142 FERC ¶ 61,198
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 510-A

Portland Natural Gas Transmission System   Docket No. RP08-306-002

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ORDER ON REQUESTS FOR REHEARING AND CLARIFICATION

(Issued March 21, 2013)

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Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

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(Issued March 21, 2013)

1. This order addresses requests for rehearing and clarification of Opinion No. 510, which the Commission issued on February 17, 2011, in the captioned docket.[1] Opinion No. 510 addressed briefs on and opposing exceptions to an Initial Decision issued on December 24, 2009 concerning a general Natural Gas Act (NGA) rate case filed by Portland Natural Gas Transmission System (Portland) in April of 2008.[2] As discussed below, the Commission grants in part and denies in part the requests for rehearing and clarification of Opinion No. 510.

I. **Background**

2. Portland's interstate pipeline system was authorized by a series of Commission orders, which approved Portland's initial and amended applications and issued certificates of public convenience and necessity pursuant to NGA section 7(c), 15 U.S.C. § 717f (c).[3] On March 14, 1996, Portland filed its initial application to construct and

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[1] *Portland Natural Gas Transmission System*, Opinion No. 510, 134 FERC ¶ 61,129 (2011).

[2] *Portland Natural Gas Transmission System*, Initial Decision, 129 FERC ¶ 63,027 (2009) (ID).

[3] *See Portland Natural Gas Transmission System*, 76 FERC ¶ 61,123, at 61,655 (1996) (issuing preliminary determination) (1996 Certificate Order), *order on reh'g*, 80 FERC ¶ 61,134 (issuing preliminary determination on amended application and denying rehearing) (July 1997 Certificate Order), *order on reh'g*, 80 FERC ¶ 61,345,

(continued…)

operate import facilities at the United States-Canada border near North Troy, VT and construct and operate approximately 242 miles of 20-inch diameter pipeline to extend from an interconnection with border facilities to an interconnection with Tennessee Gas Pipeline (Tennessee) near Haverhill, MA.[4] Portland's proposed pipeline included no compression facilities and was designed for a winter peak day capacity of 178,000 Mcf per day, 94 percent of which was committed during the winter heating season under binding precedent agreements. With the exception of the gas to be delivered to Northern Utilities, all deliveries were to be made into Tennessee's system at the Haverhill, MA interconnect.[5] On July 31, 1996, the Commission issued a Preliminary Determination on Portland's application, subject to the outcome of its review of environmental matters (1996 Certificate Order).[6] The Commission placed Portland at risk for the recovery of its off-peak costs and required that the billing determinants used to calculate the initial rates should be based on the total capacity of the system, i.e., 178,000 Mcf per day.[7]

3. Portland subsequently amended those applications and, in addition, filed another construction application jointly with Maritimes and Northeast Pipeline, LLC (Maritimes). Under the amended application, Portland proposed to construct and operate: import facilities at the United States/Canada border at Pittsburg, NH; 142 miles of mainline from the border crossing facilities to Westbrook, ME; and two laterals off the mainline (collectively, Northern Facilities).[8] Portland's import facilities connected with facilities in Canada constructed by Trans-Quebec & Maritimes Pipeline, Inc. (Trans-Quebec) and had a capacity of 178,000 Mcf per day.[9]

4. The 142-mile mainline of the Northern Facilities interconnected at its southern, downstream end with mainline facilities that Portland proposed jointly with Maritimes in

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at 62,145 (1997) (granting certificate authority and addressing rehearing requests) (September 1997 Certificate and Rehearing Order).

[4] 1996 Certificate Order, 76 FERC at 61,649,

[5] *Id.* at 61,650,

[6] *Id.* at 61,123.

[7] *Id.* at 61,661.

[8] July 1997 Certificate Order, 80 FERC at 61,444-45 (amended application filed in Docket Nos. CP96-248-000, *et al*. and CP96-249-000, *et al*.).

[9] *Id.* at 61,445,

Docket No. CP97-238-000. The proposed joint facilities consisted of 101 miles of pipeline, including 35 miles of mainline from Westbrook, ME, to Wells, ME and 66 miles of mainline from Wells, ME to Dracut MA, and three laterals off the joint mainline facilities (collectively, Joint Facilities). Seven shippers executed precedent agreements with Portland for service on the Northern and Joint Facilities. The volumes under those firm agreements totaled 170,200 per day (on a winter peak day).[10] Portland's proposed rates were calculated based on a winter-day design capacity of 178,000 Mcf per day.

5. On July 31, 1997, the Commission issued a Preliminary Determination on the amended application and the new application and granted and denied certain requests for rehearing of its 1996 Certificate Order.[11] Among other things, the Commission found, that during the first year of operation, Portland would be capable of providing 178,000 Mcf per day of firm transportation service on Northern Facilities and 169,400 Mcf per day of firm transportation service on the Joint Facilities.[12] During the second and subsequent years, the Commission found that both the Northern Facilities and Portland's share of the Joint Facilities would be capable of providing 210,000 Mcf per day of firm transportation service.[13] The Commission required Portland to revise its rates to reflect billing determinants based on 178,000 Mcf per day for the first year and an estimated increased capacity of 210,000 during subsequent years.[14] The July 1997 Order also expressly placed Portland at risk for unsubscribed capacity based on 178,000 Mcf per day for the first year of operation and 210,000 Mcf per day during subsequent years. The July 1997 Certificate Order also required Portland to make a NGA section 4 rate filing within three years of the in-service date of its system "so that rates may be effective no later than the third anniversary of its in-service date."[15]

6. Following the July 1997 Certificate Order, Portland sought rehearing of the Commission's decision to require Portland to revise its rates to reflect 210,000 Mcf per day of capacity after the first year of operation and be placed at risk for the increased

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[10] July 1997 Certificate Order, 80 FERC at 61,445.

[11] *Id.*

[12] *Id.* at 61,447.

[13] *Id.* at 61,447-48.

[14] *Id.* at 61,448.

[15] September 1997 Certificate and Rehearing Order, 80 FERC at 62,147.

unsubscribed capacity.[16] Portland argued that it was uncertain when additional compression would go into service or the actual amount of increased compression and its effect on the capacity of the Portland system. In the September 1997 Certificate and Rehearing Order, the Commission granted the requested certificate authorizations for the Northern and Joint Facilities and granted Portland's rehearing request.[17] The Commission agreed with Portland that it was premature, based on the current facts, to require Portland to revise its rates and to be placed at risk for higher capacity after its first year of operation. Instead, the Commission stated it would review the matter when Portland made its first NGA section 4 rate filing within three years of its in-service date.[18]

7. Thereafter, on October 1, 2001, in Docket No. RP02-13-000, Portland made the NGA section 4 rate filing required by the certificate orders (2001 Rate Filing). The Commission, in an order issued October 31, 2001, accepted and suspended the 2001 Rate Filing for five months — until April 1, 2002 — and made it subject to refund.[19] Subsequently, on October 25, 2002, Portland filed an uncontested Stipulation and Settlement Agreement to resolve all issues in Docket No. RP02-13-000 (2002 Settlement).

8. On January 14, 2003, the Commission approved the 2002 Settlement.[20] The 2002 Settlement established a firm transportation (FT) maximum recourse rate of $0.85 per Dekatherm (Dth) effective April 1, 2002.[21] It further stated that the settlement base tariff rates were designed "using rate levelization through March 31, 2020."[22] The settlement stated that its rate levelization methodology was the same as that approved in Portland's certificate proceeding, except that the levelization period had been extended by one year. The 2002 Settlement provided that the design of the Settlement Base Tariff

[16] *Id.* at 62,146.

[17] September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345.

[18] *Id.* at 62,147.

[19] *Portland Natural Gas Transmission System*, 97 FERC ¶ 61,131 (2001).

[20] *Portland Natural Gas Transmission System*, 102 FERC ¶ 61,026 (2003) (2002 Settlement Order).

[21] *Id.* P 3.

[22] *Id.* P 5.

Rates' design satisfied the at-risk throughput condition directed by the Commission in granting Portland's initial certificate and reflected an allocation of costs to representative levels of interruptible and off-peak services. The 2002 Settlement also modified the Most Favored Nations (MFN) clause contained in the contracts of long-term firm shippers to allow Portland to discount contracts of less than two years without being required to offer the same terms to its long-term firm shippers.[23] The 2002 Settlement required Portland to file a general NGA section 4 rate case no sooner than, and no later than, April 1, 2008.[24] The 2002 Settlement required Portland to continue to propose to design its rates using the same rate levelization methodology as in the settlement. Finally, the 2002 Settlement required Portland to use a 2.0 percent depreciation rate for transmission plant in its next general rate filing.

9. On April 1, 2008, Portland made the NGA section 4 rate filing as required by the 2002 Settlement (2008 Rate Filing), which is the subject of the instant proceeding. According to Portland, its proposed cost-of-service and determination of rates reflected the costs and billing determinants for the Base Period (12 months ending December 31, 2007), as adjusted through the Test Period (nine months ending September 30, 2008).[25] The Commission accepted and suspended Portland's tariff sheets until September 1, 2008, subject to refund, and established procedures for an evidentiary hearing.[26] The evidentiary hearing commenced on July 13, 2009 and concluded on July 28, 2009.[27]

10. On December 24, 2009, the Presiding Administrative Law Judge (ALJ) issued the Initial Decision.[28] On May 12, 2010, Portland filed a separate, general NGA section 4

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[23] *Id.* P 6.

[24] *Id.* P 7.

[25] Portland 2008 Rate Filing at 3.

[26] *Portland Natural Gas Transmission System*, 123 FERC ¶ 61,108 (2008) (Hearing Order on 2008 Rate Filing).

[27] On May 11, 2009, Portland submitted a Motion for Certification and Approval of Partial Settlement (2009 Settlement) resolving all outstanding issues related to the design of Portland's rates for short-term services. The ALJ certified the 2009 Settlement to the Commission on June 18, 2009, and the Commission approved the 2009 Settlement on September 23, 2010. *Portland Natural Gas Transmission System,* 132 FERC ¶ 61,256 (2010).

[28] ID, 129 FERC ¶ 63,027.

rate case in Docket No. RP10-729-000 (2010 Rate Filing). Thus, the resulting rates determined in this proceeding (Docket No. RP08-306-000) are effective only for a locked-in period from September 1, 2008 through November 30, 2010. The rates in the 2010 Rate Filing went into effect, subject to refund, on December 1, 2010.[29]

11. On February 17, 2011, the Commission issued Opinion No. 510, which addressed the briefs on and opposing exceptions.[30] Among other things, Opinion No. 510 affirmed the ALJ's findings in the ID with regard to levelized rates, two out of four cost-of-service issues raised, negative salvage, and in part, on determinations relating to depreciation. The Commission reversed the ALJ in part with regard to the appropriate ROE, resulting in a 12.99 percent ROE instead of the 11.65 percent adopted by the ALJ. The Commission also reversed the ALJ in part on two cost-of-service issues, ad valorem taxes and Pipeline Integrity Projects (PIP)/Maintenance of Mains. In addition, the Commission reversed the ALJ's proposal to allow Portland to file for an increased depreciation rate, finding that there was insufficient record evidence to support such a change. The Commission also reversed the ALJ's recommendation that Portland be required to credit its interruptible transportation (IT) and Park and Loan (PAL) revenues against its cost-of-service. Instead, the Commission required Portland to allocate costs to its IT/PAL services based upon a projected volume of interruptible transportation, subject to the condition that Portland's overall rate design volumes must satisfy the at-risk condition of Portland's original certificate orders. Consistent with this determination to require Portland to allocate costs to its IT/PAL services, the Commission reversed the ALJ with regard to the treatment of certain bankruptcy proceeds and required Portland to include billing determinants associated with the bankruptcy. Finally, Opinion No. 510 required Portland to file within 30 days a compliance filing consisting of revised tariff sheets and rates, including proposed accounting and workpapers, reflecting the Commission's rulings in the order.

12. On March 15, 2011, Portland filed an expedited motion for an extension of time within which to file materials as directed by Opinion No. 510. In its motion, Portland requested that the Commission defer Portland's obligation to submit its compliance filing and provide refunds until 30 days after the Commission issues its order on Portland's request for rehearing and clarification of Opinion No. 510, which it intended to file on or

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[29] *See Portland Natural Gas Transmission System*, 131 FERC ¶ 61,230 (2010) (Hearing Order on 2010 Rate Filing); *see also* Portland's Motion to Place Suspended Rates and Tariff Sheets into Effect, Docket No. RP11-1541-000 (Nov. 22, 2010).

[30] Opinion No. 510, 134 FERC ¶ 61,129.

before March 21, 2011. Upon consideration, Portland was granted an extension of time to comply with Opinion No. 510 until further order of the Commission.[31]

13. On March 18, 2011, Portland filed a request for rehearing and clarification of Opinion No. 510, which was subsequently amended on March 21, 2011. On March 21, 2011, PNGTS Shippers Group (PSG) and Canadian Association of Petroleum Producers (CAPP) also filed requests for rehearing of Opinion No. 510. On April 5, 2011, Portland filed an answer to PSG's request for rehearing of Opinion No. 510 and PSG's motion for official notice.[32]

14. On May 31, 2011, Commission staff issued data requests directed to Portland concerning both Opinion No. 510 and Portland's request for rehearing and clarification of Opinion No. 510 (Data Request).[33] Portland filed its response to the Data Request on June 30, 2011 (Response to Data Request).[34] In its Response to Data Request, Portland states that it calculated its cost of service, billing determinants and rates consistent with Order No. 510, as well as its request for rehearing and clarification.

15. Public notice of Portland's data response was issued on July 12, 2012. PSG was the only party to file comments. PSG states that it disagreed with the modifications and positions advocated by Portland in its request for rehearing and clarification and believed that Opinion No. 510 should not be modified in the various respects requested by Portland in its rehearing request. PSG also states that Portland's $0.7641 Dth per day Opinion No. 510 compliance rate appears to be within the same general range as its own, which it calculated to be approximately $0.009 per Dth less than that of Portland's. PSG states that it did not analyze the calculations that Portland performed consistent with its rehearing request.

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[31] *Portland Natural Gas Transmission System*, Docket No. RP08-306-000 (Mar. 17, 2011) (Notice of Extension of Time).

[32] In PSG's request for rehearing, PSG requests that the Commission take official notice of various inputs to the Commission's DCF analysis. While PSG does not label its request a motion, it is in fact a motion to take official notice.

[33] *Portland Natural Gas Transmission System*, Docket No. RP08-306-000 (May. 31, 2011).

[34] On June 9, 2011, Portland sought, and the Commission granted, an extension of time until June 30, 2011 for Portland to file its response to the Data Request. *Portland Natural Gas Transmission System*, Docket No. RP08-306-000 (June 15, 2011) (letter order granting extension request).

16. The Commission rejects Portland's answer to PSG's request for rehearing of Opinion No. 510, but only to the extent Portland's answer is responding to PSG's rehearing request. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure prohibits answers to requests for rehearing.[35] The Commission will accept Portland's response to PSG's motion for official notice.

II. Pipeline Integrity Projects

A. Background

17. In Opinion No. 510, the Commission reversed the ID and found that the $397,682 figure advocated by PSG before the ALJ is a just and reasonable calculation of Portland's Pipeline Integrity Project (PIP) costs. Portland's PIP costs are costs incurred to comply with the Pipeline Safety Act of 2002, and are recorded as expenses in Account No. 863.[36] In its NGA section 4 filing in this proceeding, Portland reflected actual PIP costs for the 12-month base period (calendar year 2007) of $201,218, but projected that its PIP costs for the last 12 months of the overall test period (October 2007-September 2008) would be $1,149,218.[37] Thereafter, in response to a July 2008 Trial Staff data request,[38] Portland estimated its PIP expenses for the period March 31, 2007 through 2011 as follows:

March 31-December 31, 2007	$168,389
2008	$1,354,000
2009	$262,000
2010	$248,000
2011	$262,000

18. At the hearing, these projections were challenged based on Portland's 45-day update filing, which showed only $818,727 in PIP costs during the last 12 months of the test period, which included the last three months of 2007 and the first nine months of 2008. Moreover, Portland's 2008 Form No. 2 indicated that its calendar year 2008 PIP costs were $821,011, an increase over the $201,218 reported for 2007. Despite the conflicting data, Portland and Trial Staff proposed to average the 2007 through 2011 amounts proposed by Portland, resulting in $458,878 for the pipeline's PIP/Maintenance

[35] 18 C.F.R. § 385.713(d)(1) (2012).

[36] *E.g.*, Portland Form No. 2, page 323 (2008); Ex. No. PSG-128.

[37] Portland 2008 45-Day Update Filing, Schedule H-1(1)(b).

[38] Exh. No. S-7; ID, 129 FERC ¶ 63,027 at P 132.

of Mains expenses.[39] Portland defended the five-year average because Portland was projected to incur significantly higher PIP expenses during the test period as compared to its projected expenses through 2011.

19. PSG Witness Fink, on the other hand, used a combination of the actual cost data for the last twelve months of the test period (the year ending September 2008), in combination with Portland's projected data for years 2009, 2010 and 2011. PSG averaged the available data for these four non-contiguous years to calculate $397,682 in PIP expense.[40]

20. The ALJ adopted Portland and Trial Staff's proposed $458,878 amount for PIP expense. The ALJ rejected PSG Witness Fink's calculation as distorted because it omitted data for October through December 2008 and used a non-contiguous data sequence.[41] The ALJ faulted this proposal as examining a particular time period, while failing to assess Portland's overall cost projection. The ALJ also rejected PSG's attempt to "cherry pick" certain of Portland's actual versus test period costs as improper.[42]

21. In response to PSG's objection to the use of the erroneous estimate for 2008 PIP expenses, the Commission adopted the $397,682 figure, based on a four-year average advocated by PSG's Witness Fink at hearing.

22. The Commission stated that its regulations require any proposed rate increases to be justified by filing cost and other information for a test period consisting of a base period of "12 consecutive months of the most recently available actual experience,"[43] and an adjustment period of up to 9 months immediately following the base period. Rate factors established during the base period may be adjusted for changes, including costs, which are "known and measurable" and "which will become effective within the adjustment period."[44] The Commission stated that use of costs projected to be incurred

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[39] ID, 129 FERC ¶ 63,027 at P 132.

[40] The four years to be averaged are the test year, reflecting costs incurred in December 2007, as well as Jan. – Sept. 2008 (no costs were incurred in Oct. or Nov. 2007), and the projected costs for years 2009, 2010, and 2011.

[41] ID, 129 FERC ¶ 63,027 at P 138.

[42] *Id*. P 139.

[43] 18 C.F.R. § 154.303(a)(1).

[44] 18 C.F.R. § 154.303(a)(4).

for periods after the test period, including the years 2009-2011, was inconsistent with its test period methodology, because those costs did not become effective during the test period. However, the Commission nevertheless permitted the use of the post-test period projections in the circumstances of this case, explaining:

> all participants rely on the projected post-test period costs and agree that the actual costs during the last twelve months of the test period are not representative of the costs expected to be incurred while the subject rates were in effect. Therefore, we find that considering the costs to be anticipated in future years for the PIP projects is a just and reasonable way to measure Portland's costs. In this instance, doing so results in a figure that is less than the actual costs incurred by Portland during the test period.[45]

23. However, the Commission found that Portland's projected 2008 PIP expense of $1,354,000 was not accurate. The Commission pointed out that Portland's actual PIP expense for the last 12 months of the test period ending September 30, 2008 was $818,727, and Portland's Form No. 2 for 2008 reported that its 2008 PIP expenses were $821,011. The Commission found that Portland's general statements to the effect that "actions originally budgeted for 2010 might be accelerated or deferred, based on inspections and testing results,"[46] did not adequately support its position that its overall projection may continue to be relied on. Portland's projected 2008 PIP expense was based on its estimated expense for eight specific projects it expected to complete in 2008.[47] At the July 2009 hearing, Portland presented no evidence as to what had happened with respect to any of these projects during 2008 to cause Portland not to incur the full amount of its projected PIP expenses for that year. The Commission found that Portland had failed to demonstrate that the costs of any of the underlying projects not incurred in 2008 would in fact be rescheduled and incurred in later years.

24. The Commission also addressed the ALJ's concern over PSG's proposal to use non-contiguous data, by noting that Portland's projection for 2008 was unreliable, and it is this fact that created the gap, because Portland did not provide reliable data for the last quarter in 2008. The Commission also rebutted the "cherry picking" charge, noting that the result would be even lower if the gap were filled, and the Commission averaged costs

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[45] Opinion No. 510, 134 FERC ¶ 61,129 at P 86.

[46] Portland Brief Opposing Exceptions at 28.

[47] Exh. No. S-7 at 4.

for all of 2008 with the 2007 actual costs and the projected 2009-2011 costs. That is because the five-year average of $201,218 in 2007 expense, $821,011 for 2008, and the projected costs ($358,846) is lower than the result approved in Opinion No. 510.

B. Request for Rehearing

25. Portland requests rehearing of the Commission's determination of $397,682 as PIP costs, based on PSG Witness Fink's calculation. Portland defends Staff's proposal, which it describes as representing the five-year average of the actual costs incurred in calendar year 2007 and the costs projected to be incurred between 2008 and 2011. Portland, however, objects to the Commission's reliance on a mix of actual and projected costs, stating that the Commission "improperly blended both actual costs and projected costs for a shortened and noncontiguous time period."

26. Portland criticizes the PSG approach because it reduces the period over which PIP expenses are annualized to four years, selectively eliminates data for a portion of the contiguous chronological period, and incorporates the use of actual expenses incurred during a significant period. Portland concludes that PSG's methodology limits any ability to account for the known annual fluctuation, resulting in a less than accurate level of expenses. Portland states that the Commission is in error when it asserted in Opinion No. 510 that there is no reliable data for the last quarter of 2008, since the total expense for 2008 is in the record in its 2008 Form No. 2.

27. Portland attempts to respond to the Commission's concern with the lack of evidence that projected costs not incurred in 2008 would nevertheless be incurred in 2009, 2010, or 2011. Portland defends its projections and describes Staff Exh. No. S-7 as representing a comprehensive overview of the projects to be undertaken and their cost through 2011. Portland states that Exh. No. S-7 is a comprehensive table listing the compliance projects projected to be completed, a description of the compliance projects, and the specific annual costs that would be incurred for each project. Portland notes that its exhibit listed the projected annual costs for compliance projects relating to imagery, structure identification, corrosion inline inspection, and other items. Portland argues that the details of its projections have not been contested by the Participants in this proceeding, and no participant has demonstrated that the resulting five-year projected figure is incorrect or improperly calculated. Portland faults PSG for failing to rebut its observation that, simply because actual costs were lower than projected for one year, it does not mean that the total five year sum of projected costs is overstated. Portland cites testimony indicating that the 2008 projection was based on "additional maintenance and monitoring activities required to comply with the Pipeline Safety Improvement Act of

2002."[48] According to Portland, it is the five-year projection that matters, not the individual assessment of a year.

28. Portland states that it is counter-productive to require or rely on a true up, for just one year, when the goal is to calculate a representative level of costs incurred over multiple years. Seeking to bolster its reliance on its original projection, Portland cites the Pipeline Safety regulations as requiring inspections within a specific period of time, not on a precise date.[49]

29. Portland cites an argument in its initial brief stating:

> [A] long term program of pipeline integrity projects will experience changes in terms of timing of projects as [the program] is executed and the pipeline responds to what is revealed as [its] inspection unfolds. The fact that actual costs in any given period are higher or lower than originally projected has no direct correlation to the total costs expected to be incurred over the life of the long term program of projects.[50]

30. Portland argues that it is improper to rely on a short term snapshot of costs, without taking into account the overall long-term program. Portland argues that blending a significant portion of actual costs with projected costs over a shortened time does not allow reconciliation of costs which may be overestimated in any given year. According to Portland, PSG's approach fails to take into account annual fluctuations with respect to the PIP costs, and is therefore not just and reasonable.

31. Portland asserts that if the Commission is to use actual expenses incurred by Portland for 2008, it should use the larger Form No. 2 figure, $821,011, rather than the figure for the one-year test period ending September 2008, $818,727. Portland therefore suggests for the first time on rehearing that the Commission should sum actual 2008 costs, instead of actual test period costs, and normalize that amount by averaging in the 2009, 2010, and 2011 projected costs, increasing the result from $397,682 to $398,253.

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[48] Portland Rehearing Request at 66.

[49] Portland Rehearing Request at 67 (citing Pipeline Safety regulations, 40 C.F.R. § 192.939 (2010) (generally establishing reassessment cycle of seven years)).

[50] Portland Initial Brief at 31-32.

C. Commission Determination

32. In Opinion No. 510, the Commission expressed its concern that Portland's original projection of $1,354,000 in PIP expense for 2008 was inaccurate, with Portland incurring only $821,011 total PIP expense in 2008, according to its Form No. 2 for that year. Despite the fact that its actual 2008 expenses failed to support its projections, Portland failed to explain at hearing why the projected costs for 2008 were not incurred. Also, despite the presence of detailed workplans for eight specific projects it expected to complete in 2008, Portland failed to provide any updates explaining why it had not incurred the costs projected for 2008 and when it expected to incur the costs projected for that year. In Opinion No. 510, the Commission stated:

> Portland has failed to demonstrate that the costs of any of the underlying projects not incurred in 2008 would in fact be incurred in later years, because those projects were delayed in 2008 and rescheduled into the later years. For all that appears on the present record, Portland's estimated costs may have exceeded the actual costs of the projects, or some of the projects may have been cancelled outright, deferred beyond the projection period, or displaced other projects in the later period. Portland bears the burden to support its cost figures and demonstrate that its proposed costs are just and reasonable. In light of the failure of the 2008 actual costs to meet expectations, it was incumbent on Portland to update its remaining data with revised cost estimates to reflect changed circumstances.[51]

33. In Opinion No. 510, the Commission responded to the fact that Portland's actual PIP costs for 2008, based on Form No. 2 data were 39 percent lower than its projection. Although the Commission usually relies on test period cost data, adjusted for known and measurable changes, the Commission approved a normalization based on a five-year projection of costs, because all Participants supported the normalization and agreed that the cost data was not reflective of the costs that Portland was likely to experience thereafter. The Commission adopted a methodology that used the actual 2007 costs and test period costs, and normalized them by averaging the expense for the test period year, with Portland's projections for the years 2009, 2010, and 2011.

34. On rehearing, Portland objects to the Commission's reliance on a blend of actual and projected costs. The Commission finds this argument unconvincing. The

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[51] Opinion No. 510, 134 FERC ¶ 61,129 at P 87.

Commission's goal is to develop a rate that is representative of the costs that Portland will incur to provide service. In this proceeding, the Participants agree that Portland's historic cost data is not reflective of the amount of expenditures that Portland may anticipate in the future, because the Form No. 2 data for 2008 is higher than Portland anticipates in later years (as is Portland's original projection for 2008). Portland itself proposed to use a combination of actual data for 2007 and projected data for 2008 through 2011.[52] We see no difficulty in updating the projected data for 2008 with the actual data for that year once that data became available.

35. We disagree with Portland that the shippers have the burden to rebut its tepid observation that simply because actual costs were lower than projected for one year, the total five year sum of projected costs may still be accurate. Once the actual 2008 cost data demonstrated that Portland's projections for that year were in error, Portland bore the burden to demonstrate that its original projections were nevertheless reliable on the whole. In Opinion No. 510, the Commission found that Portland failed to meet this burden and Portland's speculation on rehearing fails to convince us otherwise.

36. In Opinion No. 510, the Commission indicated its concern with Portland's continued reliance on its overall five-year projection, given that Portland failed to incur a significant portion of the expense that it predicted it would incur in the initial phase of its PIP program. The Commission expressed its concern that Portland failed to demonstrate at the hearing that the expenses that were not incurred in 2008 as predicted would nevertheless be incurred in a later period, and thus that the decline was not as a result of the costs being lower than expected, not needed, or deferred into a later time period. On rehearing, Portland points to no record evidence providing these facts, but instead refers to its original projection, which has been called into question, and to a statement in its Initial Brief stating, "The fact that actual costs in any given period are higher or lower than originally projected has no direct correlation to the total costs expected to be incurred over the life of the long term program of projects." However, the fact that, as Portland stated, the level of actual costs has no correlation to the costs to be expected over the life of the long-term program, is not the same as demonstrating that the costs will necessarily match the original projection, once that projection has been brought into question.

37. Citing the Pipeline Safety regulations, Portland suggests that the costs would necessarily be incurred within a certain timeframe. However, the seven year cycle suggested by the Pipeline Safety regulations, does not establish that costs will be incurred in the five-year 2007-2011 normalization period at issue in this proceeding, nor does

[52] The PIP costs could not be normalized using historic data in this case, since Portland's PIP program is new, and historic numbers are not available.

Portland point to record evidence demonstrating that it anticipated that any costs not incurred in 2008 would nevertheless be incurred in the normalization period. Furthermore, there is nothing in Portland's position to show, given the seven year cycle under the Pipeline Safety regulations, that projects scheduled in the five-year normalization period would not simply displace later projects to be completed later in their own seven year cycle.

38. Because the Portland proposal relied on inaccurate data for 2008, the Commission adopted the calculation made by PSG Witness Fink, using actual data for the test period year ending September 2008, $818,727, together with Portland's projections for 2009, 2010, and 2011 ($262,000, $248,000, and $262,000). Portland never updated these 2009-2011 projections, despite its later urging that the Commission recognize that expenses not incurred in 2008 could be deferred to these years. PSG Witness Fink then averaged these four years expenses to arrive at the $398,252 figure adopted in Opinion No. 510.

39. Portland faults the Fink methodology for relying on "non-contiguous" data, and contests the Commission's finding that there is no reliable data for the last quarter in 2008. Although Portland points on rehearing to the Form No. 2 expense of $821,011 for 2008, Portland fails to specify the figure for 4th Quarter 2008. However, upon further review, we note that Portland's 45-day update filing, Schedule H-1(1)(b) provides data by month, showing that the $201,218 Form No. 2 expense for 2007, was incurred entirely in December 2007.

40. This fact permits the Commission to confirm the expense incurred in the gap and reconcile the figures for the last twelve months of the test period with the Form No. 2 data. The $818,727 incurred in the last twelve months of the test period, October 1, 2007 – September 30, 2008, reflects $201,218 for October 1 to December 31, 2007. Thus, an average annual PIP expense may be calculated based on the $201,218 actual costs during the last three months of 2007, actual 2008 PIP expenses of $821,011 shown in the 2008 Form No. 2, and the 2009, 2010, and 2011 projections by Portland. Dividing the total PIP expenses for this overall period by the 51 months in the period and multiplying the monthly average by twelve provides an average annual expense of $422,169. This figure incorporates the correction to the 2008 projection sought by PSG Witness Fink, and avoids the failure to account for the three missing months in Mr. Fink's analysis where Portland continued to incur costs at a higher rate, comparable to the remainder of 2008, rather than the smaller expenses projected for the later years.

41. Thus, the Commission grants rehearing and permits a further refinement of the out-of-test period adjustment to reflect the cost data for the 4th quarter of 2008 in the PIP calculation for expenses incurred and projected to be incurred from October 1, 2007 through December 31, 2011, as described above. The data to be reflected is reflected in the record in Portland's 2008 Form No. 2. Portland's rehearing request is otherwise denied as discussed above.

III. At-Risk Condition

A. Background

42. As explained by PSG witness Fink, an at-risk condition requires that a pipeline's rates be designed based on the assumption that all capacity is subscribed at maximum recourse rates even if some or all of it is not. This is accomplished by establishing billing determinants at a level that reflects the full annualized capacity of the pipeline system.[53] In terms of a pipeline's cost-of-service, this means that each unit of the pipeline's annualized capacity would be assigned a pro rata share of the pipeline's cost-of-service and if the pipeline fails to achieve revenues equal to its capacity times its maximum rate, the pipeline would not recover its full cost-of-service.

43. The purpose of an at-risk condition was to guard against shifting the costs of potentially underutilized facilities to existing customers who do not benefit from the project and to protect future customers from rate increases if the new facilities were underutilized.[54] The Commission reasoned that, because the pipeline proposing to build the new facilities was in the best position to evaluate whether and how large to build its facilities, it was appropriate that the pipeline, not its customers, shoulder the financial risk in the event that its judgments turned out to be wrong.[55] The at-risk condition, thus, operates as a floor on a pipeline's billing determinants used to assign revenue responsibility among services.

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[53] *See, e.g.*, 1996 Certificate Order, 76 FERC at 61,660 ("Traditionally, the initial rates assume reservation billing determinants equal to the annualized capacity of the system. In [Portland's] case this would be 178,000 Mcf/day multiplied by 12 months (2,136,000 Mcf)).

[54] *See Koch Gateway Pipeline Co.*, 79 FERC ¶ 61,115 (1997). The Commission discontinued use of "at-risk" conditions with the issuance of its 1999 Certificate Policy. *See Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999). As we discussed there, the 1999 Policy Statement's requirement that a pipeline must be prepared to financially support the project without relying on subsidization from its existing customers obviated that need for an "at-risk" condition because it accomplished the same purpose, namely making the pipeline responsible for the costs of new capacity that is not fully utilized. *Id*. at 61,747.

[55] See *Questar Pipeline Co.*, 65 FERC ¶ 61,033 (1993).

44. In the 1996 Certificate Order, the Commission directed Portland, among other things, to revise its initial rates to reflect billing determinants of 178,000 Mcf per day, even though Portland only had firm contracts for 167,400 Mcf per day during the winter (November-March) and 66,000 Mcf per day during the summer (April-October).[56] Portland's billing determinants reflected the firm, winter-day design capacity of Portland's system.[57] Recognizing that Portland would have unsubscribed capacity for both the winter and summer months based on these figures, the Commission expressly placed Portland at risk for the recovery of costs based on 178,000 Mcf per day, stating:

> The Commission has traditionally put pipelines at risk for unsubscribed capacity on new pipelines.
>
> Traditionally, the initial rates assume reservation billing determinants equal to the annualized capacity of the system. In [Portland's] case this would be 178,000 Mcf/day multiplied by 12 months (2,136,000 Mcf). However, [Portland] has used lower billing determinants in calculating its proposed initial rates because it does not have firm contracts for most of its capacity during the summer months….
>
> Accordingly, the Commission will place [Portland] at risk for the recovery of the off-peak costs. The billing determinants used to calculate the initial rates should be based on the total capacity.[58]

45. Similarly, in the July 1997 Certificate Order, the Commission directed Portland to revise its initial rates to reflect billing determinants of 178,000 Mcf per day for the first year of service and, in subsequent years, 210,000 Mcf per day.[59] Specifically, the Commission stated:

> In the first year of service, [Portland] will have a capacity of 178,000 Mcf per day on its 24-inch mainline and

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[56] 1996 Certificate Order, 76 FERC at 61,649-50, 61,660.

[57] *Id.* at 61,654, 61664.

[58] *Id.* at 61,660-61.

[59] July 1997 Certificate Order, 80 FERC at 61,448.

> a capacity of 169,400 Mcf per day on the joint facilities. In subsequent years, the upstream mainline and [Portland's] share of the joint facilities' capacity will increase to 210,000 Mcf per day. Therefore, [Portland] must revise its initial rates to reflect billing determinants based on 178,000 Mcf per day for the first year and design the rates for the subsequent years to reflect billing determinants based on 210,000 Mcf per day.[60]

Recognizing that Portland would have unsubscribed capacity for both the winter and summer months based on these figures, the Commission once again expressly placed Portland at risk for the recovery of costs based on 178,000 Mcf per day for the first year of operation and 210,000 Mcf per day in subsequent years, stating:

> [Portland] has subscribed capacity of 170,200 Mcf per day from November 1 through March 31 each year and 96,600 Mcf per day from April 1 through October 31. Based on an effective system capacity of 178,000 Mcf per day in the first year of operation, there will be unsubscribed capacity of 7,800 Mcf per day during the winter months and 81,400 Mcf per day during the remainder of the year. In subsequent years, based on a system capacity of 210,000 Mcf per day, there will be unsubscribed capacity of 39,800 Mcf per day during the winter months and 113,400 Mcf per day during the remainder of the year. Accordingly, the Commission will place [Portland] at risk for the recovery of costs for the unsubscribed capacity.[61]

46. Following the July 1997 Certificate Order, Portland sought rehearing of the Commission's decision to require Portland to revise its rates to reflect 210,000 Mcf per day of capacity after the first year of operation and be placed at risk for the increased unsubscribed capacity. Portland argued that it was uncertain when additional compression would go into service or the actual amount of increased compression and its effect on the capacity of the Portland system. In the September 1997 Certificate and Rehearing Order, the Commission agreed with Portland and found that it was premature, based on the current facts, to require Portland to revise its rates and to be placed at risk

[60] *Id.*

[61] *Id.*

for higher capacity after its first year of operation.[62] Instead, the Commission stated that it would review the matter when Portland made its first NGA section 4 rate filing within three years of its in-service date.[63]

47. Thereafter, on October 1, 2001, Portland made a NGA section 4 rate filing in Docket No. RP02-13 as required by the certificate orders. The rate filing ended in an uncontested settlement, which the Commission approved on January 12, 2003.[64] The instant proceeding was Portland's first NGA section 4 rate case since the settlement.

48. In the instant proceeding, while Portland proposed to design its rates based on billing determinants of 210,840 Dth per day (approximately 210,000 Mcf per day), it asserted that its at-risk condition should remain at the 178,712 Dth per day (178,000 Mcf per day) level established in its certificate proceeding.[65] Portland based its proposed billing determinants on Portland's capacity entitlement of 210,840 Dth per day on the Joint Facilities, which it claimed represented its system's current firm capacity. Trial Staff recommended that the at-risk condition be set at 210,840 Dth per day (210,000 Mcf per day). PSG, on the other hand, argued that the at-risk condition should be established at a level of 217,405 Dth per day. In the ID, the ALJ agreed with Trial Staff that the Commission should set the at-risk condition at a level of 210,840 Dth per day.[66]

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[62] *Id.* at 62,146.

[63] *Id.* at 62,147.

[64] 2002 Settlement Order, 102 FERC ¶ 61,026.

[65] In a certificate proceeding, pipeline capacity generally is stated in volumetric units. However, pipelines are required to state their rates in thermal units. *See Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, Order No.582, FERC Stats & Regs. ¶ 31,025, at 31,392 (1995). Therefore, Portland's proposed billing determinants are stated in thermal units (Dth) and derived by multiplying the heating content of gas delivered by Portland into the Joint Facilities (1004 Btu) by Portland's volumetric capacity entitlement on the Joint Facilities (210,000 Mcf per day).

[66] *Id.* P 311.

B. Level of At-Risk Condition

49. Opinion No. 510 affirmed the ALJ's decision to establish Portland's at-risk condition at a level of 210,840 Dth per day.[67] The Commission agreed with the ALJ that, in both the July 1997 Certificate Order and September 1997 Certificate and Rehearing Order, the Commission intended to base Portland's at-risk condition on the actual capacity of the pipeline and to place Portland at-risk for any unsubscribed capacity.[68] Also agreeing with the ALJ, the Commission found that 210,840 Dth per day was the appropriate level at which to set the at-risk condition.[69] The Commission pointed out the direct relationship between Portland's total firm system capacity and the distribution of deliveries on its system.[70] Portland witness Haag described this relationship stating that, "as North System deliveries fall off, our total end to end firm system capacity approaches – or it becomes the 210,840."[71] Opinion No. 510 also pointed out that approximately 95 percent of Portland's firm contracts have delivery points on the Joint Facilities.

1. Rehearing Request

50. PSG seeks rehearing of the Commission's determination in Opinion No. 510 that Portland's at-risk condition be based on a capacity level of 210,840 Dth per day. PSG contends that the Commission erred in ignoring certain record evidence establishing that Portland's firm system capacity during the Test Period year exceeded 210,840 Dth per day and was at least 217,405 Dth per day. Specifically, PSG contends that the Commission's decision was in error because: (1) the record clearly establishes that Portland's Base and Test Period Joint Facilities capacity entitlement was not merely 210,840 Dth per day, a figure which is derived by applying the heating content of Canadian gas received by Portland at its Pittsburg, NH system origin (1004 Btu) to Portland's volumetric capacity entitlement on the Joint Facilities of 210,000 Mcf per day,[72] and (2) Portland's Northern Facilities capacity during the Test Period year, even

[67] Opinion No. 510, 134 FERC ¶ 61,129 at P 290.

[68] *Id.* P 290.

[69] *Id.* P 291.

[70] *Id.* P 292.

[71] *Id.* (citing Tr. 1135:22-1136:2).

[72] The capacity level of 210,840 Dth per day is derived by multiplying the heating content of gas delivered by Portland into the Joint Facilities (1004 Btu) by Portland's volumetric capacity entitlement on the Joint Facilities (210,000 Mcf per day).

during off-peak summer periods, was sufficient to fully satisfy its Joint Facility capacity entitlement and make further deliveries on its Northern Facilities upstream of the Joint Facilities. PSG contends that the record firmly establishes that Portland's Test Year capacity was at least 217,405 Dth per day — the level of firm system delivery obligations which Portland maintained throughout the 2007-2008 winter.

51. PSG contends that, based upon the engineering studies prepared by Portland in Docket No. CP08-70,[73] which represent Portland's winter capacity commencing November 1, 2007 and summer capacity commencing April 1, 2008 on both Portland's Northern Facilities and Joint Facilities, Portland's thermal capacity entitlement on the Joint Facilities is a derivative of the higher, commingled heating value of all gas flowing on the Joint Facilities, as opposed to a derivative of the lower heating value of gas delivered by Portland to the Joint Facilities (i.e., 1004 Btu on average), as Portland contended. As a result, PSG claims that Portland's thermal entitlement to capacity on the Joint Facilities exceeds 210,840 Dth per day.

52. Based upon those same engineering studies, PSG also argues that, throughout the Test Period year, Portland's capacity to receive gas at Pittsburg was great enough to enable it to satisfy the roughly 5 percent of Portland firm delivery obligations with primary delivery points on its Northern Facilities and still have capacity sufficient to make deliveries in excess of 210,840 Dth per day into and off the Joint Facilities.[74] PSG also points out that as of the start of the Base Period in this case (i.e. January 1, 2007) Portland was maintaining firm delivery obligations of 273,405 Dth per day, and Portland maintained firm delivery obligations of 217,405 Dth per day or more for 5 months of the Test Period year.[75] PSG contends that pipelines could not be expected to commit to firm delivery obligations unless they have firm capacity to satisfy them.[76]

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[73] On January 31, 2008, in Docket No. CP08-70, Portland filed a petition for declaratory order requesting that the Commission determine that the physical capacity across Portland's system from Pittsburg, New Hampshire to Dracut, Massachusetts will be 168,000 Mcf per day on a firm year-round basis once the Maritimes Phase IV Expansion facilities were placed into service. These engineering studies are contained in Exh. Nos. PSG-85 and PSG-127.

[74] PSG Rehearing Request at 12-13.

[75] *Id.* at 15-16 (citing Exh. No. PSG-1 at 32:16-17; Exh. No. PSG-17 at 4; Exh. No. PSG-82 at 11:17-21).

[76] *Id.* at 16 (citing Exh. No. PSG-1 at 32:13-21; Exh. No. PSG-82 at 11/20-12/2).

53. PSG also notes the system capacity representations that Portland made in its Form No. 2 Annual Reports to the Commission for the fourth quarters of 2007 and 2008.[77] In both those reports, Portland states that the pipeline has a "firm peak day capacity" of 214,200 Mcf per day.[78] PSG argues that this evidence directly contradicts the proposition that Portland's Test Period capacity is limited by a purported Joint Facility capacity entitlement of 210,840 Dth per day.

54. Lastly, PSG argues that Portland's Operationally Available Capacity Postings filed with the Commission show that for every single day of the Test Period Portland was advising shippers that it had both design and operating capacity to: (1) receive 236,000 Mcf per day of gas at Pittsburg, New Hampshire, and (2) deliver 210,000 Mcf per day in the Joint Facilities at Westbrook, Maine and out of the Joint Facilities at Dracut, Massachusetts.[79] PSG argues that these postings demonstrate that Portland had sufficient capacity to fully satisfy its volumetric Joint Facilities capacity entitlement of 210,000 Mcf per day, regardless of the thermal conversion, and still have at least 26,000 Mcf per day to service its Northern markets.

2. <u>Commission Determination</u>

55. The Commission grants PSG's rehearing request. Upon further review, the Commission finds that the level of Portland's at-risk condition should be 217,405 Dth per day. Portland maintained throughout this proceeding that its firm capacity entitlement on the Joint Facilities' dictated its total system capacity.[80] Portland's assertion was based on the fact that the Definitive Agreements limited Portland's capacity entitlement on the Joint Facilities to 210,840 Dth per day, i.e. 210,000 Mcf per day based on a thermal conversion factor of 1004 Btu.[81] In Opinion No. 510, the Commission agreed with the ALJ, and with Portland, that 210,840 Dth per day, Portland's capacity entitlement on the Joint Facilities, was the appropriate level at which to set Portland's at-risk condition. In Portland's certificate proceedings, however, the Commission did not limit Portland's at-risk condition to its capacity entitlement on the Joint Facilities. Instead, the Commission

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[77] *Id.* at 13 & n.19.

[78] Exh. No. PSG-16 at 2 and PSG 128 at 122.2.

[79] PSG Rehearing Request at 17 (citing Exh. No. PSG-133).

[80] *See, e.g.*, Exh. PNG-60 at 9:18-20.

[81] *See, e.g.*, Tr. 1128, 1194

based the at-risk condition on the then higher winter-day design capacity of the Northern Facilities, stating:

> In the first year of service, [Portland] will have a capacity of 178,000 Mcf per day on its 24-inch mainline and a capacity of 169,400 Mcf per day on the joint facilities. In subsequent years, the upstream mainline and [Portland's] share of the joint facilities' capacity will increase to 210,000 Mcf per day. Therefore, [Portland] must revise its initial rates to reflect billing determinants based on 178,000 Mcf per day for the first year and design the rates for the subsequent years to reflect billing determinants based on 210,000 Mcf per day.[82]

It is thus clear that the Commission intended that, if the capacity of the Northern Facilities was more than the capacity of the Joint Facilities, the at-risk condition should be set at the higher capacity of the Northern Facilities.

56. We find that the engineering studies submitted by Portland and relied upon by the Commission, in Docket No. CP08-70, as well as the firm commitments made by Portland during the winter of 2007-2008, are the best evidence of Portland's design capacity during the test period in this rate case. Portland's filings with the Commission in Docket No. CP08-70 and the firm service commitments it entered into are indicators of Portland's system capacity and therefore should determine Portland's at-risk condition. First, as PSG points out, for nine months during the Base and Test Period of this case, including each month during November 2007-March 2008, Portland contracted to provide 217,405 Dth per day or more of firm transportation service on the Northern Facilities.[83] This was composed of 209,405 Dth per day or more of firm services from Pittsburg, NH to primary delivery points on the Joint Facilities and an additional 8,000 Dth per day of firm services from Pittsburg to primary delivery points on the Northern Facilities. Accordingly, Portland was able to commit to firm deliveries in excess of its Joint Facilities' capacity entitlement.

57. Second, on January 31, 2008, in Docket No. CP08-70, Portland filed a petition for declaratory order requesting that the Commission determine that the physical capacity across Portland's system from Pittsburg, NH to Dracut, MA would be 168,000 Mcf per day on a firm year-round basis after the Maritimes Phase IV Expansion facilities were placed into service on November 1, 2008. Included with its petition were the engineering

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[82] July 1997 Certificate Order, 80 FERC at 61,448.

[83] *See* Exh. No. PSG-82 at 11:17-21; *see also* Exh. No. PSG-125.

studies (sometimes referred to as flow diagrams) from the Maritimes Phase IV Expansion application. The engineering studies were based on the requirements for Exhibit G of the Commission's certificate filing requirements, specifically sections 157.14(a)(7)-(9) of the Commission's regulations.[84] These engineering studies are used by the Commission to evaluate a pipeline's proposed design capacity. Among other things, the pipeline is required to provide a study of the existing system to show "daily design capacity and reflecting operating conditions with only existing facilities in operation," as well as a second study for the combination of the existing and the proposed facilities.[85] Accordingly, Portland included flow diagrams which illustrated Portland's winter design capacity and summer design capacity prior to and after November 1, 2008.[86] Based on these studies, the Commission concluded that Portland's physical capacity from Pittsburg to Dracut would be 168,000 Mcf per day on a firm year-round basis once the Maritimes Phase IV Expansion facilities were placed into service.[87]

58. As stated above, among the engineering studies submitted by Portland in Docket No. CP08-70 were the flow diagrams representing Portland's winter design capacity commencing November 1, 2007 and summer design capacity commencing April 1, 2008 (i.e., Portland's design capacity before the expansion).[88] As PSG points out, these

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[84] 18 C.F.R. § 157.14(a) (2012).

[85] 18 C.F.R. § 157.14(a)(7) (2012).

[86] Portland Declaratory Petition, Docket No. CP08-70, at 11-12 (filed Jan. 31, 2008).

[87] *Portland Natural Gas Transmission System*, 123 FERC ¶ 61,275, at P 28, *order denying reh'g*, 125 FERC ¶ 61,198 (2008) (collectively, 2008 Declaratory Order). In a footnote, the Commission stated that its finding did not affect Portland's capacity rights of 210,000 Mcf per day in the Joint Facilities between Westbrook and Dracut as defined by the Definitive Agreements between Portland and Maritimes. 2008 Declaratory Order, 123 FERC ¶ 61,275 at n.30. Similarly, the flow diagrams attached as Exhibit E to the petition showed that Portland's capacity rights of 210,000 Mcf per day in the joint facilities remain unchanged by the petition. *Id.*

[88] Portland Declaratory Petition, Docket No. CP08-70, at Appendix E2-3, E6-7 (filed Jan. 31, 2008). Below is a summary of the capacity information for Portland's system prior to the Maritimes Phase IV Expansion based on the engineering studies:

	Northern Facilities	Joint Facilities

(continued…)

diagrams indicate that Portland had capacity to deliver at least 217,405 Dth per day, i.e., 8,000 Mcf per day on the Northern Facilities and still have capacity sufficient to deliver 210,840 Dth per day into the Joint Facilities. Given that these diagrams, together with the "after the expansion" diagrams, were submitted by Portland as evidence of what Portland could deliver on a firm year-round basis or its winter/summer design capacity, we find it is reasonable to rely on these diagrams to ascertain Portland's winter design capacity for purposes of establishing its at-risk condition.

59. In light of this evidence, we believe that Portland's at-risk condition should be based on 217,405 Dth per day, as opposed to its capacity entitlement on the Joint Facilities. Portland's flow diagrams indicate that Portland was able to deliver on a firm basis at least 217,405 Dth per day during the winter which spanned the Base and Test Period. Similarly, Portland obligated itself to make firm deliveries of at least 217,405 Dth per day during the winter 2007-2008 during the base and adjustment period.[89] This evidence directly contradicts Portland's claim that its total system capacity is limited to Portland's capacity entitlement on the Joint Facilities.[90] Accordingly, we grant PSG's

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Season	Receipt Pittsburg	Delivery Westbrook	Receipt Westbrook	Delivery Dracut
Winter MMcfd	229.7	221.7	215.6*/	215.6*/
Summer MMcfd	222.8	214.2	215.6*/	215.6*/

*/ Portland notes that these values are based upon its Joint Facility entitlement of 210 MMcfd, as adjusted for Portland's and Maritime's heating values.

[89] Portland concedes that its system is a winter-based system. *See* Tr. 1151:12-15.

[90] It is also worth noting that in its Form 2 Annual Reports for 2007 and 2008, Portland reported firm peak day capacity of greater than 210,000 Mcf per day. Specifically, in Portland's Form No. 2 Annual Report to the Commission for 2007/Q4, Portland states that, "[t]he Pipeline has a current firm peak day capacity of 214,200 mcf/day." Exh. No. PSG-16 at 2. Similarly, in Portland's Form No. 2 Annual Report to the Commission for 2008/Q4, Portland states that, "[d]uring 2008, the Pipeline had a firm peak day capacity of 214,200 thousand cubic feet per day (Mcf/d)." Exh. No. PSG-128 at 122.2.

request for rehearing and find that Portland's at-risk level should be established at 217,405 Dth per day.[91]

C. At-Risk Condition and Certificate Orders

1. Rehearing Request

60. Portland requests that the Commission clarify that its at-risk condition permits it to design its rates based on its design capacity, even when its projected billing determinants exceed that level.[92] Portland states that the 1996 Certificate Order stated that when implementing Portland's at-risk condition, "[t]he billing determinants used to calculate the initial rates should be based on the *total capacity*."[93] Portland interprets this

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[91] We disagree with PSG's contention that Portland's capacity entitlement on the Joint Facilities is a derivative of the higher, commingled heating value of all gas flowing on the Joint Facilities, as opposed to a derivative of the lower heating value of gas delivered by Portland to the Joint Facilities (i.e., 1004 Btu on average), as Portland contended. The Definitive Agreement specifically provides that,

> the operator shall operate the system in a manner that ensures each owner is able to transport on the main line of the joint facilities up to its volumetric capacity, i.e., 210,000 Mcf per day for Portland and 421,860 Mcf per day for Maritimes, *multiplied by the thermal equivalent of gas that each owner tenders to the joint facilities at the Westbrook main interconnect from its upstream facilities.*

Tr. 1534:20-1535:5 (emphasis added); *see also* paragraph 6 of the settlement approved by the Commission in Docket No. CP02-78-001, which amended section 2.07, subpart (g) of the operating agreement between Portland and Maritimes. *Maritimes & Northeast Pipeline, L.L.C.*, 101 FERC ¶ 61,348 (2002). Based on the average heating value of the gas tendered by Portland to the Joint Facilities, which Portland witness Haag testified, and PSG does not contest, was 1004 Btu, the Definitive Agreements specifically limit Portland's maximum capacity entitlement on the Joint Facilities to 210,840 Dth per day. Tr. 1128:25. For purposes of determining Portland's firm capacity entitlement on the Joint Facilities, the commingled heating value of all gas flowing on the Joint Facilities is irrelevant.

[92] Portland Rehearing Request at 59-60.

[93] *Id*. (citing 1996 Certificate Order, 76 FERC at 61,661).

statement to mean that its rates should always be designed based upon its design capacity, regardless of its projected billing determinants. Therefore, Portland believes that Opinion No. 510 modifies the at-risk terms of the certificate order by exposing Portland to a potential new method of computing the at-risk level which is not to be limited to existing capacity, but instead potentially further inflated by: (1) the inclusion of billing determinants associated with Bankruptcy Proceeds (defined infra); and (2) the inclusion of discounted IT/PAL volumes associated with the remarketing of the capacity formerly held by the bankrupt shippers in the derivation of rates. Thus, Portland contends, Opinion No. 510 represents an unexplained and unlawful departure from the Commission's orders issued involving Portland's at-risk condition and a change in the original terms of the certificate order.[94]

2. <u>Commission Determination</u>

61. Portland's request for clarification and rehearing is denied. As discussed below, the at-risk condition established in Portland's certificate orders places a floor on its rate design volumes equal to its design capacity. The at-risk condition does not place any ceiling on those rate design volumes. Therefore, contrary to Portland's assertions, Opinion No. 510 did not change how Portland's at-risk condition is determined and Portland's billing determinants can be greater than Portland's at-risk condition.

62. As discussed above, the purpose of the at-risk condition was to protect Portland's future customers from rate increases if the new facilities are underutilized. This was accomplished by requiring that the pipeline design its rates based on volumes equal to or no less than its design capacity. There is no need to cap the pipeline's rate design volumes in order to protect future customers from underutilization of the system. In fact, such a cap could permit the pipeline to charge rates in excess of a just and reasonable level, contrary to the requirement in the Commission's Part 284 regulations that a pipeline design its rates based upon its projected units of service for all its services.[95] It is not unusual then for a pipeline's rate design volumes to exceed its design capacity. To take a simple example, a pipeline's capacity may be fully subscribed by long-term firm shippers paying the maximum rate, but the pipeline may also provide interruptible service when its firm shippers are not making full use of their capacity. In that situation, the pipeline's total firm and interruptible billing determinants would exceed its design capacity. If, in such a situation, the Commission nevertheless designed the pipelines rates

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[94] *Id*. at 59-60.

[95] 18 C.F.R. § 284.10(c)(2) (2012), requiring pipelines to design their rates based on projected units of service. *See also Panhandle Eastern Pipe Line Co.*, 74 FERC ¶ 61,109, at 61,385-86 (1996).

based on its design capacity the pipeline would over-recover its cost-of-service assuming it continued to provide services at projected levels.

63. Therefore, in a case such as this, where the pipeline is subject to an at-risk condition, Commission policy generally requires that the pipeline's rates be designed based upon the greater of its projected billing determinants or the volumetric level of the at-risk condition.[96] Moreover, nothing in Portland's certificate orders indicates that the Commission intended to waive the section 284.10(c)(2) requirement to design rates based on projected units of service, if Portland's projected billing determinants in a future NGA section 4 rate case exceeded its design capacity. This is why the mere fact, standing alone, that Portland proposed to design its rates based on billing determinants equal to its proposed design capacity was not sufficient to show that those proposed billing determinants were just and reasonable.

64. Portland does not offer any evidence to support its assertion that the certificate orders intended to limit Portland's billing determinants in future rate cases to Portland's at-risk level. In fact, Portland's contentions are belied by the certificate orders, which approved initial rates for Portland reflecting a projection that it would provide services in excess of its design capacity. As the 1996 Certificate Order stated, "Traditionally, the initial rates assume reservation billing determinants equal to the annualized capacity of the system." Accordingly, the Commission required Portland to increase its initial rate billing determinants to equal an annualization of its winter-day design capacity.[97] However, in the next section of the 1996 Certificate Order, the Commission also required Portland to reflect interruptible services in its rates either by crediting 100 percent of the IT revenues, net of variable costs, to its firm shippers, or proposing an allocation of costs to interruptible service.[98] Whether reflecting interruptible services through a revenue credit or an allocation of costs, both methods recognize that services can be above certificated capacity. Portland subsequently complied with this requirement by allocating costs to interruptible services.[99] As a result, Portland's proposed initial rates were calculated utilizing firm billing determinants equal to the total capacity of 178,000 Mcf per day plus additional interruptible throughput represented by a $1,000,000 revenue credit to its cost-of-service.

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[96] *See Kern River*, Opinion No. 486-A, 123 FERC ¶ 61,056, at P 86 (2008).

[97] 1996 Certificate Order, 78 FERC at 61,660.

[98] 1996 Certificate Order, 78 FERC at 61,661.

[99] 1997 Certificate Order, 80 FERC at 61,451.

65. Based on the foregoing, Portland's request for rehearing is denied.

D. At-Risk Condition in Portland's Next Rate Case

1. Rehearing Request

66. Portland also seeks clarification that Opinion No. 510 does not modify or limit the assurances in orders issued in Docket No. CP08-70 that any rate issues associated with Portland's reduction in capacity to 168,000 Mcf per day, including billing determinants to design Portland's rates, would be addressed in Portland's next rate case in Docket No. RP10-729. Portland states that the orders in Docket No. CP08-70 specified that Portland's next rate case would be the forum to take up the impact on billing determinants and the at-risk condition of the reduction in Portland's capacity.[100] Therefore, Portland contends, these issues are appropriately addressed in Portland's rate case in Docket No. RP10-729. If the Commission declines to provide the clarification sought, Portland seeks rehearing of Opinion No. 510.

2. Commission Determination

67. In the orders issued in Docket No. CP08-70, the Commission expressly limited its ruling to establishing the certificated capacity across the Portland system on the date the Maritimes Phase IV Expansion was placed in service.[101] The Commission stated that its ruling did not address the impact of its decision on Portland's rates and that any rate issues, including the appropriate determinants to use to design Portland's rates, were to be addressed in Portland's next rate case.[102] The Commission also stated that its rulings did not address or change the at-risk condition imposed on Portland by the certificate orders.[103] The Commission stated that the at-risk condition relates to the design of Portland's rates and therefore, should be addressed in Portland's next rate case. The Commission noted that the Test Period for the instant rate case ended on September 30, 2008, which was prior to the proposed in-service date of the Maritimes Phase IV

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[100] Portland Rehearing Request at 61 (citing 2008 Declaratory Order, 123 FERC ¶ 61,275 at P 30, *reh'g denied*, 125 FERC ¶ 61,198 at P 20).

[101] 2008 Declaratory Order, 123 FERC ¶ 61,275, *order denying reh'g*, 125 FERC ¶ 61,198.

[102] 2008 Declaratory Order, 123 FERC ¶ 61,275 at P 30, *order denying reh'g*, 125 FERC ¶ 61,198 at P 20.

[103] *Id.* P 20.

Expansion of November 1, 2008 and Portland's reduction in capacity on its Northern Facilities to 168,000 Mcf per day. Therefore, Portland is correct that any rate issues associated with Portland's reduction in capacity can be addressed in Portland's 2010 Rate Filing in Docket No. RP10-729, which is Portland's "next rate case."

IV. Rate Design Volumes

A. Background

68. In this case, Portland proposed to design its rates based on billing determinants of 210,840 Dth per day. It stated that it had based these billing determinants on the firm capacity (or design capacity) of its system. Although section 284.10(c)(2) of our regulations requires pipelines to design their rates to recover costs on the basis of projected units of service, Portland made no projection of what its billing determinants for each service would be upon the effective date of its proposed rates.

69. In Opinion No. 510, the Commission held that the mere fact, standing alone, that Portland's proposed billing determinants equaled its asserted firm capacity was not sufficient to show that those billing determinants were just and reasonable.[104] The Commission stated that its regulations require that a pipeline design its rates based upon its projected units of service and a pipeline's rate design volumes may exceed its design capacity. Therefore, in a case such as this, where the pipeline is subject to an at-risk condition, Commission policy generally requires that the pipeline's rates be designed based upon the greater of its projected billing determinants or the volumetric level of the at-risk condition. Opinion No. 510 concluded that Portland's proposed rate design volumes of 210,840 Dth per day are only just and reasonable if its projected units of service for all firm and interruptible services are 210,840 Dth per day or less. Therefore, determining whether Portland's proposed rate design volumes are just and reasonable required that both its interruptible and firm billing determinants be projected.

70. Accordingly, the Commission required that Portland calculate its projected billing determinants. Opinion No. 510 required Portland to include in its projected billing determinants: (1) an allocation of costs to its Interruptible Transportation and Parking and Lending services based on a projected volume of interruptible transportation, and (2) 62,000 Dth per day of contract demand associated with two firm transportation contracts that were rejected in bankruptcy by Androscoggin and Rumford and the interruptible and short-term firm billing determinants associated with its remarketing of the capacity formerly held by the bankrupt shippers. As described in more detail below, the Commission permitted Portland to reduce these billing determinants to the extent the

[104] Opinion No. 510, 134 FERC ¶ 61,129 at P 309.

associated revenues were below its maximum rates, consistent with the Commission's discount adjustment policies.

71. Opinion No. 510 concluded that, if Portland's total adjusted projected billing determinants, as determined in its compliance filing are less than or equal to the design capacity found by Opinion No. 510 of 210,840 Dth per day, then consistent with the at-risk condition, its rates should be designed using total billing determinants of 210,840 Dth per day. If Portland's total adjusted projected billing determinants exceed 210,840 Dth per day, then those projected billing determinants should be used to design its rates.[105]

72. In its response to the Staff Data Request following Opinion No. 510, Portland recalculated its billing determinants consistent with Order No. 510 and alternatively, with its request for rehearing and clarification. In its response, Portland states that, whether it calculates its billing determinants consistent with Order No. 510 or its rehearing and clarification request, its total projected billing determinants, adjusted or otherwise, never exceed the at-risk level of 210,840 Dth per day established by the Commission in Opinion No. 510.[106] This order's determination that the at-risk level should be 217,405 Dth per day instead of 210,840 Dth per day doesn't change the fact that Portland's projected billing determinants, adjusted or otherwise, do not exceed the at-risk level and therefore, Portland must design its rates based on the level of its at-risk condition, 217,405 Dth per day.

73. PSG requested rehearing of Opinion No. 510's holding concerning Portland's IT/PAL billing determinants. Portland requested rehearing of the requirement that it include in its rate design volumes billing determinants associated with its two contracts rejected in bankruptcy.

B. Credit for Interruptible Transportation (IT) or Parking and Lending Revenues (PAL)

74. The Commission's "long-standing policy regarding new interruptible services requires either a 100 percent credit of interruptible services, net of variable costs, to firm and interruptible customers or an allocation of costs and volumes to such services."[107] In its original certificate application, Portland proposed not to allocate any costs to its

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[105] *See, e.g.*, Opinion No. 510, 134 FERC ¶ 61,129 at P 357.

[106] Portland Response to Data Request at 10, 11.

[107] *Wyoming Interstate Co., Ltd.*, 121 FERC ¶ 61,135, at P 9 (2007).

interruptible services. Therefore, the Commission required Portland to credit 100 percent of its interruptible revenues to its firm shippers.[108] However, in its amended certificate application, Portland allocated costs and volumes to its Rate Schedule IT service.[109] Accordingly, the Commission accepted Portland's proposal, stating that "[b]ecause Portland has now allocated costs to Rate Schedule IT service, we will allow Portland to retain its Rate Schedule IT revenues, and not credit them to firm shippers as we had formerly required."[110] Portland's settlement of its last rate case continued to allocate costs and volumes to its interruptible services.[111]

75. In this rate case, Portland proposed to design its rates based upon its firm capacity of 210,840 Dth per day, without any express allocation of costs to its IT and PAL services. It also proposed not to credit its cost-of-service with any test period IT or PAL service revenues. While acknowledging that Commission policy requires IT customers to contribute to the recovery of a pipeline's fixed costs based on an estimated volume of interruptible transportation,[112] Portland argued that policy is inapplicable in this case. It explained that it is already "at risk" for any under collection of its costs, as it has derived its rates using full year round capacity in effect at the end of the test period without seeking an adjustment for unsubscribed capacity.

76. In the ID, the ALJ found that Portland's cost-of-service should be credited by $3,360,522, i.e., the IT/PAL revenues during the Test Period.[113] The ALJ found that the Commission's 1996 and 1997 Certificate Orders already addressed this issue making clear that Portland must either allocate some of its costs to IT service or credit its IT/PAL revenues to FT customers.[114]

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[108] 1996 Certificate Order, 76 FERC at 61,661.

[109] July 1997 Certificate Order, 80 FERC at 61,451.

[110] *Id*.

[111] *See* 2002 Settlement Order, 102 FERC ¶ 61,026 at P 5.

[112] ID, 129 FERC ¶ 63,027 at P 223.

[113] *Id.* P 235.

[114] *Id.* (citing 1996 Certificate Order, 76 FERC at 61,661; July 1997 Certificate Order, 80 FERC at 61,447-51).

1. **Opinion No. 510**

77. In Opinion No. 510, the Commission affirmed the ALJ's decision that IT/PAL services had to be recognized in Portland's rate design. However, the Commission reversed the ALJ's recommendation that Portland be required to credit its IT/PAL revenues against its cost-of-service.[115] Instead, the Commission required Portland to allocate costs to its IT/PAL service based upon a projected volume of interruptible transportation, consistent with the cost allocation and rate methodology underlying its preexisting rates, subject to the condition that Portland's overall rate design volumes must satisfy the at-risk condition discussed in the previous section. The Commission found that because Portland had not previously credited interruptible revenues against its cost-of-service and did not propose to do so in this rate case, any requirement that Portland credit such revenues against its cost-of-service would constitute a change in its existing rate design of allocating costs and volumes to interruptible services without any revenue credit. In order for the Commission to require Portland to make such a change in its existing rate design, the Commission stated that it would have to show, not only that Portland failed to support its NGA section 4 proposal, but also, in accordance with NGA section 5: (1) that Portland's preexisting rate design of allocating costs to interruptible service without a revenue credit is unjust and unreasonable; and (2) that a revenue credit is just and reasonable.

78. Opinion No. 510 held that Portland must project its IT/PAL billing determinants, along with its firm billing determinants, in order to apply the requirement that its rates be designed based upon the greater of its projected billing determinants or the volumetric level of the at-risk condition.[116] Without such a determination, the Commission could not determine whether Portland's total projected billing determinants (1) exceed its at-risk condition volumes, in which case the projected billing determinants must be used to design its rates or (2) are less than or equal to its at-risk condition volumes, in which case the at-risk condition volumes must be used to design its rates.

79. Opinion No. 510 recognized that, in order to obtain its IT/PAL throughput, Portland had to offer significant discounts. Discounting to obtain additional throughput benefits all customers by allowing the pipeline to spread its fixed costs across more units of service. Therefore, in order to avoid a disincentive to discounting, the Commission has stated that, in the next rate case after giving discounts, the pipeline need not design its rates on the assumption that the discounted volumes would flow at the maximum rate.

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[115] Opinion No. 510, 134 FERC ¶ 61,129 at PP 307-14.

[116] *See Kern River*, Opinion No. 486-A, 123 FERC ¶ 61,056 at P 86 (citing 18 C.F.R. § 284.10(c)(2) (2006), 18 C.F.R. §§ 157.100-157.106 (1989)).

Rather, the pipeline is permitted to reduce the discounted volumes used to design its rates so that, assuming market conditions require it to continue giving the same level of discounts when the new rates are in effect that it gave during the test period, the pipeline will be able to recover 100 percent of its costs-of-service (subject in this case to compliance with Portland's at-risk condition).[117] Opinion No. 510 pointed out that Commission policy permits pipelines to make the discount adjustment using the "ratio method," under which volumes that flowed at a discount are adjusted by multiplying them by the ratio of the pipeline's average discounted rate to its just and reasonable rate established in the subject rate case.[118] Accordingly, consistent with Commission policy, Opinion No. 510 permitted Portland to reduce its projected IT and PAL volumes using that method.[119]

80. Opinion No. 510 concluded that the requirement for Portland to project all its billing determinants and design its rates based on the greater of its projected billing determinants or its at-risk condition volumes should render Portland's rates just and reasonable, without the need to take action under NGA section 5 to require Portland to credit its interruptible revenues against its cost-of-service. The Commission stated that in either case, Portland's rates will already reflect a full allocation of costs to its interruptible services. Opinion No. 510 pointed out that the Commission's policy is "to require a pipeline *either* to allocate costs to interruptible service *or* to credit revenues from such service."[120] Therefore, because Portland will be allocating costs to its interruptible service, Commission policy does not require that it also credit revenues from that service to its cost-of-service. The Commission concluded that there is no basis for NGA section 5 action to require such crediting.

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[117] *Interstate Natural Gas Pipeline Rate Design*, 47 FERC ¶ 61,295, at 62,056-57 (1989). *Williston Basin Interstate Pipeline Co.*, 67 FERC ¶ 61,137, at 61,379 (1994) (*Williston I)*. *Trunkline Gas Co.*, Opinion No. 441, 90 FERC ¶ 61,017, at 61,086 (2000).

[118] *See Williston Basin Interstate Pipeline Co.*, 84 FERC ¶ 61,081, at 61,401-02 (1998) (*Williston III*), for a description of the somewhat complicated iterative mathematical computation used to carry out the ratio discount adjustment method.

[119] Opinion No. 510, 134 FERC ¶ 61,129 at P 310.

[120] *Overthrust Pipeline Co*., 83 FERC ¶ 61,003, at 61,014 (1998) (emphasis supplied).

2. Requests for Rehearing

81. PSG argues that the Commission erred in determining that imposition of an IT revenue crediting requirement as of the effective date of Portland's rates in this proceeding would be impermissible under section 4 of the NGA. PSG states that in Portland's original system certificate orders the Commission imposed its longstanding rate design policy of requiring pipelines either to allocate costs to IT services or credit revenues attributable to such services to their costs-of-service, making it clear that if Portland did not allocate costs it would be subject to IT revenue crediting. Relying on *Kern River*,[121] PSG states that the Commission's requirement that Portland comply with that policy in the instant case is thus not a retroactive rate design change prohibited under section 4 of the NGA, but enforcement of the rate design principles previously imposed in Portland's certificate orders.

3. Commission Determination

82. The Commission denies PSG's request for rehearing. PSG contends that in the original certificate orders the Commission, instead of requiring that Portland either credit 100 percent of the interruptible revenues, net of variable costs, to firm customers or allocate costs and volumes to these services, required that Portland credit IT revenues if it did not employ a cost allocation alternative.[122] PSG argues that, because Portland did not propose an allocation of costs to IT services, the ALJ's requirement that Portland credit IT revenues to its cost-of-service is nothing more than a requirement that Portland "comply with the rate design principles set forth in its certificate orders,"[123] and therefore the ALJ did not require a change to Portland's pre-existing rate design. First, PSG misinterprets the certificate orders. Second, based on Portland's data response, finding in PSG's favor would result in double counting Portland's IT/PAL services in Portland's rate design, contrary to the requirements of the certificate orders.

83. In the 1996 Certificate Order, the Commission stated, "The Commission's policy regarding new interruptible service has been to require either a 100 percent credit of the interruptible revenues, net of variable costs, to firm customers or an allocation of costs and volumes to these services."[124] Finding that Portland had failed to allocate costs to the

[121] PSG Rehearing Request at 23 (citing *Kern River Gas Transmission Co.*, Opinion No. 486-D, 133 FERC ¶ 61,162, at PP 35, 42 (2010)).

[122] PSG Rehearing Request at 20.

[123] Opinion No. 486-D, 133 FERC ¶ 61,162 at P 47.

[124] 1996 Certificate Order, 76 FERC at 61,661.

IT service, the Commission required Portland to credit 100 percent of the IT revenues to its firm shippers.[125] In the 1997 Certificate Order, the Commission reiterated its policy stating, "the Commission's policy regarding new interruptible services, as we explained in the July 31, 1996 preliminary determination, is to require either a 100 percent credit of the interruptible revenues, net of variable costs, to firm shippers, or an allocation of costs and volumes to these services."[126] But, because Portland allocated costs to its IT service, the Commission allowed Portland to retain its IT revenues, and not credit them to firm shippers as required in the July 31, 1996, preliminary determination.[127]

84. Both certificate orders consistently applied the Commission's policy regarding the treatment of interruptible services when establishing initial rates in a certificate proceeding – i.e. a pipeline must *either* allocate costs to IT services *or* credit 100 percent of its IT revenues to its firm shippers. The only reason the Commission required Portland to credit revenue in the first certificate proceeding was because Portland had failed to allocate any costs to interruptible services. The second certificate order made clear that a credit of IT revenues to firm shippers or an allocation of costs to IT services are mutually exclusive alternatives for the treatment of IT services in designing a pipeline's rates by holding that, because Portland was allocating costs to its IT service, it need not credit its IT revenues to its firm shippers.

85. Contrary to the requirements of the certificate orders, PSG seeks on rehearing to require Portland both to allocate costs to IT services and to credit IT revenues to the cost of service. This would result in an unjust and unreasonable double counting of Portland's IT/PAL services in Portland's rate design, contrary to Commission policy. Opinion No. 510 required Portland to allocate costs to its IT/PAL service based upon a projected volume of interruptible transportation, consistent with the cost allocation and rate methodology underlying its preexisting rates, subject to the condition that Portland's overall rate design volumes must satisfy the at-risk condition discussed in the previous section.[128] Portland's response to the Staff Data Request states that its total projected billing determinants, calculated consistent with Order No. 510 are 179,930 Dth per day, including projected IT/PAL discount-adjusted billing determinants of 10,283 Dth per day.[129] Thus, Portland's total projected billing determinants are less than its at-risk

[125] *Id.*

[126] 1997 Certificate Order, 80 FERC at 61,451.

[127] *Id.*

[128] Opinion No. 510, 134 FERC ¶ 61,129 at 307.

[129] Portland Response to Data Request at 10, Scenario 1, Schedule G-1,

(continued…)

condition, held above to be 217,405 Dth per day, and we are requiring Portland to design its rates using billing determinants equal to the at-risk condition. Because the at-risk billing determinants exceed Portland's total projected billing determinants for all services, including IT and PAL, we find that these billing determinants reflect an allocation of costs to Portland's IT/PAL services, consistent with the requirements of the certificate orders.[130]

86. In its rehearing request, PSG would have the Commission not only require Portland to allocate costs to its IT/PAL services in the manner described above, but also require Portland to credit its cost of service based on its IT/PAL services revenues. Such an outcome would be unjust and unreasonable, because it would require Portland to allocate costs to its IT/PAL services twice, once through an allocation based on projected billing determinants and a second time through a credit to its cost of service. We conclude that our treatment of Portland's IT/PAL services is consistent with the requirements of the certificate orders that Portland either allocate costs to IT services or credit IT revenues to firm shippers. Therefore, our actions here are fully consistent with the policies set forth in *Kern River* of requiring pipelines to comply with rate design conditions in their certificates.

87. Based on these reasons, PSG's request for rehearing is denied.

C. Adjustments to Billing Determinants related to Rejected Contracts

88. Among the issues raised before the ALJ at hearing was to what extent, if any, Portland should be entitled to retain the $119,761,258 in bankruptcy proceeds (Bankruptcy Proceeds) that it received from the termination of the Androscoggin and Rumford Agreements (the rejected contracts). Prior to the Base Period in this case (calendar year which commenced on January 1, 2007), Portland had 20-year firm transportation (FT) agreements in effect with Androscoggin and Rumford. The Androscoggin agreement covered 18,000 Dth per day and was to run through October 31, 2019; the Rumford agreement covered 44,000 Dth per day and was to run through October 31, 2020. The Androscoggin and Rumford agreements were rejected and terminated in June 2005 and April 2006, respectively, as part of the bankruptcy

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Iteration 10 provides IT adjusted volumes of 8,612 Dth per day and PAL adjusted volumes of 1,671 Dth per day.

[130] Earlier in this order the Commission granted rehearing and determined that Portland's at-risk condition should be based on 217,405 Dth per day, instead of 210,840 Dth per day. This increase in the at-risk condition, however, does not affect Portland's projected billing determinants.

proceedings of Calpine and its affiliates, resulting in the aggregate termination of 62,000 Dth per day of maximum firm delivery commitments on the Portland system.[131] Portland filed bankruptcy claims as a result of those contract terminations and on the basis of such claims, recovered a net total of $119,761,258 in bankruptcy proceeds before and during the Test Period (period ending September 30, 2008) in this case and before the rates took effect on September 1, 2008. The $119,761,258 in net proceeds consisted of the sums of: (1) $16,460,850 of cash distributions from the Androscoggin estate, (2) $2,250,000 of credit collateral posted by Androscoggin, and (3) $103.1 million obtained from the sale of stock of the reorganized Calpine distributed as part of the Rumford bankruptcy proceeding, minus $2,088,742 of Portland legal fees related to the bankruptcy recoveries. The Androscoggin recoveries occurred largely during 2006 and 2007.[132] The $103.1 million in recovery from Rumford occurred in February 2008.[133] Portland expects to receive further recoveries — up to $125 million in total recoveries — as a result of the Rumford bankruptcy, but the exact time and amount of the future recovery is currently unknown.

89. Portland argued that it should be entitled to retain all of the Bankruptcy Proceeds because, among other things, Portland developed its rates based upon its year-round firm system capacity. In the ID, the ALJ found that "Portland is recovering twice for capacity associated with the rejected contracts: once through its considerable Bankruptcy Proceeds and again through its shorter-term firm revenues."[134] Accordingly, the ALJ found that, based on Commission precedent, "there should be some recognition of the receipt of these double-collected revenues in the Portland rate structure such as a credit to account for the over-recoveries that Portland has received for the capacity related to the rejected contracts."[135] Accordingly, the ALJ recommended that a credit of $4,886,978 be directly applied to Portland's cost-of-service to reflect one-half of the estimated annual amount of Portland's over-recovery.

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[131] *See* Portland Response to Data Request at Schedule 2, Straight-line Amortization Schedule, n.1; *see also* Exh. PNG-1 at 4. Portland Witness Haag testified that the remaining term of the Androscoggin and Rumford Agreements at the time of their rejection were 170 and 172 months, respectively. Exh. PNG-60 at 16.

[132] Exh. PSG-131 at 122.5.

[133] Exh. PSG-131 at 122.5

[134] ID, 129 FERC ¶ 63,027 at P 213.

[135] *Id.*

1. **Opinion No. 510**

90. While the Commission agreed with the ALJ that there should be recognition of the receipt of the bankruptcy award for the rejected contracts in Portland's rate design, it disagreed with the ALJ's decision that such recognition should take the form of a credit to Portland's cost-of-service in the amount of one-half of the estimated annual amount of the pipeline's over-recovery.[136] Instead, the Commission required Portland to include in its rate design volumes both: (1) the 62,000 Dth per day of contract demand associated with the Androscoggin and Rumford Agreements, subject to a discount adjustment to reflect the fact the bankruptcy award only partially compensated Portland for loss of those maximum rate contacts; and (2) the interruptible and short-term firm billing determinants associated with its remarketing of the capacity formerly held by Androscoggin and Rumford.

91. Opinion No. 510 found that Portland's proposal to design its rates based upon its asserted design capacity of 210,840 Dth, thus reflecting billing determinants associated with the rejected contracts, did not, by itself, justify allowing Portland to retain the Bankruptcy Proceeds without any further recognition in rates. Opinion No. 510 pointed out that, during the test period, Portland had received two revenue streams with respect to the turned-back Androscoggin and Rumford capacity: (1) the Bankruptcy Proceeds and (2) the short-term firm and interruptible sales. The Commission stated that these facts make Portland's situation analogous to the situations addressed by the Commission's orders in *Trailblazer Pipeline Co.*[137] and *Wyoming Interstate Co. (WIC).*[138]

92. In both those cases, a shipper paid the pipeline an exit fee in order to terminate its transportation service agreement early. The pipelines proposed to include the billing determinants associated with the terminated contracts in their rate design volumes, and asserted that that sufficiently recognized the exit fees. In both *Trailblazer* and *WIC*, the Commission nevertheless required the pipeline to credit the exit fee against its cost of service. In *Trailblazer,* where the pipeline had successfully remarketed the capacity to other shippers, the Commission explained that failure to credit the exit fee to the cost-of-service would result in the pipelines' current customers paying rates that cover costs the

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[136] Opinion No. 510, 134 FERC ¶ 61,129 at P 350.

[137] *Trailblazer Pipeline Co.,* 80 FERC ¶ 61,141, *order on reh'g,* 81 FERC ¶ 61,032 (1997); *see also Trailblazer Pipeline Co.,* 88 FERC ¶ 61,168 (1999) (rehearing order on subsequent settlement) (*Trailblazer*).

[138] *Wyoming Interstate Co. Ltd.,* 87 FERC ¶ 61,339 (1999) (*WIC*).

pipeline has already recovered in the exit fee.[139] In *WIC*, the Commission explained that, to the extent the pipeline remarkets the capacity to other shippers, the pipeline would be effectively selling the same capacity twice, once to the departing customer and once to the new shippers. That would inevitably lead to an over-recovery of the pipeline's cost-of-service.[140] Opinion No. 510 rejected Portland's reliance on *Kern River*[141] where the pipeline was not required to recognize a bankruptcy award in its rates. The Commission explained that at the close of the evidentiary record in that case, the pipeline had not received any bankruptcy award and thus had received only one revenue stream with respect to the turned-back capacity, a portion of its revenues from remarketing the capacity.

93. Rather than requiring Portland to credit the Bankruptcy Proceeds against its cost of service, as in *Trailblazer* and *WIC*, the Commission required Portland to include in its projected billing determinants both the billing determinants associated with the rejected contracts and the interruptible and short-term firm billing determinants associated with its remarketing of the capacity under the rejected contracts. Including both sets of billing determinants in the design of Portland's rates, the Commission explained, should avoid requiring Portland's shippers to pay rates that cover costs Portland has already recovered in the bankruptcy award.[142]

94. The Commission also stated that requiring Portland to account for the bankruptcy award through an adjustment to its billing determinants, rather than a credit against Portland's cost-of-service, would assist in making the determination whether Portland has satisfied its at-risk condition.[143] The Commission explained that, if Portland's compliance filing shows that its total projected billing determinants, including the bankruptcy associated determinants are less than the at-risk condition, then its rates should be designed using the at-risk condition volumes. If Portland's total projected billing determinants exceed the at-risk condition, then those projected billing determinants should be used. Opinion No. 510 concluded that either way Portland will

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[139] *Id. See also Trailblazer*, 81 FERC ¶ 61,032 (order denying rehearing).

[140] *WIC,* 87 FERC at 62,309.

[141] *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077 (2006), *order on reh'g*, Opinion No. 486-A, 123 FERC ¶ 61,056, *order on reh'g*, Opinion No. 486-B, 126 FERC ¶ 61,034, *order on reh'g*, Opinion No. 486-C, 129 FERC ¶ 61,240 (2009).

[142] Opinion No. 510,134 FERC ¶ 61,129 at P 356.

[143] *Id.* P 357.

be allocating costs to both the rejected contracts and the new IT and short-term firm contracts obtained by remarketing the capacity, and therefore Commission policy does not require that Portland also credit the bankruptcy award to its cost-of-service.

95. Because the bankruptcy award received by Portland reflected only a portion of the revenue to which Portland would have been entitled had the rejected contracts remained in effect, Opinion No. 510 found that Portland would be entitled to a discount adjustment to reflect the fact that the bankruptcy award equated to Portland receiving an amount per Dth that was less than the maximum rate it would have otherwise received had the contracts remained in effect.[144] Opinion No. 510 stated that Portland could carry out the discount adjustment using the ratio method described in the preceding section of this order. The Commission stated that Portland could add the discount-adjusted billing determinants associated with its rejected contracts to its other projected firm billing determinants to determine whether its overall projected billing determinants are less than or greater than the at-risk condition.

96. As discussed in the next section, Opinion No. 510 also required Portland to use the full Bankruptcy Proceeds, net of legal costs incurred by Portland in the bankruptcy proceeding and taxes paid on the proceeds, as a reduction to rate base.[145] The Commission found that the rate base reduction was necessary to account for the fact the bankruptcy award allowed Portland to recover immediately costs that would otherwise have been recovered only over the remaining terms of the Androscoggin and Rumford agreements.

2. Request for Rehearing

97. Portland contends, for multiple reasons, that Opinion No. 510 erred in all its rulings concerning the treatment of the Bankruptcy Proceeds. Portland contends that the Commission erred in requiring Portland to include in its rate design volumes both the

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[144] The unit rate of the rejected contracts to be used in Portland's discount adjustment calculations is equal to the bankruptcy proceeds ($119,761,258) divided by total contract volumes over the number of years left of the rejected contracts when they were rejected.

[145] Opinion No. 510, 134 FERC ¶ 61,129 at P 360. Since the revenues received by Portland were subject to income taxes, Portland was directed to reflect the appropriate deferred income taxes in rate base. Portland estimates that the after tax amount of the bankruptcy proceeds totals $71,081,780, indicating that the tax liability totals $48,679,478 ($119,761,258 – ($119,761,258 x 40.6471 percent)). *Id*. n.512. Further, these adjustments were to be reflected in the remaining levelization period. *Id.*

62,000 Dth per day of contract demand associated with the rejected contracts and the interruptible and short-term firm billing determinants associated with its remarketing of the capacity formerly held by Androscoggin and Rumford. Portland also contends that the Commission erred in requiring it to credit the proceeds against its rate base.

98. In response to staff's Data Request issued after Opinion No. 510, Portland states that its total projected billing determinants, including the bankruptcy related billing determinants calculated consistent with Order No. 510, are 179,930 Dth per day,[146] and it admits that, under all rate calculation scenarios that reflect its rehearing positions, the total projected billing determinants are less than Opinion No. 510's at-risk condition.[147] Therefore, Portland's rates in this rate case must be designed using volumes equal to the higher level of its at-risk condition. As a result, Opinion No. 510's requirement that Portland include bankruptcy related volumes in its projected billing determinants has no effect on the level of the rates we establish in this rate case. Only Opinion No. 510's holding requiring the Bankruptcy Proceeds to be subtracted from rate base will actually have an impact on the final rates approved in this proceeding. In these circumstances, the Commission will address Portland's rehearing contentions which relate to both aspects of Opinion No. 510's directives concerning the Bankruptcy Proceeds in the next section concerning the rate base reduction.

99. However, one of Portland's contentions on rehearing relates primarily to Opinion No. 510's requirement that it allocate costs to both the rejected contracts and the new IT and short-term firm contracts obtained by remarketing the capacity by projecting billing determinants associated with both sets of volumes. Because that allocation is part of our overall approach to the treatment of the Bankruptcy Proceeds, we will address that contention in this section of the order.

100. Specifically, Portland contends that Opinion No. 510 erred in determining that *Trailblazer* and *WIC* present analogous situations to this case and that *Kern River* is distinguishable from this case. Regarding *Trailblazer* and *WIC*, Portland maintains that those cases are distinguishable from the instant case because: (1) they involved exit fees as opposed to bankruptcy proceeds, which the Commission has distinguished,[148] (2) the capacity that was the subject of the terminated contracts in those cases was successfully

[146] Portland Response to Data Request at 10.

[147] *Id.* at 11, 12.

[148] Portland Rehearing Request at 11 (citing *Columbia Gas Transmission Corp.*, 67 FERC ¶ 61,397, *order on reh'g*, 68 FERC ¶ 61,375 (1994)).

remarketed in those cases, unlike in the instant case,[149] and (3) the period remaining on the terminated contracts in those cases was much shorter than the Androscoggin and Rumford agreements in this case.

101. Portland also contends that Opinion No. 510 erred in distinguishing *Kern River* on the ground that Kern River had not received bankruptcy proceeds during the test period. Portland contends that, in fact, Kern River did receive compensation during the test period of that proceeding, as reflected in the record of that case[150] and on Kern River's 2004 FERC Form No. 2.[151] Portland states that, despite this fact, *Kern River* did not impose the ratemaking remedy that the Commission applied in Opinion No. 510, and accordingly, the Commission should grant rehearing and follow the approach taken in *Kern River*.

3. Commission Determination

102. The Commission reaffirms its requirement that Portland include in its rate design volumes both the 62,000 Dth per day of contract demand associated with the rejected contracts and the interruptible and short-term firm billing determinants obtained by remarketing the capacity formerly held by Androscoggin and Rumford, as adjusted for discounting.

103. In this case, Portland has received approximately $101 million in bankruptcy proceeds as partial compensation for the payments Rumford would have made under its contract over the 14 and a half year period from the April 2006 rejection of that contract until its October 31, 2020 expiration. Approximately 83 percent of that amount, or $83.9

[149] *Id.* (citing *Columbia Gas Transmission Corp.*, 70 FERC ¶ 61,157, at 61,469 (1995) (*Columbia Gas*) (explaining that the exit fees paid to Trailblazer and WIC were derived based on the pipelines' excess capacity at that time); *Wyoming Interstate Co. Ltd.*, 96 FERC ¶ 63,040, at 65,272 (2001) (Initial Decision) ("In this case, there is no dispute that the entirety of the volumes have been replaced at predominantly maximum rate contracts").

[150] *Id.* at 10, 49 (citing Exh. No. PNG-69 at 3-4 (providing a Calpine exhibit from the *Kern River* proceedings that states, "On May 25, 2004, the bankruptcy court issued an order permitting Kern River to apply 100 percent of the approximately $14.8 million cash security deposit to its claim for damages."); Exhibit No. PNG-69 at 1-2 and 7-8 (providing pleadings from Kern River which cite to the fact that Kern River obtained bankruptcy proceeds during the test period of that proceeding)).

[151] *Id.* (citing Appendix B).

million, relates to payments Rumford would have made during the period after the September 30, 2008 end of the test period in this rate case. Portland has also received approximately $18.4 million in bankruptcy proceeds as partial compensation for the payments Androscoggin would have made under its contract over the 14 year, 4 month, period from the June 2005 rejection of that contract until its October 31, 2019 expiration. Approximately 77 percent of that amount, or $14.2 million, relates to payments Androscoggin would have made during the period after the September 30, 2008 end of the test period in this rate case.[152] In addition, during the last 12 months of the test period, Portland states that it remarketed approximately 15,607,027 Dth of the capacity turned back by Rumford and Androscoggin at discounted rates, collecting revenues of $7,569,043.[153] These facts raise the same issue addressed in both *Trailblazer* and *WIC*: how to account for the fact that a pipeline has received compensation for payments a shipper would have made in the future pursuant to a firm contract that has been terminated before the end of its term.

104. In both *Trailblazer* and *WIC*, as here, the pipelines received contract termination payments related to certain turned back capacity, in addition to remarketing revenues. In *Trailblazer*, the Commission considered whether to credit Trailblazer's cost-of-service with a $16.4 million exit fee that the pipeline received from Columbia Gas Transmission Company (Columbia) for the early termination of a firm transportation service agreement. The capacity associated with the Columbia contract was fully re-subscribed and Trailblazer argued that no credit was warranted, as the capacity associated with the Columbia contract was still reflected in the pipeline's billing determinants.[154] Like Portland in this case, Trailblazer asserted that crediting the Columbia exit fee "would effectively require Trailblazer to double count the volumes for rate design purposes" and that the Commission should consider "the fact that Trailblazer received less than dollar for dollar in exit fee payment."[155] Despite Trailblazer's contentions, the Commission

[152] Portland Response to Data Request at Schedule 2 (response to Data Request No. 1).

[153] *Id.* at Schedule 6 (response to Data Request No.4). To put the 15,607,027 Dth annual figure into perspective compared to the 62,000 Dth per day associated with the rejected contracts, there was an average of 41,404 Dth per day of short-term firm and 1,355 Dth per day of IT, for a total of 42,759 Dth per day of remarketed capacity during the test period.

[154] *Trailblazer*, 80 FERC at 61,518.

[155] *Id.*

determined that a credit against Trailblazer's cost-of-service was warranted. The Commission explained,

> An exit fee in the amount of $16.4 million was paid to Trailblazer to terminate Columbia's contract which otherwise would not have terminated until January 1, 2003. A portion of that payment is applicable to each month during the test period and the period into the future during which the contract would have run. Failure to credit some or all of the buyout payment to the cost-of-service … would result in Trailblazer's customers paying rates that cover costs Trailblazer has already recovered in the buyout payment. This would result in a windfall to Trailblazer….[156]

The Commission set for hearing the issue of the level of the credit, and the case subsequently settled.

105. Similarly, in *WIC*, the Commission considered whether it should credit the pipeline's cost-of-service for an exit fee paid to the pipeline by Columbia. As in *Trailblazer*, the pipeline proposed to include the volumes associated with the capacity formerly held by Columbia in its rate design volumes. The Commission nevertheless determined that a credit to the pipeline's cost service was necessary:

> The fact that WIC has not removed the volumes associated with the former Columbia capacity from the volumes used to design its rates does not, by itself, eliminate the need for a credit. Columbia's exit fee compensates WIC for revenue it would have collected from Columbia if Columbia's contract had remained in effect through January 1, 2004. Therefore, to the extent WIC has remarketed that capacity to other shippers, WIC is effectively selling the same capacity twice, once to Columbia and once to the new shippers. That would inevitably lead to an over-recovery of its cost-of-service.[157]

As in *Trailblazer*, the Commission established further procedures to resolve what the level of the credit should be, but the case subsequently settled.

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[156] *Id. See also Trailblazer*, 81 FERC ¶ 61,032 (order denying rehearing).

[157] *WIC*, 87 FERC at 62,309.

106. We find that the reasoning in *Trailblazer* and *WIC* is equally applicable here. A significant portion of Portland's Bankruptcy Proceeds relates to payments Rumford and Androscoggin would have made under their contracts after the September 1, 2008 effective date of the rates in this rate case and continuing until the October 31, 2020 and October 31, 2019 expiration dates of those contracts. Therefore, to the extent Portland has remarketed the capacity to other shippers, Portland is effectively selling the same capacity twice, once to Rumford and Androscoggin and once to the new shippers. Failure to allocate a portion of Portland's cost-of-service to the terminated contracts would unreasonably require Portland's current customers to pay rates that cover costs that Portland has already recovered through the Bankruptcy Proceeds.

107. As stated in Opinion No. 510, the fact that Portland's lump sum contract termination payment was received in the form of bankruptcy proceeds rather than a contract exit fee or buyout payment does not distinguish its circumstances from the holdings of *Trailblazer* and *WIC*. In each case, the pipeline is receiving revenues for services not yet provided and the pipeline is in a position to remarket that capacity to a third party, raising the potential for a double recovery of costs. For our purposes here, i.e., determining how to account for the revenues in Portland's rates, it makes no difference whether the revenues resulted from a contract exit fee or a bankruptcy claim.[158]

108. In *Trailblazer* and *WIC*, we adopted a two prong remedy to the pipeline's potential double recovery of costs. First, we required the pipeline to allocate a portion of the pipeline's cost of service to the terminated contracts by requiring those pipelines to reduce their cost of service by a credit for the exit fee. Second, we required those pipelines to include in their rate design volumes the full amount of the billing determinants associated with the terminated contracts to reflect the fact those pipelines had remarketed the entire amount of the subject capacity at or near their maximum rates.

109. In this case, we have adopted essentially the same two-prong remedy to ensure no double recovery of costs. In the first prong, we are requiring Portland to allocate a portion of its cost of service to the rejected contracts. However, rather than requiring the Bankruptcy Proceeds to be credited against the cost of service as in *Trailblazer* and *WIC*,

[158] Portland's reliance on *Columbia Gas* is unpersuasive. *Columbia Gas* involved a settlement between Columbia and Tennessee Gas Pipeline Company regarding the early termination of certain contracts between the two pipelines in exchange for the payment of an exit fee by Columbia to Tennessee. In explaining the benefits of the settlement, the Commission pointed out the uncertainty that Tennessee's customers would likely face if the contracts became part of Columbia's bankruptcy proceeding. *Columbia Gas* did not address the treatment of the exit fee in Tennessee's rates.

we are requiring Portland to include discount-adjusted billing determinants associated with the rejected contracts in its rate design volumes. We take this approach for the same reason we have required Portland to project IT/PAL billing determinants, rather than credit those revenues to cost of service: to permit a comparison of Portland's total projected billing determinants to its at-risk volumes so as to determine whether Portland's rate design volumes comply with its at-risk condition. Nevertheless, the requirement that Portland account for the Bankruptcy Proceeds by a projection of discount-adjusted billing determinants achieves the same end result as a credit of the Bankruptcy Proceeds against the cost of service. Each method of accounting for the Bankruptcy Proceeds allocates a portion of the pipeline's cost of service to the rejected contracts in a way that takes into account the fact the Bankruptcy Proceeds may have produced less revenue for the pipeline than if the departed shipper was continuing to pay the pipeline's maximum rate.[159] In its response to the Staff Data Request, Portland estimates that the discount adjustment permitted by Opinion No. 510 will reduce its projected billing determinants associated with the rejected contracts from the unadjusted level of 62,000 Dth per day to 25,657 Dth per day.[160]

110. In the second prong of the remedy, we are requiring Portland to include in its rate design volumes the interruptible and short-term firm billing determinants associated with its remarketing of the capacity under the rejected contracts, also adjusted for discounting. This requirement corresponds to the requirement in *Trailblazer* and *WIC* that those pipelines include the full amount of the billing determinants associated with the terminated contracts in order to reflect the fact those pipelines had remarketed the entire amount of that capacity at or near their maximum rates.

111. We recognize that Portland has not been as successful at remarketing the capacity turned back by Rumford and Androscoggin as Trailblazer and WIC were in remarketing their turned-back capacity. Unlike those pipelines, Portland has not been able to remarket all of the capacity that was subject to the rejected contracts and it has

[159] In the *Rate Design Policy Statement*, the Commission suggested two approaches to adjusting rates to reflect projected discounting. These were (1) the ratio method we have permitted Portland to use in this case and (2) the revenue credit method. Under the revenue credit method, revenues obtained in discounted rate transactions are subtracted from the cost of service and per unit rates are then designed based on the billing determinants in the pipeline's other transactions. *See Williston I*, 67 FERC at 61,382-83. The *Trailblazer* and *WIC* requirement to credit the exit fee against cost of service effectively permitted a discount adjustment to the extent the exit fee produced revenues below the maximum rate via the revenue credit discount adjustment method.

[160] Portland Response to Data Request at 2, Scenario 1, Schedule G-1, Iteration 10.

substantially discounted the capacity it has remarketed. However, we have taken these facts into account by requiring Portland to include in its projected billing determinants only the discount-adjusted billing determinants obtained during the test period by remarketing the turned-back capacity period to interruptible and short-term firm shippers. In its response to the Staff Data Request, Portland states that its total unadjusted daily test period short-term firm and interruptible IT/PAL billing determinants were 41,832 Dth and 25,724 Dth respectively.[161] Portland estimates that the discount adjustment permitted by Opinion No. 510 will reduce these quantities to 10,573 Dth per day and 10,263 Dth per day respectively.[162] Thus, the short-term firm and interruptible billing determinants we require Portland to include in its projected billing determinants total only about 20,856 Dth per day, or approximately a third of the total 62,000 Dth per day of capacity turned back by Rumford and Androscoggin. Moreover, this amount reflects not only short-term firm and interruptible billing determinants Portland obtained by remarketing the turned-back capacity, but also all other short-term firm and interruptible service provided during the test period.[163]

112. Thus, the two-pronged remedy adopted by Opinion No. 510 requires Portland to include no more than about 46,513 Dth per day in its projected billing determinants.[164] That amount is less than the unadjusted 62,000 Dth per day of billing determinants related to the rejected contracts, which Portland proposed to include in its rate design volumes. In short, far from the confiscatory result depicted by Portland in its rehearing request, Opinion No. 510's bankruptcy-related billing determinant requirements are

[161] *Id.*

[162] *Id.* Because the discount adjustment is based on the ratio of the discounted rate to the final approved maximum rate in this proceeding and because certain other rulings in this order will affect the final approved maximum rate, the discount adjusted quantities set forth above are likely to be slightly different when Portland files to comply with this order. However, any such change will be too minor to affect the analysis in this section of the order.

[163] *See* n.153 supra, wherein Portland drew a distinction between remarketed rejected contract capacity as compared to total short term firm and interruptible services.

[164] Portland Data Response at 2, Scenario 1, Schedule G-1, Iteration 10: (Adjusted rejected contracts of 25,657 Dth per day) + (Adjusted total short term firm + total interruptible volumes of 20,856 Dth per day) = 46,513 Dth per day. The Commission notes that, while Portland argues that some interruptible services can be attributed to remarketed rejected contract capacity, the Commission is not agreeing with the concept that interruptible service can be ascribed to any specific firm contract.

actually more favorable to Portland than its own proposal. Portland's proposal to use billing determinants of 210,840 Dth per day implicitly included 62,000 Dth per day, unadjusted, in unsubscribed firm capacity associated with the rejected contracts.[165] Notwithstanding the foregoing, as stated above, it is the at-risk condition, not Opinion No. 510's holdings concerning bankruptcy-related billing determinants, that ultimately controls the rate design volumes that Portland must use in this rate case.

113. Portland also points out that it has only remarketed the capacity on a short-term basis and the remaining terms of the Rumford and Androscoggin rejected contracts are significantly longer than the remaining terms of the terminated contracts in *Trailblazer* and *WIC*. These facts do not distinguish this case from *Trailblazer* and *WIC*. In all three cases, the Commission has required the pipeline to allocate a portion of its cost of service to both the terminated contracts and any remarketed capacity, using the Commission's standard test period methodology for projecting revenues and billing determinants. The Commission uses the most representative data available to establish a pipeline's cost-of-service and throughput.[166] In the instant proceeding, the ALJ agreed with several parties that Portland's actual test period interruptible and short-term firm revenues were the most representative data available for these services.[167] Opinion No. 510 rejected the ALJ's decision to credit Portland's cost of service by the actual test period interruptible and short-term firm revenues. However, Opinion No. 510 accepted the ID's finding that Portland's actual test period interruptible and short-term firm revenues were the most representative data available for these services and required Portland to use in calculating

[165] Portland argues that Opinion No. 510 erred by justifying its proposed remedy based on the conclusion that Portland was "double-selling" its capacity. Portland Rehearing Request at 34. Portland contends that pipelines "double sell" available capacity otherwise subject to FT forward haul contracts all the time (e.g., IT/PAL), but the Commission does not require those pipelines' rates to be designed using the allegedly cumulative and punitive approach adopted in Opinion No. 510. We agree that pipelines often attain billing determinants in excess of their design capacity in the manner described by Portland. However, Portland is incorrect that the Commission permits pipelines to retain "double sold" revenues in the context of establishing rates in a rate proceeding and it fails to point to any regulation or case law in support of this statement. Consistent with other rate cases, we are requiring Portland to use all such billing determinants in the design of its rates, so that the pipeline's rates will not be designed to recover more revenues than its cost of service.

[166] *Trunkline*, 90 FERC at 61,082-84.

[167] ID, 129 FERC ¶ 63,027 at P 235.

its projected billing determinants the actual test period revenue data.[168] Portland has not pointed to any record evidence that would suggest it cannot continue to obtain the same level of interruptible and short-term firm revenues as it did during the last 12 months of the test period. The fact the remaining terms of the Androscoggin and Rumford agreements are longer than the terminated contracts in *Trailblazer* and *WIC* does not in any way alter the essential fact that the Bankruptcy Proceeds provide Portland a stream of revenue related to the rejected contracts which, if not reflected in rates, could lead to Portland double recovering costs related to the capacity under the rejected contracts.

114. Portland's reliance on *Kern River* is misplaced. In Opinion No. 510, the Commission found that *Kern River* was not analogous to the instant case.[169] In *Kern River,* contracts between Kern River and Mirant were rejected during the bankruptcy of Mirant. Following the bankruptcies, the Mirant capacity had been used for interruptible transportation and contributed to what was termed in that proceeding as "market oriented revenues."[170] In its rate case, Kern River proposed to retain the portion of the market oriented revenues deemed associated with the Mirant capacity and credit its overall cost-of-service by the remaining amount. Kern River argued, and the Commission agreed, that this was reasonable given its proposed billing determinants reflected the capacity associated with the Mirant capacity though it had been unable to contract that capacity to a new long-term firm shipper. However, no issue arose in the *Kern River* proceeding concerning the treatment of any bankruptcy award related to the Mirant capacity. As the ALJ stated, "the Commission never addressed Kern River['s] receipt of substantial bankruptcy proceeds in any of the three Kern River Orders in the Docket No. RP04-274 proceeding."[171] This fact is also made clear in Opinion No. 486-C, where the Commission observed, in relation to another issue in the case, that while Kern River ultimately did receive substantial bankruptcy proceeds, it was after the test period in the case: "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."[172]

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[168] Opinion No. 510, 134 FERC ¶ 61,129 at P 310 & n.452.

[169] *Id.* PP 351-352.

[170] *Kern River*, Order No. 486-A, 117 FERC ¶ 61,077 at P 370. Market oriented revenues were revenues derived from interruptible, authorized overrun, and short-term firm services. *Kern River*, Order No. 486-A, 123 FERC ¶ 61,056 at P 277.

[171] *Id.*

[172] *Kern River*, Opinion No. 486-C, 129 FERC ¶ 61,240 at P 115 & n.175

115. On rehearing, Portland still does not point to any language in the Kern River orders in Docket No. RP04-274 demonstrating that the Commission addressed or considered Kern River's receipt of bankruptcy proceeds in making its determination. Moreover, the pleadings and other documentation cited by Portland as evidence of Kern River's receipt of bankruptcy proceeds are unpersuasive. While Portland cites to several documents indicating that the bankruptcy court permitted Kern River to apply $14.8 million drawn on a letter of credit to its bankruptcy claim,[173] none of those documents show that the parties in *Kern River* ever argued that the $14.8 million should be considered by the Commission in determining Kern River's rates.

116. Accordingly, Portland's request for rehearing on this issue is denied.

V. <u>Rate Base/Bankruptcy Proceeds</u>

A. <u>Opinion No. 510</u>

117. In Opinion No. 510, the Commission required Portland to use the full Bankruptcy Proceeds, net of legal costs incurred by Portland in the bankruptcy proceeding and taxes paid by Portland, as a reduction to rate base.[174] Opinion No. 510 explained the basis for this requirement as follows:

> The Commission finds that a reduction to Portland's rate base is justified to account for the fact the bankruptcy award allowed Portland to recover immediately costs that would otherwise have been recovered only over the remaining terms of the Androscoggin and Rumford Agreements. Based on the

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[173] According to the CES exhibit cited by Portland, by way of background, Mirant entered into a firm gas transportation contract with Kern River for 90,000 Dth/day of expansion capacity and provided a letter of credit equivalent to 12 months of reservation charges as security. In July, 2003, Mirant filed for Chapter 11 bankruptcy protection and in October, 2003 Mirant informed Kern River that Mirant did not intend to renew its letter of credit. Kern River then drew on the letter of credit and held $14.8 million as cash collateral. Effective December l8, 2003, Mirant rejected its firm service agreement pursuant to procedures under the Bankruptcy Code and paid all post-petition amounts owing under the contract through December 18, 2003. On January 13, 2004, Kern River filed a proof of claim with the bankruptcy court for an aggregate total of $210.2 million and on May 25, 2004, the bankruptcy court issued an order permitting Kern River to apply the $14.8 million cash security deposit to its claim for damages.

[174] Opinion No. 510, 134 FERC ¶ 61,129 at P 360.

> facts presented in this proceeding, the Commission will require Portland to use the full bankruptcy proceeds, net of legal costs incurred by Portland in the bankruptcy proceeding, as a reduction to rate base.
>
> We find this rate base adjustment to be a reasonable approach since it provides recognition that Portland received significant lump sum payments for early contract termination. At the same time, consistent with our prior findings in *Trailblazer* and *WIC,* a pipeline should not over-recover its cost-of-service by selling the same capacity twice. The lump sum payment is an early recovery of future costs. Reducing the rate base by the net lump sum bankruptcy proceeds reduces the return allowance that would otherwise be included in Portland's rates, thereby mitigating cost over-recovery. Further, the Commission believes this approach simplifies what is an inexact projection of calculating benefits to the pipeline, simplifies the estimate of the potential over-recovery of revenues in this proceeding, as the bankruptcy proceeds were largely received in a lump sum and within the test period, and eliminates the need to develop an appropriate discount rate factor and NPV calculation of revenue lost under the terminated contracts.[175]

118. The Commission also noted that since the revenues received by Portland are subject to income taxes, Portland should reflect the appropriate deferred income taxes in rate base.[176] The Commission stated that Portland estimated that the after tax amount of the Bankruptcy Proceeds totaled $71,081,780, indicating that the tax liability totaled $48,679,478. The Commission also noted that the rate base adjustment should be reflected in the remaining levelization period.[177]

119. In its request for rehearing, Portland objects to Opinion No. 510's requirement that the Bankruptcy Proceeds be subtracted from its rate base on a number of grounds. Portland also requests clarification concerning how the reduction in rate base should be carried out.

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[175] *Id.* PP 360-61 (footnotes omitted).

[176] *Id.* n.512.

[177] Opinion No. 510, 134 FERC ¶ 61,129 at n.512.

B. Burden of Proof

120. Portland contends that the Commission must proceed under NGA section 5 in order to require it to subtract the Bankruptcy Proceeds from its rate base and that the Commission failed to satisfy its burden of proof under section 5 of the NGA with respect to that requirement.[178] Portland asserts that the Commission's authority under NGA section 4 is limited to reviewing rate increases proposed by the pipeline, and when the Commission seeks to impose its own rate determinations the Commission must act under NGA section 5. Portland states that it did not propose the method for accounting for the Bankruptcy Proceeds adopted by Opinion No. 510. Citing *Western Resources, Inc. v. FERC,*[179] Portland contends that, before the Commission can impose its own rate design under section 5, it must show that: (1) the pipeline's proposed rates are not just and reasonable, (2) the default position, the preexisting rate design, is unjust and unreasonable; and (3) the Commission's proposed rate design is just and reasonable.

121. Therefore, to satisfy the requirements of section 5 with respect to the rate base reduction, Portland contends that the Commission must demonstrate that (1) Portland failed to satisfy its NGA section 4 burden to show that its proposal to design its rates based upon billing determinants of 210,840 Dth per day was just and reasonable, (2) Portland's prior practice of designing its rates based upon billing determinants of 178, 000 Mcf per day is no longer just and reasonable, and (3) establish that the method adopted by Opinion No. 510 for accounting for the Bankruptcy Proceeds is just and reasonable. Portland contends that the Commission has failed to satisfy that burden. In particular, Portland claims that Opinion No. 510 methodology deprives Portland of an opportunity to recover its costs and to earn an adequate return on its investment.

Commission Determination

122. In this rate case, Portland has proposed under NGA section 4 to increase its rates. As part of that proposal, Portland proposed to design its rates based upon its claimed design capacity of 210,840 Dth per day, and not reflect in its rates any portion of the $119 million in Bankruptcy Proceeds which it received after the rates in its last NGA section 4 rate case took effect.

123. NGA section 4 places on the pipeline the burden of supporting any proposed rate increase. As the Commission held in *Northwest Pipeline Corp*.,[180] since each item in the

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[178] Portland Rehearing Request at 56-58.

[179] 9 F.3d 1568, 1578 (D.C. Cir. 1993) (*Western Resources*).

[180] 87 FERC ¶ 61,266, at 62,038-9 (1999). *See also Tennessee Gas Pipeline Co.*,

(continued…)

pipeline's proposed cost of service is a part of the pipeline's proposed rate increase, the pipeline's burden of supporting its proposed rate increase includes the burden of supporting the dollar amount of each item in the cost-of-service. This includes unchanged cost of service items. In addition, in *Western Resources*, the court stated that "differences as to the extent of specific cost items may be handled in a Section 4 proceeding."[181]

124. The level of a pipeline's rate base is a key component in determining the dollar amount of the overall return on rate base to include in a pipeline's cost of service, since the overall return is a percentage of the rate base. Therefore, Portland has the burden under NGA section 4 to show that the proposed rate base underlying the return included in its cost of service is just and reasonable. As part of that burden, Portland must show that its NGA section 4 proposal not to subtract the Bankruptcy Proceeds from its rate base is just and reasonable.

125. We reject Portland's contention that we have a burden under NGA section 5 to show that Portland's prior practice of designing its rates based upon its previous design capacity of 178,000 Mcf per day, without any rate base reduction for Bankruptcy Proceeds is unjust and unreasonable. Portland had not received any Bankruptcy Proceeds before this rate case, and therefore this is the first rate case which has raised the issue of how such proceeds should be treated in Portland's rates. In these circumstances, there is no prior approved practice which we must find unjust and unreasonable under NGA section 5 before requiring Portland to subtract the Bankruptcy Proceeds from its rate base.[182]

126. In any event, even if under *Western Resources* our rate base reduction requirement is considered to be an action that goes beyond accepting or rejecting the pipeline's proposal and thus requires us to act under NGA section 5, our findings below satisfy our burden of persuasion under that section. In the following sections of the order, we address each of Portland's various contentions concerning the justness and reasonableness of the rate base reduction. For all the reasons discussed below, we find both that Portland's failure to make any such reduction is unjust and unreasonable and

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25 FERC ¶ 61,020, at 61,108 (1983), *reh'g denied*, 26 FERC ¶ 61,109 at 61,263-64 (1984).

[181] 9 F.3d at 1579.

[182] *Contrast Western Resources*, 9 F.3d at 1580, where the Commission sought to modify the pipeline's prior practice of designing its backhaul rates.

that our requirement that Portland subtract the Bankruptcy Proceeds from its rate base, as clarified below, is just and reasonable.

C. Rationale for Rate Base Reduction

127. Portland contends that Opinion No. 510 erred in its determination that Portland must reduce its rate base by the Bankruptcy Proceeds. First, Portland states that the Commission incorrectly assumed that Portland had over-recovered its costs through the receipt of Bankruptcy Proceeds and the partial remarketing of the associated capacity at discounted rates.[183] Portland states that where it is under recovering it should be permitted to retain the time value of money associated with the lump sum payment so that it can come closer to achieving recovery of the value of revenues lost from the rejected contracts. Otherwise, Portland contends, it will remain under-funded while its customers receive a windfall associated with the rate base credit. Portland states that this is especially true given that bankruptcy proceedings, when computing claims against the estate for executory contracts subject to rejection, apply a discount factor to any claim to reduce nominal dollars that would have been paid by the debtor in the future, to present value. Portland states that implicit in that calculation is the understanding that the time value of money is a key component of creditor's compensation under the claim. Portland states that removing that part of the compensation, without even considering whether Portland had actually over-recovered, arbitrarily creates a situation where Portland will never be able to recover the full value of its rejected contracts.

128. Portland also states that Opinion No. 510 uses Portland's firm system capacity to derive Portland's rates while illogically eliminating from rate base the value of Portland's investment made to provide such service. In order for it to provide service at that level of capacity, Portland states that it had to invest in all of its plant. By crediting rate base, Portland argues, the Commission has effectively determined that the Bankruptcy Proceeds were a return of Portland's investment. However, Portland argues, the Bankruptcy Proceeds reflect compensation for all costs contributing to Portland's entire rate, including *inter alia*, O&M, taxes, return and also depreciation. If Portland is presumed to continue providing service at its current level of firm system capacity, then allowing it to recover rates using its full rate base is necessary to achieve that level of service.

Commission Determination

129. Portland's request for rehearing is denied. Opinion No. 510 allows Portland to retain the full $71,081,780 after-tax amount of the Bankruptcy Proceeds and invest that

[183] Portland Rehearing Request at 38-39.

money or apply it against its cost of service as it sees fit. As explained below, all that Opinion No. 510 requires is that the return included in Portland's rates be reduced to reflect that portion of the Bankruptcy Proceeds representing prepayments for future service. As Opinion No. 510 explained, this is a reasonable approach "since it provides recognition that Portland received significant lump sum payments for early contract termination."[184]

130. Portland contends that the Commission has effectively determined that the Bankruptcy Proceeds were a return of Portland's investment and, if it is to continue providing service at its current level of firm system capacity, then allowing it to recover rates using its full rate base is necessary to achieve that level of service. First, Opinion No. 510 is not treating the Bankruptcy Proceeds as a return of Portland's investment. Portland recovers its invested capital through the depreciation allowance included in its cost of service. The rate base adjustment required by Opinion No. 510 will have no impact on the depreciation allowance included in Portland's cost of service. The depreciation allowance will continue to be calculated by dividing the full amount of Portland's unrecovered invested capital by its depreciable life, without any adjustment related to the Bankruptcy Proceeds.

131. Rather, Opinion No. 510 only requires a reduction in the rate base amount upon which Portland's return is calculated. In addition, as explained in more detail in the next section, we are only requiring Portland to reduce its rate base during each year of the levelization period by that portion of the after-tax Bankruptcy Proceeds which represents compensation for payments Androscoggin and Rumford would have made under their contracts in subsequent years. To the extent the Bankruptcy Proceeds represents payments Androscoggin and Rumford would have made for service during the current or earlier years of the levelization period, there is no rate base reduction. This rate base reduction only reduces the return on invested capital included in Portland's cost of service, to the extent that Portland receives Bankruptcy Proceeds before the periods in which the revenues they represent would have been payable and received by Portland. As Portland retains the net proceeds, Opinion No. 510 allows Portland to invest those proceeds elsewhere as it sees fit, earn a return on the proceeds, and retain in full that return for its shareholders.

132. Opinion No. 510's treatment of the Bankruptcy Proceeds is not unlike the Commission's treatment of accumulated deferred income taxes (ADIT) (also referred to as, normalization). ADIT is the amount of income taxes collected by the pipeline in

[184] Opinion No. 510, 134 FERC ¶ 61,129 at P 361.

rates, but not yet needed to pay current income taxes.[185] This difference in the amount of taxes collected in rates and the amount of taxes actually paid is accumulated each year and is deducted from a pipeline's rate base as ADIT.[186] While sitting on the First Circuit, Justice Breyer explained the reason for the adjustment to rate base. Assuming a pipeline received $25,000 from ratepayers for tax liabilities that were not currently due, Justice Breyer stated:

> In a nutshell, the adjustment to the rate base reflects the fact that, under the normalization approach, the $25,000 was given to the company by its customers to pay taxes not yet due. One might alternatively view the $25,000 as being "loaned" to the company by the Internal Revenue Service. Either way, the firm at no cost to itself has obtained funds which it can invest as it chooses. The return the company is usually allowed to recover on its rate base compensates it for its costs in obtaining the requisite capital. So, in the regulators' view, the company should not be allowed to charge the ratepayers for a "return" on this $25,000

[185] 18 C.F.R. § 154.305(c) (2012). ADIT arises from timing differences, such as when a pipeline uses an accelerated depreciation or amortization method for income tax purposes that varies from the Commission's straight line methodology. For example, if the pipeline accelerates depreciation, this increases operating expenses in the early years of an investment and reduces the pipeline's income and the tax liability that is incurred in that year for IRS purposes. However, the income tax allowance embedded in the pipeline's rates is constant and therefore, that particular year would generate more cash flow than is actually required to meet the income tax liability created by the pipeline's IRS income. This difference in the amount of taxes collected in rates and the amount of taxes actually paid are accumulated each year and are deducted from a pipeline's rate base as ADIT. There will be a point in time when the depreciation expense computed on an accelerated basis for tax purposes will be less than the depreciation expense under the straight-line method. At this point, a pipeline will be collecting less taxes in rates than it needs to pay for income tax purposes. Thus, the monies accumulated as ADIT will be used to pay these taxes and the ADIT balance will start to decline.

[186] *Id. See also* Opinion No. 486, 117 FERC ¶ 61,077 at P 228, *order on reh'g,* Opinion No. 486-A, 123 FERC ¶ 61,056 at P 269 ("Commission policy requires a regulated firm to adjust its rate base to reflect the timing difference between the receipt of cash flows generated by the income tax component of its rates and the timing of its actual tax payments."); *SFPP, L.P.*, 86 FERC ¶ 61,022, at 61,092 (1999).

> (temporary) addition to the firm's capital, because it was obtained by the company without cost.[187]

The Commission has also stated it requires the pipeline to reduce rate base by the amount of the deferred tax income liability "to recapture the additional return the carrier can earn on the cash generated by the deferred income tax liability."[188]

133. Similarly, in this case, Portland has recovered from its customers revenues related to expenses Portland has not yet incurred. As a result, Portland will have the opportunity to invest upwards of $70 million and earn an additional return for its shareholders. Consistent with our ADIT policy, we believe that Portland's opportunity to earn an additional return should be reflected in a reduction to rate base. As discussed in more detail in the next section, the credit to rate base will be reduced with each succeeding levelization period (effectively, the same period remaining on the term of the rejected contracts), until it is fully dissipated.

134. Second, we disagree with Portland's contention that the rate base reduction improperly denies it the time value of money arising from the Bankruptcy Proceeds. Portland argues that it should be permitted to retain the time value of money associated with the lump sum payment so that it can come closer to achieving recovery of the value of revenues lost from the rejected contracts. Otherwise, Portland contends, it will remain under-funded. The Commission, in Order No. 144, which codified the Commission practice of adjusting rate base for ADIT, stated that the "benefit of accelerated tax deductions is only the time value of money which benefit is given to ratepayers through the deduction of accumulated deferred taxes from rate base."[189] Here, there is also no

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[187] *Distrigas of Massachusetts Corp. v. FERC*, 737 F.2d 1208, at 1213-14 (1st Cir. 1984) (*Distrigas*). In *Distrigas*, the court held that the Commission had not justified removing from rate base certain deferred tax liabilities related to a period before the company was subject to Commission regulation. On remand, in *Distrigas of Massachusetts Corp.*, 31 FERC ¶ 61,276 (1985), the Commission stated that Distrigas could continue to include in rate base the deferred tax liabilities that were at issue in the First Circuit case. Here, Portland has been subject to Commission jurisdiction throughout its existence, and the concern raised by the court in *Distrigas* does not arise.

[188] *See SFPP, L.P.*, 121 FERC ¶ 61240, at P 140 (2007).

[189] *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, FERC Stats. & Regs. ¶ 30,254, at 31,555 (1981), *reh'g denied*, Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 (1982), *aff'd sub nom., Public Systems v. FERC*, 709 F.2d 73, 83 (D.C. Cir. 1983).

need to permit Portland to recover the time value of money of the Bankruptcy Proceeds by eliminating the rate base reduction. Portland is in possession of the Bankruptcy Proceeds and there are no restrictions on its ability to invest it elsewhere. Portland may keep any income it receives in these alternative investments, because that income is not reflected in Portland's cost of service. Therefore, Portland's rate base should be reduced to reflect the fact the Bankruptcy Proceeds provide a temporary addition to Portland's capital without cost. It is for these reasons that the rate base reduction is required.

135. Portland states that removing the time value of money without even considering whether Portland had actually over-recovered, arbitrarily creates a situation where Portland will never be able to recover the full value of its rejected contracts. However, it is not our treatment of the Bankruptcy Proceeds that leads to any under-recovery of costs by Portland, but rather the at-risk condition. Absent the at-risk condition, we would permit Portland to reduce its rate design volumes as necessary so that, taking into account its discounting during the test period and the fact that the bankruptcy proceeds do not fully compensate it for the payments its would have received under the rejected contracts, it would have an opportunity to recover its full cost of service. It is only because Portland's projected billing determinants are less than its at-risk condition, that its rates may under-recover its cost of service. However, the existence of the at-risk condition does not justify including in rate base amounts which we would not otherwise include in rate base so as to increase the return included in its rates. To do that would give Portland a back door means of avoiding the effects of the at-risk condition. To the extent Portland's at-risk condition results in Portland under-recovering its costs, Portland accepted that risk when it accepted its certificate subject to the at-risk condition and we will not mitigate that risk by artificially inflating the return included in its rates.

136. Portland also argues that the rate base adjustment does not allow Portland to recover its out of pocket operating expenses. However, as explained in more detail in the next section, we are limiting the amount of the rate base reduction to that portion of the Bankruptcy Proceeds which in any given year represents prepayments for service which would have been performed under the rejected contracts in subsequent years. Thus, Portland may apply that portion of the Bankruptcy Proceeds representing payments that would have been made for service in current or past years to the recovery of its operating expenses, without any credit of those amounts against the rate base.

D. <u>Treatment of Rate Base Reduction in Levelized Rates</u>

137. Portland seeks clarification, and in the alternative rehearing, that the contemplated rate base adjustment is consistent with levelization.[190] Portland contends that crediting

[190] Portland Rehearing Request at 39-40.

the entire amount of the proceeds against rate base would be an incorrect step under the levelization model. Portland states that a levelized rate reflects the average of remaining annual balances included in rate base over the levelization period. A levelization approach, Portland states, averages the level of rate base starting in the first year of the levelization period, throughout and including the last year of the levelization period. Portland states that any rate base credit under Opinion No. 510 should reflect this feature of levelization by using an average of the rate base reducing offset. If such clarification is not provided, Portland seeks rehearing on this point, arguing that it would be a fundamental mismatch to create a crediting obligation for Bankruptcy Proceeds that is a static offset based on the amount in the first year of a levelization period to be applied for years to a rate base that is averaged across, among other things, Year I and Year II levels (i.e., starting in 2008 and running through 2019).

138. Further, Portland seeks clarification that any rate base offset contemplated by Opinion No. 510 would be reduced over time.[191] Portland states that the Commission analogized prepayments to its approach regarding the rate base reduction related to Bankruptcy Proceeds.[192] Portland states that over what would have been the remaining terms of the rejected contracts, a prepayment would be reduced each year by the amount that Androscoggin and Rumford should have paid Portland for service rendered in that year. Like in its orders concerning the posting of security for new construction, Portland states the Commission has required that the level of security be reduced to reflect reductions to the customer's remaining liability over time.[193] Moreover, Portland states that if the rate base credit is not amortized, net plant could even become negative, when Portland's rate base (without considering the credit) falls below the credit required by Opinion No. 510. Therefore, Portland states, to correctly reflect the prepayment in a levelized rate, only a portion of the lump sum amount should be included as a rate base credit, and that amount should be "worked off" as the service under the rejected contracts would have been performed. Portland states that, at worst for future rate proceedings, the Commission should clarify that portions of the rate base credit that are so amortized over time no longer represent an imputed prepayment of the rejected contract.

[191] Portland Rehearing Request at 40-41.

[192] *Id.* at 40 (citing Opinion No. 510, 134 FERC ¶ 61,129 at P 355 (second sentence) and P 361 (third sentence)).

[193] *Id.* at 40 (citing *Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, FERC Stats. & Regs. ¶ 31,191, at P 19 (2005) ("The pipeline should also reduce the amount of collateral it holds as the shipper's contract terms is reduced.")).

Commission Determination

139. The Commission clarifies that like all other Portland rate base items, the Bankruptcy Proceeds rate base adjustment is a component of the levelized cost-of-service model, specifically rate base. Further, the rate base adjustment should be amortized over the period of the levelized cost of service beginning on the date the contracts were rejected.[194] Schedule 1, Scenario 2 of Portland's Response to Data Request correctly reflects this method.[195] The Commission believes that amortizing the Bankruptcy Proceeds over the period of levelization is reasonable given that the Bankruptcy Proceeds reflect payments (albeit partial) that would otherwise have been due over the remaining term of the rejected contracts and that the remaining term of the rejected contracts generally coincides with the remaining levelization period.[196]

140. This method of amortizing the rate base reduction in Portland's levelized cost-of-service matches the portion of the Bankruptcy Proceeds which constitutes a payment for service with the corresponding costs in each year of the levelization period. Thus, this method is consistent with the purpose of rate base reduction described in the preceding section of this order, namely to reduce the rate base by prepaid amounts which Portland is free to invest as it sees fit. This method also recognizes that Bankruptcy Proceeds were intended to provide Portland partial compensation for payments that would have been made over the terms of the contracts as payments for service under those contracts. That is because it does not include in the rate base reduction that portion of the Bankruptcy Proceeds related to earlier years of the levelization period, and thus give Portland the full benefit of such proceeds without any reduction in rate base.

141. Portland also proposes an alternative to the straight-line amortization method used to reduce the credit to rate base over time. Under its "work-off" proposal, Portland begins with the total Bankruptcy Proceeds and reduces the proceeds by the transportation revenue Portland would have received had the contracts of the bankrupt shippers remained in place until the proceeds equal zero, beginning on the date contracts were

[194] Portland asserts in its Response to Data Request that the Androscoggin contract was rejected in June, 2005 and would have continued to November, 2019 absent rejection and that the Rumford contract was rejected in April, 2006, and would have extended to November, 2020 absent rejection.

[195] Portland Response to Data Request at Schedule 1, Scenario 2. *See also* Portland Response to Data Request at Schedule 2 (Straight-line Amortization Schedule).

[196] The levelization period ends on March 31, 2020. Opinion No. 510, 134 FERC ¶ 61,129 at P 15.

rejected.[197] The starting balance in the first year of the levelization period begins with the remaining balance ($40.4 million), after recognizing the work-off between the date of the court ordered rejection of the transportation contracts and the end of the test period ($51.7 million). The work-off calculates revenues at the previous transportation rate times the contractual billing determinants until the entire balance of the Bankruptcy Proceeds are extinguished (or "worked-off"). Under Portland's proposal, the Bankruptcy Proceeds are "worked off" within 5 years of the start of the remaining levelization period.[198]

142. The Commission rejects Portland's work-off proposal. Portland's work-off proposal results in a rate base adjustment only through year 14 of the levelization period (or 2012), as opposed to the end of the levelization or contract periods (2019 or 2020). Portland effectively treats the Bankruptcy Proceeds as payment for services beginning with the date the contracts were rejected and continuing only through 2012. However, as stated above, the Bankruptcy Proceeds were intended to reflect payments beginning with the date the contracts were rejected and continuing through the end of the Androscoggin and Rumford contracts in 2019 and 2020, respectively. Portland's proposal unjustifiably frontloads the rate base adjustment, even though the proceeds reflected revenue to which Portland would have been entitled throughout the term of the rejected contract.[199] In addition, Portland's work off method uses a significant portion of the revenues meant to recover future period costs to recover costs incurred and not recovered in past periods, including periods prior to the September 1, 2008 effective date of the subject rates. Accordingly, Portland's request for rehearing is denied.

E. **Retroactive Ratemaking**

143. Portland argues that the Commission engaged in impermissible retroactive ratemaking because it mandated that, in calculating rates, Portland include revenue attributable to service provided prior to the Docket No. RP08-306 rate period and also reflect collections obtained prior to the Docket No. RP08-306 rate period. Portland states that Opinion No. 510 gives no recognition to the fact that some of the Bankruptcy Proceeds related to service performed earlier than September 1, 2008 (i.e., the date when

[197] Portland Response to Data Request at 4, Schedule 3.

[198] Portland's supporting work paper for the Work-Off method was filed as Schedule 3 within the spreadsheet file Schedule 3.XLS.

[199] It is also unclear why Portland, under the work-off method, only deducted taxes from the Bankruptcy Proceeds when calculating the rate base adjustment post October 1, 2008 and not when calculating the work-off amount prior to October 1, 2008.

Docket No. RP08-306 rates were placed into effect).[200] Because Opinion No. 510 does not grant any recognition of the bankrupt shippers' liability for any time before the beginning of Docket No. RP08-306 rate period, this allegedly constitutes another form of impermissible retroactive ratemaking.

144. Portland states that, in *Williston III*,[201] the pipeline collected insurance proceeds during the test period of its rate case that compensated it for reductions in interruptible transportation revenues experienced prior to that docket's effective date because of a fire and explosion at one of the pipeline's compressor stations.[202] Portland states that even though the insurance proceeds were received during the test period, the Commission declined to credit the pipeline's cost of service, stating that the insurance proceeds were a non-recurring one time event, and "[t]he issue here is to develop rates which will enable Williston to recover its projected costs during the period rates are in effect. To allow past over- or under-recoveries of costs to affect the rates being established here would be inappropriate retroactive ratemaking."[203] Portland states that the "Commission is prohibited from adjusting current rates to make up for previous over- or undercollections of costs in prior periods. . . . The Commission may not allow a utility to 'recoup past losses' nor may it force a utility to reduce its current rates to make up for overcollections in previous periods."[204]

145. Portland states that the situation here is similar. Portland states that it received approximately $103 million of proceeds from the Rumford bankruptcy during the test period of this proceeding[205] and approximately $19 million of revenues from the Androscoggin bankruptcy before the test period.[206] Portland states that these payments were non-recurring and they also compensate Portland for prior period contracts that were rejected. Consequently, Portland states, it has received proceeds that are a prior

[200] Portland Rehearing Request at 35.

[201] Portland Rehearing Request at 35 (citing *Williston III*, 84 FERC at 61,363).

[202] *Id.* at 35.

[203] *Id.* at 35-36 (citing *Williston III*, 84 FERC at 61,364).

[204] *Id.* at 36 (citing *Associated Gas Distributors v. FERC*, 898 F.2d 809, 810 (D.C. Cir. 1990).

[205] *Id.* (Exh. No. PSG-131 at 122.5; ID, 129 FERC ¶ 63,027 at P 173).

[206] *Id.* (Exh. No. PSG-14 at 2-4; Exh. No. PSG-131 at 122.5; ID, 129 FERC ¶ 63,027 at P 173).

period recovery of funds that should not be used to determine Portland's future rates consistent with *Williston III*.

146. Portland also states that the Bankruptcy Proceeds related at least in part to service performed or which would have been performed prior to when Docket No. RP08-306 rates took effect. Portland states that, at a minimum, the Commission is not permitted to adjust future rates based upon proceeds that properly should be attributed to the rejected contracts for a period prior to when Docket No. RP08-306 rates took effect, whether due to the time value of money or the remarketing of the capacity. Portland states that the Bankruptcy Proceeds compensated Portland for both prior and future service. Therefore, Portland states, some attribution of Bankruptcy Proceeds must be made with regard to prior periods. Portland states that the Commission's rate base adjustment cannot be based upon the revenues that Portland should have received under the rejected contracts from the date they were terminated until the date the Docket No. RP08-306 rates went into effect (i.e., September 1, 2008).

Commission Determination

147. The Commission grants in part and denies in part Portland's requests for rehearing on this issue. As described above, the Rumford contract was rejected on April 2006, about 2 years and four months before the September 1, 2008 effective date of the rates in this rate case, and the Androscoggin contract was rejected in June 2005, about 2 years and two months before the September 1, 2008 effective date of the rates in this rate case. However, the two contracts would have continued to remain in effect until October 31, 2020 and 2019 respectively, long after the effective date of the rates in this rate case. Thus, Portland's Bankruptcy Proceeds provide it partial compensation for payments it would have received both before and after the effective date of the rates in this rate case.

148. We agree that, to the extent the Bankruptcy Proceeds compensate Portland for payments Rumford and Androscoggin would have made under their contracts before September 1, 2008, it would be retroactive ratemaking to reflect them in the design of Portland's rates in this rate case. Those proceeds relate to past service, not current service. For that reason, in the preceding section, we held that Portland should allocate the Bankruptcy Proceeds received with respect to each contract across its entire remaining term from the date the contracts were rejected on a straight-line basis, and rejected Portland's proposed work-off method. The portion of the Bankruptcy Proceeds thus allocated to the period before September 1, 2008 will not be used to reduce the rate base used to calculate Portland's return on equity in this rate case.

149. However, the part of the Bankruptcy Proceeds that compensates Portland for payments Rumford and Androscoggin would have made under their contracts after September 1, 2008 does relate to the post-September 1, 2008 period. These proceeds are, in effect, prepayments for service that would have been provided in the current period.

Thus, unlike the insurance proceeds in *Williston III* which related to past services and were non-recurring,[207] the Bankruptcy Proceeds the Commission is requiring Portland to include in the rate base adjustment are related to recurring, future services. As of September 1, 2008, the Bankruptcy Proceeds not allocated to the prior period are reasonably treated as prepayments related to current and future service which the pipeline may currently invest for its own profit during the period the rates in this rate case are in effect. Accordingly, using those funds to reduce Portland's rate base no more violates the rule against retroactive ratemaking than our requirement, described above, that pipelines subtract from rate base deferred income tax amounts collected from customers in the past but to be used to pay income taxes in the future.[208]

150. Similarly, Opinion No. 510's requirement that Portland include in its rate design volumes projected billing determinants associated with the rejected contracts does not violate the prohibition on retroactive ratemaking. In *Trailblazer*, the pipeline raised similar arguments concerning the requirement that it credit the exit fee received from Columbia against its cost of service. The Commission dismissed those arguments noting that, "[i]n requiring this adjustment, the Commission is addressing the appropriate rates to be charged by Trailblazer prospectively, not retroactively."[209] Similarly, in this case, as explained above, we are requiring Portland to include in its projected billing determinants the discount-adjusted daily contract demand associated with the rejected contracts to reflect the fact that the Bankruptcy Proceeds constitute prepayments for service that would have been provided during the future period and thus inclusion of such billing determinants is necessary to avoid a double recovery of future costs.

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[207] The insurance proceeds that Williston received in March 1995 (during the base period) were a one-time payment that compensated Williston for a loss of interruptible revenue in 1992 several years before the effective date of the rates in that rate case due to an explosion and fire at one of Williston's compressor plants.

[208] The Commission notes that our finding here with regard to the treatment of prepayment of transportation revenues is also consistent with Order No. 144, as codified at section 154.305 of the Commission's regulations. Order No. 144 recognized differences that result from transportation revenues being included in taxable income and such revenues being deferred for book purposes as one of the timing differences that the requirement to normalize and perform a rate base adjustment was intended to address. Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,546, which incorporates Appendix C of the *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, *Federal Register* 45 Fed. Reg. 22,053 (1980).

[209] *Trailblazer*, 81 FERC at 61,172 & n.12.

F. Risks and Benefits of Bankruptcy Outcomes

151. Portland contends that the Commission's determination that "there should be a recognition of the receipt of the bankruptcy award for rejected contracts in Portland's rate design" is in error because it reflects a departure from existing precedent and requires investors to bear the risk of unfavorable outcomes in bankruptcy proceedings while denying them the benefit of successful outcomes. First, Portland states that Commission policy has repeatedly mandated that bad debt expenses not be reflected in a pipeline's cost of service.[210] Portland states that under that policy a pipeline is exposed to the risk that it will under collect its costs from bankrupt shippers, but it is compensated for that risk through the pipeline's return on equity.[211] Portland contends that Opinion No. 510 appears to expand the method of exposing pipelines to the risk of under-recovery for bankrupt shippers by including adjustments both to billing determinants and to rate base. Portland states that under Opinion No. 510, the level at which the return has been set is no longer the exclusive, or even primary, vehicle for dealing with decontracting risk. Instead, Portland argues, the Commission is trying to use billing determinants and an adjustment to rate base, not equity return, to reflect the risk of bad debts.

152. Second, Portland contends that Opinion No. 510 erred by requiring pipeline investors to bear the risk of unfavorable outcomes in bankruptcy proceedings while denying them the benefits of successful outcomes.[212] Portland contends that Opinion No. 510 imposes on the pipeline the risk that a bankrupt shipper will not meet its contractual obligations, but if the pipeline achieves a material level of recovery on such a rejected contract, it will have to convey that benefit to its shippers, potentially up to 3 times.[213] Portland contends that such an asymmetrical approach violates the

[210] Portland Rehearing Request at 3-4, 29-34 (citing *Williston I*, 67 FERC at 61,360, *reh'g denied*, 71 FERC ¶ 61,019; *Panhandle Eastern Pipe Line Co.*, Opinion No. 395, 71 FERC ¶ 61,228, at 61,838 (1995); *Panhandle Eastern Pipe Line Co.*, Opinion No. 404, 74 FERC ¶ 61,109, at 61,365-66 (1996) ("[F]or the reasons stated above, the Commission will not permit the pipeline to include bad debt as an expense in its cost of service under any circumstances")).

[211] *Id.* (citing *Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, FERC Stats. & Regs. ¶ 31,191 at P 11).

[212] *Id.* at 4, 31.

[213] That is, Portland states, through reduced rate base, through billing determinants, and through the inclusion of the remarketed capacity in the derivation of the its rates.

constitutional principle articulated in *Duquesne Light Co. v. Barasch,*[214] wherein the Court stated that a "decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions."[215] Portland states that it should at least be able to recover the full value of the rejected contract prior to any crediting, and in fairness should be able to reap the reward associated with the risk it endured.

153. Lastly, Portland argues that, by way of capacity release, shippers are serving loads at Portland's Rumford and Jay delivery points and thereby, substantially benefitting from the bankruptcy of Portland's two prior shippers which used to pay Portland for firm transportation at recourse rates to these delivery points.[216]

Commission Determination

154. The Commission generally requires that a pipeline be at risk for any cost under-recovery between rate cases. At the same time, the pipeline may retain any cost over-recoveries between rate cases.[217] However, when the pipeline files its next rate case, the pipeline's rates will be designed to recover 100 percent of the pipeline's projected just and reasonable costs of service, subject to any at-risk condition established in its certificate proceeding.

155. The Commission's treatment of bad debt follows this general policy. Thus, the Commission treats bad debts incurred between rate cases as a risk of doing business, and the Commission does not permit a pipeline to recover in its next rate case, any losses incurred as a result of a customer's failure to make payments for past service performed

[214] Portland Rehearing Request at 4, 31 (citing *Duquesne*, 488 U.S. 299, 315 (1989); *Democratic Central Committee of D.C. v. Washington Metropolitan Transit Comm.*, 485 F.2d 786, 806-07 (D.C. Cir. 1973) (stating that the proposition that any gain rightly inures to the benefit of the party that bore the risk of loss has been accepted in ratemaking law)).

[215] *Id.* (citing *Duquesne*, 488 U.S. at 315).

[216] *Id.* at 33-34 (citing Exh. No. PNG-31 at 39; Exh. No. PNG-60 at 13:8-17)

[217] *See ANR Pipeline Co.*, 70 FERC ¶ 61,143, at 61,431 (1995), and *Canyon Creek Compression Co.*, 99 FERC ¶ 61,351, at P 14 (2002). As explained in those cases, this policy follows from the requirement in section 284.10(c)(2) that pipelines design their rates based on projected units of service.

before the effective date of the new rates.[218] However, the Commission does not require the pipeline to continue to bear this risk in connection with payments for service to be performed in the future after the rates in a new rate case take effect. In the next rate case, the pipeline may design its rates to recover its full cost of service taking into account any rejection of a contract in bankruptcy and any inability to obtain full recovery of the future payments. For example, if the customer has rejected a contract through a bankruptcy proceeding, the pipeline has not recovered full compensation for payments that would have been made in the future, and the pipeline has not successfully remarketed the subject capacity, the pipeline generally would be able to reduce its proposed billing determinants to reflect the loss of those volumes associated with the rejected contract. By the same token, we believe that, as found in *Trailblazer* and *WIC*, if a pipeline is able to collect on the debt and the amount collected relates to services to be covered by the pipeline's newly filed rate case, that amount should be taken into account in designing the pipeline's new rates.

156. Opinion No. 510 is entirely consistent with this policy. As clarified above, Portland is entitled to retain that portion of the Bankruptcy Proceeds that relates to services prior to this rate case. Portland, therefore, is allowed keep the bankruptcy award related to services before its new rates took effect, just as it was required to absorb the cost of bad debt incurred during the that period. But, Portland has also received significant lump sum payments for services to be performed after the rates in this case took effect. We can see no reason why Portland should not be required to reflect those payments in its rates. Like in *Trailblazer* and *WIC*, failure to include the pipeline's receipt of those proceeds in its rate design would result in the pipeline's customers paying rates that cover costs the pipeline has already recovered.[219]

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[218] *Williston I*, 67 FERC at 61,360. Williston proposed to include in its cost of service $389,854 for uncollectible accounts. Williston deemed these accounts unpayable because two of its customers refused to pay certain transportation charges. The customers claimed that no charges were payable under their service agreements. Rather than sue for payment, Williston wrote those accounts off and was attempting to recover the costs as a cost-of-service item. The Commission held that bad debts are a risk of doing business that is compensated through the pipeline's rate of return and accordingly, would not allow Williston to have its other rate payers shoulder the burden of risk that is already reflected in its rates. *Id*. at 61,359.

[219] As the Commission noted elsewhere in Opinion No. 510, the considerable bankruptcy proceeds Portland received actually reduce Portland's business risk in that they provide Portland with guaranteed, upfront revenues. Opinion No 510, 134 FERC ¶ 61,129 at P 268.

157. In addition, Opinion No. 510 does not require Portland's shareholders to absorb the losses from the rejected contracts related to the period after the rates in this rate case take effect except to the extent required by the at-risk condition. First, Opinion No. 510 recognized that the Bankruptcy Proceeds were less than what Portland would have otherwise received if the contracts were not rejected. Accordingly, Opinion No. 510 found that Portland was entitled to a discount adjustment to reflect the fact that the bankruptcy award equated to Portland receiving an amount per Dth that was less than the maximum rate it would have otherwise received had the contracts remained in effect.[220] This adjustment, absent the application of the at-risk condition, would have permitted Portland to shift costs not recovered from the Bankruptcy Proceeds to other customers. Second, Opinion No. 510 only required Portland to include remarketed capacity in its billing determinants to the extent it had remarketed the capacity during the test period. Third, Opinion No. 510 did not require Portland to include any new or speculative projected units of service utilizing the rejected contracts' capacity. But for the at-risk condition, under Opinion No. 510, Portland would only have to achieve the same level of marketing success it achieved during the test period to meet its revenue requirements. To the extent that Portland is able to market capacity above the billing determinants used to establish its rates, Opinion No. 510 established no requirement to credit that additional revenue to its customers and that excess revenue would also confer to Portland's shareholders.

158. We also find that Portland's claim that shippers are substantially benefitting from the bankruptcy of Portland's two prior shippers is unsubstantiated. Except to say that certain shippers have been able to resell their Portland capacity to serve the Androscoggin and Rumford facilities, Portland has not provided any evidence demonstrating that those releases utilized capacity other than the capacity dedicated to the releasing shippers and did indeed result in a benefit, substantial or otherwise, to those releasing shippers. Accordingly, Portland's request is denied.

G. <u>Capital Structure Impact On Revenues</u>

159. Portland contends that Opinion No. 510 erred in affirming the Administrative Law Judge's decision regarding Portland's capital structure, when Opinion No. 510 failed to consider the revenue impact that its treatment of Bankruptcy Proceeds would have on Portland.[221] In order to maintain its financial integrity under the rates derived pursuant to this Opinion, Portland states that it would have to pay down its debt (losing the potential tax benefits of reasonable debt financing) to lower costs and maintain its financial

[220] Opinion N. 510, 134 FERC ¶ 61,129 at P 358.

[221] Portland Rehearing Request at 43-45.

integrity. Portland states that it must maintain credit metrics, such as a Debt Service Coverage Ratio of at least 1.4 times consistently through the term of its remaining debt to maintain its credit rating. Portland states that using the rates derived under Opinion No. 510, a ratio such as the DSCR could only be maintained by paying down its debt. Yet, Portland states, this consequence was not reflected in the Opinion's calculation of Portland's capital structure. Portland states that unless the logical consequence of the Opinion No. 510 methodology is reflected in capital structure, Portland's metrics will mean that it is not comparable to the investment grade, dividend/distribution paying members of the proxy group, which describes all of the proxy group members.

160. Further, Portland states that a rate base credit assumes that Portland would be able to earn a return on the "prepayments." Portland states that in order to try and make up for the time value of money credit to its ratepayers, Portland would either have to invest in more plant for which it could earn a return or pay down its debt. Portland states that since it had excess firm system capacity (caused in part by the bankrupt shippers) and no prospects for expansion, indeed a weak market for existing capacity, the only reasonable means for Portland to limit its exposure to the rate base credit would be to pay down its debt. Portland states that, under that scenario, it would have collected Bankruptcy Proceeds and recorded an increase in its cash balance on the asset side of the balance sheet and an increase in its equity (retained earnings) on the liabilities side of the balance sheet. Portland states that, then, it would have used the cash from the proceeds to pay down its debt, recording a decrease in its cash balance on the asset side of the balance sheet and a decrease in its debt on the liabilities side of the balance sheet.[222] Portland states that Opinion No. 510 erred by failing to adjust Portland's capital structure given the Bankruptcy Proceeds crediting methodology adopted by Opinion No. 510. Portland states that failure to recognize such a request would be a separate basis for concluding that the result of Opinion No. 510 fails to satisfy the requirements of *Hope*/*Bluefield*, supra. Portland states that the end result should have been that Portland's capital structure reflected 66.75 percent equity and 33.25 percent debt.

<u>Commission Determination</u>

161. Portland's request for rehearing is denied. The Commission's regulations require that a pipeline's rates be based on actual data for a one-year base period, as adjusted to reflect known and measurable changes within the following nine months (adjustment period).[223] Section 154.303(a)(4) of the Commission's regulations requires that the

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[222] Portland states that the net capitalization effect is shown in Appendix D to its Rehearing Request.

[223] *See* 18 C.F.R. § 154.303(a) (2012).

changes that a pipeline projects in its filing "become effective within the adjustment period." Consistent with that regulation, the Commission generally rejects rate adjustments proposed by pipelines for projected events which ultimately did not become effective during the test period.[224] Consistent with these regulations, the Commission generally determines the pipeline's capital structure based on the capital structure in existence at the end of the test period.[225]

162. In its request for rehearing, Portland seeks an adjustment to its capital structure. Portland asserts that, as a result of Opinion No. 510, it might have to take various actions in the future that will result in modification of its capital structure. By definition, none of these actions would be a known and measurable change that became effective as of the end of the test period, as required by section 154.303(a)(4). If in the future Portland does take these, or any other, actions which modify its capital structure, it can always file a new rate case. Portland does not state in its rehearing request that it in fact paid down any debt during the locked-in period at issue in this rate case. Consistent with Commission regulations, speculation as to what actions Portland might take in the future cannot be taken into account in establishing its rates in this rate case with regard to its capital structure. If Portland modifies its capital structure in the future, it may file a new section 4 rate case to revise its rates to reflect the modified capital structure, as well as any other changes in its cost and revenues that have occurred in the interim.

H. Due Process

163. Portland argues that Opinion No. 510 erred by implementing a methodology that was not presented at the hearing and was not implemented in any prior case.[226] Portland states that it was not presented with an adequate evidentiary opportunity to respond to the

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[224] *See, e.g.*, *Williston Basin Interstate Pipeline Co.*, 87 FERC ¶ 61,265, at 62,020-22 (1999) (*Williston IV*). In *Williston IV*, the pipeline proposed to reduce its billing determinants to reflect certain bypasses of its system which it projected would occur during the test period. However, at the end of the test period, the bypasses were the subject of certain ongoing litigation, and they did not actually occur until several months after the end of the test period. The Commission rejected the pipeline's proposed reduction in billing determinants, because the bypasses had not become effective at the end of the test period. In addition, because litigation concerning the bypasses had not concluded as of the end of the test period, there was no certainty at that time that the bypasses would occur.

[225] *Trunkline*, 90 FERC 61,111.

[226] Portland Rehearing Request at 55-56.

proposal now advanced in Opinion No. 510. Thus, it states, it did not have adequate opportunity to test the methodology and present objections, nor has the Commission had an opportunity to properly consider the impacts of this new method across the natural gas pipeline industry. Moreover, Portland states that the Commission did not implement the same methodology as implemented in *Trailblazer* and *WIC*. Portland argues that in those cases the Commission gave Trailblazer and WIC the opportunity to present and confront evidence concerning the appropriate methodology for any possible over-recoveries and here, it should do the same.

Commission Determination

164. Portland's request for rehearing is denied. The issue of how the Bankruptcy Proceeds should be treated was among the issues addressed at the hearing in this case. At the hearing, PSG, along with CES, argued that one-half of the Bankruptcy Proceeds should be credited against rate base. Following the hearing, the ALJ decided that a credit to Portland's cost-of-service was more appropriate. Throughout this entire case, including in its Brief on Exceptions and in its request for rehearing of Opinion No. 510, Portland has maintained that it is entitled to retain the entirety of the Bankruptcy Proceeds, without any adjustment to rate base or its cost-of-service. Consequently, a lengthy record has been amassed in this proceeding regarding the proper treatment of the Bankruptcy Proceeds in Portland's rates.

165. The Commission has stated that a mere allegation of lack of due process is insufficient to mandate an additional evidentiary opportunity. Such allegations must be supported by an adequate proffer of evidence.[227] Portland, in support of its request for rehearing, does not make any proffer of new evidence not already in the record in support of another evidentiary hearing. Moreover, there are no issues of material fact raised by Portland in its request for rehearing that cannot be resolved on the basis of the existing, lengthy record. We find that there exists substantial evidence in the record on which the Commission can decide the issue of how the Bankruptcy Proceeds received by Portland should be treated.

166. Furthermore, in *Trailblazer* and *WIC*, the record was insufficient for purposes of a Commission determination regarding the amount of the credit. In those cases, unlike the

[227] *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 114 FERC ¶ 61,070, at P 1 (2006). *See also El Paso Natural Gas Co.*, 48 FERC ¶ 61,202 (1989) (stating that where a party has not specified why it is unable to develop facts through written submissions, a mere demand to cross-examine without detailing the particular lines of cross-examination, will not suffice).

situation here, there had not yet been a hearing or an initial decision in the cases.[228] In fact, in *Trailblazer*, the Commission's decision requiring a credit occurred in the initial suspension order on Trailblazer's rate case, prior to a hearing or any discovery having being conducted and the only issue the Commission set for hearing was the level of the credit to rate base.[229] As stated above, at the time of the Commission's decision in this case, there was already substantial record developed at the hearing before the ALJ upon which the Commission could base its decision. Accordingly, Portland's request for rehearing is denied.

I. Alternative Methodologies

167. Portland also argues that the Commission erred by failing to consider alternative methods of ensuring that the cost of service is not over-recovered.[230] Portland states that, presuming one intended to achieve only the goal of preventing the over-recovery of the cost of service, use of a direct "over-recovery" test could achieve that policy goal while avoiding some of the punitive aspects of Opinion No. 510. But, Portland states that even the direct "over-recovery" test still ignores the risk Portland bore in pursuing the Bankruptcy Proceeds and remarketing the decontracted capacity.

Commission Determination

168. Portland's request for rehearing is denied. The Commission is not obliged to change our rate making policies to ensure Portland receives its desired revenues.

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[228] *See, e.g.*, *WIC*, 89 FERC at 61086. On rehearing, the Commission explained why it did not issue a merits decision on the exit fee:

> The current record consists solely of the parties' written testimony filed before the hearing. There has been no hearing for the purpose of cross-examining witnesses, nor an initial decision or briefs on exception. From the Commission's experience in ruling on the contested issues in Koch Gateway Pipeline Company, it is a difficult task for the Commission to review prepared testimony and exhibits without the benefit of an initial decision and exceptions to the initial decision to narrow the issues and focus the relevant evidence. (footnotes omitted)

[229] *Trailblazer*, 80 FERC at 61,518.

[230] Portland Rehearing Request at 58-59.

Portland assumed the at-risk condition voluntarily. That condition requires that Portland absorb the cost of any underutilization of its system below its design capacity. As Portland's response to the Staff Data Request demonstrates, its system was underutilized during the test period in this rate case. Its projected billing determinants, calculated in accordance with Opinion No. 510, were 179,930 Dth per day as compared to its design capacity of 217,405 Dth per day. In the preceding sections, we have explained why crediting the Bankruptcy Proceeds against rate base is necessary to determine a just and reasonable return to include in Portland's cost of service and, thus, a just and reasonable over-all cost of service. We recognize that designing Portland's rates based on its design capacity will result in per unit rates that will not fully recover Portland's cost of service, unless it is able to sell more capacity at higher rates than during the test period in this rate case. However, that is necessary to carry out the purpose of the at-risk condition: to require Portland to bear the risk of underutilization of its system. To instead allow Portland to credit against its cost of service only that amount necessary to avoid an over-recovery of the cost of service would shift the risk of underutilization of Portland's system to its customers contrary to the purpose of the at-risk condition.

J. <u>Hope and Bluefield</u>

169. Opinion No. 510 rejected Portland's contention that any reduction of its cost-of-service based on the bankruptcy award would violate the *Hope/Bluefield*[231] standard for determining a reasonable return on equity for a pipeline. In *Hope*, the Supreme Court held,

> [T]he return to the equity owner should be commensurate with returns on investments on other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[232]

170. Opinion No. 510 found that its holdings concerning the treatment of the bankruptcy award do not violate *Hope/Bluefield*. The Commission explained that, except to the extent that Portland's projected units of service are less than its at-risk condition, its rates will be designed to provide it an opportunity to recover its full cost-of-service, taking into account its receipt of the bankruptcy award. Opinion No. 510 concluded that,

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[231] Portland cited *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*), and *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) (*Bluefield*).

[232] *Hope*, 320 U.S. at 603.

Portland having accepted its certificate subject to the at-risk condition, it is just and reasonable to continue to require that it design its rates consistent with the at-risk condition.

171. On rehearing, Portland contends that the rates produced by Opinion No. 510 do not satisfy the *Hope/Bluefield* standard, in large part due to the Commission's treatment of the Bankruptcy Proceeds, and related adjustments to rate base and the level of billing determinants used to establish Portland's rates. Portland states that the final rate derived from Opinion No. 510 may produce a dangerously low level of cash flow for Portland, and actual realized return on equity that is far below the lowest return calculated using the Commission's selected proxy group.[233] Portland states that the Commission may not have taken this into account, because it did not perform a revenue check or make any effort to assess its results under *Hope* and *Bluefield*. Portland states that even if the Commission is correct in theory, it must show that its order will produce enough revenues for Portland to maintain its financial integrity and attract capital in the future.

Commission Determination

172. As Portland states, the Supreme Court's decision in *Hope* established the general standard for determining a just an reasonable return on equity under the NGA, and the Supreme Court has subsequently reaffirmed that standard in cases such as *Permian Basin Area Rate Cases,*[234] and *Duquesne Light Co. v. Barasch.*[235] However, the Supreme Court has also held that a pipeline or public utility may bind itself to a rate that is lower than that which would otherwise be established pursuant to the *Hope* standard. Thus, in *FPC v. Sierra Pacific Power Co*.,[236] the Supreme Court held,

> [W]hile it may be that the Commission may not normally *impose* upon a public utility a rate which would produce less than a fair return, it does not follow that the public utility may not itself agree by contract to a rate affording less than a fair return or that, if it does so, it is entitled to be relieved of its improvident bargain.

[233] Portland includes as Appendix A to its rehearing request an exhibit purporting to show that Opinion No. 510 will result in an effective return on equity of 3.81 percent.

[234] 390 U.S. 747, 792 (1968) (*Permian Basin*).

[235] 488 U.S. 299, 311-312 (1989).

[236] 350 U.S. 348, 354-5 (1956) (emphasis in original) (*Sierra*).

173. As Portland recognizes in its rehearing request, the 1997 Certificate Order placed "Portland at risk for the recovery of the costs of its unsubscribed capacity."[237] Portland voluntarily accepted the certificate with that condition in it. Therefore, both Portland and its original firm shippers proceeded with construction of the project, and the execution of contracts for service on the pipeline, with the understanding that Portland's rates in subsequent NGA section 4 rate cases would be designed using billing determinants equal to at least its design capacity, so as to impose the risk of any unsubscribed capacity on Portland, rather than the shippers.

174. By asserting that the end result of our rate determinations in this rate case must satisfy the *Hope* standard, Portland is, in essence, seeking to overturn the at-risk condition it agreed to in its certificate proceeding. As discussed above, Portland's design capacity is 217,405 Dth per day. However, based on its test period experience, and accounting for the Bankruptcy Proceeds as required by Commission policy, it is projected that Portland will only be able to sell sufficient capacity to produce revenues to recover the full costs of only 179,930 Dth per day of its capacity. Therefore, assuming market conditions remain as they were during the test period in this case, rates designed based upon Portland's design capacity will inevitably produce insufficient revenues to fully recover Portland's cost-of-service. This will reduce Portland's actual ROE below the 12.99 percent level included in its approved cost-of-service. However, that is the natural consequence of requiring Portland to be at risk for its unsubscribed capacity. It is inherent in that requirement that if Portland has unsubscribed capacity, it will not recover its full cost-of-service. Therefore, we cannot alter this result, without removing the at-risk condition and shifting the risk of unsubscribed capacity from Portland to its shippers, contrary to the shippers' expectations when they agreed to take service on the pipeline.

175. The Commission concludes that Portland's at-risk condition should not be modified, unless it could show that designing its rates consistent with the condition would impair Portland's financial ability to continue service to its shippers. However, our analysis of the end result of the rate determinations in this order indicates that those determinations will not impair Portland's financial ability to continue service. As shown in Appendix A to this order, we have determined the just and reasonable level of Portland's cost-of-service to be approximately $63,834,932, including an ROE of 12.99 percent.[238] Portland's total costs unrelated to its return on rate base are

[237] Portland Rehearing Request at 24 & n.43.

[238] This figure is drawn from Scenario 2, in Portland's Response to Data Request, which elsewhere we have found to be closest to the Commission's findings in Opinion No. 510 and this rehearing order. However, Scenario 2's PIP costs are not the same as found in this order. We use Scenario 2 numbers for the analysis here as they are

(continued…)

$23,926,130. Those costs include its operation and maintenance expenses, its depreciation expense, and its taxes other than income taxes. The remaining $39,909,212 of Portland's cost-of-service is related to the recovery of its pre-tax return on rate base, including debt cost of $12,617,308 and pre-tax return on equity of $26,691,904. Assuming market conditions remain as during the test period, rates designed based on Portland's design capacity of 217,405 Dth per day consistent with the at-risk condition will produce revenues of $54,982,847. While these revenues are $8,852,084 less than Portland's cost of service, they are sufficient to recover Portland's total costs unrelated to return, plus $31,056,717 of its $39,909,212 costs related to the recovery of its pre-tax return on rate base. This amount of pre-tax return of $31,056,717 is well in excess of Portland's debt cost, which Portland states is approximately $13,617,308.[239]

176. The Commission concludes that the rates approved in this proceeding will allow Portland to recover all the out-of-pocket costs of operating its system including debt cost and its full depreciation allowance, and also provide some return on equity, albeit not the full 12.99 percent included in its cost of service. This will allow Portland to continue to operate its system, as required by its certificate. The Commission concludes that it is just and reasonable to require Portland to design its rates based upon its design capacity, consistent with the at-risk condition in its certificate.

VI. Return on Equity (ROE)

A. Derivation of ROE

177. As discussed in Opinion No. 510, the Supreme Court has held that "the return to the equity owner should be commensurate with the return on investment in other enterprises having corresponding risks.[240] That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[241] In order to attract capital, "a utility must offer a risk-adjusted expected rate of return sufficient to attract investors."[242] In theory, this requires an

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close to what the final numbers will be, and the numbers and underlying workpapers are in the record.

[239] *See* Appendix A.

[240] Opinion No. 510, 134 FERC ¶ 61,129 at P 156 (citing *Policy Statement on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return On Equity*, 123 FERC ¶ 61,048, *reh'g dismissed*, 123 FERC ¶ 61,259 (2008) (Policy Statement)).

[241] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

evaluation of the regulated firm's needed return compared to other regulated firms of comparable risk.

178. Most natural gas pipelines, including Portland, are wholly-owned subsidiaries and their common stock is not publicly traded. Therefore, the Commission performs a discounted cash flow (DCF) analysis of publicly-traded proxy firms to determine the return the equity markets require a pipeline to give its investors in order for them to invest their capital in the pipeline. As discussed in Opinion No. 510,[243] 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.'"[244] As we explained, it is crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined, or, in other words, the proxy group must be "risk-appropriate." The Commission also noted that due to recent changes few corporations have satisfied the Commission's historical proxy group standards, it issued the Policy Statement, which approves the use of master limited partnerships (MLP) in the ROE proxy group for natural gas pipelines and provides general criteria for the inclusion of MLPs in such proxy groups.

179. As to the DCF analysis, 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."[245] With simplifying assumptions, the DCF model results in the investor using the following formula to determine share price:

$$P = D/ (r-g)$$

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[242] *CAPP v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001).

[243] Opinion No. 510, 134 FERC ¶ 61,129 at P 163 (citing *Petal Gas Storage, LLC v. FERC*, 496 F.3d 695 (D.C. Cir. 2007) (*Petal v. FERC*)).

[244] *Petal v. FERC*, 496 F.3d at 697 (quoting *CAPP v. FERC*, 254 F.3d 289 at 293).

[245] *CAPP v. FERC*, 254 F.3d 289 at 293.

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.[246]

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

$$R = D/P + g$$

181. 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 as published by the 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).[247] 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.[248] The DCF methodology produces a zone of reasonableness in which the pipeline's rates may be set based on specific risks.[249]

B. <u>Opinion No. 510 ROE Determination</u>

182. In Opinion No. 510, the Commission determined that Portland's ROE should be 12.99 percent. Opinion No. 510 modified the proxy group recommended by the ALJ,[250]

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

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

[248] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,423-24, *reh'g denied*, Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,266-70 (1998), *aff'd*, *CAPP v. FERC*, 254 F.3d 289 (D.C. Cir. 2001).

[249] *Williston v. FERC*, 165 F.3d at 54, 57.

[250] Opinion No. 510, 134 FERC ¶ 61,129 at P 162.

and adopted a proxy group consisting of TC Pipelines LP (TC Pipelines), Southern Union Gas Company (Southern Union), Boardwalk Pipeline Partners (Boardwalk), Spectra Energy Corporation (Spectra Corp.), El Paso Pipeline Partners, LP (El Paso Partners), and Spectra Energy Partners, LP (Spectra Partners). The Commission denied PSG's exception to the ALJ's adoption of Trial Staff's method of calculating the proxy entities' dividend yield.[251]

183. The Commission performed a DCF analysis of each entity in the proxy group, using Trial Staff's methodology and data for the six-month period beginning November 2008 and ending April 2009. That was the most recent period for which the record contained the necessary data, and post-dated the test period in this rate case, which ended on September 30, 2008. The Commission found that use of this six-month period was "consistent with the Commission's longstanding policy to use the latest six month dividend yields, growth rates and GDP data in the record for its DCF analysis in pipeline rate cases,"[252] and that "on balance …, it is better to use the updated record data submitted by Portland for the six month period ending April 2009, than to use the data for the earlier six month period ending December 2008 supported by the ALJ, Trial Staff, and PSG."[253] The resulting DCF analysis established a zone of reasonableness of 12.18 percent to 14.89 percent and a median of 12.99 percent.[254] The Commission also set Portland's ROE at the median of the proxy group range based on the finding that Portland had an average business risk relative to other pipelines. The details of the Commission's findings on these elements are discussed below.

184. None of the parties sought rehearing regarding the proxy group adopted by the Commission or the approval of the methodology for calculating dividend yield adopted by the ALJ. However, PSG and Canadian Association of Petroleum Producers (CAPP) seek rehearing of the Commission use of data from the six-month period November 2008 through April 2009, and Portland seek rehearing of our holding that its ROE should be set at the 12.99 percent median of the proxy group ROEs. We address below the issues raised or implicated by the rehearing requests. For the reasons provided, the Commission denies the parties' requests for rehearing.

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[251] *Id.* PP 232-234.

[252] *Id.* P 242.

[253] *Id.* P 246.

[254] *Id.* P 162 and Appendix A.

C. Time Period for Calculating DCF

1. Opinion No. 510

185. The Commission determined in Opinion No. 510 that the appropriate time period for the DCF analysis in this proceeding is the six month period ending April 2009, that is, November 2008 through April 2009. The Commission chose to use the DCF data from this period from among three competing proposals. In addition to the period approved in Opinion No. 510 (and supported by Portland), the Commission evaluated the use of (1) the six month period from July through December 2008 (advocated by Trial Staff and PSG, and adopted by the ALJ); and (2) a proposal to calculate dividend yield using stock prices over a 12-month period (advocated by CAPP).[255] While Opinion No. 510 described CAPP's proposal as using the period January 2007 through January 2008 to determine dividend yield, a review of the exhibits in which it made its proposal indicates that, in fact, it proposed to use dividend yields for the 12-month period February 2008 through January 2009.[256] The Commission also rejected Portland's request to use post record data by denying Portland's motion to take judicial notice of its post record July 2010 credit rating downgrade to below investment level.[257]

186. The Commission relied on several factors to justify its DCF time period determination. The Commission stated that adopting the 6-month period ending April 2009 was consistent with the Commission's longstanding policy to use the latest six month dividend yields, growth rates, and Gross Domestic Product (GDP) data in the record for its DCF analysis in pipeline rate cases.[258] That policy is an exception to our usual policy of determining rates based on test period data, which in this case ended on September 30, 2008. The Commission found that the DCF analysis for the ROE adopted by the ALJ was based on record data through December 2008, while the Portland's proposed ROE was based on a DCF calculation using record data up to April of 2009. Thus, the Commission determined that it was appropriate to use Portland's data instead of PSG's data to determine the ROE as that was the most recent available record information. The Commission noted that its policy is to use the most recent data in the

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[255] *Id.* at P 235.

[256] Exh. No. CAP-4, schedule 3, page 4.

[257] Opinion No. 510, 134 FERC ¶ 61,129 at P 248, 271.

[258] *Id.* at P 242 (citing *Boston Edison Co. v. FERC*, 885 F.2d 962, 966 (1st Cir. 1989) (*Boston Edison)*; *Trunkline*, 90 FERC at 61,117).

record, even if the data is from outside the test period, because the later figures reflect current investor needs in an ever changing market.

187. Although PSG supported the ALJ's decision to use the July through December 2008 period which included three months of post-test period data, it opposed Portland's request to use the November 2008 through April 2009 period on the ground Portland's request was contrary to the Commission's alleged policy not to use post test period data in calculating ROE unless doing so is necessary to avoid "substantial error." The Commission found the precedent upon which PSG relied for this claim, *Enbridge Pipelines* (*KPC*),[259] was not addressing whether to use the most recent data in the record for the DCF analysis but whether the Commission should consider information or events that occurred after the close of the record. The Commission noted that while it prefers to use the most recent financial data in the record for calculating a pipeline's ROE, updates are not permitted once the record has been closed.[260]

188. Based on the record in this proceeding, the Commission found that on balance it was better to use the updated record data for the six month period ending April 2009 than that used by the ALJ, because the more recent data captured both increases in dividend yield resulting from the crisis and offsetting downward adjustments to other DCF components.[261] The Commission explained that the dividend yield component of its DCF analysis is the monthly dividend divided by the average stock price for that month, and thus the immediate effect of a sudden drop in stock prices caused by a financial crisis is an increase in dividend yield and a corresponding increase in ROE. The Commission further noted, however, that other inputs to the DCF formula, which may cause offsetting decreases to ROE, do not adjust as quickly to the changed circumstances caused by the financial crisis. Accordingly, the use of data from a later period may capture some of these delayed adjustments. The Commission noted that in this case, the record evidence shows that IBES growth projections declined between the period used by the ALJ and the time period ending April 2009.

189. Thus the Commission found that the use of the most recent record data, which included figures from the financial crisis, most accurately reflects the actual market conditions during the period for which the rates determined in this proceeding would be

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[259] 100 FERC ¶ 61,260, *reh'g denied*, 102 FERC ¶ 61,310 (2002).

[260] Opinion No. 510, 134 FERC ¶ 61,129 at P 242. The Commission also relied on this policy in determining not to reopen the record to consider a July 2010 change in Portland's credit rating.

[261] *Id.* P 246.

effective. Acknowledging that the use of the most recent record data in this case may not be entirely representative of a long term pipeline ROE, the Commission found this analysis was warranted here, where Portland had initiated a separate case proceeding in 2010, and thus the rates to be determined in this proceeding would only be effective for a locked-in period ending November 30, 2010. Thus, the ROE approved in Opinion No. 510 reflects the effects of the financial crisis that occurred in late 2008 and early 2009 during the locked-in period and yet is limited in its prospective application to a time period representative of the actual effects of that crisis. The rates for the period after November 30, 2010 will be decided in the next rate case.

190. The Commission also found that its decision not to consider financial data for periods after the July 2009 close of the record was consistent with its denial of Portland's August 20, 2010 motion to take official notice of the July 2, 2010 post-record reduction in Portland's credit rating to below investment grade.[262] The Commission stated that all developments since the close of the record in this case, including both the change in the in credit rating and post-record changes in DCF inputs such as stock prices, dividends and growth projections should be addressed at the hearing in the new rate case, where all interested participants will have an opportunity to develop a full record concerning how such developments should affect Portland's ROE.

191. The Commission also affirmed the ALJ's determination to reject CAPP's proposal to use a 12-month dividend yield analysis.[263] CAPP had asserted that the 12-month period should be used to address the aberrant market conditions during the fall of 2008. The Commission rejected this claim based on its finding that the most recent record data accurately reflects those market conditions and on the fact that using a 12-month period is contrary to Commission policy.[264]

2. <u>Requests for Rehearing</u>

192. PSG and CAPP, in their respective requests for rehearing, both challenge the Commission's use of data from the six month period beginning November 2008 and ending April 2009 in calculating the DCF used to determine Portland's ROE. PSG asserts that the time period chosen was "characterized by highly aberrational market conditions due to the financial crisis of 2008 – 2009,"[265] and thus the Commission should

[262] Opinion No. 510, 134 FERC ¶ 61,129 at P 248.

[263] *Id.* P 249.

[264] *Id.*

[265] PSG Rehearing Request at 23.

have taken official notice of post-record data for a later, more representative time period, or alternatively, used record data for an earlier more representative time frame within the test period.[266] Along the same lines, CAPP contends that the volatile economic conditions encompassed within the test period produced uncertainty not "reasonably representative of the operating circumstances of regulated companies such as Portland," and thus, what it terms the "blind application of the formulaic elements of the Commission's policy and the rote use of the DCF formula, without taking those unique and unrepresentative conditions into account, produces unreasonable results.[267] CAPP argues that the Commission should have either adopted its proposal to use an average of 12-month dividend yields for its DCF analysis instead of the 6-month average generally used or accounted in some other manner for what it considers the distortions in the DCF results.

193. PSG asserts that consistent with the Commission's order in *SFPP*, *LP*,[268] and in view of the financial crisis, it is reasonable to attempt to arrive at a more representative test period for DCF analyses involving test periods that occurred during the crisis to protect shippers from potentially undue rate impacts. It further asserts that one approved option for doing so is for the Commission to rely in hindsight on knowledge of post record changes in market conditions, amenable to official notice, to establish ROE. PSG states that the data relied on for the Commission's DCF analysis is largely aberrational because of the high volatility of DCF inputs during the chosen period. PSG further asserts that the Commission should not adhere to its rule to not consider post record data when the current record data is aberrational.

194. According to PSG, there are three potentially appropriate time periods (in descending order of appropriateness, for application of the DCF analysis to the proxy group approved in Opinion No. 510: (1) a six-month period ending November 30, 2010 (the last six months of the locked-in period); (2) the six month period ending January 31, 2008; and (3) the 27-month period ending November 30, 2010 (entire locked-in period).[269] PSG states that for option 1, the applicable DCF inputs are amenable to official notice, would be the most current within the locked-in period, and are allegedly the least reflective of the aberrational affects of the financial crisis. PSG asserts the data

[266] *Id.* at 2.

[267] CAPP Rehearing Request at 3.

[268] PSG Rehearing Request at 26 (citing *SFPP*, *LP*, 128 FERC ¶ 61,214, *order on certified question*, 129 FERC ¶ 61,050 (2009) (*SFPP*)).

[269] PSG Rehearing Request at 28.

for option 2 was previously entered into the record by Portland.[270] According to PSG option 3 would include data from the financial crisis and contain only six months of record data, none of which is in the test period.

195. To provide the necessary data to implement its first and third proposed time periods, PSG attached to its rehearing request a series of "DCF Studies" for January 2008 and for each six month period between August 2008 and November 2010 for the proxy group members adopted in Opinion No. 510.[271] According to PSG, it used analysts' earning forecast as of the particular month for each month from August 2008 to January 2010. PSG contends that the Commission took official notice of IBES growth projections for the proxy group members and thus should take official notice of the "data" and the other information it provided in Attachments A-D of its rehearing request, claiming it is publicly available data not typically subject to dispute.[272] PSG further argues that the Commission has previously relied on post record evidence to determine ROE and other capital costs for natural gas pipelines in the context of locked-in periods.[273]

196. PSG argues that the period chosen by the Commission in Opinion No. 510 is the worst of all worlds because the DCF data for that period "reflects the *nadir* of proxy group stock unit/prices – and correlatively, the *peak* of proxy group dividend/distribution yields – during the *height* of the severe and aberrational financial crisis."[274] PSG argues that because the Commission's approved time period comprises the six worst months of the financial crisis it does not accurately reflect the market conditions during the test period. PSG argues that adherence to a rigid rule to evaluate the most recent DCF data in the record would confer an unfair advantage on pipelines and is subject to manipulation by the pipelines.

197. PSG further takes issue with the Commission's determination in Opinion No. 510 that the Commission's ROE calculation was the best analysis based on the record data available, and with the claim that the Commission was bound to use record data. PSG

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[270] *Id.* at 28 (citing Exhibit No. PNG-11 at E-18).

[271] Attachment B to PSG's Rehearing Request.

[272] PSG Rehearing Request at 32-33.

[273] *See, e.g.,* PSG Rehearing Request at 33-34 (citing *Distrigas of Massachusetts Corp.,* 26 FERC ¶ 61,256 (1984) and other cases).

[274] PSG Rehearing Request at 29.

argues that in the unusual circumstances presented in this case as a result of the financial crisis, the Commission could properly rely on the record data entered by Portland for the 6-month period ending January 31, 2008, prior to the financial crisis, which results in an ROE for Portland of 11.23 percent, or take official notice of post record data. PSG notes that this result is reasonable because it exceeds the lowest ROE within the zone of reasonableness (8.74 percent) established on the record in this proceeding (for six-month period ending January 30, 2008).

198. In support of its favored choice of the Commission taking official notice of post record DCF data to arrive at a more representative ROE for Portland, PSG claims that the Commission has long relied on post record evidence in determining ROEs and other capital costs for natural gas pipelines.[275] PSG asserts the Commission took official notice of IBES growth projections in Opinion No. 510, and should accordingly do the same for the DCF inputs that PSG attaches to its rehearing request. PSG contends that the supplied data consists of publicly available DCF data and interest rate data that are not typically subject to dispute, and thus are appropriate for official notice. PSG points out that the Commission itself, apparently concerned about using data from during the financial crisis, included post record DCF results for the Commission's approved proxy group in Opinion No. 510 for the six-month period ending June 30, 2010. PSG notes that the 10.10 percent ROE it asserts results from using the most current data for the locked-in period (six months ending November 30, 2010) is above the 8.74 percent ROE floor established using record data.[276]

199. Alternatively, PSG argues the Commission should at least revert to the DCF data initially presented by Portland as part of its case in chief – for the six-month period ending January 31, 2008, which is prior to the financial crisis and is within the test period. PSG claims the resulting ROE for that period is 11.30 percent if El Paso Partners is included (only 3-months of data available) or otherwise results in an ROE of 11.47 percent.

200. CAPP makes arguments similar to PSG's in its rehearing request, arguing that the Commission has, and should here, take into account the anomalous effects of turbulent financial conditions on the financial data in determining ROE. CAPP asserts that it proposed a reasonable alternative to the Commission's normal DCF analysis using six-months of DCF input data to account for the financial crisis, namely to use a full 12 months of data. That proposal used the 12-month period from February 2008 through January 2009. CAPP argues that the proposed use of an extended average dividend yield

[275] *See* PSG Rehearing Request at 33-34, and cases cited therein.

[276] *Id.* at 33.

measurement was tailored to the facts of this proceeding and the Commission erroneously ignored the proposal. CAPP asserts that the Commission failed to justify the rote application of its general DCF policy in this case. Specifically CAPP challenges the Commission's analysis on several points: (1) the decline in the IBES growth projections after December 2008 was insufficient to offset the unusual increase in dividend yields caused by the substantial reduction in stock prices; (2) the Commission's analysis fails to account for continuous "rebasing" of IBES rates, which may lead to an eventual higher earnings forecasts; (3) the Commission's reasoning overlooks the fact MLPs are unlikely to reduce their distributions during a financial crisis because of the way they are structured; and (4) if a proxy company did cut its dividends it likely would not be eligible for inclusion in the proxy group, because companies that cut dividends are not reliable proxy group members.

201. On April 21, 2011, Portland filed a motion for leave to respond and a response to PSG's rehearing request. Recognizing that responses to rehearing requests are not generally allowed, Portland asserts that PSG's request is essentially a motion for the Commission to take judicial notice of various DCF inputs and thus Portland's response is in effect a response to PSG's motion.

202. With respect to ROE, Portland argues that PSG's rehearing request should be denied and that the Commission's determination regarding the time period for evaluating data for the DCF analysis was fully supported by record evidence and Commission precedent. Portland states that PSG has changed its position on the appropriate time frame numerous times throughout this proceeding and that PSG's latest proposals are unsupported. Portland claims that after discovering the time periods PSG had previously espoused would lead to a higher ROE because of the Commission's modification of the proxy group, PSG now presents three additional time periods that are unsupported and at odds with PSG's prior position. Portland thus claims that PSG's new proposals should be rejected.

203. In support of its claim, Portland notes that it is not clear the proxy group approved in Opinion No. 510 based on data for the six months ending April 2009 would be risk appropriate when considered for a time period ending November 2010. Portland further asserts that it would be arbitrary and capricious to establish its ROE based on a time period a year and a half after the updated data was provided in this proceeding. It asserts the Commission should not use post record "updated" information just because such data results in a lower ROE. Portland notes that litigation must end somewhere, and that more recent data should be applied to Portland's new rate case. Portland also claims that the Commission cannot simply take judicial notice of 27 separate six-month periods, as PSG would suggest for its option 3. Portland contends that to consider such data the Commission would have to also allow experts to testify on each of the DCF inputs, proxy group entries, and other screening criteria, and that PSG does not address how the vetting of this information would occur. Portland also argues that use of data from a time period

prior to the financial crisis ignores both the pipeline's actual market cost of capital during the test period and the increased risk caused by the recession.

3. **Commission Determination**

204. The Commission denies the requests for rehearing on the issue of the appropriate time period for calculating DCF in this proceeding. The determination in Opinion No. 510 relied on longstanding Commission policy regarding the DCF analysis in natural gas pipeline rate cases, namely to use the most current record data available but to exclude post-hearing data. As noted in Opinion No. 510, that approach was particularly appropriate here because the rates established would only be effective for a determined locked-in period. Further, nothing in the various Commission orders relied on by PSG compels a different result. Finally, the alternative time periods proposed by the parties create a variety of evidential and other issues that on balance do not warrant pursuing at this stage of the proceeding.

205. In Opinion No. 510, the Commission followed its longstanding policy in natural gas pipeline rate cases of using the latest six-month dividend yields, growth rates, and GDP data in the record for its DCF analysis to calculate Portland's ROE.[277] The Commission chose to use the most recent record data instead of the six month period ending December 2008 as favored by PSG or using dividend yields from the 12-month period ending January 2009 as favored by CAPP. In its analysis the Commission explained its preference to use the latest data in the record in ROE calculations, as opposed to capital structure or cost-of-service determinations, because ROE depends upon an ever changing market where later figures more accurately reflect current investor needs. The Commission further held that the use of updated data does not extend to post record data and thus updates are not permitted once the record has closed and the hearing has concluded.[278]

206. On rehearing neither PSG nor CAPP challenges directly the Commission's statement of its policy or the validity of the precedent upon which the Commission relied for its time period determination. Instead, they contend that none of those cases involved the circumstances of the instant case where purportedly "the most current data of record was aberrational" because of the financial crisis in 2008.[279] Thus, the parties contend the

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[277] *See* Opinion No. 510, 134 FERC ¶ 61,129 at PP 242-246 and cases cited therein.

[278] *Id.* P 242.

[279] PSG Rehearing Request at 27.

Commission should have gone outside its existing policy to either (1) take official notice of post record data or (2) use record data from some earlier period than that used by Opinion No. 510. For the reasons explained below, the Commission continues to find that, in the circumstances of this case, the approach taken in Opinion No. 510 is the most reasonable of the various options presented to us for addressing the timing issue.

Official Notice of Post-Record Data

207. We first address PSG's request, made for the first time on rehearing of Opinion No. 510, that we take official notice of post-record data. In its brief opposing exceptions filed on April 5, 2010, PSG supported the ALJ's decision to use data from the last six months of 2008, and opposed the use of any subsequent data as contrary to Commission policy. However, PSG now contends that due to the "unusual circumstances" of this case, there are three new time periods that would be "appropriate" for application of the DCF analysis, including two of which would require the use of post-2008, post-record data, which until now PSG has opposed using. In order to adopt either PSG's now preferred option (the six months ending November 30, 2010 or its third option (the entire 27-month period locked-in period ending November 30, 2010), the Commission would have to take official notice of proxy member financial data not in the record for the period May 2009 through November 30, 2010. The Commission rejects PSG's request at this late stage of this proceeding to take official notice of financial data not in the record.

208. In Opinion No. 510, the Commission stated that it would not reopen the record in this proceeding to allow consideration of changes in the DCF inputs of the proxy members occurring after the July 2009 close of the record, including stock prices, dividends and growth projections. The Commission pointed out that it was rejecting Portland's request to take official notice of S&P's July 22, 2010 downgrade of Portland's BBB- corporate credit rating to a below investment grade BB+ Stable rating and that Portland had filed a new rate case whose rates took effect on December 1, 2010. The Commission accordingly concluded that all developments since the close of the record in this case should be addressed at the hearing in the new rate case, where all interested participants will have an opportunity to develop a full record concerning how such developments should affect Portland's ROE. The Commission continues to find that this is the correct approach.

209. While PSG asserts that the post-record DCF inputs would be amenable to official notice, we find that it would be inappropriate to simply take official notice of post-record DCF inputs without establishing further proceedings to give all parties an opportunity to present evidence concerning all developments during the post-record period relevant to the determination of Portland's ROE. In *Office of Consumers' Counsel, Ohio v.*

FERC,[280] the United States Court of Appeals for the District of Columbia Circuit held that, in a case in which an ALJ has conducted a hearing, the Commission should not rely on new evidence presented in a post-hearing pleading without giving other parties an adequate opportunity to respond.

210. Here, PSG requests that we take official notice of post-record financial data for each proxy member so that Portland's ROE can be set based upon data for either the last six months of the locked-in period (June through November 2010) or the entire locked-in period (September 2009 through November 2010). S&P's downgrade of Portland's credit rating to below investment grade took place in July 2010, during both of those periods. The Commission has held that credit ratings are an appropriate consideration in determining a pipeline's relative risk within the range of ROEs established by the proxy group.[281] Therefore, if we were to use PSG's proposed post-record financial data for the proxy members to establish the range of reasonable returns, it would follow that we would have to consider S&P's downgrade of Portland's credit rating during the same period in determining whether Portland has a higher risk than the proxy members justifying setting Portland's ROE above the median of the range of reasonable returns. This would require permitting all parties an opportunity to present evidence concerning the significance of S&P's credit downgrade and any other changes in Portland's circumstances relevant to where in the range of reasonable returns we should set Portland's ROE.

211. Similarly, if we were to use PSG's proposed post-record proxy member financial data, we would have to consider whether the proxy group selected in Opinion No. 510 is a risk appropriate group for the later time period recommended by PSG.[282] Because those companies may have bought or sold assets or changed operations in a manner that

[280] 783 F.2d 206, 232 (D.C. Cir. 1986) (The Commission's reliance "on ex parte submissions appearing in a posthearing brief . . . violate[s] fundamental canons of due process.") *Tennessee Gas Pipeline Co.*, Opinion No. 406-A, 80 FERC ¶ 61,070, at 61,222 (1997).

[281] *Kern River*, Opinion No. 486-B, 126 FERC ¶ 61,034 at P 137. *See also Transcontinental Pipeline Corp*., 90 FERC ¶ 61,279 at 61,937 (2000), and *Transcontinental Pipeline Corp*., Opinion No. 414-A, 84 FERC at 61,427-4 – 61,427-5 (1998).

[282] PSG itself acknowledges that there may be problems with having reliable data for all the approved proxy group members for the time periods it suggests the Commission should adopt on rehearing. *See* PSG Rehearing Request at p. 28 & notes 66 and 68.

would either cause them not to meet the threshold test for appropriate proxy group members or alter their risk profile as compared to Portland, the parties would need to do a new analysis of the companies to make such a determination for the post record period.

212. Re-opening the record to allow the parties to present evidence on these matters would likely set-off a flood of new submissions of testimony concerning whether the proxy group adopted by Opinion No. 510 remains appropriate and how Portland's risk profile compares to that of the members of the proxy group. The Commission and the parties would have to expend considerable resources verifying and analyzing the information, an exercise not warranted at this stage of the proceeding given the substantial record evidence supporting the time period approved in Opinion No. 510. As we have stated previously, even though changes may occur after the close of the record, litigation must end at some point.[283] Accordingly, we generally do not reopen the record absent extraordinary circumstances, which we have described as "a change in circumstances that is more than just material, but goes to the very heart of the case."[284] Here, we do not find such extraordinary circumstances, particularly in light of the fact that Portland filed an updated rate case with rates to be effective December 1, 2010, and the test period in that rate case includes both PSG's preferred period for determining Portland's ROE and the credit rating downgrade Portland sought to include in this rate case.[285] Thus, it is most efficient to resolve the instant case based on the record already developed at the hearing before the ALJ and to consider in Portland's next rate case whether its ROE should be modified in light of subsequent developments occurring long after the close of the test period in this case.[286]

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[283] *See KPC*, 100 FERC ¶ 61,260 at P 382 (denying request to reopen record based on finding that the need for finality in the administrative process outweighed the existence of unusual circumstances).

[284] *Id.*

[285] *See* Portland's May 12, 2010 filing in Docket No. RP10-729 (2010 Rate Filing) at 2. According to Portland, its cost-of-service and determination of rates in that proceeding reflect the costs and throughput for a Base Period of twelve months ended February 28, 2010, as adjusted through the Test Period ending November 30, 2010.

[286] *See KPC*, 100 FERC ¶ 61,260 at P 383. In a contemporaneous order on the ALJ's ID in the subsequent Docket No. RP10-729-000 rate case, we are finding that Portland's below investment grade credit rating, combined with its at-risk condition, justifies setting its ROE at the top of the range of reasonable returns, which in that case we find to be 11.59 percent.

213. The cases relied on by PSG to contend that we should take official notice of post-record proxy member financial data are distinguishable from this case. As PSG points out, in electric rate cases, the Commission updates the ROE allowed electric utilities based on post-record changes in the yields on 10-year constant maturity U.S. Treasury bonds, so long as the updated ROE remains within the range of reasonable returns determined based on record evidence.[287] The courts have approved that practice, on the ground that such Treasury bond data is not typically subject to dispute.[288] Here, however, PSG does not seek to update Portland's ROE based on post-record changes in U.S. Treasury bond yields, as is done in electric rate cases. Rather, PSG asks us to update the DCF analysis of each proxy company, using post-record updated financial data for each individual member of the proxy group, which is not done in electric rate cases.[289] While PSG states that its revised median remains within the zone of reasonableness established by the record evidence consistent with the electric practice, that fact does not address our concern discussed above that other changes may have occurred in the businesses of the proxy members that either renders them no longer appropriate for the proxy group or could alter the analysis of how Portland's risk compares to the risk faced by the proxy members. Indeed, it is for this reason that we do not use post-record evidence to update the DCF analysis of proxy companies in electric rate cases.

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[287] *Southern California Edison Co.*, 131 FERC ¶ 61,020, at PP 99-101 (2010) (*SoCal Edison*). *See also DistriGas of Massachusetts*, 26 FERC ¶ 61,256, at 61,585 (1984), in which the Commission considered a post-record decrease in various bond yields in setting the return on equity of a liquefied natural gas company and *Williston III*, 84 FERC at 61,381-82, in which the Commission determined not to take official notice of post-record changes in bond yields in a natural gas pipeline rate case.

[288] *Union Electric Co. v. FERC*, 890 F. 2d 1193, 1203 (D.C. Cir. 1989) (*Union Electric*). *Mississippi Industries v. FERC*, 808 F.2d 1525, 1568 (D.C. Cir. 1987). *Boston Edison Co. v. FERC*, 885 F.2d 962, 966-69 (1st Cir. 1989) (*Boston Edison*). In *Boston Edison*, the court also affirmed the Commission's reversal of the ALJ's decision to use one year's worth of dividend yield data. Instead, the Commission used only the dividend yields during the last six months of that one year period, finding that the most recent six months was more reflective of current investor needs. Because the dividend yield data the Commission used was in the record, *Boston Edison's* affirmance of that aspect of the Commission's orders is not precedent for taking official notice of post-record dividend yields.

[289] *See S.C. Generating Co.*, 44 FERC ¶ 61,008, at 61,039 (1988) (The updating methodology "does not take into account changes in company-specific business or financial risk.").

214. Perhaps more significantly, unlike in the electric cases where we have updated ROE based on post-record changes in bond yields, in this case Portland has sought to have us take official notice of the post-record reduction to its credit rating to below investment grade. In *Union Electric,* a case involving the Commission's policy in an electric rate case to adjust the median based on post-record changes in bond yields, the court was concerned that the utility should have an opportunity to "parry the effect" of information of which the agency take official notice.[290] As explained above, if we were to update the DCF analysis of the individual members of the proxy group, we would have to give Portland an opportunity to "parry the effect" of that update by presenting evidence of its reduced credit rating, as well as evidence of relevant changes in the circumstances of the proxy members.

215. The other cases relied on by PSG in support of its request to take official notice of post-record changes in the financial data of the proxy members also do not support its request. In *Williams Natural Gas Co*.,[291] the Commission took notice of information in the pipeline's Form No. 2 filing and testimony it had filed in a subsequent rate case to find that the pipeline had refinanced its debt at a lower cost, and the Commission required the pipeline to reflect its reduced debt cost in its rates as of the date of the refinancing. However, the determination of a pipeline's debt cost is a simple factual matter which, unlike the determination of ROE, does not require an evaluation of the pipeline's business and financial risk as compared to a proxy group. Therefore, the concerns discussed above about the need for further evidentiary proceedings to allow the pipeline to present evidence of offsetting factors, such as a reduction in its credit rating below investment grade, did not arise in *Williams*.[292]

216. Finally, to the extent PSG relies on the Commission's August 31, 2009 suspension order in *SFPP*[293] to support its request to take official notice of post-record data, that reliance is misplaced. That order established a hearing before an ALJ on a new filing by an oil pipeline to increase its rates. Because that order was issued at the beginning of the

[290] *Union Electric*, 890 F.2d at 1203.

[291] 77 FERC ¶ 61,277, at 62,193 (1996), *reh'g denied*, 80 FERC ¶ 61,158, at 61,684-85 (1997). *Algonguin Gas Transmission Co*., 43 FPC 53, 59-60 (1970) is distinguishable on similar grounds.

[292] The Federal Power Commission decision cited by PSG, *Kansas-Nebraska Natural Gas Co., Inc*. 53 FPC 1691, 1714 (1975), is not relevant, because it predates our use of a proxy group and the DCF methodology.

[293] 128 FERC ¶ 61,214, *order on certified question*, 129 FERC ¶ 61,050.

proceeding before a hearing was conducted, no issue arose concerning whether official notice of post-record evidence should be taken after the hearing was concluded and the Commission had issued an order on the ALJ's initial decision, as PSG asks us to do in this case.

Use of Earlier Data Than Used by Opinion No. 510

217. We now turn to the contentions by PSG and CAPP that the Commission should use data from a period before the November 2008 through April 2009 period used in Opinion No. 510 in order to limit the alleged distortions arising from use of data during the 2008 financial crisis. PSG argues that if the Commission declines to take notice of post record data, then we should revert to using the earliest data in the record, namely the DCF data initially presented by Portland for the six month period prior to January 31, 2008. PSG claims using such data would address the anomalies of the financial crisis because such data predates the crisis and is within the test period.

218. The use of this earliest record data would be inconsistent with the Commission's policy to use the most recent record data in calculating ROE. The Commission uses the most recent data in the record "because the market is always changing and later figures more accurately reflect investor needs."[294] As Portland's witness testified, after the January 31, 2008 end of the six-month period PSG seeks to use, "many critical events have occurred that influence the cost of capital today."[295] These included the collapse of the Bear Stearns Company in March 2008, the bankruptcy filing of Lehman Brothers Holdings, Inc. and the U.S. government's takeover of American International Group in September 2008, and Congress's establishment of the Troubled Asset Relief Program in October 2008 to address the urgent needs of the credit markets. These events all occurred in close proximity to the September 1, 2008 effective date of the rates in this rate case, and were followed by the worst economic recession since the Depression of the 1930s.

219. CAPP's witness, Mr Parcell, recognized that, as a result of these events, "current economic/financial circumstances are radically different from any that have prevailed since at least the 1930s."[296] He also recognized that the "recent deterioration in stock prices and the decline in U.S. Treasury bond yields and increase in corporate bond yields reflect the 'flight to quality' that describes the extreme reluctance of investors to purchase

[294] *Trunkline*, 90 FERC at 61,117. Opinion No. 414-A, 84 FERC at 61,426-7. *Panhandle Eastern Pipe Line Co*., 74 FERC at 61,363-63.

[295] Ex. PNG-56 at 2-3.

[296] Ex. CAP-3 at 12.

common stocks and corporate bonds while moving investments into the very safe government bonds."[297] In these circumstances, we are unwilling to rely on financial data for the proxy member companies from a period before the financial crisis in order to determine the ROE to include in Portland's rates taking effect in September 2008 after the financial crisis commenced.[298] Such pre-crisis data is simply not a reliable indicator of investor needs during the period after the crisis, and thus that data does not provide a reasonable basis on which to establish Portland's ROE in this rate case.[299]

220. We are also concerned that adopting PSG's proposal to use the six-months ending January 2008 would simply reflect a subjective effort to use data from whatever period will produce the lowest ROE. As the Commission found in Opinion No. 414-A, our policy of using the most current data in the record avoids such subjective judgments.[300]

221. The Commission's suspension order in *SFPP* relied on by PSG[301] to argue that the Commission should now consider going outside its established policy to consider "non-aberrational" data does not support its proposal to use pre-financial crisis data during the six months ending January 2008. PSG claims that in *SFPP*, the Commission expressed concern that the financial crisis might necessitate the need to consider "more representative" test periods for ROE calculations. However, the suspension order suggested that a later test period ending December 31, 2009 might be more representative

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[297] *Id.*

[298] If the rates we are approving in this proceeding were to be in effect indefinitely into the future, we would consider reopening the record in order to examine more recent proxy member financial data to determine the continuing effect of financial crisis on investor expectations. See *SFPP*, Opinion No. 511, 134 FERC ¶ 61,121, at P 206, 209, *reh'g denied*, Opinion No. 511-A, 137 FERC ¶ 61, 220, at P 257 (2011). However, as discussed in the preceding section, we will not do that in this case which only involves a locked-in period and where such issues are being considered in Portland's next rate case in Docket No. RP10-729-000.

[299] PSG's proposal to use the six-month period ending in January 2008 would also create proxy group issues. As PSG admits, using data from that period would mean that there was only three months of dividend yield data available for El Paso Partners, a company the Commission found had been wrongly excluded from the proxy group by the Presiding Judge.

[300] Opinion No. 414-A, 84 FERC at 61,427.

[301] *SFPP, LP*, 128 FERC ¶ 61,214.

than the earlier test period ending on June 30, 2009 used by SFPP. Thus, the Commission did not suggest that an earlier, pre-financial crisis test period of the type PSG is requesting here could be more representative. Moreover, in response to a question subsequently certified to the Commission by the ALJ, the Commission clarified that it had not intended to modify the filed base and test periods established in SFPP's filing.[302]

222. The electric rate cases cited by PSG in support of its proposal to use the six months ending January 2008 are also distinguishable. PSG points out that in *SoCal Edison*,[303] we required use of proxy member financial data for the six-month period immediately before SoCal Edison's rate filing, explaining:

> Using any different six-month period other than the latest available at the time of SoCal Edison's filing could create a continual moving target and would make it difficult to determine the most appropriate six-month period. Additionally, the base ROE established herein is for the locked-in period from March 1, 2008 through December 31, 2008. Therefore, it is not reasonable to apply data ending April 30, 2008 because the effective date for the rates would have already taken place prior to the time some of the financial data would be available.

223. PSG contends that its proposal to use proxy member financial data initially presented by Portland in its NGA section 4 rate filing in this case for the six month period prior to January 31, 2008 is consistent with this precedent and would avoid permitting Portland to create a moving target. PSG also contends that Opinion No. 510's use of the six-month period ending April 30, 2009 is inconsistent with this precedent, because that six month period falls outside the test period in this rate case and post dates the September 1, 2008 effective date of the rates in this rate case.

224. Contrary to PSG's contentions, *SoCal Edison* does not support its proposal to determine Portland's ROE based on data from the six-month period ending January 2008 without any update to take account of the significant changes in the capital markets after

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[302] *SFPP, LP*, 129 FERC ¶ 61,050.

[303] 131 FERC ¶ 61,020 at P 21. PSG also cites other orders in electric rate cases making similar rulings, including *Pioneer Transmission, LLC*, 130 FERC ¶ 61,044, at P 42 (2010), and *Pacific Gas and Electric Co.*, 53 FERC ¶ 61,146, at 61,520 (1990) (*PG&E*).

that date. As described in the preceding section, in electric rate cases, including *SoCal Edison*,[304] the Commission uses post-test period and post-record changes in U.S. Treasury bond yields to update the ROE produced by the DCF analysis of test period financial data for the proxy group members.[305] As the Commission explained in *SoCal Edison*, the Commission does this "because market conditions often change substantially between the time a utility filed its case-in-chief and the date the Commission issues a final decision."[306] Thus, PSG's proposal to use data from Portland's case-in-chief without any update[307] is, in fact, directly contrary to the electric rate case precedent on which it relies.

225. It is true that the Commission uses different ROE updating methodologies in natural gas pipeline and electric rate cases, using the most recent financial data for the proxy members in the record to update its DCF analysis in pipeline rate cases, and using post-record changes in bond yields to adjust the ROE produced by the test period DCF analysis in electric rate cases. However, this difference has its genesis in the difference between our natural gas pipeline and electric utility test period regulations. As explained in *Williston IV*,[308] the natural gas pipeline test period regulations[309] "vest far less weight in estimates" included in the pipeline's case-in chief than do the test period regulations governing electric utilities.[310] As illustrated by the *PG&E* case cited by PSG, the Commission generally accepts the cost estimates made by an electric utility based on the test year used in its case-in-chief, if the cost estimates were reasonable when made and do not yield unreasonable results.[311] However, the natural gas pipeline test period

[304] *SoCal Edison*, 131 FERC ¶ 61,020 at PP 99-102.

[305] In electric rate cases involving a past locked-in period, the Commission uses average bond yields during the locked-in period when the rates at issue were in effect.

[306] *Id*. P 100.

[307] As pointed out above, PSG has not requested that we update Portland's ROE based on changes in bond yields.

[308] 87 FERC at 62,020-22.

[309] 18 C.F.R. §§ 154.303 and 154.311 (2012).

[310] 18 C.F.R. § 35.13(d) (2012).

[311] *See also Indiana Municipal Electric Ass'n v. FERC*, 629 F.2d 480 (7th Cir. 1980).

regulations require that any estimate made by the pipeline in its case-in-chief actually take effect by the end of a nine-month adjustment period following the base year used in its case-in-chief,[312] and section 154.311 of those regulations requires the pipeline to file actual data for the nine-month adjustment period after that data becomes available.[313] The adjustment period generally ends when the pipeline's rates take effect, six months after its rate filing.

226. Thus, in natural gas pipeline rate cases there is no limit on updating the pipeline's cost of service based on cost data for the adjustment period that was unavailable at the time the pipeline filed its case-in chief, as there is in electric utility rate cases. This difference has led to the different methods of accomplishing the same goal of reflecting current capital market conditions in our ROE determinations. In natural gas pipeline rate cases, the less stringent limit on updating cost data used in the pipeline's case-in chief has led to the Commission permitting updates of proxy member financial data even beyond the end of the adjustment period, so long as the data is in the record. In electric rate cases, the more stringent limit on updating cost data in the electric utility's case-in-chief has led to use of changes in U.S. Treasury bond yields, rather than the use of any company specific data. In this case, no party, including PSG, has requested that we use the electric rate case updating methodology, and we will not do so. While PSG claims that the updating practice in pipeline rate cases confers an unfair advantage on the pipeline by enabling it alone to determine whether to update DCF data depending upon whether its interests are served, that is untrue. At the hearing, any party is free to present the most recently available DCF data for purposes of updating the pipeline's ROE.

227. We now turn to CAPP's contention in its rehearing request that we erred in rejecting the proposal by its witness, Mr. Parcell, to use dividend yields over a twelve month period ending January 2009, rather than applying our standard policy of using dividend yields over a six month period. CAPP contends that the exception from the general policy proposed by its witness is justified in this case to avoid the distorting effects of the financial crisis. As demonstrated below, however, regardless of the theoretical merits of Mr. Parcell's proposal, it does not appear that his proposal, when modified to reflect the proxy group approved in Opinion No. 510, would produce an ROE substantially different from the 12.99 percent ROE we approved based on the more recent six-month period ending April 2009.

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[312] 18 C.F.R. § 154.303(a)(4) (2012).

[313] 18 C.F.R. § 154.311 (2012).

228. CAPP's witness described his proposal as follows:

> I have compared the DCF costs rates, using the FERC preferred methodology, for my group of seven proxy companies for two periods: 1) the six-month period March-August 2008 (i.e., the period preceding the onset of the current financial crisis) and 2) the six-month period July 2008-January 2009 (i.e. the most recent six-month period, which largely includes the financial crisis). I found the median DCF result for the first period is 10.10 percent, while the median DCF result for the second period is 11.50 percent, and increase of 140 basis points between the two periods. It is apparent that the opportunity cost of equity has declined over the period, as is evidenced by the dramatic reduction in profits associated with the current recession, yet the FERC DCF methodology would indicate that the cost of equity for regulated pipelines has increased by nearly 15 percent (i.e., from 10.10 percent to 11.50 percent). I propose that a proper modification to the FERC DCF methodology under these circumstances is to use a 12-month average of stock prices instead of the 6-month average. I have used a 12-month average of stock prices for my proposed proxy group and the resulting median DCF result is 10.81 percent.[314]

229. In conducting the above described DCF analyses, CAPP's witness used his proposed proxy group consisting of National Fuel Gas, TC Pipelines; Kinder Morgan Energy Partners, Southern Union, TransCanada Corp, El Paso Corp. and the Williams Companies. However, Opinion No. 510 adopted a proxy group which included four members not proposed by CAPP's witness (Boardwalk, Spectra Corp., El Paso Partners, and Spectra Partners) and only two members that CAPP's witness did propose (TC Pipelines and Southern Union). CAPP has not sought rehearing of our proxy group determinations. Therefore, if the Commission were to accept CAPP's 12-month proposal, the Commission would have to modify that proposal to use the proxy group approved in Opinion No. 510. In its rehearing request, CAPP does not identify where in the record we are to find the dividend yield data for the members of the Opinion No. 510 proxy group for the entire February 2008 to January 2009 period it contends we should have used, nor has CAPP provided any revised DCF calculations for its proposed period.

[314] Exh. CAP-3 at 2-3.

230. Nevertheless, for illustrative purposes, and in order to estimate the median ROE that would be produced by CAPP's 12-month proposal using the Opinion No. 510 proxy group, we have utilized the dividend yield data for the February 2008 through January 2009 period included in Attachment C of PSG's rehearing request. As shown in Appendix B of this order, a DCF analysis of the Opinion No. 510 proxy group using dividend yields for the 12-month period proposed by CAPP produces a median ROE of 12.82 percent, which is only marginally lower than the 12.99 percent median ROE produced by Opinion No. 510's DCF analysis for the six-month period November 2008 through April 2009. Moreover, use of the 12-month period beginning in February 2008 raises the problem that El Paso Partners had only been in existence for several months as of February 2008, and a review of its dividend yield data for the first three months of the 12-month period (February through April 2008) indicates that its distributions during that period were significantly lower than during the remaining nine months of the 12-month period.[315] If the 12-month dividend yield data for El Paso Partners was normalized to account for its unusually low distributions during its first months of operation, the ROE produced by CAPP's proposal would approximately match that produced by Opinion No. 510's DCF analysis.

231. In these circumstances, we see little reason to depart from our longstanding policy in both natural gas pipeline and electric rates cases to use the most recent six months of dividend yield data, rather than 12 months of data. As the Commission has explained, "Although using a long period to assess stock prices decreases the influence of short-run volatility, it also makes it less likely that the outcome will reflect *current* capital costs."[316] While CAPP contends that the rote application of the policy of using 6 months of data for the DCF analysis does not result in a figure that is reflective of investor expectations of future cash flows, the analysis above shows that CAPP's proposed remedy arrives at virtually the same result of as Opinion No. 510's DCF analysis using the six-month period ending April 2009.

232. The possibility that the declines in IBES growth projections after December 2008 pointed out by Opinion No. 510 may not have fully offset increases in dividend yields during the financial crisis, or that the downward adjustments to the IBES growth projections may eventually flatten or increase does not render that Commission's analysis arbitrary or unreasonable, particularly given that CAPP offers no specific approach that

[315] El Paso Partners' dividend yields averaged 2.26 percent during the period from February to April 2008, while its average dividend yield for the May 2008 to January 2009 period was a significantly higher 6.61 percent.

[316] *Allegheny Generating Co.*, Opinion No. 281, 40 FERC ¶ 61,117, at 61,316 & n.5 (1987) (emphasis in original). *Williston III*, 84 FERC at 61,3818-2.

reaches a significantly different result than that reached in Opinion No. 510. Further, the fact that the proxy group included MLPs in accordance with the Policy Statement[317] concerning the composition of proxy groups used to determine oil and gas pipelines' ROE, does not make application of the Commission's DCF policy invalid. CAPP's arguments that the financial crisis likely had no effect on the MLPs' obligations to distribute cash flow, and thus the recession is not reflected in the per unit distributions of the MLP members of the proxy group, appear to bolster the Commission's reasoning that use of the most recent MLP data in the record does not produce an aberrant result. Rather that data reflected the market realities for these companies during the economic crisis, as reflected by the record data.

233. As we stated in Opinion No. 510, on balance we find that the use of the most recent data in the record consistent with long standing policy outweighed any adjustments to reflect purportedly anomalous results. The use of data from the six months ending April 2009, which included some of the months of the financial crisis, accurately reflected the cost of capital to Portland during the crisis. The use of pre-financial crisis data would not reflect this increased risk that Portland and other proxy group members faced during the locked-in period in this case. Moreover, in Opinion No. 510, the Commission evaluated the impact of using different time periods and found that the use of the most recent record data was most supportable in terms of capturing both increases and later downward adjustments to DCF inputs,[318] a goal espoused by PSG itself in its arguments during the hearing to use the time period ending December 2008.[319] Moreover, the Commission did consider relevant market conditions in determining the appropriate time period for the DCF analysis and did not blindly adhere to its policy to use the most recent record data. Rather, after analysis of the available record data for the time periods that could be used to calculate Portland's ROE, the Commission continues to find that the most reasonable choice is to follow its established policy. As discussed above, neither PSG nor CAPP have shown that their proposed alternative time periods are

[317] 123 FERC ¶ 61,048.

[318] Opinion No. 510, 134 FERC ¶ 61,129 at P 246.

[319] *See* PSG Brief Opposing Exceptions at 89 ("PSG maintains that the best resolution of all is simply to affirm the Presiding Judge's reliance on data presented by PSG (for a six month period through December 2008), which reflects some but not all of the aberrational (temporary) steep decline in stock prices (and concomitant rise in dividend yields) beginning in late 2008), and also reflects the natural gas spike in the summer of 2008 (which would tend to mitigate rising dividend yields in the case of many proxy candidates in this case").

just and reasonable or that they provide a more accurate reflection of the prevailing market conditions.

D. Placement in the Proxy Group

1. Opinion No. 510

234. In Opinion No. 510, the Commission found that Portland's ROE should be set at the median of the proxy group range, relying on our traditional assumption that absent highly unusual circumstances indicating an anomalously high or low risk as compared to other pipelines, the Commission will set the pipeline's return at the median of the zone of reasonable returns.[320] The Commission found that Portland had failed to present a comprehensive analysis comparing its own business risk to that of each of the proxy group members. The Commission also found that despite Portland's contentions to the contrary, it is appropriate to compare credit ratings to assess whether proxy group members reasonably reflect the business risks of the subject pipeline. Finally, the Commission determined that many of the factors upon which Portland relied for its alleged high risk claim, including favored nations clauses, decontracting options, free off-peak transportation provisions and the use of joint facilities, are the consequence of Portland's own business decisions and thus are not an appropriate basis for adjusting Portland's ROE upward.

235. The Commission also denied Portland's request for official notice of S&P's post record downgrade of Portland's corporate credit rating. The Commission found that event, which occurred nearly 21 months after the close of the test period, is irrelevant to the determination of Portland's ROE for this proceeding, especially as Portland had already filed a new rate case where the post record events could be addressed.[321]

2. Request for Rehearing

236. Portland requests rehearing of the Commission's determination to place Portland at the median of the proxy group range. Portland claims the Commission ignored or misinterpreted the weight of record evidence in this proceeding that allegedly demonstrates Portland's relatively high business risk as compared to other pipelines. Portland claims these risks include (1) contractual provisions, e.g. most favored nations clauses, shipper contract reduction options); (2) shared ownership of its joint facilities with Maritimes & Northeast Pipeline, L.L.C (Maritimes); (3) market characteristics;

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[320] Opinion No. 510, 134 FERC ¶ 61,129 at P 265.

[321] Opinion No. 510, 134 FERC ¶ 61,129 at P 271.

(4) location, age and size of facilities; and, (5) contract reductions from bankruptcies and poor market conditions. Portland challenges the findings in Opinion No. 510 that Portland's analysis of these risks is lacking, particularly as they relate to the proxy group members, and that Portland's risks are not unique from those facing other gas pipelines. Portland contends its witnesses addressed the relevant risk analysis in testimony and that it is the total combination of risks Portland faces that makes it more risky than other natural gas pipelines.

237. As justification for its unique risk combination claim, Portland contends that contrary to the implication in Opinion No. 510, the vast majority of natural gas pipelines in the United States do not share facilities, much less with a competitor. Portland argues that even the Commission has recognized Portland's joint ownership of facilities "unique circumstances."[322] According to Portland, the situation restricts its operational flexibility, provides Maritimes with notice of certain Portland business development initiatives, and puts Portland at risk for immediate by-pass. Portland argues further that no party rebutted these facts or presented evidence to show that any other pipelines share the challenging market and contracting conditions that Portland does. Portland concludes that there is no record evidence showing that there is another pipeline with even a "subset" of the risk faced by Portland, and thus the Commission's finding must be reversed.

238. Portland also argues that the finding in Opinion No. 510 that several of the risks it faces are the result of its own business decisions does not change the fact that the risk is real. Portland asserts that all enterprises will take actions to increase their risk in order to compete, and thus the fact that Portland may have done so as well is not grounds for ignoring the severity of the actual risks. Portland argues that to place it at the median of the proxy group range on the basis that its risk is the result of its own business decision is inconsistent with the Commission's decision in *Ozark Gas Transmission System*,[323] where the Commission afforded Ozark an above-median risk return even though one of the risk factors was allegedly the result of the pipeline's own business decisions.

239. Portland also argues the fact it has recovered some bankruptcy funds does not mitigate the continued risk it faces. Portland contends that the risk of further shipper bankruptcies, coupled with the contracting difficulties it faces, render its potential cost under-collection issues a serious risk that should be reflected in its ROE. Portland states that Opinion No. 510 shifted several business risks to the pipeline (for example the

[322] Portland Rehearing Request at 73 (citing *Maritimes and Northeast Pipeline, LLC and Portland Natural Gas Transmission System*, 84 FERC ¶ 61,130 (1998)).

[323] 68 FERC ¶ 61,032 (1994) (*Ozark*).

treatment of Bankruptcy Proceeds) and claims those risks should be recognized in placing Portland above the median of the zone of reasonableness.

240. Portland also argues the Commission erred in denying its request to take official notice of its credit downgrade. Portland contends that contrary to Opinion No. 510 the downgrade is not irrelevant to this proceeding but goes directly to the question of whether Portland is being afforded an adequate rate to meet the standards set by the Supreme Court in *Hope* and *Bluefield*.[324]

3. Commission Determination

241. We deny Portland's request for rehearing on this issue. As we noted in Opinion No. 510, the Commission's policy toward relative risk assumes that pipelines generally fall into a broad range of average risk absent highly unusual circumstances indicating anomalously high or low risk factors and a very persuasive demonstration by the pipeline supporting the need for an upward adjustment. As in Opinion 510, we determine that Portland has failed to justify increasing its ROE to the 14.89 percent top of the zone of reasonableness from the 12.99 percent median based on the record in this proceeding.

242. Portland's arguments regarding its placement in the zone of reasonableness ignore the fact that our use of the most updated data in the record, reflecting the impact of the financial crisis, helps recognize the business risks faced by Portland. As noted by the other participants in this proceeding, the DCF results for that time period were arguably at the high end of possible outcomes, because the increased dividend yields resulting from decreased stock prices were not fully offset by later downward adjustments to other inputs to the DCF analysis. Thus, the decision to use the most recent record data because it best reflects the actual market conditions while the rates at issue here were in effect takes into account a certain amount of Portland's claimed risk.

243. Portland seeks to support its contention that it is more risky than the proxy members by requesting we take official notice of S&P's July 2010 downgrade of Portland's corporate credit rating to below investment grade. Portland points out that the credit downgrade occurred during the September 1, 2008 through November 30, 2010 locked-in-period at issue in this rate case. However, as discussed in the preceding section, we have determined that the significance of the credit downgrade is best considered in Portland's subsequent Docket No. RP10-729-000 rate case, where all participants have had an opportunity to present evidence related to the credit downgrade,

[324] Portland Rehearing Request at 79 (citing *FPC v. Hope Natural Gas* Co., 320 U.S. 591, 603 (1944) (*Hope*); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va*, 262 U.S. 679, 692-93 (1923) (*Bluefield*)).

as well as later financial data for the proxy members than is available in the record in this case.

244. In a contemporaneous opinion in the Docket No. RP10-729-000 rate case, we are approving the same proxy group as in this case, and we are finding that the credit downgrade, combined with the at-risk condition in Portland's certificate, does warrant an upward adjustment to the top of the zone of reasonableness determined in that rate case. However, in Docket No. RP10-729-000, we are determining, based on financial data for the six-month period October 2010 through March 2011, including two months at the end of the locked-in period in this rate case, that the top of the zone is 11.59 percent. That is 140 basis points lower than the 12.99 percent median of the range being awarded to Portland in this rate case.

245. If we were to take official notice of the July 2010 credit downgrade in this rate case, we would, as discussed in the preceding section, also have to consider post-record proxy member financial data for the entire locked-in period in this rate case, either by taking official notice of that data or establishing further procedures. If we were to do that, the post-record financial data for the proxy group attached to PSG's rehearing request suggest we would find that during the last twelve months of the locked-in period, the top of the zone of reasonableness varied from 10.94 percent to 13.38 percent, and was higher than the 12.99 percent median we are awarding to Portland in only three months. Moreover, Portland's own direct testimony in the Docket No. RP10-729-000 rate case, using data for the six-month period ending March 2010, only supported setting the top of the zone at 13.40 percent.[325] In these circumstances, we find that increasing Portland's ROE to the 14.89 percent top of the zone or reasonableness established in this proceeding based on data for the six months ending April 2009 is not necessary to reflect any increased risk it faces.

246. Absent consideration of the credit downgrade, the record developed at the hearing in this case would be insufficient to overcome the presumption that Portland had average risk. For example, the Commission found that Portland had not prepared a comprehensive analysis of its business risks compared to that of the proxy group members. Portland's re-recitation of its testimony on that point does not support a change in that finding.

247. Further, as to Portland's claims that it faces above-average risk because it shares joint facilities, while that may be a "unique" situation, Portland has not demonstrated that joint ownership is inherently more risky or that it makes Portland's specific situation more risky than other pipelines that may own joint facilities. Likewise, we continue to

[325] Exh. PNG-30 in Docket No. RP10-729-000.

find unpersuasive Portland's arguments that the fact its high business risk is a result of such business choices as offering most favored nation clauses and contract reduction options in contracts should not factor into determining Portland's level of risk. While, as Portland argues, the fact that its business decisions created certain risk factors does not make the risk any less real, Portland should not be rewarded for, and its shippers should not have to shoulder the effect of, Portland's risky business decisions.

248. Portland's reliance on *Ozark* on this point is unavailing. There, the Commission did uphold the judge's finding that the pipeline faced substantially greater than average risk due in part to uncertainty about future contracting. The facts that the Commission relied on for that determination, however, are not similar to Portland's in this proceeding. The Commission found that Ozark faced an above average risk because one of Ozark's principal customers was in bankruptcy and still had the choice to reject its contract with the pipeline. The Commission found that the uncertainty as to whether Columbia would reject its contract with Ozark, coupled with the heavy dependency of Ozark on Columbia, heightened Ozark's risk as compared to other pipelines facing similar situations.[326] In this case, however, Portland does not have a current customer in bankruptcy, and it has already collected Bankruptcy Proceeds for the terminated Androscoggin and Rumford Agreements. A second reason for finding Ozark faced above average risk was that its current lenders would not finance Ozark's debt, and that the pipeline's investors would have little to no incentive to refinance. Portland has made no such claims in this proceeding.

249. Not only does *Ozark* not support Portland's claim that it faces high risk, it supports the decision in Opinion No. 510 that Portland should be placed at the median based on the items the Commission found did not support a higher risk finding. Akin to the current case, Ozark argued that it faced significant capacity turn back due to the future expiration of firm contracts. The Commission determined that the termination of contracts in the future, at a date outside the test period of the proceeding, cannot serve as a basis for assigning a level of risk to the pipeline. That same reasoning applies here.

250. The Commission concludes that Portland has not shown that an ROE above 12.99 percent would be just and reasonable.

VII. <u>Compliance Filing</u>

251. Opinion No. 510 required Portland to file revised tariff records and rates reflecting the Commission's rulings in that order and make refunds. However, on March 7, 2011, the Commission granted Portland an extension of time to make its compliance filing until

[326] *Ozark*, 68 FERC at 61,108.

further order of the Commission. While Portland accordingly has not yet filed any revised tariff sheets or made refunds in accordance with Opinion No. 510, on May 31, 2011, Commission staff issued a Data Request that directed Portland to reflect a recalculation of its cost of service, billing determinants and rates that would be necessary to comply with Opinion No. 510. In response, Portland calculated its cost of service, billing determinants and rates using 20 different scenarios and two variations for each scenario. The two variations are comprised of different PIP costs. Each of Portland's scenarios was supported with working spreadsheet models. Portland's response was noticed, and only PSG filed comments. PSG stated that it did not review the model used by Portland to design the reflected rate scenarios, but indicated that it was satisfied with the results as shown by Portland.

252. In its Response to the Staff Data Request, Portland filed a variety of rate scenarios which it states correspond with its arguments regarding the correct interpretation of Opinion No. 510. The Commission finds that Portland's Scenario No. 2 best reflects the necessary compliance with Opinion No. 510. Under Scenario No. 2 Portland reflects PSG's levelization model with a levelization period that ends on March 31, 2020.[327] Portland's Scenario No. 2 also reflects an average rate base in its rate computation. Portland's Scenario No. 2 also addresses the Bankruptcy Proceeds in a manner consistent with the Commission's findings in Opinion No. 510[328] and the clarification granted above with regard to the start and end periods of the amortization schedule.[329]

[327] The ID found that Portland was required to design levelized rates utilizing: (1) PSG Witness Briden's iterative levelization model, as reflected in Exhibit No. PSG-26; (2) a 21-year levelization period that ends on March 31, 2020; and (3) an average rate base computation. ID, 129 FERC ¶ 63,027 at P 81. The ALJ found the record clear that an average rate base computation was used in the Docket No. RP02-13 Settlement and that the same approach was used in the levelization process in the Portland's certificate proceedings. The ALJ expressly found that the Docket No. RP02-13 Settlement obligates Portland to use the same levelization methodology as approved in Portland's certificate orders and that Portland is still bound by this obligation. Moreover, the ALJ agreed with PSG that to generate the levelized cost-of-service utilizing the results reflected in Appendix D of the Docket No. RP02-13-000 Settlement, it was necessary for Portland to use an average rate base. *Id*. PP 75, 80. Opinion No. 510 affirmed these findings, and no party requested rehearing of that aspect of Opinion No. 510.

[328] *See* Opinion No. 510, 134 FERC ¶ 61,129 at n.508.

[329] Portland should note the treatment provided the Bankruptcy Proceeds in a footnote to Page 278 of its Form 2.

253. Although the Commission finds Scenario No. 2 best complies with the dictates of Order No. 510, we granted rehearing, as discussed above, with regards to our PIP decision. Accordingly, the Commission will permit Portland to recover $422,169 in PIP related costs. This finding is not reflected in either of Portland's Scenario 2's variations. Portland is directed to reflect this amount in its compliance filing.

254. Finally, the Commission also granted rehearing of the at-risk condition. In Opinion No. 510, the Commission found the at-risk condition to be 210,840 Dth per day. Above, we find that the at-risk condition is more appropriately reflected as 217,405 Dth per day. This finding will require Portland's maximum rates to be recalculated to reflect the revised at-risk condition.

255. Portland is required, within 30 days of the date of this order, to file revised tariff records, to be effective September 1, 2008, through November 30, 2010.[330] Portland is required to provide work papers in electronic spread sheet format, including formulas and following the Scenario 2 model, supporting the recalculated rates. Within sixty days, Portland is required to provide refunds and provide a report to the Commission[331] consistent with section 154.501 of the Commission's regulations.[332]

The Commission orders:

(A) Rehearing of Opinion N0. 510 is granted in part and denied in part consistent with the discussion above.

[330] The locked-in period of September 1, 2008 through November 30, 2010, spans the period that the Commission changed its electronic tariff system. Portland is not required to file revised electronic tariff sheets in the FASTR format, as the Commission no longer maintains that system. For the period of September 1, 2008 through September 29, 2010, Portland is required to file a rate summary tariff sheet document with content similar to Portland's Second Revised Volume No. 1, Third Revised Sheet No. 100. In the same compliance filing, Portland is required to file tariff records for the period of September 30, 2010 through November 30, 2010. This filing should be an eTariff compliance filing using Type of Filing Code (TOFC) 580, with no Associated Filing Identifier at either the Filing or Tariff Record levels. The Filing Title should include "Docket No. RP08-306 Compliance Filing". This compliance filing will be given a new docket number.

[331] Portland is required to use eTariff TOFC 670 for its Refund Report.

[332] 18 C.F.R. § 154.501 (2012).

(B) Within 30 days of the issuance of this order, Portland must file revised tariff records and rates, including proposed accounting and workpapers, reflecting the Commission's rulings in Opinion No. 510, as modified in this order.

(C) Within 60 days of the issuance of this order, Portland must refund amounts recovered in excess of the just and reasonable rates calculated pursuant to Ordering Paragraph (B) and file a refund report consistent with section 154.501 of the Commission's regulations.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A, Docket No. RP08-306-002

Estimate of Portland Pre Tax Return
Based on Portland's Scenario 2

	Break Out of Pre-Tax and Non-Return Costs		
Line No.	**Description (a)**	**Source (b)**	**Scenario 2 (c)**
	Non-Levelized Costs		
1	Operation & Maintenance Exp.	Schedule H-1	$ 7,312,935
2	Depreciation Expense	Statement H-2	$ 51,247
3	Return Allowance	Statement B / Line 9	$ 238,428
4	Federal and State Income Tax Allowance	Statement H-3 / Line 11	$ 104,581
5	Taxes Other Than Income	Statement H-4	$ 6,117,559
	Levlized Costs		
6a	Book Depreciation from Levelization Model	Scenario 2 Model, L 42	$ 10,444,389
6b	Pre-Tax Return from Leveliation Model	Scenario 2 Model, L47-L42	$ 39,566,204
6	Total Levelized Cost of Service	L6a+L6b	$ 50,010,593
7	**Total Senario 2 Cost of Service**	L1+L2+L3+L4+L5+L6; also equals Scenario 2 COS	$ 63,835,342
	Non-Return Costs		
8	Operation & Maintenance Exp.	L1	$ 7,312,935
9	Depreciation Expense	L2+L6a	$ 10,495,636
10	Taxes Other Than Income	L5	$ 6,117,559
11	Total Non-Return Items	L8+L9+L10	$ 23,926,130
	Pre-Tax Return		
12	Debt Cost	Statement F-2/L1d*L1g	$ 13,617,308
13	Pre-Tax Equity Return	(L3+L4+L6b)-L12	$ 26,291,904
14	Total Pre-Tax Return		$ 39,909,212
15	**Total Senario 2 Cost of Service**	L11+L14	$ 63,835,342
	At Risk Pre-Tax Return		
16	At Risk Revenue Responsibility	L25(d)	$ 54,982,847
17	Non-Return Costs	L11	$ 23,926,130
18	Pre-Tax Return under At Risk Revenue	L14-L15	$ 31,056,717
19	Debt Costs	L12	$ 13,617,308
20	Pre-Tax Equity Return	L18-L19	$ 17,439,408

Revenue Responsibility for Projected and At Risk Unit Rates

			Revenue Responsibility	
	Service (a)	**Source (b)**	**Projected Unit Rate $1.0152, Sch. G1 for Scenario 2 (c)**	**At Risk Unit Rate $0.8044 @ 217,405 Dth/d (d)**
21	TOTAL FT (NON-DISCOUNTED)	(c) Scenario 2, G-1, G8*$1.0152 (d) Scenario 2, G-1, G8*$0.8044	$ 31,286,142	$ 24,791,618
22	TOTAL FT (DISCOUNTED)	Scenario 2, G-1, D10	$ 5,942,502	$ 5,942,502
23	TOTAL FT (WINTER SEASONAL - NO DISCOUNTS)	(c) Scenario 2, G-1, G12*$1.0152 (d) Scenario 2, G-1, G12*$0.8044	$ 11,357,097	$ 8,999,538
24	TOTAL SHORT TERM FT (< 1 YEAR - ALL DISCOUNTED)	Scenario 2, G-1, D14	$ 3,455,053	$ 3,455,053
25	TOTAL FX (ALL DISCOUNTED)	Scenario 2, G-1, D16	$ 49,200	$ 49,200
26	TOTAL IT (ALL DISCOUNTED)	Scenario 2, G-1, E18	$ 2,814,550	$ 2,814,550
27	TOTAL PAL (ALL DISCOUNTED)	Scenario 2, G-1, E20	$ 545,972	$ 545,972
28	BANKRUPTCY RELATED CAPACITY	Scenario 2, G-1, D22	$ 8,384,415	$ 8,384,415
29	Total Revenue Responsibility for Scenario 2	SUM(L17:L24)	$ 63,834,931	$ 54,982,847
30	Revenue Responsibility Difference	L25(c)-L25(d)	$ 8,852,084	

Appendix B, Docket No. RP08-306-002

RP08-306-000 PORTLAND NATURAL GAS TRANSMISSION SYSTEM

FERC DCF Analysis: Natural Gas Model Using Data for the Twelve-Month Period Beginning February 2008 and Ending January 2009

		12 Mos. Avg		Growth Rate ("g")		Adj. Div.	DCF	
Ticker	Company Name	Div. Yield	I/B/E/S	GDP	Composite	Yield	Result	
BWP	Boardwalk Pipeline Partners, LP	8.29%	8.40%	2.21%	6.34%	8.55%	14.89%	
EPB	El Paso Pipeline Partners, L.P.	5.52%	10.13%	2.21%	7.49%	5.73%	13.22%	
SUG	Southern Union Co.	3.00%	8.60%	4.42%	7.21%	3.11%	10.31%	
SE	Spectra Energy Corp.	4.44%	9.50%	4.42%	7.81%	4.61%	12.42%	
SEP	Spectra Energy Partners, LP	6.12%	7.67%	2.21%	5.85%	6.30%	12.15%	
TCLP	TC Pipelines, LP	9.32%	5.00%	2.21%	4.07%	9.51%	13.58%	
	Zone of Reasonableness					**10.31%**	---	**14.89%**
						Median:	**12.82%**	
						Midpoint:	**12.60%**	