Opinion No. 486.

166. In addition, Kern River states BP's contention that, prior to the March 2, 2009 compliance filing, Kern River consistently used the same billing determinants for cost allocation and rate design for the rolled-in services, is erroneous. Kern River states that in its Original Rate Case Filing and its 45-day update, it allocated costs between 10-year and 15-year rolled-in shippers based on 100 percent load factor reservation billing determinants, and designed rates on 95 percent billing determinants. Hence, Kern Rivers contends that its use of 100 percent load factor determinants for allocating costs between the 10-year and 15-year rolled-in services in the March 2, 2009 compliance filing is consistent with Kern River's prior practice and with the Commission's rulings.

v. <u>Commission Determination</u>

167. The Commission finds that it is unjust and unreasonable for Kern River to use different reservation billing determinants for allocating costs between the 10-year and 15-year Rolled-in System shippers and for calculating the per-unit rates for the same shippers.

168. In Opinion No. 486, the Commission stated that Kern River must design its rates using billing determinants based on 100 percent of Kern River's design capacity.[211] Consistent with this directive, in the March 2, 2009 compliance filing, Kern River designed its rates for rolled-in firm transportation services on the basis of reservation billing determinants of 639,570 dth. However, when allocating costs between the 10-year and 15-year Rolled-in System shippers, Kern River used reservation billing determinants of 624,416 dth for the 15-year shippers.

169. BP argues that Kern River's use of one set of reservation billing determinants for allocating costs and another for designing rates is inappropriate and results in a disproportionate allocation of costs to the 10-year shippers. The Commission agrees. All aspects of Kern River's Rolled-in System rate design, including allocation of costs, should be based on the same reservation billing determinants.

170. In the Original Rate Case Filing, Kern River proposed to design its rates using reservation and usage billing determinants equal to 95 percent of the design capacity of its Original System facilities. Kern River states in its answer that it also proposed in the

[211] Opinion No. 486, 117 FERC ¶ 61,077 at P 84.

Original Rate Case Filing to allocate costs between the 10-year and 15-year rolled-in shippers based on 100 percent load factor reservation billing determinants. In Opinion No. 486, the Commission rejected Kern River's interpretation of the 95 load factor condition and ordered Kern River to increase its billing determinants for purpose of designing rates; however, nothing in Opinion No. 486 permitted Kern River to change how it allocated costs between 10-year and 15-year shippers. Thus, it was improper for Kern River in its March 2, 2009 compliance filing to lower the amount it previously used for cost allocation in the Original Rate Case Filing.

171. Moreover, Kern River's argument that parties should have raised this issue earlier holds little merit. As Kern River acknowledged in its answer, it did not change how it allocated costs between the 10-year and 15-year rolled-in shippers until the compliance stage of this proceeding, so there was no opportunity for parties to raise the issue earlier. Thus, consistent with the approach proposed in the Original Rate Case Filing, the Commission directs Kern River to use the actual reservation billing determinants of 639,570 dth for allocating costs between the 10 and 15-year Rolled-in System shippers, as well as for the purpose of designing per-unit rates for those shippers.

c. Date of Implementation of SFV Rate Design

172. In 1992, the Commission restructured the gas industry in Order No. 636.[212] As part of its restructuring, it adopted the SFV method of rate design. Consequently, the Commission amended its regulations to require pipelines to recover their transportation costs under the SFV method.[213] Under SFV, a pipeline collects all of its fixed costs for firm transportation service, including ROE, through the reservation charge. It collects only variable or usage costs through its usage rate.

173. In 1993, the Commission ordered Kern River to use the SFV rate design in accordance with Order No. 636.[214] On March 31, 1999, Kern River filed a settlement

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[212] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636**,** FERC Stats. & Regs. ¶ 30,939, *order on reh'g*, Order No. 636-A**,** FERC Stats. & Regs. ¶ 30,950, *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *order on reh'g*, 62 FERC ¶ 61,007 (1993), *aff'd in part and remanded in part sub nom. United Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

[213] 18 C.F.R. § 284.7(e) (2009).

[214] *See Kern River Gas Transmission Co.*, 62 FERC ¶ 61,191, at 62,256-58 (1993), *reh'g denied*, 64 FERC ¶ 61,049 (1993), *aff'd*, *Union Fuels v. FERC*, 129 F.3d 157 (D.C. Cir. 1997).

(1999 Settlement) proposing, among other things, to depart from the SFV rate design and instead use an Enhanced Fixed Variable (EFV) rate design. The Commission approved the 1999 Settlement.[215]

174. In this proceeding, Kern River proposed to continue to depart from the SFV rate design and use its EFV rate design. On May 28, 2004, the Commission accepted and suspended Kern River's proposed EFV rates subject to refund, conditions, and hearing.[216] The rates went into effect November 1, 2004.[217] However, upon further examination, in Opinion No. 486, the Commission rejected Kern River's proposal to continue using its EFV rate design and ordered Kern River to use the SFV rate design.[218]

175. Kern River's March 2, 2009 compliance filing proposes to implement the SFV rate design change on a prospective basis.

i. BP's Protest

176. BP argues that Kern River must implement the SFV rate design as of November 1, 2004. BP states that since 1992 and the implementation of Order No. 636, Commission policy has required that natural gas pipeline rates be designed on the SFV method of assigning all fixed costs related to transportation to the reservation charge. BP further notes that in 1993, the Commission stated that "the requirement that pipelines shift to an SFV rate design [is] fully applicable to Kern River."[219] BP explains that as a result, the SFV rate design was utilized on Kern River until the shippers agreed to deviate from SFV and implement the EFV rate design in the 1999 Settlement.

177. BP argues that when the 1999 Settlement expired on November 1, 2004 and Kern River began collecting the rates it proposed in the instant proceeding, the SFV rate design should have been implemented on Kern River, consistent with Commission policy. BP

[215] *Kern River Gas Transmission Co*., 90 FERC ¶ 61,124 (2000); *Kern River Gas Transmission Co*., 98 FERC ¶ 61,245 (2002).

[216] *Kern River Gas Transmission Co*., 107 FERC ¶ 61,215 (2004), *order on reh'g*, 109 FERC ¶ 61,060 (2004).

[217] *Kern River Gas Transmission Co.*, Docket No. RP04-274-000 (October 27, 2004) (unpublished letter order).

[218] Opinion No. 486, 117 FERC ¶ 61,077 at P 308-10.

[219] BP's March 31, 2009 Protest at 11 (citing *Kern River Gas Transmission Co.*, 64 FERC ¶ 61,049, at 61,414 (1993); *Kern River Gas Transmission Co.*, 62 FERC ¶ 61,191, at 62,261-62 (1993)).

states that where existing Commission policy, as it applies to the pipeline at the time it files its proposed rate changes, makes the resulting rates unjust and unreasonable, the pipeline does not have a reliance interest in existing rates, and should expect retroactive changes.[220] BP argues the implementation of the SFV rate design on Kern River's system as of November 1, 2004, is legally mandated given the termination on that date of the 1999 Settlement's limited dispensation from the Commission's prior requirement that Kern River use SFV.

178. BP argues that here it was legal error for the Commission to allow Kern River to implement rates designed upon EFV when Kern River was obligated to observe SFV. BP argues that when the Commission commits legal error in exercising its remedial powers under NGA sections 4 and 5, it must order refunds to put parties where they would have been had the Commission not committed legal error.[221] Accordingly, BP argues that the Commission should require Kern River to calculate its rates using the SFV method from November 1, 2004 forward.

ii. <u>Kern River's Answer</u>

179. Kern River argues that it properly implemented the rate design change to SFV prospectively in the March 2, 2009 compliance filing. Kern River asserts that the change in rate design from EFV to SFV ordered in Opinion No. 486 was a change imposed by the Commission, and not proposed by Kern River. Kern River contends that pursuant to section 5(a) of the NGA,[222] such changes may only be lawfully implemented prospectively from the date of the Commission's final order in this proceeding.[223] Kern River states that such an order has not yet been issued and will not occur until the Commission takes final action on the March 2, 2009 compliance filing. Therefore, Kern River asserts that in the March 2, 2009 compliance filing, it properly calculated the Period One Rates based on the EFV rate design remaining in effect for the Locked-in Period, i.e., from November 1, 2004, until the date of the Commission's final order establishing new rates for Kern River's services.

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[220] *Id.* at 13 (citing *East Tennessee Natural Gas Co. v. FERC*, 863 F.2d 932, 943 (D.C. Cir. 1988)).

[221] *Id.* at 14 (citing *Great Lakes Gas Transmission LP*, 75 FERC ¶ 61,089, at 61,286 (1996)).

[222] Kern River's April 15, 2009 Answer at 4 (citing 15 U.S.C. § 717d(a) (2009)).

[223] *Id.* (citing *ANR Pipeline Co. v. FERC*, 771 F.2d 507, 513-14 (D.C. Cir. 1985) (stating that the proponent of "an alteration in an unchanged part of a proposed higher rate" must satisfy the requirements of section 5(a) to prevail)).

iii. Commission Determination

180. The Commission finds that Kern River properly implemented the SFV Rate design on a prospective basis in its March 2, 2009 compliance filing.

181. When Kern River filed its rate case in this proceeding, it proposed to continue the EFV rate design implemented under the 1999 Settlement. However, in Opinion No. 486, the Commission rejected this proposal and directed Kern River to design its rates using the SFV methodology. Thus, the change in rate design in this proceeding was not proposed by Kern River, but was imposed by the Commission.

182. When the Commission seeks to impose its own rate determinations – rather than to accept or reject a change proposed by the company – the Commission must act under NGA section 5(a).[224] The Commission is limited to ordering prospective changes in pipeline rates when it acts under NGA section 5(a), as it did in this case.[225]

183. BP argues that because the Commission previously determined Kern River should use the SFV rate design, it was legal error for the Commission to allow the rates designed using the EFV methodology to go into effect, subject to refund. We disagree. It was not legal error for the Commission to accept and suspend, subject to refund, the EFV rates that Kern River originally proposed in this proceeding. While the Commission did order Kern River to implement the SFV rate design in 1993 in response to Order No. 636,[226] this is a different proceeding with a different set of facts. Here, the Commission was obligated to consider Kern River's proposal and determine if the rates and rate design were just and reasonable. Given that Kern River had been designing its rates using the EFV methodology for many years prior to this case pursuant to the 1999 Settlement, it was not legal error for the Commission to consider Kern River's proposal to continue such a rate design and accept the rates subject to refund.

184. Moreover, no party sought rehearing of the Commission's decision to accept Kern River's proposed rates based on the EFV rate design in the May 28, 2004 suspension order. Given that BP did not argue on rehearing that the Commission committed legal error by failing to order Kern River to immediately implement SFV rates, it cannot now

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[224] *See ANR Pipeline Co. v. FERC*, 771 F.2d 507, 513-14 (D.C. Cir. 1985).

[225] *Williston Basin Interstate Pipeline Co.*, 69 FERC ¶ 61,360, at 62,362-3 (1994).

[226] *Kern River Gas Transmission Co.*, 62 FERC ¶ 61,191, at 62,256-58 (1993), *reh'g denied*, 64 FERC ¶ 61,049 (1993), *aff'd*, *Union Fuels v. FERC*, 129 F.3d 157 (D.C. Cir. 1997).

proffer such an argument. For these reasons, we find that it was proper for Kern River to implement the SFV rate design prospectively in its March 2, 2009 compliance filing.

d. Locked-in Period Rates and Last Clean Rate Doctrine

185. In this rate case, Kern River's proposed EFV rates increased both the reservation and usage components of its preexisting rates. In its March 2, 2009 compliance filing, Kern River proposed rates for the Locked-in Period, i.e., the period from November 1, 2004 to the date the prospective rates become effective, based on a continuation of the EFV rate design. Kern River asserted that, while full implementation of the merits rulings in Opinion Nos. 486, 486-A, and 486-B will result in an overall rate decrease from its rates in effect before this rate case, those merits rulings do not affect its proposed small increase in the EFV usage charge.[227] Rather, the entire overall rate decrease arises from a reduction in the EFV reservation charges for most customer groups below the level of the EFV reservation charge in effect before this rate case.

186. In these circumstances, Kern River asserts that each component of its rates for the Locked-in Period should be the higher of (1) that rate component as in effect before this rate case (the "last clean rate" not subject to refund) or (2) the same rate component found just and reasonable in this rate case. Thus, for the Locked-in Period, Kern River asserts its usage charge should be the $0.06/dth usage rate it proposed in this rate case, which it states Opinion Nos. 486, 486-A, and 486-B approved. However, Kern River asserts its reservation charges for the Locked-in Period for all customer groups other than the 10-year Rolled-in System shippers determined pursuant to Opinion Nos. 486, 486-A, and 486-B are lower than the reservation charges in effect before this rate case. Thus, it argues that the reservation charges for the Locked-in Period for the non-10 year rolled-in system shippers should be the preexisting reservation charges. Kern River asserts that this result is required by the provision in NGA section 4 that the Commission may not order refunds below the level of the last approved rates.

i. Protests

187. Calpine and RCG request that the Commission reject Kern River's proposed rates for the Locked-in Period, i.e., the period from November 1, 2004 to the date the prospective rates become effective. The parties argue that Kern River erred in determining the Locked-in Period Rates based upon a comparison of each rate component to the last clean rate, instead of using an overall rate comparison.[228] The parties state

[227] Before this rate case, Kern River's usage charge was $0.058/dth for firm rolled-in system service and $0.0573/dth for firm 2003 Expansion service. In this rate case, Kern River proposed to increase its usage charge to $0.06/dth for all firm services.

[228] The parties state that Schedule J-2 of Kern River's March 2, 2009 compliance (continued …)

that, in some cases, this approach leads to a hybrid rate for the Locked-in Period, where the usage charge is from the rate Kern River asserts has been approved in this rate case and the reservation charge is from the last clean rate.

188. Calpine and RCG explain that as a practical matter, the Locked-in Period Rates correspond to the rates Kern River will use to determine the refunds owed to its shippers as a result of Opinion Nos. 486, 486-A, and 486-B. The parties argue that Kern River is inappropriately picking between rate calculations (last clean rate vs. rate calculated pursuant to merits determinations in this rate case) in order to reduce the pipeline's refund liability. The parties assert that such a mixing of methodologies is not authorized by the Commission.

189. Calpine and RCG also object to Kern River's use of \$0.06/dth as the usage rate determined pursuant to Opinion No. 486. The parties assert that \$0.06/dth is the usage rate Kern River proposed in this instant filing, which is higher than the \$0.0573/dth rate that was in effect prior to November 1, 2004, i.e., the last clean usage rate. The parties argue that it is inappropriate for Kern River to use \$0.06/dth as the usage rate approved by Opinion No. 486, because nowhere in Opinion No. 486 does the Commission find that rate to be just and reasonable. Rather, the parties argue that the Commission stated in its order suspending Kern River's filing, "the rate changes reflected in the proposed tariff sheets have not been shown to be just and reasonable, and may be unjust, unreasonable, unduly discriminatory, or otherwise unlawful."[229]

ii. <u>Kern River's Answer</u>

190. Kern River contends that its proposed rates for the Locked-in Period are consistent with the last clean rate doctrine. Kern River asserts that when determining the rate for the Locked-in Period, it is proper to look at the usage and reservation rates separately, and to pick the highest of each.

191. Kern River further contends that the usage rate of \$0.06/dth it proposes is the just and reasonable usage rate under Opinion No. 486. Kern River explains that because the change to the SFV rate design in this proceeding is prospective, the EFV rate design remains in effect for the Locked-in Period. Kern River explains that prior to this case, the EFV usage rate for firm transportation service was \$0.058/dth for Rolled-in System service, and \$0.0573/dth for 2003 Expansion service. Kern River states that in this case, it proposed to increase the EFV usage rate to \$0.06/dth for all firm services. Kern River

filing sets forth a comparison of the calculated rates with the last clean rates. *See* Kern River's March 2, 2009 Compliance Filing, Appendix D, Schedule J-2 at 5.

[229] *See Kern River Gas Transmission Co.*, 107 FERC ¶ 61,215, at P 11 (2004).

states that Opinion No. 486 did not change the EFV usage rate of $0.06/dth that Kern River proposed, and thus it continues to be in effect for the Locked-in Period.[230] Kern River asserts that the approved just and reasonable rates under Opinion No. 486 for the Locked-in Period are EFV rates, with a usage charge of $0.06/dth, calculated to recover the cost of service resulting from the Commission's rulings.

iii. Commission Determination

192. Section 4 of the NGA limits the Commission's authority to require refunds to the amount of any increase in rates proposed by the pipeline relative to the pipeline's last clean rate.[231] The last clean rate refund floor applies when a pipeline proposes to increase its rates pursuant to NGA section 4, but the Commission subsequently determines that the new just and reasonable rates are lower than the rates in effect prior to the pipeline's filing. The Commission has explained that, in such cases, "pipelines should refund the difference between the revenues actually collected from the proposed rates for each service and the greater of (1) revenues from the rates found to be just and reasonable applied to each actual service rendered during the refund period, or (2) revenues from the last clean rates applied to each actual service rendered during the refund period, plus interest."[232]

193. Here, Kern River began collecting the rates it proposed in this proceeding, subject to refund, on November 1, 2004. In Opinion No. 486, the Commission determined that these proposed rates were not just and reasonable. The new just and reasonable rates resulting from Opinion Nos. 486, 486-A, and 486-B, will become effective as of the issuance of this order and are lower than the rates in effect prior to November 1, 2004. Thus, refunds for the Locked-in Period in this proceeding will be limited to the difference between the revenues actually collected during the Locked-in Period and the greater of the revenues Kern River would have collected under (1) the calculated rate, i.e., the just and reasonable rate determined in accordance with Opinion Nos. 486, 486-A, and 486-B, or (2) the last clean rate, i.e., the rate in effect prior to November 1, 2004.

194. While Kern River did not calculate refunds in its compliance filing, it did propose rates for the Locked-in Period (from which refunds will be determined). In determining

[230] Kern River states that while Opinion No. 486 modified Kern River's rate design prospectively and lowered its overall cost of service retroactive to November 1, 2004, it did not alter Kern River's proposed EFV usage rate.

[231] *ANR Pipeline Co.*, 85 FERC ¶ 61,231, at 61,968 (1998) (citing *FPC v. Sunray DX Oil Co.*, 371 U.S. 145 (1962)).

[232] *Id.*

these rates, Kern River chose the "higher of" the last clean rate usage charge or the usage charge calculated in accordance with Opinion No. 486. Kern River used the same approach for determining the reservation charge. The protesters argue that Kern River erred by separately selecting the higher reservation and usage components, instead of using the higher overall rate (last clean rate vs. calculated rate). The Commission agrees.

195. Commission policy is that using the entirety of the revenues derived from a rate schedule is the standard method of calculating refunds.[233] Thus, when determining the refunds for a locked-in period, it is improper to apply the last clean rate doctrine on a component by component basis. Reservation and usage components of the rate for a particular service should be considered together as one filed rate charge for one service for purposes of calculating refunds.[234] By determining its rates for the Locked-in Period on a component-by-component basis, Kern River failed to abide by this policy. Therefore, the Commission directs Kern River to revise its rates for the Locked-in Period within 45 days of the issuance of this order.

196. The protesters also argue that Kern River proposes to use the incorrect calculated usage rate of $0.06/dth. They assert that this usage rate is not the new just and reasonable rate under Opinion No. 486.

197. When determining the new just and reasonable rate for a locked-in period, it is important to consider whether there has been a change in rate design, as there has been here. Because the change to the SFV rate design in this case is prospective, the EFV rate design continues to apply through the Locked-in Period. Thus, in order to determine the new just and reasonable rate for the Locked-in Period, Kern River must apply the EFV rate design to the new just and reasonable cost of service determined in Opinion No. 486.

198. Kern River argues that the determination in Opinion No. 486 did not result in any changes to Kern River's EFV usage rate; it only changed Kern River's proposed cost of service. Kern River thus contends that the new just and reasonable usage rate under Opinion No. 486 is the same as the usage rate Kern River proposed in its original filing. However, Kern River fails to consider that the EFV usage charge includes a percentage of fixed costs, and the resulting reduction in the cost of service would reduce the EFV usage charge. Thus, Kern River's use of $0.06/dth as the calculated usage rate is incorrect. However, this determination is largely moot because, as the Commission explained above, when determining the new just and reasonable rate for the Locked-in

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[233] *Northwest Pipeline Corp.*, 76 FERC ¶ 61,068, at 61,425 (1996) (citing *Panhandle*, 73 FERC ¶ 61,287, at 61,790 (1995); *Niagara Mohawk Power Corp.*, 40 FERC ¶ 61,335, at 61,021-22 (1987)).

[234] *Id.*

Period, Kern River should consider together the reservation and usage components of a rate as one filed rate charge.

e. Disparate Impact of Rolled-in System Rates

i. Protests

199. BP argues that the March 2, 2009, compliance filing results in Period One Rates that disparately impact the 10-year Rolled-in System shippers as compared to the 15-year Rolled-in System shippers. BP asserts that, during the Locked-in Period, the rates of the 10-year shippers on the Rolled-in System increase by 18.9 percent over the rates they paid before this rate case, while the rates of the 15-year Rolled-in System shippers remain the same.

200. BP also asserts that under Kern River's proposed prospective rates to take effect after a final order in this rate case, the 15-year Rolled-in System shippers would experience a 6.3 percent rate decrease from their rates in effect before this rate case. However, BP asserts that the 10-year shippers would still experience a 12.2 percent rate increase.[235]

201. BP argues that any rate factors should affect the unit rates proportionately between 10-year Rolled-in System shippers and 15-year Rolled-in System shippers and that this argument has not been adequately answered by Kern River.

202. BP asserts that Kern River has previously explained that this rate disparity is the result of the continuation of compressor and general plant in the levelized cost of service and the elimination of the O&M inflation factor. BP argues that these factors justify only a small portion of the rate disparity, if any, while keeping with the existing levelization methodology. BP states that the removal of the O&M inflation factor yields a rate impact of one half of a cent (approximately 7 percent of the rate disparity).[236] BP asserts that the remaining 93 percent of the total rate disparity has not been explained by Kern River.

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[235] BP states that it determined these rate increases and decreases based upon a comparison of (1) the proposed prospective SFV rates in Kern River's compliance filing stated on a 100 percent load factor basis with (2) Kern River's EFV rates approved in its last rate case also stated on a 100 percent load factor basis.

[236] BP's March 31, 2009 Protest at Appendix B, Ex. 1 (Affidavit of Elizabeth H. Crowe).

ii. **Kern River's Response**

203. Kern River responds that it has explained the reasons for the rate disparity between 10-year Rolled-in System shippers and 15-year Rolled-in System shippers. First, Kern River states that gas plant additions and retirements reduce the accumulated depreciation amounts and increase the gas plant to be depreciated in the Rolled-in System rates. Kern River explains that these additions and retirements are depreciated 70 percent during the applicable levelization periods. It asserts that as a result, the allocated cost of additional plant and retirements is depreciated over a shorter life for the 10-year Rolled-in System shippers than for the 15-year Rolled-in System shippers. Kern River explains that this creates a greater change in the rate for the 10-year Rolled-in System shippers. Kern River adds that the general plant and compressor engine amounts included in the Docket No. RP04-274 rates are greater than the amounts in the existing rates.

204. Kern River states that the second reason for the rate disparity is because its accumulated deferred income taxes (ADIT) were reset to zero when Kern River was purchased by MidAmerican Energy Holdings Company (MEHC) in 2002. Kern River explains that ADIT accumulates faster for the 15-year Rolled-in System shipper service than for the 10-year Rolled-in System shipper service due to the larger difference between tax depreciation and regulatory depreciation included in the 15-year Rolled-in System shipper rate. Kern River further explains that since the 15-year Rolled-in System shipper service accumulated deferred income taxes faster, its ADIT balance was built up faster than the 10-year Rolled-in System shipper balance from 2002 until the effective date of Kern River's new rates in Docket No. RP04-274.

205. In addition, Kern River states that cost information used to derive the compliance filing rates is different than cost information it used to derive the pre-Docket No. RP04-274 rates. Kern River states that for its pre-Docket No. RP04-274 rates, it used an ADIT balance of $127,200,000 for 15-year Rolled-in System shipper service, compared to the ADIT balance of $45,743,081 it used to derive the compliance rates, which resulted in a 64 percent decrease.[237] Kern River further states that pre-Docket No. RP04-274, it used an ADIT balance of $22,963,000 for 10-year Rolled-in System shipper service, compared to the ADIT balance of $3,220,627 it used to derive the compliance rates, which resulted in a 86 percent decrease. Kern River asserts that the difference in beginning ADIT balances results in a relatively lower rate base for 15-year Rolled-in System shipper service than for 10-year Rolled-in System shipper service. Kern River explains that this translates into a disparate rate change between 10-year Rolled-in System shipper service and 15-year Rolled-in System shipper service when deriving Kern River's compliance filing rates as compared to its pre-Docket No. RP04-274 rates.

[237] Kern River's April 15, 2009 Answer at n.38.

206. Kern River states that the third reason for the rate disparity is due to the elimination of the 3 percent O&M inflation factor. Kern River explains that the elimination of the O&M inflation factor reduced the average O&M expense for 15-year Rolled-in System shipper cost of service by $2.6 million which is equal to a $0.01/dth reduction. Kern River states that the 10-year Rolled-in System shipper cost of service decreased by only $227,000, resulting in a reduction of approximately $0.005/dth. Kern River explains that the reduction of $0.01/dth for 15-year Rolled-in System shippers is a greater percentage change than the reduction of $0.005/dth for 10-year Rolled-in System shippers. Kern River states that in addition to the shorter levelization period for 10-year Rolled-in System shippers, fewer billing determinants are used to derive the 10-year Rolled-in System shipper rate compared to the 15-year Rolled-in System shipper rate resulting in another factor for rate disparity. Kern River concludes that the Commission has already determined that Kern River has carried its burden of proving that the distinction in rates between 10-year Rolled-in System shippers and 15-year Rolled-in System shippers produces just and reasonable rates.[238]

iii. Commission Determination

207. The Commission rejects BP's contentions on this issue. Aside from making a general assertion that any rate factors should similarly affect the unit rates of the 10 and 15-year Rolled-in System shippers, BP points to no specific error in Kern River's compliance filing as causing an improper rate disparity. In fact, as Kern River explains, the different remaining contract terms of the two groups of shippers cause various rate factors to affect the rates of the 10 and 15-year shippers differently.

208. First, because each group of shippers has agreed to pay 70 percent of their allocated capital costs over the terms of their current contracts, the allocated cost of additional plant and retirements is depreciated over a shorter period for the 10-year Rolled-in System shippers than for the 15-year Rolled-in System shippers. Second, the ADIT reduction in rate base accumulates faster for the 15-year Rolled-in System shipper service than for the 10-year Rolled-in System shipper service due to the larger difference between tax depreciation and regulatory depreciation included in the 15-year Rolled-in System shipper rate. Third, the elimination of the O&M inflation factor reduced the average O&M expense for 15-year Rolled-in System shipper cost of service by a greater percentage change than the reduction for 10-year Rolled-in System shippers. Fourth, in addition to the shorter levelization period for 10-year Rolled-in System shippers, fewer billing determinants are used to derive the 10-year Rolled-in System shipper rate compared to the 15-year Rolled-in System shipper rate resulting in another factor for rate

[238] Kern River's April 15, 2009 Answer at 22 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 59).

disparity. As a result, the Commission finds that no further action is required with regard to BP's objection to rate disparity.

f. Cost of Debt Calculation

209. In Opinion No. 486, the Commission approved Kern River's proposal to use a blended cost of debt, including the cost of its Series A and Series B notes. In its compliance filing, Kern River proposes to use a blended debt cost of 6.214 percent. BP protests that in determining the blended debt cost, Kern River improperly used an 8.455 percent cost of debt for the Series A notes, because it failed to make a downward adjustment required by Opinion No. 486. The facts relevant to this issue are as follows.

210. The Series A notes were issued in August 2001 and included a fixed coupon rate of 6.676 percent. However, Kern River also incurred approximately $48 million in swap cancellation and debt issuance costs in order to refinance its Series A notes. Therefore, the 6.676 percent coupon rate had to be adjusted upward to obtain the effective cost of debt for the Series A note. Kern River originally proposed an adjustment up to 9.675 percent. Among other things, Kern River asserted that it had financed $29 million of the refinancing costs with stockholder equity, and therefore it should be permitted an equity return on that $29 million. In Opinion No. 486, the Commission disallowed any equity return on the refinancing costs, and therefore reduced Kern River's claimed effective cost of debt for the Series A notes to 8.455 percent.[239]

211. In Opinion No. 486-A, the Commission affirmed its finding in Opinion No. 486 that Kern River is not entitled to an ROE on the $29 million of refinancing costs financed by equity. In addition, the Commission found that Kern River was not entitled to a return on these funds as if they were debt. The Commission stated that appropriate treatment of all refinancing expenses, whether the $29 million financed by equity or the $19 million financed by debt, is to amortize them.[240] In other words, the Commission determined that the pipeline was entitled to a *return of* the refinancing costs, but not a *return on* the refinancing costs.[241]

212. Having found that Kern River was not entitled to a return on debt for any of the $48 million in refinancing costs, Opinion No. 486-A next considered the question of whether Kern River's claimed 8.455 percent Series A debt cost actually included any debt return on those costs. Kern River argued that its proposed debt cost of 8.455 percent

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[239] Opinion No. 486, 117 FERC ¶ 61,077 at P 202, 209.

[240] *Id.*

[241] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 251 (emphasis added).

did not include interest expense related to the $29 million of equity that it used to pay the Series A issuance fees and swap redemption costs. Kern River provided spreadsheets and other materials in Appendix 3 to its Rehearing Request to support its claim.[242] In Opinion No. 486-A, the Commission found that Kern River relied on material not in the record to support its claim. The Commission also determined that it was difficult to tell whether the 8.455 percent debt cost included a return on debt for the $29 million. Moreover, the Commission stated:

> [I]t is difficult to tell whether the 8.455 debt cost included a return on debt for the $29 million. Even if it did not, however, it appears the 8.455 debt cost may include a return on debt for the $19 million of non-equity funds used to pay refinancing costs for the Series A notes. To the extent that the 8.455 percent debt cost includes a return on debt for the $19 million, it is incorrect and overstated. It appears likely that the 8.455 percent is overstated because page 3 of Ex. BP-71 reflects a cost of debt that we approved for the Series A issuance of 8.22 percent, which differs from the 8.455 percent cost of debt that we approved for the Series A issuance.[243]

213. Accordingly, the Commission directed Kern River to file to remove any return on debt for refinancing costs, including the $19 million, from the calculation of its cost of debt for the Series A notes.

i. <u>Protests</u>

214. BP argues that that Opinion No. 486-A specifically directed Kern River to remove any return for debt financing costs and points out that Kern River's March 2, 2009 compliance filing did not change the debt cost calculation to comport with the holding of Opinion No. 486-A.[244] BP asserts that the workpapers accompanying Kern River's March 2, 2009 compliance filing reflect an overall blended cost of debt (i.e., 6.214 percent) that is the same as the cost of debt reflected in its December 18, 2009 compliance filing rates. Therefore, BP infers that Kern River did not reduce its claimed Series A note 8.455 percent debt cost to remove any return on debt reflected in that percentage.

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[242] *Id.* P 259.

[243] *Id*. P 260.

[244] *Id*. P 260.

215. As a result, BP asserts that Kern River's rates are overstated by the inflated debt cost. BP asserts that the Commission should require Kern River to correct this debt cost calculation to reflect a rate of 6.02 percent. BP argues that this corrected debt cost calculation must be implemented on a retroactive basis to November 1, 2004, because Kern River's initial filing in this docket was contrary to existing law and thus a legal nullity from the outset.

ii. Kern River's Answer

216. Kern River states that the 6.214 percent blended cost of debt in its March 2, 2009 compliance filing is properly calculated using 8.455 percent as the cost of the Series A debt issue.[245] As noted above, in Opinion No. 486-A, the Commission stated that, "[i]t appears likely that the 8.455 percent is overstated because page 3 of Exhibit BP-71 reflects a cost of debt for the Series A issuance of 8.22 percent, which differs from the 8.455 percent cost of debt that we approved for the Series A issuance."[246] In its April 15, 2009 Answer, Kern River argues that this suggestion is incorrect.[247]

217. Kern River states that the 8.22 percent cost of debt figure shown on page 3 of Exhibit BP-71 "was the basis for [the Docket No.] RP00-298-005 settlement cost of debt." [248] It asserts that the revisions to the calculation that yielded the change from 8.22 percent cost of debt in its last rate case in Docket No. RP00-298 to 8.455 percent at the time of Kern River's filing in the instant proceeding merely updated and, in some instances, corrected the same cost items that were included in the Docket No. RP00-298 calculation. However, Kern River argues that such revisions did not include the carrying costs on the subject $19 million of non-equity funds. Kern River states that it included workpapers in the March 2, 2009 compliance filing documenting the removal of all costs related to the equity funded refinance costs, which reduced the Series A cost of debt to the corrected 8.455 percent figure.

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[245] Kern River March 2, 2009 Compliance Filing at 2 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 209; Opinion No. 486-A, 123 FERC ¶ 61,056 at P 258-260; Schedule F-2).

[246] Opinion No. 486-A, 123 FERC ¶ 61,056 at P 260 (footnote omitted).

[247] Kern River's April 15, 2009 Answer at 16.

[248] *Id.* at 17 (citing Ex. BP-71 at 1).

iii. **Commission Determination**

218. Based upon its review of Exhibit BP-71, and Kern River's explanation here, the Commission finds that its suggestion that the 8.455 percent figure was overstated because it differed from the approved rate for the Series A issuance of 8.22 percent, was incorrect.

219. Exhibit BP-71 reveals that in this case Kern River originally proposed a 9.675 percent cost of money calculated by including the cost of a return on the equity portion ($29 million) of the refinancing costs. This $29 million figure was included within a $55.9 figure referred to as "debt fees and carrying costs." As shown by Exhibit BP-71, the removal of the $55.9 million amount (which includes the $29 million at issue here), results in the lower effective debt cost of 8.455 percent that the Commission accepted in Opinion No. 486. Therefore, despite the Commission's concerns that the 8.455 percent figure might include the $29 million cost of equity financing, because the 8.455 percent figure differed from the 8.22 percent figure originally set forth in Kern River's prior settlement, Exhibit BP-71 reflects that the $29 million was removed from the calculation of the 8.455 figure.

220. Kern River also argues that debt fees and carrying costs related to the non-equity, $19 million portion of the refinancing costs were not included in the original 8.22 percent cost of debt calculated in Docket No. RP00-298 and that the 8.455 percent cost calculation in this proceeding is an update of that original cost of debt. Kern River provides a schedule in its answer reflecting the difference between the 8.22 percent Series A cost calculated in Docket No. RP00-298 and the 8.455 percent cost calculation shown on page 5 of Exhibit BP-71.[249] Neither Exhibit BP-1 or the schedule filed by Kern River reflects the inclusion of an amount calculated to permit Kern River to earn a return on its refinancing costs whether related to a return on equity for the $29 million or to a return on debt for the $19 million of non-equity funds used to pay refinancing costs for the Series A notes, as suggested by Opinion No. 486-A.

221. The Commission's supposition in Opinion No. 486-A was based solely on the fact that there was a difference between the 8.22 percent cost of debt used in the settlement of the last rate case and the 8.455 percent cost of debt reflected in the instant filing. The Commission surmised that the reason related to this difference may have been an attempt by Kern River to recover a return on amounts used to refinance its debt. Kern River has adequately explained the reason for the differences and the Commission finds no support for any conclusion that Kern River has included amounts related to a return on refinancing amounts into its cost of debt. Accordingly, the Commission agrees with Kern River that no further modification is necessary to its 8.455 percent cost of the Series A

[249] *Id.* at Appendix 2.

debt issue or its weighted average cost of debt of 6.214 percent to meet the directives of Opinion No. 486-A.

g. **Lower Tax Rate for Net Operating Losses and Bonus Depreciation for Rolled-in System Shippers**

222. In its September 22, 2009 revised compliance filing, Kern River adjusted the effective income tax rate embedded in the levelized rate model to reflect limitations to bonus depreciation contained in certain state tax codes. This reduced the effective tax rate to a level lower than the 38.12 percent contained in a prior filing.

i. **Protests**

223. BP asserts that Opinion Nos. 486 and 486-A held that all bonus depreciation should be allocated to the 2003 Expansion Shippers. BP then asserts that changing the tax rate reduces the amount of the deferred income tax amortization and thereby increases the rate base, which in turn increases Kern River's dollar return and consequently its rates. BP therefore concludes that any change in the effective rate changes the allocation of deferred income tax account among the different shipper categories, and therefore, their rates. BP requests that the impact of any adjustment to the effective income tax rate fall only on the 2003 Expansion Shippers.

ii. **Kern River's Answer**

224. Kern River's answer does not dispute that lowering the effective tax rate increases the deferred tax component of its rate base and thereby increases its return and its rates. Kern River states that this does not mean that the change reallocates the deferred income tax accounts among the various classes of shippers. Rather, what changes is the rate of amortization of the deferred income tax accounts established and allocated to each shipper category based on any accelerated depreciation or amortization related to those facilities at the time they were placed in service. Kern River thus concludes that there is no need to differentiate the change in the effective income tax allowance among the different shipper categories.

iii. **Commission Determination**

225. The Commission concludes Kern River is correct. The effective income tax rate reflects the impact of all calculations and factors leading to that rate. The rate applies uniformly to all accounts that are impacted by the rate because the rate applies to the taxable income derived from all parts of Kern River's operations. For this reason the same effective rate is applied to all deferred income tax accounts because it is the rate applicable to the entire ordinary income of the corporation. Kern River is correct that this may change the dollar amount of deferred income tax account for the different categories of assets, and hence the relevant shipper's rates, but it does not affect the initial

allocations based on the amount of the investment and the depreciation or amortization allocated to a particular asset. The protest is denied.

2. **Period Two Rates**

a. **Background**

226. Kern River's shippers only pay the levelized Period One rates until their current contracts expire. The current 10-year extended term contracts for firm shippers on the original system will expire on September 30, 2011. The other five sets of contracts expire between 2012 and 2018. The Period Two rates for all shipper groups will be lower than the Period One rates, because the Period One rates allow Kern River to recover more invested capital during that period than it would under ordinary straight-line depreciation. In order to ensure that Kern River's firm shippers obtain the benefit of the lower Period Two Rates if they continue service beyond the terms of their existing contracts, Opinion No. 486 required Kern River to include in its tariff the Period Two Rates that will take effect when the firm shippers' existing contracts expire.

227. In its March 2, 2009 compliance filing, Kern River proposes to use a traditional rate design for its Period Two rates, rather than continue the levelized rate methodology used for its Period One rates. It also proposes a new section 30 of its GT&C defining when and how shippers become eligible for Period Two Rates.

b. **Motion for Summary Disposition**

228. On March 19, 2009, Williams and BP (Kern River Shippers) filed a motion for summary disposition regarding the Kern River's March 2, 2009 compliance filing. The Kern River Shippers argue that the March 2, 2009 compliance filing fails to comply with the Commission's directives to file levelized Period Two rates. Other parties filing comments to Kern River's March 2, 2009 compliance filing generally agree with this position.[250]

229. The Kern River Shippers argue that the Commission has repeatedly directed Kern River to use levelized rates for Period Two, starting with the Kern River Original Certificate Order.[251] They maintain that, "the Commission has been consistent in finding

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[250] *See* Calpine's March 31, 2009 Comments at 6-9; Nevada's March 31, 2009 Comments at 2; Questar's March 31, 2009 Comments at 1-5; RCG's March 31, 2009 Comments at 9-14; Williams' March 31, 2009 Comments at 1; Southwest's March 31, 2009 Comments at 13; BP's April 15, 2009 Answer at 15-20.

[251] Original Certificate Order, 50 FERC ¶ 61,069 (1990).

that the parties will retain the benefit of their bargain and that the levelization methodology will be maintained. . . ."[252] They point out that in the Original Certificate Order, the Commission stated that "Kern River's rates are based on two levelized calculations, one for the first fifteen years and the other for the [pipeline's remaining depreciable life.]"[253]

230. The Kern River Shippers argue that when Kern River filed the instant rate case, it proposed to continue the use of the rate levelization methodology and that Opinion No. 486 required Kern River to file tariff sheets setting forth Period Two levelized rates,[254] as well as specifically stating that "the levelization methodology must remain in place" as approved in the Original Certificate Order.[255] They assert that Opinion No. 486 found that "the levelized rates approved in Kern River's certificate included separate *levelized rates for* . . . different periods, (1) the term of the firm shippers' initial contracts, [and] (2) *the period from the expiration of those contracts to the end of Kern River's depreciable life* . . . ."[256]

231. They assert that, in Opinion No. 486-B, the order which the March 2, 2009 filing is to comply with, the Commission stated it had accepted Kern River's proposal for separate levelized rates during three periods, including Period Two.[257] Further, they

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[252] Kern River Shippers' March 19, 2009 Motion for Summary Disposition at 5 (citing Opinion No. 486-B, 126 FERC ¶ 61,034 at P 186).

[253] *Id.* (citing Amended Original Certificate Order, 58 FERC ¶ 61,073, at 61,244 n.38 (1992) (emphasis added)).

[254] *Id.* at 6 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 37). Southwest adds that Opinion No. 486 requires that Kern River "may and should continue the levelized rate model agreed to in its certificate proceeding and subsequent proceedings." Southwest's March 31, 2009 Comments at 13 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 39).

[255] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 37, 44).

[256] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 19 (emphasis added)). The Kern River Shippers also argue that in Opinion No. 486-A, the Commission affirmed this understanding stating that it "accepted Kern River's proposal for separate levelized rates for different periods," (Opinion No. 486-A, 123 FERC ¶ 61,056 at P 2), and that retaining levelized rates would preserve the allocation of risks memorialized in the Original Certificate Order. Opinion No. 486-A, 123 FERC ¶ 61,056 at P 21-25.

[257] *Id.* at 7 (citing Opinion No. 486-B, 126 FERC ¶ 61,034 at P 2).

(continued …)

assert that Opinion No. 486-B stated that "[i]n Opinion No. 486, the Commission recognized that Kern River's levelization methodology would *levelize* Kern River's rates *over several different periods*."[258]

232. The Kern River Shippers assert that Kern River has admitted that in "Opinion No. 486, the Commission reaffirmed its approval of Kern River's levelized rate methodology,"[259] which, the Kern River Shippers assert, required that Period Two rates are to be levelized.[260] They argue that Kern River did not seek rehearing of this requirement, and that it failed to seek rehearing of comparable subsequent Commission reaffirmations that Period Two rates must be levelized.

233. The Kern River Shippers argue that Kern River has again filed non-complying Period Two tariff sheets and has delayed the opportunity to assess whether levelized rates that must ultimately be proposed by Kern River comply with Commission directives. They argue that Kern River should be directed to promptly comply. They assert that Kern River's proposed traditional rate for Period Two is both an undirected change and an unauthorized change. Therefore, the Kern River Shippers argue that summary disposition by the Commission is warranted. The Kern River Shippers argue that the Commission should dismiss the tariff sheets containing the Period Two Traditional Rates as a legal nullity without awaiting action on other issues involving the instant compliance filing. Further, they argue that Kern River should be directed to file, within 15 days, revised Period Two tariff sheets that contain only rates levelized for the entirety of Period Two (i.e., through the end of the remaining depreciable life of the Kern River system as established in Opinion Nos. 486, *et seq.*), along with the supporting data and calculations in both hardcopy and electronic format with all cells, links, formulae and data intact.

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[258] *Id*. (citing Opinion No. 486-B, 126 FERC ¶ 61,034 at P 178 (emphasis added)).

[259] *Id.* at 8 (citing Kern River's July 6, 2007 Answer at 10).

[260] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 37 (stating "[t]he Commission… finds that Kern River's rates should continue to be designed based on the levelized methodology…. [T]he Commission will require that Kern River include in its tariff the Period Two rates that will take effect when the firm shippers' existing contracts expire. This will assure that these shippers will obtain the benefit of the lower Period Two rates if they continue service beyond the terms of their existing contracts.")).

i. **Comments**

234. Questar agrees with the Kern River Shippers and states that Kern River's position set forth below is based upon orders which pre-date Opinion No. 486. Questar argues that the compliance filing must comply with Opinion Nos. 486, *et seq*. and Questar argues that the Opinion Nos. 486, *et seq*. orders are explicit in requiring that the Period Two rates be levelized. Questar states that in the Original Certificate Rehearing Order, the Commission rejected the levelization method initially proposed by Kern River and required Kern River to apply the levelization "method the Commission has prescribed for optional certificate pipelines in general and, since it underlies Kern River's authorized rates, for Kern River in particular."[261] Questar argues that subsequently, in Opinion No. 486, the Commission again determined "that Kern River's rates should continue to be designed based on the levelized methodology approved in its certificate proceeding."[262]

235. Questar argues that the Commission found that absent any overarching policy reason, the original methodology approved by the Commission was necessary to properly allocate the economic risks of the project that were assumed by Kern River. Questar asserts that the Commission emphasized that "the depreciation recovery under levelized rates is, by necessity, a long term proposition"[263] and that "the levelization methodology must remain in place for shippers to realize the benefits bargained for."[264]

236. Calpine argues that the Commission has found that the levelization bargain struck between Kern River and its shippers should continue in effect throughout the three rate periods[265] and joins Questar in noting that Opinion No. 486-B found that, "[t]hroughout

[261] Questar's March 31, 2009 Comments at 2 (citing Amended Original Certificate Order, 58 FERC ¶ 61,073, at 61,243 (1992)). Questar also asserts that when Kern River proposed the 2003 Expansion, the Commission approved application of the approved levelized rate methodology for those expansion shippers. *Kern River Gas Transmission Co.*, 98 FERC ¶ 61,205, at 61,722-23 (2002).

[262] *Id.* at 2 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 37).

[263] *Id.* at 3 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 42).

[264] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 44).

[265] Calpine's March 31, 2009 Comments at 8 (citing Opinion No. 486-A, 123 FERC ¶ 61,056 at P 19 (stating that "BP, and all the other parties who agreed to Kern River's levelized rate methodology, should have reasonably anticipated from the beginning that [the levelized] methodology would continue in effect throughout Kern River's life, absent agreement by all parties to modify or eliminate that rate design. Nor

(continued …)

this proceeding, the Commission has been consistent in finding that the parties will retain the benefit of their bargain and that the levelized methodology will be maintained in absence of an overarching policy reason."[266] Calpine argues that there is no evidence that the parties ever agreed to replace levelization with a "traditional" rate design. Calpine further states that proposals to do so were contested and ultimately rejected during the course of this proceeding. Calpine argues that consistent with Opinion Nos. 486, 486-A, and 486-B, Kern River should be required to modify its Compliance Filing to reflect levelized Period Two rates.

237. Calpine asserts that any earlier Kern River proposals or interpretations of prior Commission orders simply do not modify the compliance obligations imposed by the Commission in this docket. Calpine asserts that the Commission has made clear that levelization on the Kern River system represents "a long term proposition"[267] that should not be displaced absent "an overarching policy reason" for doing so. Moreover, Calpine argues that the necessity to levelize the Period Two rates is buttressed by the fact that earlier in this proceeding the Commission rejected proposals by BP and Commission Trial Staff to predicate Period Two rates on a traditional cost of service basis[268] and therefore its is not credible to maintain, as Kern River does, that transitioning the pipeline to a more "traditional" rate structure complies with the levelization directives of Opinion Nos. 486, 486-A, and 486-B.

238. Questar also argues that Kern River's claim that it cannot calculate Period Two levelized rates without firm service contracts is without merit. Questar argues that the Commission required the Period Two rates "to increase the assurance that Kern River's shippers will obtain the benefit of the lower Period Two rates if such shippers continue service beyond the term of their existing contracts."[269] Therefore, Questar maintains that

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should it come as any surprise to the parties that the Commission would hold the parties to their agreement.")).

[266] *Id.* at 8-9 (citing Opinion No. 486-B, 117 FERC ¶ 61,077 at P 186); Questar's March 31, 2009 Comments at 3.

[267] Calpine's March 31, 2009 Comments at 10 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 42).

[268] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 37-54).

[269] *Id.* (citing Opinion No. 486-B, 126 FERC ¶ 61,034 at P 168).

the Commission required the filing of Period Two rates even though it acknowledged that some Period One shippers might not extend their service into Period Two. Questar states that the Commission did not link Period Two rates to underlying contract terms, but rather directed that Kern River's Period Two rates correspond to "the period from the proposed expiration of [Period One] contracts to the end of Kern River's depreciable life."[270] Questar states that the Commission uses a pipeline's economic life to determine depreciation[271] and that, in this proceeding, the Commission has determined that Kern River has a remaining economic life of 35 years.[272] Because Kern River knows the expiration date of its shippers' Period One contracts and the remaining economic life of its system, Questar asserts that Kern River should have no difficulty in calculating terms for use in deriving Period Two rates.

239. RCG agrees with the Kern River Shippers that Kern River is obligated under the Commission's orders to continue a levelized rate design for Period Two and beyond. In addition to the language quoted above by other protesters, RCG argues that the Commission confirmed in Opinion No. 486 that levelization was to continue for all three rate periods on Kern River.[273] RCG asserts that the position Kern River has taken in its

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[270] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 19).

[271] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 410).

[272] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 408).

[273] RCG states that in Opinion No. 486, the Commission stated:

> As described above, the levelized rates approved in Kern River's certificate included separate, levelized rates for three different periods, (1) the term of the firm shippers' initial contracts, (2) the period from the expiration of those contracts to the end of Kern River's depreciable life, and (3) the period thereafter. The levelized rates for the first period (hereafter Period One Rates) were designed to recover 70 percent of Kern River's invested capital, an amount approximately equal to the portion of its invested capital funded through debt. Since this would allow Kern River to recover more invested capital during Period One than it would under ordinary straight-line depreciation for the depreciable life of its system, the rates for the second two periods (hereafter Period Two and Period Three Rates) were lower than for the first period. Subsequent Kern River rate proceedings have continued this

(continued …)

Answer to the Kern River Shippers that "the Commission has never required levelization for Period Two rates," is not true and that there is no support for this position in any of the Commission's orders.[274] RCG argues that Kern River's position ignores the findings of Opinion Nos. 486, 486-A, and 486-B requiring the continuation of levelization.

ii. <u>Kern River's Answer</u>

240. Kern River asserts that its Period Two Compliance Rates comply with Opinion Nos. 486, *et seq*. Kern River states that the Kern River Shippers' argument that when the Commission originally approved Kern River's levelization methodology, it held that levelization should apply for the initial term of the shippers' contracts, and also apply in Period Two, after the primary terms of the contracts expire, is without merit. Kern River argues that the fallacy of this argument is that Kern River has never proposed, and the Commission has never required, levelization for Period Two rates.[275]

241. Kern River argues that in the January 1990 Original Certificate Order, the Commission acknowledged that "Kern River propose[d] … to levelize its costs and rates for the first 15 years of the project's life."[276] Kern River argues that this first 15 years of the project corresponded with the duration of the original shippers' initial service agreements with Kern River. Kern River argues that in its subsequent application to

> same methodology, as updated to reflect (1) the extended terms of the original shippers' contracts and longer overall depreciable life of the original system provided for in the 2000 ET Settlement, and (2) the new contracts of the 2002 and 2003 expansion shippers and the Big Horn Lateral contracts. Opinion No. 486, 117 FERC ¶ 61,077 at P 37.

[274] RCG's March 31, 2009, 2009 Comments at 13-14 (citing Kern River's April 15, 2009 Answer at 4).

[275] Kern River states that it was unaware of any suggestion that Period Two rates should be levelized until BP first raised the idea on January 3, 2007, in supplemental comments on Kern River's December 18, 2006 filing to comply with Opinion No. 486.

[276] Kern River's March 26, 2009 Answer at 5 (citing Original Certificate Order, 50 FERC ¶ 61,069, at 61,146, 61,150 (1990) (stating "the Commission will permit Kern River to utilize a levelized cost of service for a period of 15 years")).

amend its Original Certificate in order to increase its initial rates, it again presented levelized rates only for the 15-year term of its customers' contracts.[277]

242. Kern River argues that the Kern River Shippers base their argument on the Commission's statement in its January 1992 Amended Original Certificate Order that rates for Kern River's service were "based on two levelized calculations, one for the first fifteen years and the other for the next 10 years."[278] Kern River argues that in this quoted language the Commission was referring to calculations that the Commission performed itself, employing a different levelization methodology than the one Kern River proposed.[279] Kern River argues that, subsequently, the Commission granted rehearing and accepted the rates that Kern River proposed (i.e., rates levelized for only the 15-year term of shippers' contracts) stating:

> The Commission has … reevaluated the rates proposed by Kern River and Mojave in their amendment applications. The Commission concludes that the rates proposed in the amendment applications comply with the principles established in the January 24, 1990 and January 30, 1992 orders. Accordingly, the Commission is approving the rates proposed in the amendment applications.[280]

243. Kern River argues that the initial rates the Commission ultimately approved for its Original System were the levelized rates for the 15-year term of its shippers' original contracts that Kern River proposed in its amendment application. Therefore, Kern River argues that the Commission's affirmation of Kern River's levelization methodology and

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[277] Kern River's March 26, 2009 Answer at 5 (citing *Kern River Gas Transmission Co.*, Docket No. CP89-2048-006, Abbreviated Application for Amendment to Optional Certificate of Public Convenience and Necessity, at Ex. P, Schedule 2 (filed Aug. 9, 1991) (showing levelized cost of service for only the 15 years of 1992 through 2006)).

[278] *Id.* at 6 (citing Kern River Shippers' March 19, 2009, 2009 Motion for Summary Disposition at 5-6 (quoting Amended Original Certificate Order, 58 FERC ¶ 61,073, at 61,244 n.38 (1992)).

[279] *Id.* (citing Amended Original Certificate Order, 58 FERC 61,242).

[280] *Id.* (citing Amended Original Certificate Rehearing Order, 60 FERC ¶ 61,123, at 61,437 (1992)). The January 24, 1990 and January 30, 1992 Orders referred to in the quoted material are found at *Kern River Gas Transmission Co*., 50 FERC ¶ 61,069 (1990) and *Kern River Gas Transmission Co*., 58 FERC ¶ 61,073 (1992), respectively.

reference to the Amended Original Certificate Order in Opinion No. 486, provides no foundation for the Kern River Shippers' motion.

244. Kern River also argues that its traditionally-based Period Two rates fulfill the original bargain of the parties and provide rates that are lower than the Period One rates. Kern River argues that its filing proposes Period Two rates derived from a traditional cost of service and is based upon the remaining 30 percent of its original capitalization. Kern River states that the regulatory liability associated with accelerated recovery of depreciation during the levelization period is amortized over the remaining life of the relevant facilities. Therefore, Kern River argues that the proposed Period Two rates provide it with the opportunity to recover the remaining 30 percent of its original capitalization, while returning all the accelerated depreciation paid in Period One (i.e., the entire regulatory liability accrued as of the end of Period One) to qualifying shippers. Kern River asserts that the Kern River Shippers do not explain why a levelized cost of service in Period Two is required to maintain these bargained for elements.

245. Kern River argues that the "bargain" and the "agreed upon period" for levelization which the Commission says must be preserved[281] refer to the contracts that shippers and Kern River entered into prior to the construction of Kern River's original pipeline, as those agreements were extended pursuant to the ET settlement.[282] Kern River asserts that the Kern River Shippers cannot show any "bargain" for an "agreed upon period" with respect to rates, let alone for the establishment of a particular rate-setting methodology, for Period Two rates.

246. Kern River also argues that the Commission has ruled that cost of service levelization must be coterminous with the contracts under which a pipeline's shippers will take service at levelized rates.[283] Kern River points out that it has no contracts for Period Two and therefore, there is no basis on which to calculate a levelized cost of service for Period Two. Kern River argues the only directive stated in Opinion Nos. 486, *et seq*., is that Period Two rates be structured to preserve the parties' original "bargain." Kern River asserts that the traditionally-derived Period Two rates it proposes meet this

[281] *Id.* (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 42, 44).

[282] *Id*. (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 43; *Kern River Gas Transmission Co*., 92 FERC ¶ 61,061 (2000)).

[283] *Id.* at 9 (citing *Ingleside Energy Ctr., LLC*, 112 FERC ¶ 61,101, at P 76-78 (2005) (*Ingleside*); *Corpus Christi LNG, L.P*., 111 FERC ¶ 61,081, at P 30-32 (2005) (*Corpus Christi*); *Questar Southern Trails Pipeline Co*., 89 FERC ¶ 61,050, at 61,147 (1999) (*Southern Trails*)).

criterion. Accordingly, Kern River requests that the motion of the Kern River Shippers be denied with prejudice.

iii. Commission Determination

247. For the reasons discussed below, the Commission finds that Kern River must offer its various groups of long-term firm shippers levelized Period Two rates. However, the Commission sets for hearing issues concerning how those rates should be calculated and what conditions the shipper must satisfy in order to be eligible for the levelized Period Two rates.

(a) Levelized Period Two Rates as Part of Parties' Risk Sharing Agreement

248. In Opinion Nos. 486 and 486-A, the Commission held that Kern River's levelized rate methodology must be maintained because it was part of the risk sharing agreement among Kern River, its shippers and lenders underlying Kern River's original optional expedited certificate. The Commission pointed out that a central issue in approving an application for an optional certificate was whether the pipeline's proposed rates reflected an appropriate allocation of the risks of the project as between the pipeline, its customers and other interested parties. Therefore, once the Commission has issued the certificate, the Commission will not lightly change the allocation of risk inherent in the optional certificate as granted absent some overarching policy reason.[284] Accordingly, the issue of whether the Period Two rates must be levelized turns on whether levelized rates for Period Two were part of the risk sharing agreement underlying the certificate for the Original System and carried forward in the Extended Term Settlement and the certificates for the 2002 and 2003 expansions.

249. The Commission finds that levelized rates for Period Two were part of the original risk sharing agreement. This original bargain is reflected in the January 1990 Original Certificate Order. In that order, the Commission authorized Kern River "to charge one rate for its first 15 years of service, another rate for years 16 through 25, and a third rate for service rendered after 25 years."[285] The Commission also calculated the three sets of rates and included them in the certificate order.[286] While the Original Certificate did not explicitly describe the calculated Period Two rates as levelized, the fact the Commission

[284] Opinion No. 486, 117 FERC ¶ 61,077 at P 38. Opinion No. 486-A, 123 FERC ¶ 61,056 at P 19.

[285] Original Certificate Order, 50 FERC 61,069, at 61,150 (1990).

[286] *Id*. at 61,151.

required a single, level rate to be applied throughout the ten years of Period Two necessarily carried with it a determination that the Period Two rates would be levelized. If the Commission had calculated the required Period Two rates based on a traditional rate methodology, those rates would have allowed Kern River to substantially overrecover its allowed return on equity during Period Two. That is because under a traditional rate methodology, the return on equity would have been calculated as a return on Kern River's rate base as of the end of Year 15, without regard to the decline in the rate base during Period Two to zero at the end of Year 25. In its request for rehearing of the Original Certificate Order, Kern River did not challenge the rate determinations in the Original Certificate Order, other than to request clarification that it was not foreclosed from filing section 4 rate cases in the future, a clarification which the Commission granted.[287]

250. The fact that the original risk sharing agreement included levelized rates for Period Two is further confirmed by the Commission's January 30, 1992 Order, granting Kern River's request to amend the Original Certificate Order to reflect Kern River's updated cost estimates (Amended Original Certificate Order). In the Amended Original Certificate Order, the Commission stated that, "[c]onsistent with the January 24 [Original Certificate] order," the revised initial rates proposed by Kern River "are based on the use of a levelized cost of service."[288] The Commission further stated that "*[t]he levelized rate structure will enable Kern River to recover* substantially all of its debt capital during the first 15 years and *its equity capital during the next 10 years*."[289] The Amended Original Certificate Order again set forth a single, level rate to apply during every year of Period Two. The Commission also stated that under the levelized cost-of-service method, recovery of the costs of facilities varies each year throughout the levelization period. Therefore, in order to avoid confusion, the Commission set forth a table reflecting the plant cost recovery percentages which were to underlie Kern River's authorized rates. In describing this table, the Commission clearly set forth its understanding that the levelized methodology was to be used in all rate periods associated with this project when it stated, "[T]he sudden drop in plant recoveries in year 16 occurs because Kern River's rates are based upon *two levelized calculations, one for the first fifteen years and the other for the next 10 years*."[290]

[287] Original Certificate Rehearing Order, 51 FERC 61,195, at 61,359 (1990).

[288] Amended Original Certificate Order, 58 FERC 61,073, at 61,242 (1992).

[289] *Id.* (emphasis added).

[290] *Id.* at 61,244 n.38 (emphasis added).

251. It is thus clear that both the January 1990 Original Certificate Order and the January 1992 Amended Original Certificate Order contemplated the use of levelized rates for Period Two. Kern River points out, however, that in August 1992, the Commission granted its request for rehearing of the Amended Original Certificate Order, [291] and it asserts that the grant of rehearing eliminated any requirement that its Period Two rates be levelized. The Commission disagrees. In response to Kern River's rehearing request, the Commission determined that the "spreadsheet formulas used to calculate the rates authorized in the January 30 Orders do not in every instance reflect the principles and determinations of the January 30 Orders." Specifically, the Commission explained that its spreadsheet formulas had maintained the 70/30 debt/equity ratio throughout the lives of the projects. However, Kern River had used the *Ozark* methodology, "which recognizes that the original capitalization ratio of the projects will not be maintained throughout the project's lives; rather the depreciation accumulated during the first 15 years will be used to retire the debt principle, resulting, after 15 years, in project capitalized with 100 percent equity."[292] Because the *Ozark* methodology more accurately reflected Kern River's proposed rate structures over time, the Commission granted rehearing and allowed its use in calculating Kern River's initial reservation charges.[293] The Commission required Kern River to make a revised rate filing using the *Ozark* method, but stated that the filings "must be consistent with the rate orders in Docket Nos. RP92-53 and RP92-86, and the January 30, 1992 certificate orders *in all other respects*."[294]

252. Therefore, contrary to Kern River's contentions, the August 1992 Amended Original Certificate Rehearing Order only granted rehearing with respect to how Kern River's levelized rates are to be calculated, i.e., to allow the levelized rates to reflect the changes in Kern River's capital structure during the periods those rates are in effect. There is nothing in the August 1992 Order to suggest that the Commission was making such a fundamental change to its prior holdings as to permit elimination of the levelized rate structure at the end of Period One and the use of traditional rates during Period Two.

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[291] Amended Original Certificate Rehearing Order, 60 FERC ¶ 61,123 (1992).

[292] *Id.* at 61,437.

[293] This methodology was developed in *Ozark Gas Transmission System*, 32 FERC ¶ 63,019, *aff'd*, 39 FERC ¶ 61,142, at 61,508 (*Ozark*), *reh'g denied in relevant part*, 41 FERC ¶ 61,207 (1987), *rev'd on other grounds sub nom*. *Public Service Commission v. FERC*, 866 F.2d 487 (D.C. Cir. 1989).

[294] Amended Original Certificate Rehearing Order, 60 FERC at 61,437 (emphasis added).

If the Commission had intended such a fundamental change in the approved initial rates, it would have expressly stated that intention.

253. Finally, Kern River points to nothing in the Commission's approval of the Extended Term Settlement or the subsequent orders certificating the 2002 and 2003 Expansions modifying the original intent that Period Two rates be levelized. Those subsequent proceedings all carried forward the original risk sharing agreement, with the exception that shippers were offered the option of 10 or 15-year contracts for Period One. Otherwise, all aspects of the agreement remained the same, with levelized rates for Period One recovering 70 percent of the relevant invested capital and levelized rates for Period Two recovering the remaining 30 percent of invested capital.

(b) <u>Length of Period Two Contracts</u>

254. Kern River also contends that the fact that none of its shippers currently have contracts for service during Period Two prevents it from calculating levelized rates for Period Two. It asserts that this is because Commission policy requires that a levelized cost of service must be coterminous with the contracts under which a pipeline's shippers will take service at levelized rates.[295] As discussed below, Kern River's characterization of the Commission's general levelized rate policy is incorrect. However, in this case, it may nevertheless be consistent with the parties' risk sharing agreements for Kern River to establish some method of coordinating contract length with rate levelization, such as a minimum contract length to which shippers must agree in order to be eligible for levelized rates during Period Two. The Commission sets that issue for hearing, together with all other issues concerning the eligibility requirements for levelized Period Two rates and the design of such levelized rates.

255. Kern River's contention that Commission policy only permits levelized rates if shippers have contracts for the entire levelization period confuses the accounting requirements for regulatory asset treatment with levelized rates. The *Ingleside* and *Southern Trails* orders, cited by Kern River as supporting its contentions on this point, are limited to holding that the levelized rate proposals in those cases did not meet the probability of recovery requirement in our accounting regulations[296] to record a regulatory asset. The Commission held that, in the circumstances of those cases, that requirement could only be satisfied with respect to the amounts that would be recovered

[295] Kern River's March 26, 2009 Answer at 9 (citing *Ingleside*, 112 FERC ¶ 61,101, at P 76-78 (2005); *Corpus Christi*, 111 FERC ¶ 61,081, at P 30-32 (2005); *Southern Trails*, 89 FERC ¶ 61,050, at 61,147 (1999)).

[296] *See* Instructions to Account No. 182.3, 18 C.F.R. Part 201 (2009).

during the terms of the pipeline's existing shipper contracts.[297] However, despite the fact the Commission in *Ingleside* and *Southern Trails* only authorized the pipelines to record regulatory assets during the terms of the shippers' current contracts, the Commission nevertheless approved the pipelines' proposals to charge rates levelized over periods longer than the shippers' contract terms.[298] Moreover, the Commission has previously permitted levelized rate treatment (and regulatory asset treatment) not linked to any specific contract term, particularly in situations where it was faced with a pipeline that had a rapidly declining rate base.[299] Also, whether regulatory asset treatment is utilized in any regulatory manner is based on accounting concepts, and the particular accounting methodology used by a regulatory entity does not compel the use of any particular ratemaking procedure.[300]

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[297] *See, e.g.*, *Ingleside*, 112 FERC ¶ 61,101 at P 78 (stating "San Patricio's rate levelization plan which covers a twenty year period would leave a substantial portion of the balance of the regulatory asset unrecovered at the end of the 15 year contract term with Occidental Energy. Therefore, the Commission will not permit San Patricio to record a regulatory asset under its rate levelization plan."); *Southern Trails*, 89 FERC at 61,147 (stating "Southern Trails' rate levelization proposal does not meet the probability requirement to record a regulatory asset because the Commission has limited the amount that can be recorded as a regulatory asset to those amounts that would be recovered under the term of the pipeline's shipper contracts.").

[298] *See, e.g.*, *Ingleside*, 112 FERC ¶ 61,101 at P 27 (stating "The Commission has reviewed the proposed cost-of-service and proposed initial rates, and generally finds them reasonable for a new pipeline entity, such as San Patricio, subject to the conditions discussed below."); *Southern Trails*, 89 FERC at 61,148 (stating "Southern Trails should keep records which are not part of its financial statements that support the rate treatment of the unrecovered costs even though they are not recordable as a regulatory asset.").

[299] *Ozark Gas Transmission System*, 50 FERC ¶ 61,252 (1990) (requiring a pipeline to implement levelized rates to ensure that its shippers received the benefit of its declining rate base). *See also Trailblazer Pipeline Co.*, 50 FERC ¶ 61,188 (1990); *Overthrust Pipeline Co.*, 53 FERC ¶ 61,118 (1990); *Wyoming Interstate Pipeline Co*., 69 FERC ¶ 61,259 (1994).

[300] *See United Gas Pipe Line Co*., 32 FERC ¶ 63,080, at 65,242 (1985) (holding that the USOA "do[es] not control ratemaking situations"); *Public Service Comm'n of New Mexico*, 13 FERC ¶ 63,041 (citing *Tennessee Gas Pipeline Co. v. FPC*, 561 F.2d 955 (D.C. Cir. 1977) and *Alabama-Tennessee Natural Gas Co. v. FPC*, 359 F.2d 318 (5th Cir. 1966), for the proposition that "[a]lthough relevant, . . . accounting principles are not to be blindly followed . . . for ratemaking purposes").

256. Lastly, in the *Corpus Christi* case, the Commission found that the pipeline proposed to levelize its rates for the first ten years of a proposed twenty-year cost of service, in spite of the fact that the pipeline also had a twenty-year contract for service. The Commission found that the pipeline could over-recover its cost of service if it was permitted to levelize rates for only a portion of twenty-year term of the contract and then shift to traditional rates. Therefore, the Commission required the pipeline to design its initial rates based on a levelized cost of service over the entire twenty year operational life of the project, which was also consistent with its sole firm shipper's contract.[301] Thus, the *Corpus Christi* case did not involve the issue, raised by Kern River here, of whether a pipeline can levelize rates for a period longer than the terms of its current shipper contracts. Accordingly, the cases cited by Kern River do not preclude its use of levelized rates for Period Two.

257. However, it does not follow from the fact that Commission policy permits rates to be levelized over a longer period than the terms of shipper contracts that there should be no coordination in this case between the duration of shipper contracts for service during Period Two and the length of the Period Two rate levelization period. While the risk sharing agreements between Kern River and its shippers included levelized rates for Period Two, the present record contains no indication that the parties fully considered or agreed upon the terms and conditions under which Kern River would offer such levelized rates. In particular, the present record contains no evidence whether the parties considered if shippers must have contracts for service during all, or part, of Period Two.

258. As Kern River points out, since Kern River commenced service, its firm shippers' contracts for service during Period One have at all times been coterminous with the length of the Period One applicable to each shipper. This fact may suggest an underlying assumption, at least at the time the Original System was certificated, that firm shippers would also be required to have contracts for the entire length of Period Two.

259. On the other hand, at that time, Period Two was only expected to last for 10 years. In this case, we have found that Kern River's depreciable life is significantly longer than originally anticipated. As a result, when the extended 10-year Period One contracts of shippers on the Original System expire on September 30, 2011, Kern River will have a

[301] *Corpus Christi*, 111 FERC ¶ 61,081 at P 31-32 (2005) (stating "Cheniere Pipeline has proposed to only levelize the cost of service and rates for the first 10 years of service. However, it has not proposed rates to apply to service for the remainder of the 20-year period underlying the calculation of Cheniere Pipeline's proposed cost of service and rates. Cheniere Pipeline's proposed rates, reflecting only levelized costs for years 1 through 10, are not consistent with the 20-year term of its shipper's contract. Moreover, Cheniere Pipeline's proposed rates may allow it to overrecover the project's estimated 20-year total cost of service. . .").

remaining depreciable life of over 30 years. Moreover, the orders approving the Extended Term Settlement and the 2002 and 2003 Expansions reflected a modification in the original risk sharing agreement to permit shippers to choose between 10 and 15-year contracts during Period One, with the length of Period One depending upon which option was chosen. These changed facts raise the issue as whether it is reasonable to require shippers to enter into contracts for the entire remaining depreciable life of Kern River in order to obtain Period Two levelized rates, particularly if there was no clear intent in the original risk sharing agreement that shippers must have contracts for the entire length of Period Two.

260. There appear to be a number of options for resolving the issue of coordinating the length of the shippers' Period Two contracts with the length of the levelization period. These include, but are not limited to: (1) requiring shippers to enter into contracts for the entire length of Period Two, if they desire levelized rates for Period Two, (2) offering the shippers one or more options permitting them to enter into contracts of some specified minimum duration but shorter than Kern River's remaining depreciable life, while nevertheless levelizing Kern River's Period Two rates over the entire remaining depreciable life, (3) offering optional contract lengths that are shorter than Kern River's remaining depreciable life as in the previous option, but requiring the rates in those contracts to reflect a Period Two cost of service levelized over the term of the contracts, rather than Kern River's remaining depreciable life, and (4) not requiring any minimum contract duration.

261. The Commission concludes that the present record is inadequate to resolve the issue of whether, and how, the duration of shipper contracts for service during Period Two should be coordinated with the length of the Period Two rate levelization period. The hearing conducted by the ALJ in this case only addressed issues concerning Kern River's Period One rates. Thus, the participants have not had an opportunity to present evidence relevant to resolving the Period Two contract duration issue. In addition, the parties have not had an opportunity to present evidence on other issues concerning what conditions shippers must satisfy in order to be eligible for the levelized Period Two rates or how such levelized rates should be calculated. For example, parties have protested various aspects of Kern River's proposed section 30 to its GT&C, setting forth when and under what conditions the Period Two Rates will be available to different types of shippers.

262. In addition, the Commission notes that BP's protest to Kern River's revised September 22, 2009 compliance filing raises two issues concerning the calculation of Kern River's Period Two rates. In that filing, Kern River stated that it had failed to account for the fact that Period One for the 2002 Expansion Rolled-in shippers ends seven months later than Period One for Original System shippers and that this had caused it to incorrectly calculate the deferred taxes, regulatory liability and amortization period of the regulatory assets and liabilities for Period Two for the Rolled-in shippers. Kern

River stated that it had also misapplied the remaining economic life adopted by the Commission in its calculations for amortization in Period Two of the regulatory liability arising from levelization in Period One. Accordingly, Kern River revised its March 2, 2009 compliance filing to correct both of these alleged errors. BP protested both of these changes in Kern River's calculation of its Period Two rates.

263. Therefore, while the Commission finds that Kern River must offer levelized rates for Period Two as discussed in the preceding section, the Commission establishes a hearing to consider all other issues concerning the Period Two rates, including the eligibility requirements shippers must satisfy in order to obtain such rates and how the levelized rates should be calculated.[302] The Commission rejects Kern River's proposed tariff sheets related to its Period Two Rates, because those tariff sheets are premised on the use of a traditional rate design for Period Two. The Commission directs Kern River to file, within 45 days, *pro forma* Period Two tariff sheets, setting forth its proposal for offering firm shippers levelized Period Two rates, consistent with the discussion above. Kern River should also include in its compliance filing supporting data and calculations.

264. While we are setting matters related to Period Two rates for a trial-type evidentiary hearing, the Commission believes that the Period Two rate issues would be best resolved by settlement, because at bottom they are rooted in the parties' assessment of how the risks should be shared during Period Two, given the current circumstances. Accordingly, while the Commission continues to find that such matters should be set for hearing, we encourage the parties to resolve these issues among themselves.

265. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[303] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[304] The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions.

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[302] The Commission does not intend that any issues already litigated and decided in this proceeding be re-litigated. Therefore, the Period Two Rates must be calculated consistent with all of the rulings in Opinion Nos. 486, 486-A, 486-B, and 486-C.

[303] 18 C.F.R. § 385.603 (2009).

[304] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their background and experience (www.ferc.gov – click on Office of Administrative Law Judges).

Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

V. Conclusion

266. Given the Commission's findings in the instant order, in regard to Period One, and the Locked-in Period of this proceeding, [305] the Commission will accept the tariff sheets listed in Appendix C, subject to the conditions of this order, effective as of the dates indicated in Appendix C. With regard to Period Two rates, the Commission rejects the tariff sheets filed by Kern River as listed in Appendix D. Further, the Commission will reject as superseded the tariff sheets previously filed by Kern River in Docket Nos. RP04-274-008, RP04-274-017, and RP04-274-018 to comply with Commission orders as listed in Appendices A and B.

The Commission orders:

(A) The requests for rehearing of Opinion No. 486-B are denied for the reasons stated in the body of this order.

(B) The tariff sheets concerning Kern River's Period One rates, which are listed in Appendix C, are accepted, subject to conditions, to be effective as set forth in Appendix C.

(C) Kern River is directed to file revised tariff sheets for the Period One Rates within 45 days of the date of this order, as discussed in the body of this order.

(D) Kern River is directed to file *pro forma* tariff sheets setting forth levelized Period Two rates within 45 days of date of this order, consistent with the discussion in the body of this order.

(E) The tariff sheets listed in Appendices A, B and D are rejected as discussed in the body of this order.

(F) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Natural Gas Act, particularly sections 4, 5, 8 and 15 thereof, and pursuant to the Commission's Rules of Practice and Procedure

[305] The Locked-in Period in the instant proceeding is the period from November 1, 2004 to the date the prospective rates become effective, based on a continuation of the EFV rate design. *See supra* P 177-189.

and the regulations under the Natural Gas Act (18 C.F.R., Chapter I), a public hearing shall be held concerning the justness and reasonableness of the Kern River's Period Two rates. However, the hearing will be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (G) and (H) below.

(G) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2006), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the participants decide to request a specific judge, they must make their request to the Chief Judge in writing or by telephone within five (5) days of the date of this order.

(H) Within sixty (60) days of the date of this order, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the participants with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the participants' progress toward settlement.

(I) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding administrative law judge, to be designated by the Chief Administrative Law Judge, shall convene a conference in these proceedings in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure. A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge for that purpose pursuant to 18 C.F.R. § 375.304, must convene a prehearing conference in this proceeding to be held within 20 days after issuance of this order, in a hearing or conference room of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. The prehearing conference is for the purpose of the clarification of the positions of the participants and establishment by the presiding judge of any procedural dates necessary for the hearing. The presiding administrative law judge is authorized to conduct further proceedings in accordance with this order and the Rules of Practice and Procedure.

By the Commission.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

Kern River Gas Transmission Company
Docket No. RP04-274-008
Second Revised Volume No. 1
Rejected Tariff Sheets

Second Substitute Thirteenth Revised Sheet No. 5
Third Substitute Ninth Revised Sheet No. 5-A
Second Substitute Eleventh Revised Sheet No. 6
Second Substitute First Revised Sheet No. 8
Second Substitute Fourteenth Revised Sheet No. 5
Third Substitute Tenth Revised Sheet No. 5-A
Second Substitute Twelfth Revised Sheet No. 6
Second Substitute Second Revised Sheet No. 8
First Revised Fifteenth Revised Sheet No. 5
First Revised Eleventh Revised Sheet No. 5-A
First Revised Thirteenth Revised Sheet No. 6
First Revised Sixteenth Revised Sheet No. 5
First Revised Twelfth Revised Sheet No. 5-A
First Revised Fourteenth Revised Sheet No. 6
First Revised Seventeenth Revised Sheet No. 5
First Revised Thirteenth Revised Sheet No. 5-A
First Revised Fifteenth Revised Sheet No. 6
First Revised Eighteenth Revised Sheet No. 5
First Revised Fourteenth Revised Sheet No. 5-A
First Revised Sixteenth Revised Sheet No. 6
Nineteenth Revised Sheet No. 5
Original Sheet No. 5.01
Fifteenth Revised Sheet No. 5-A
Original Sheet No. 5-B
Seventeenth Revised Sheet No. 6
Sixth Revised Sheet No. 7
Third Revised Sheet No. 8

Appendix B
Page 1 of 3

Kern River Gas Transmission Company
Docket No. RP04-274-017
Second Revised Volume No. 1
Rejected Tariff Sheets

Fourth Substitute Thirteenth Revised Sheet No. 5
Fifth Substitute Ninth Revised Sheet No. 5-A
Third Substitute Eleventh Revised Sheet No. 6
Second Substitute Second Revised Sheet No. 7
Third Substitute First Revised Sheet No. 8
Fourth Substitute Fourteenth Revised Sheet No. 5
Fifth Substitute Tenth Revised Sheet No. 5-A
Third Substitute Twelfth Revised Sheet No. 6
Second Substitute Third Revised Sheet No. 7
Third Substitute Second Revised Sheet No. 8
Second Substitute First Revised Fifteenth Revised Sheet No. 5
Second Substitute First Revised Eleventh Revised Sheet No. 5-A
Substitute First Revised Thirteenth Revised Sheet No. 6
Second Substitute First Revised Sixteenth Revised Sheet No. 5
Second Substitute First Revised Twelfth Revised Sheet No. 5-A
Substitute First Revised Fourteenth Revised Sheet No. 6
Substitute Fourth Revised Sheet No. 7
Second Substitute First Revised Seventeenth Revised Sheet No. 5
Second Substitute First Revised Thirteenth Revised Sheet No. 5-A
Substitute First Revised Fifteenth Revised Sheet No. 6
Second Substitute First Revised Eighteenth Revised Sheet No. 5
Second Substitute First Revised Fourteenth Revised Sheet No. 5-A
Substitute First Revised Sixteenth Revised Sheet No. 6
Substitute Fifth Revised Sheet No. 7
Second Substitute Second Revised Eighteenth Revised Sheet No. 5
Second Substitute Second Revised Fourteenth Revised Sheet No. 5-A
Third Substitute Sixteenth Revised Sheet No. 6
Second Substitute Third Revised Eighteenth Revised Sheet No. 5
Second Substitute Third Revised Fourteenth Revised Sheet No. 5-A
Second Substitute Third Revised Sixteenth Revised Sheet No. 6
Substitute First Revised Fifth Revised Sheet No. 7

Appendix B
Page 2 of 3

Kern River Gas Transmission Company
Docket No. RP04-274-017
Second Revised Volume No. 1
Rejected Tariff Sheets

Second Substitute Fourth Revised Eighteenth Revised Sheet No. 5
Second Substitute Fourth Revised Fourteenth Revised Sheet No. 5-A
Second Substitute Fourth Revised Sixteenth Revised Sheet No. 6
Substitute Second Revised Fifth Revised Sheet No. 7
Second Substitute First Revised Second Revised Sheet No. 8
Second Substitute Fifth Revised Eighteenth Revised Sheet No. 5
Second Substitute Fifth Revised Fourteenth Revised Sheet No. 5-A
Second Substitute Fifth Revised Sixteenth Revised Sheet No. 6
Third Substitute Sixth Revised Eighteenth Revised Sheet No. 5
Third Substitute Sixth Revised Fourteenth Revised Sheet No. 5-A
Second Substitute Sixth Revised Sixteenth Revised Sheet No. 6
Third Substitute Third Revised Fifth Revised Sheet No. 7
Second Substitute Third Revised Sheet No. 8
Substitute Second Revised Nineteenth Revised Sheet No. 5
Substitute Second Revised Fifteenth Revised Sheet No. 5-A
Second Revised Seventeenth Revised Sheet No. 6
Substitute Second Revised Sixth Revised Sheet No. 7
First Revised Fourth Revised Sheet No. 8
First Revised Twentieth Revised Sheet No. 5
First Revised Sixteenth Revised Sheet No. 5-A
Twenty-First Revised Sheet No. 5
First Revised Sheet No. 5.01
Seventeenth Revised Sheet No. 5-A
First Revised Sheet No. 5-B
Eighteenth Revised Sheet No. 6
Seventh Revised Sheet No. 7
Fifth Revised Sheet No. 8
Tenth Revised Sheet No. 71
Sheet Nos. 215-229
Original Sheet No. 230
Original Sheet No. 231
Sheet Nos. 232-299

Appendix B
Page 3 of 3

Kern River Gas Transmission Company
Docket No. RP04-274-018
Second Revised Volume No. 1
Rejected Tariff Sheets

First Revised First Revised Sheet No. 5.01
First Revised First Revised Sheet No. 5-B
Second Revised Sheet No. 5.01
Second Revised Sheet No. 5-B

Appendix C
Page 1 of 4

Kern River Gas Transmission Company
Docket No. RP04-274-019
Second Revised Volume No. 1
Accepted Tariff Sheets

Effective November 1, 2004

Fifth Substitute Thirteenth Revised Sheet No. 5
Sixth Substitute Ninth Revised Sheet No. 5-A
Fourth Substitute Eleventh Revised Sheet No. 6
Third Substitute Second Revised Sheet No. 7
Fourth Substitute First Revised Sheet No. 8

Effective January 1, 2005

Fifth Substitute Fourteenth Revised Sheet No. 5
Sixth Substitute Tenth Revised Sheet No. 5-A
Fourth Substitute Twelfth Revised Sheet No. 6
Third Substitute Third Revised Sheet No. 7
Fourth Substitute Second Revised Sheet No. 8

Effective April 1, 2005

Third Substitute First Revised Fifteenth Revised Sheet No. 5
Third Substitute First Revised Eleventh Revised Sheet No. 5-A
Second Substitute First Revised Thirteenth Revised Sheet No. 6

Effective October 1, 2005

Third Substitute First Revised Sixteenth Revised Sheet No. 5
Third Substitute First Revised Twelfth Revised Sheet No. 5-A
Second Substitute First Revised Fourteenth Revised Sheet No. 6
Second Substitute Fourth Revised Sheet No. 7

Effective April 1, 2006

Third Substitute First Revised Seventeenth Revised Sheet No. 5
Third Substitute First Revised Thirteenth Revised Sheet No. 5-A
Second Substitute First Revised Fifteenth Revised Sheet No. 6

Appendix C
Page 2 of 4

Kern River Gas Transmission Company
Docket No. RP04-274-019
Second Revised Volume No. 1
Accepted Tariff Sheets

Effective October 1, 2006

Third Substitute First Revised Eighteenth Revised Sheet No. 5
Third Substitute First Revised Fourteenth Revised Sheet No. 5-A
Second Substitute First Revised Sixteenth Revised Sheet No. 6
Second Substitute Fifth Revised Sheet No. 7

Effective April 1, 2007

Third Substitute Second Revised Eighteenth Revised Sheet No. 5
Third Substitute Second Revised Fourteenth Revised Sheet No. 5-A
Fourth Substitute Sixteenth Revised Sheet No. 6

Effective October 1, 2007

Third Substitute Third Revised Eighteenth Revised Sheet No. 5
Third Substitute Third Revised Fourteenth Revised Sheet No. 5-A
Third Substitute Third Revised Sixteenth Revised Sheet No. 6
Second Substitute First Revised Fifth Revised Sheet No. 7

Effective January 1, 2008

Third Substitute Fourth Revised Eighteenth Revised Sheet No. 5
Third Substitute Fourth Revised Fourteenth Revised Sheet No. 5-A
Third Substitute Fourth Revised Sixteenth Revised Sheet No. 6
Second Substitute Second Revised Fifth Revised Sheet No. 7
Third Substitute First Revised Second Revised Sheet No. 8

Effective April 1, 2008

Third Substitute Fifth Revised Eighteenth Revised Sheet No. 5
Third Substitute Fifth Revised Fourteenth Revised Sheet No. 5-A
Third Substitute Fifth Revised Sixteenth Revised Sheet No. 6

Appendix C
Page 3 of 4

Kern River Gas Transmission Company
Docket No. RP04-274-019
Second Revised Volume No. 1
Accepted Tariff Sheets

Effective October 1, 2008

Fourth Substitute Sixth Revised Eighteenth Revised Sheet No. 5
Fourth Substitute Sixth Revised Fourteenth Revised Sheet No. 5-A
Third Substitute Sixth Revised Sixteenth Revised Sheet No. 6
Fourth Substitute Third Revised Fifth Revised Sheet No. 7
Third Substitute Third Revised Sheet No. 8

Effective January 1, 2009

Second Substitute Second Revised Nineteenth Revised Sheet No. 5
Substitute First Revised First Revised Sheet No. 5.01
Second Substitute Second Revised Fifteenth Revised Sheet No. 5-A
Substitute First Revised First Revised Sheet No. 5-B
Substitute Second Revised Seventeenth Revised Sheet No. 6
Second Substitute Second Revised Sixth Revised Sheet No. 7
Second Revised Sheet No. 7-A
Substitute First Revised Fourth Revised Sheet No. 8

Effective April 1, 2009

Substitute First Revised Twentieth Revised Sheet No. 5
Substitute First Revised Sixteenth Revised Sheet No. 5-A

Effective October 1, 2009

Third Revised Twentieth Revised Sheet No. 5
Third Revised Sixteenth Revised Sheet No. 5-A
Fourth Revised Seventeenth Revised Sheet No. 6
Fourth Revised Sixth Revised Sheet No. 7

Appendix C
Page 4 of 4

Kern River Gas Transmission Company
Docket No. RP04-274-019
Second Revised Volume No. 1
Accepted Tariff Sheets

Effective The Date This Order Issues

Substitute Twenty-First Revised Sheet No. 5
Substitute Seventeenth Revised Sheet No. 5-A
Substitute Eighteenth Revised Sheet No. 6
Substitute Seventh Revised Sheet No. 7
Substitute Fifth Revised Sheet No. 8
Sheet Nos. 218-229
Sheet Nos. 232-299

Appendix D

Kern River Gas Transmission Company
Docket No. RP04-274-019
Second Revised Volume No. 1
Rejected Tariff Sheets

Substitute Second Revised Sheet No. 5.01
Substitute Second Revised Sheet No. 5-B
Substitute Tenth Revised Sheet No. 71
Substitute Original Sheet No. 230
Substitute Original Sheet No. 231