

142 FERC ¶ 61,197
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 524

Portland Natural Gas Transmission System

Docket No. RP10-729-000

OPINION AND ORDER ON INITIAL DECISION

(Issued March 21, 2013)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Portland Natural Gas Transmission System

Docket No. RP10-729-000

OPINION NO. 524

APPEARANCES

Mark Sundback, Catharine Davis, Kenneth Wiseman, Lisa Purdy, William M. Rappolt, and Jennifer Spina on behalf of Portland Natural Gas Transmission System

Sandra E. Safro, Sarah Novosel, and Paul Forshay on behalf of Calpine Energy Services

Andrew N. Beach, Steven E. Hellman, James D. Seegers, James Olson, and Sabina D. Walia on behalf of Maritimes & Northeast Pipeline, LLC

Emil J. Barth and Thomas Eastment on behalf of Repsol Energy North America

Roxane Maywalt, Edwin G. Kichline, Frederick W. Peters, and Kenneth T. Maloney on behalf of National Grid Gas Delivery Companies

John B. Rudolph and Timothy W. Bergin on behalf of Portland Natural Gas Transmission System Shippers Group (PSG)

James H. Holt on behalf of Canadian Association of Petroleum Producers

Randall S. Rich on behalf of Verso Paper Company

Joel M. Cockrell, Thomas J. Burgess, and Lauren R. Bregman on behalf of the Federal Energy Regulatory Commission

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

Portland Natural Gas Transmission System

Docket No. RP10-729-000

OPINION NO. 524

ORDER ON INITIAL DECISION

(Issued March 21, 2013)

1. This order addresses briefs on and opposing exceptions to an Initial Decision (ID) issued on December 8, 2011 by the Presiding Administrative Law Judge (ALJ) in the captioned proceeding.¹ The ID set forth the ALJ's findings concerning the general rate case filed on May 12, 2010 (2010 Rate Filing) by Portland Natural Gas Transmission System (Portland) pursuant to section 4 of the Natural Gas Act (NGA).

2. In this order, the Commission affirms the ALJ in part and reverses the ALJ in part. The Commission affirms the ALJ's findings in the ID with regard to several cost-of-service issues, Portland's levelized rate structure, depreciation and negative salvage, capital structure and cost of debt.

3. The Commission reverses the ALJ in part with regard to several rate design issues. The Commission determines that the ID errs in its findings regarding the appropriate at-risk level for Portland, and holds that Portland's rates must be designed using billing determinants of at least 210,840 dekatherms (Dth) per day, instead of the 168,672 Dth per day approved by the ALJ. The Commission also reverses the ALJ in part with regard to the calculation of billing determinants to compare to the at-risk condition, and we reverse the ALJ's decision to allow Portland to credit its cost-of-service for certain lump sum bankruptcy proceeds. In accordance with our prior rulings in Opinion Nos. 510 and 510-A, we require Portland to include the volumes associated with the rejected contracts in

¹ *Portland Natural Gas Transmission System*, Initial Decision, 137 FERC ¶ 63,018 (2011) (ID).

assessing billing determinants in comparison to the at-risk condition, and to reduce its rate base by the net amount of the payments received.²

4. The Commission affirms the ALJ's findings concerning the proxy group to be used to determine Portland's return on equity (ROE), but reverses his decision to set Portland's ROE at the median of the proxy group. Instead, the Commission sets Portland's ROE at the 11.59 percent top of the range of reasonable returns.

I. Background

5. Portland's interstate pipeline system extends from Pittsburg, New Hampshire at the U.S.-Canadian border to Dracut, Massachusetts. The system is divided into two parts, the Northern (or wholly owned) facilities and the Joint Facilities. The Northern Facilities consist of 142 miles of mainline from an interconnection with Trans-Quebec & Maritimes Pipeline Inc (Trans-Quebec & Maritimes) at the U.S. Canadian border to Westbrook, Maine, and two laterals. The Northern Facilities are owned and operated solely by Portland. The Joint Facilities consist of about 101 miles of mainline from Westbrook, Maine to Dracut, Massachusetts, as well as three laterals (Joint Facilities).³ Portland shares the Joint Facilities with another interstate pipeline, Maritimes and Northeast Pipeline, LLC (Maritimes/Northeast).⁴ Portland's capacity on the Joint Facilities is 210,840 Dth.

6. In the 2010 Rate Filing, Portland sought an increase in its base transportation rates based on its claims of increased business risks, unsubscribed capacity, and changes in the

² *Portland Natural Gas Transmission System*, Opinion No. 510, 134 FERC ¶ 61,129 (2011), *order on reh'g*, Opinion No. 510-A, 142 FERC ¶ 61,198 (2013).

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, at 61,445-46 (1997) (issuing preliminary determination on amended application and denying rehearing) (July 1997 Certificate Order), *order on reh'g*, 80 FERC ¶ 61,345, at 62,145 (1997) (granting certificate authority and addressing rehearing requests) (September 1997 Certificate and Rehearing Order).

⁴ As relevant to our determination below on Portland's at-risk condition, Maritimes/Northeast increased its capacity by some 400,000 Dth per day to accommodate the importation of regasified liquefied natural gas (LNG) from Canada (Phase IV Expansion). Maritimes/Northeast's May 16, 2006 certificate filing was addressed by the Commission in Docket No. CP06-335-000. *E.g.*, *Maritimes and Northeast Pipeline, LLC*, 118 FERC ¶ 61,137 (2007) (Phase IV Certificate Order).

pipeline infrastructure affecting its market area. Portland asserts that its cost of service and determination of rates reflect the costs and throughput for the base period (12 months ended February 28, 2010), as adjusted through the test period ending November 30, 2010. The Commission accepted and suspended Portland's proposed rate increase until December 1, 2010, subject to refund, and established a hearing before an ALJ.⁵

7. The rates proposed in this rate case replace the rates Portland proposed in its last general NGA section 4 rate filing in Docket No. RP08-306-000 (2008 Rate Filing). Those rates took effect on September 1, 2008, subject to refund. After hearing, the Commission issued Opinion No. 510 on February 17, 2011, affirming and reversing the ALJ's initial decision in that rate case.⁶ Contemporaneously with our order in this rate case, the Commission is issuing Opinion No. 510-A generally denying rehearing of Opinion No. 510 but clarifying several points. Our holdings in Opinion Nos. 510 and 510-A will govern the outcome of similar issues in this rate case.

8. The hearing in this rate case commenced on April 27, 2011 and concluded on May 25, 2011. Testimony was taken from 27 witnesses and over 700 exhibits were received into evidence. Portland, Trial Staff, Portland Natural Gas Transmission System Shippers Group (PSG), Canadian Association of Petroleum Producers (CAPP), Maine Public Advocate, and Maritimes/Northeast were active participants. On December 8, 2011, the ALJ issued the ID.

II. Summary

9. As reflected in the ID, the hearing examined issues relating to Portland's 2010 Rate Filing,⁷ including: (1) Operations and Maintenance expense, including Pipeline Integrity Program (PIP)/Maintenance of Mains expenses (Acct. 863), (2) whether to accept Outside Services Employed (Outside Services) (Acct. 923) costs established under affiliate service agreements and (3) Regulatory Commission Expenses (Acct. 928) paid outside the test period; (4) whether Portland should modify its accounting practices for the service companies, (5) *ad valorem* tax expenses (6) treatment of bankruptcy proceeds from Androscoggin Energy LLC (Androscoggin) and Rumford Power Associates, LP

⁵ See *Portland Natural Gas Transmission System*, 131 FERC ¶ 61,230 (2010) (Hearing Order); see also Portland's Motion to Place Suspended Rates and Tariff Sheets into Effect, Docket No. RP11-1541-000 (Nov. 22, 2010).

⁶ Opinion No. 510, 134 FERC ¶ 61,129; Opinion No. 510-A, 142 FERC ¶ 61,198 (2013).

⁷ ID, 137 FERC ¶ 63,018 at P 27 (statement of issues).

(Rumford), (7) Interruptible Transportation/Park and Loan (IT/PAL) cost allocation, (8) prepaid tax in working capital, (9) levelized cost of service calculation, (10) depreciation rates in light of Opinion No. 510, gas supply forecasts and demand for transportation service, (11) negative salvage, (12) the level of the at-risk condition and billing determinants in light of system capacity loss, (13) forward interest rate swap costs in debt cost, (14) capital structure, and (15) return on equity (ROE) and risk analysis.

10. As discussed in greater detail below, in this Opinion, the Commission affirms the ALJ's determinations on: (1) establishing PIP expense using test period costs, (2) calculating Outside Services based on costs that TransCanada Corp. (TransCanada) charges to its service companies, rather than Portland's contract rates with the affiliated service companies (3) the application of the Commission's accounting policies to Portland, (4) *ad valorem* tax expenses, (5) the prepaid tax allowance in working capital, (6) calculating the levelized cost of service using average rate base, (7) the 2 percent depreciation rate, (8) negative salvage, and (9) calculation of debt cost. The Commission reverses the determination in the ID of capital structure and the calculation of Regulatory Commission Expenses, which would have excluded TransCanada service agreement invoices but included bills not received in the test period. In addition, the Commission reverses the ID's determination that the at-risk condition is 168,672 Dth per day, finding instead that it should be set at 210,840 Dth per day in light of capacity on the Joint Facilities. The Commission reverses the ID on several rate design issues to reflect the at-risk condition and the approach set forth in Opinion No. 510, including IT/PAL cost allocation, billing determinants, and treatment of bankruptcy proceeds. Finally, the Commission reverses the ID's finding that Portland's ROE should be set at the median of the zone of reasonableness and instead sets Portland's ROE at the top of the zone.

III. Cost of Service Issues

A. Operations and Maintenance (O&M)

1. Regulatory Commission Expenses (Account 928)

11. Portland claimed Regulatory Commission Expenses (Account 928) of \$2,378,562, representing a three-year average of costs incurred between December 1, 2007 and November 30, 2010.⁸ Portland states that it calculated its Regulatory Commission Expense by identifying costs incurred for the instant proceeding, including costs for services rendered during the test period that were billed and paid outside of the test period, that is, after December 1, 2010. Portland provided invoices from its outside counsel, Andrews Kurth, as well as from consultants Brown, Williams, Moorhead

⁸ ID, 137 FERC ¶ 63,018 at P 918; Exh. Nos. PNG-94 at 9, 12, PNG-119 at 9.

& Quinn, Inc., Concentric Energy Advisors, and David W. Elrod. In addition, Portland relied on invoices from the service company set up by TransCanada, 9207670 Delaware, Inc.⁹

12. Trial Staff sought to exclude approximately \$900,000 in costs that Portland claimed it accrued in November 2010 which were incurred for services performed during the test period, but were not billed prior to the close of the test period. PSG supported Trial Staff's exclusion of costs incurred in the test period that were not billed and not paid in the test period. In addition, PSG proposed to project Portland's regulatory expenses based on the costs it incurred during the three-year, eleven-month period from January 1, 2007 through November 30, 2010, which it described as encompassing Portland's regulatory expenses incurred in defense of the current, 2010 Rate Filing and the 2008 Rate Filing. PSG then proposes to calculate Portland's annual regulatory expense by dividing the total January 2007-November 2010 expenses by five, arguing that there is no reason to expect that Portland will file another rate case in less than five years. PSG also claims a five-year average is consistent with Commission precedent that the number of years to be used to calculate an average of regulatory expenses depends on the number of years until the pipeline is expected to make its next rate filing.

13. In the ID, the ALJ approved Portland's proposal to include Regulatory Commission Expenses based on invoices for services performed up to the November 30, 2010 close of the test period, but rejected *sua sponte* costs billed by the TransCanada service company, 9207670 Delaware Inc.¹⁰ Portland reported \$2,378,562 as its three-year average costs; however, the ALJ excluded the TransCanada service company costs from that total. The ALJ also approved Portland's proposal to average costs during the three-year period between December 1, 2007 and November 30, 2010.¹¹

⁹ TransCanada, the majority owner of Portland (61.71 percent), incorporated a second TransCanada service company, 1120436 Alberta Ltd., to charge for services associated with Canadian operations. The Canadian operations are not a factor in calculating Regulatory Commission Expenses, but may affect other accounts.

¹⁰ For the test period, Portland reported \$318,186 in service company costs. Exh. Nos. PNG-245 at 112, PNG-258 at 2.

¹¹ The ALJ found that "it is just and reasonable for [Portland] to calculate its regulatory commission expenses on a three year basis," ID, 137 FERC ¶ 63,018 at P 932, thereby appearing to adopt Portland's 36 month time frame, rather than Trial Staff's proposal to annualize data for the last 11 months of the test period and average with 2008 and 2009 calendar year data.

14. The ALJ rejected PSG's and Trial Staff's claim that that a pipeline's costs may be excluded from Regulatory Expenses if not paid in the test period, finding instead that the determining factor is whether the legal expenses claimed "were incurred during the test period."¹² The ALJ also rejected Trial Staff's argument that the expenses incurred by Portland in November 2010 were only estimates. The ALJ found such expenses were supported by bills and noted that Trial Staff admitted Portland incurred the costs. Accordingly the ALJ held that these proven costs are not estimates because they represent services performed during November 2010 for which Portland had a legal obligation to make payment.

15. The ALJ relied on Opinion No. 486 in approving the use of a three-year average of historic costs.¹³ The ALJ noted that Opinion No. 486, which allowed for use of a three or five year average, adopted a five year average because the pipeline had a history of filing rate cases every five years that was not likely to change. However, in this case, reviewing Portland's filing history, including activities related to the Maritimes/Northeast facilities, the ALJ found that Portland has incurred regulatory expenses, in varying amounts, on a fairly regular basis over the years.¹⁴

16. Although the ALJ supported Portland's proposal to rely on invoices for services that were performed during the test period, the ALJ excluded invoices from the TransCanada service company, 9207670 Delaware, Inc.¹⁵ According to the ALJ, he reviewed the invoices from the service company but remained "unconvinced" the services allegedly performed were valid Regulatory Commission Expenses.¹⁶

¹² ID, 137 FERC ¶ 63,018 at P 929 (characterizing test as whether pipeline proved that "all the legal expense costs it claim[ed] . . . were incurred during the test period;" (quoting *Panhandle Eastern Pipe Line Co.*, 74 FERC ¶ 61,109, at 61,373 (1996) (*Panhandle*)).

¹³ *Kern River Gas Transmission Co.*, Opinion No. 486, 117 FERC ¶ 61,077, at P 278 (2006), *order on reh'g*, Opinion 486-A, 123 FERC ¶ 61,056 (2008), *order on reh'g*, Opinion 486-B, 126 FERC ¶ 61,034, *order on reh'g*, Opinion No. 486-C, 129 FERC ¶ 61,240 (2009), Opinion No. 486-D, 133 FERC ¶ 61,162 (2010), Opinion No. 486-E, 136 FERC ¶ 61,045 (2011).

¹⁴ ID, 137 FERC ¶ 63,018 at P 932.

¹⁵ Such costs totaled \$318,186 in the test period. Exh. No. PNG-245 at 112.

¹⁶ ID, 137 FERC ¶ 63,018 at P 933 (citing costs claimed in Exh. No. PNG-245 at 2-5, 7-10, 12-19, 24-27, 35-36, 41-44, 51-52, 56-59, 65-68, 71-74, 81-84).

Briefs On and Opposing Exceptions

a. Exclusion of Costs Accrued in the Adjustment Period

17. In their briefs the Participants largely reiterate their prior positions. PSG and Trial Staff except to Portland's proposal to count Regulatory Commission Expenses based on invoices that were not billed or were not paid in the test period. PSG advocates amortizing Portland's Regulatory Commission Expenses for the current rate case and the 2008 Rate Filing over five years, instead of the three-year historic averages supported by Trial Staff and Portland. Portland excepts to the exclusion of the TransCanada service company costs.

18. PSG describes the ALJ's calculation as being an average of expenses for three years from December 1, 2007 through the end of the test period. However, PSG objects to the ALJ including roughly \$1 million in costs that it asserts were not "known and measurable" in the test period, claiming that the ALJ should have excluded costs that were invoiced and/or paid outside the test period, or after November 30, 2010. According to PSG, *Panhandle* establishes that the Commission would not accept legal expense "accruals" because the accruals "were only estimates of future expenses and so were not costs that were known and measurable [during the test period] in conformance with . . . 18 C.F.R. § 154.63(e)(2)."¹⁷ According to PSG, Portland seeks to expand the Commission's use of the term "incurred" to include costs that are "accrued" as services are rendered.¹⁸ PSG also contends that all of Portland's calendar year 2007 regulatory expenses should be included in the calculation of its average annual expenses, and that the annual amount should be determined by averaging the total costs for the three-year, eleven-month period from January 2007 through November 2010 over a five-year period.¹⁹

¹⁷ PSG Brief on Exceptions at 90 (citing *Panhandle*, 74 FERC ¶ 61,109 at 61,372-73).

¹⁸ *Id.* at 93 (citing *ad valorem* tax cases indicating that "incurred" means paid in the test period: *Northwest Pipeline Corp.*, 92 FERC ¶ 61,287, at 61,989-90 (2000) (*Northwest*), *Williston Basin Interstate Pipeline Co.*, 76 FERC ¶ 61,066 (1996) (*Williston I*); 79 FERC ¶ 61,311, at 62,389 (1997) (*Williston II*), *remanded by Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, at 57 (D.C. Cir. 1999) (*Williston v. FERC*), 87 FERC ¶ 61,265, at 62,024 (1999) (*Williston Remand*).

¹⁹ PSG Brief on Exceptions at 89-91; Exh. No. PSG-1 at 23.

19. Trial Staff supports the use of a three-year average of Portland's regulatory expenses during the period January 1, 2008 through the November 30, 2010 end of the test period, but seeks to exclude \$968,874 as not paid in the Test Period (following *Panhandle*). In addition, Trial Staff would annualize the 2010 data (dividing the 2010 expenses by 11 and multiplying by 12), and average the 2010 annualized figure with 2008 and 2009 expenses.²⁰ The combined effect of Trial Staff's adjustments is to lower the figure for Regulatory Commission Expenses from Portland's proposed \$2,378,562 to \$1,865,018.²¹

20. PSG and Trial Staff question the ALJ's failure to apply *Panhandle* on the grounds that Portland claimed to have incurred, or accrued, expenses during the test period, despite the fact that these expenses were only invoiced and paid some time later. PSG asserts that *Panhandle* stands for the proposition that no cost may be claimed in the test period, even though a service associated with a future payment is performed in the test period, unless the cost is both "known and measurable" within the test period and becomes effective during the test period. PSG asserts that the latter standard is not met where the pipeline "did not have to pay . . . until after the [test period]."²² Trial Staff also argues that *Panhandle* establishes that a pipeline is entitled to collect only those expenses that were incurred within the test period and known and measurable in the test period.²³

21. PSG also claims the Commission rejected the accrual approach in Opinion No. 510. PSG concludes that the ID should be overruled to disallow accrued amounts for estimated legal and consulting expenses invoiced after the test period and, in particular,

²⁰ Trial Staff Brief on Exceptions at 80 (citing Opinion No. 486, 117 FERC ¶ 61,077 at P 278).

²¹ *Id.* at 79.

²² PSG Brief on Exceptions at 92 (quoting discussion of *ad valorem* tax payments in *Panhandle*, 74 FERC ¶ 61,109 at 61,372).

²³ See Trial Staff Brief on Exceptions at 80-82 (quoting *Panhandle* at 61,373: "accruals are only estimates of future expenses and are not known and measurable in conformance with the Commission's regulations. *Panhandle* has not met its burden of showing that all the legal expense costs it claims here were incurred during the test period. Historically, the Commission has only allowed rates to be set based upon known and measurable costs. *Panhandle's* claimed legal expense costs . . . were not known and measurable during the test period. Therefore, we will only allow *Panhandle* legal expenses based on its actual legal expenses.").

amounts claimed for November 2010 which were neither invoiced nor paid during the test period.²⁴

b. Exclusion of TransCanada Service Company Invoices

22. Portland defends its proposed inclusion of \$2,378,562 in Regulatory Commission Expense. Portland excepts to the ALJ's statement that he remained unconvinced that services performed by the TransCanada service company, 9207670 Delaware, Inc. were valid Regulatory Commission Expenses.²⁵ Portland questions the basis for the exclusion, because the ID only mentioned that 9207670 Delaware, Inc. is a member of the TransCanada family in rejecting its invoices for TransCanada employees' costs.²⁶ Portland states that the exclusion is contrary to existing regulations, which define Regulatory Commission Expenses to include "all expenses . . . properly includible in utility operating expenses, incurred by the utility in connection with formal cases before regulatory commissions"²⁷ According to Portland, such expenses include "salaries, fees, retainers, and expenses of counsel, solicitors, attorneys, accountants, engineers, clerks, attendants, witnesses, and others engaged in the proceeding."²⁸ Portland questions the rulings in the ID to accept expenses for services provided by outside counsel and expert witnesses, while rejecting invoices for services performed by TransCanada personnel. According to Portland, the invoices reflect time that TransCanada employees spent on the rate case, which was separately tracked from other activities, and was not included in the overhead costs accounted for as Outside Services (Account No. 923).

²⁴ PSG also suggests that the Commission disallow certain amounts because the underlying invoices were initially withheld and produced in redacted form as evidentiary issues were resolved. However, as PSG gives no reason to question the underlying costs, we decline to overturn the ALJ's ruling on this issue. ID, 137 FERC ¶ 63,018 at P 931.

²⁵ ID, 137 FERC ¶ 63,018 at P 933; *see also* PP 182, 188, 191, 204 (summarizing Portland witness Sieppert's testimony stating that the affiliated service companies' bills were not itemized to show tasks performed or hours spent on the task, nor were the amounts of the invoices verified, but were instead accepted as developed by the affiliate company, being calculated based on a "redistribution" of salaries and benefits charges based on "salary guideposts," described as "the average market-based salary for the person's role").

²⁶ Portland Brief on Exceptions at 22.

²⁷ *Id.* (citing Uniform System of Accounts, 18 C.F.R. Part 201, Account 928).

²⁸ *Id.* (edits omitted).

23. PSG supports the ALJ's exclusion of expenses allocated for services performed by TransCanada.²⁹ Shippers assert that the claimed costs are unsupported because Portland did not provide any detail on the record as to the specific personnel and other costs incurred by TransCanada in rendering services to Portland. According to PSG, this lack of detail and Portland Witness Sieppert's lack of knowledge or inquiry into the development of the charges means that Portland has failed to support these charges.³⁰ PSG also argues that Portland's lack of detail makes it impossible to ensure that the tasks and charges allocated to Regulatory Commission Expenses were not included in tasks performed under the service agreements.

c. 3 year average versus five-years

24. PSG objects to the use of a three-year average, instead of a five-year average, claiming that Portland is unlikely to file another rate case in the next five years, and thus the three-year average fails to establish a rate that is representative of the regulatory expenses that Portland is likely to incur in the future.³¹ PSG claims the ALJ's ruling produces "an allowance reflecting an extraordinary spike in Portland's regulatory expenses that is not likely to be repeated within three years, if ever."³²

25. PSG also disputes the ALJ's finding that Portland has incurred Regulatory Commission Expenses on a "fairly regular basis over the years," through its own regulatory filings and through its joint ownership agreement with Maritimes/Northeast.³³ PSG claims that this assertion does not support Portland's proposed regulatory expense allowance as representative of the expense to be incurred in the future.

26. Portland contests PSG's five-year average proposal, noting that PSG's own witness contradicted its position when it stated that Portland has "a penchant for filing

²⁹ PSG Brief Opposing Exceptions at 91.

³⁰ *Id.*

³¹ Opinion No. 486, 117 FERC ¶ 61,077 at PP 277-80.

³² PSG Brief on Exceptions at 95.

³³ *Id.* at 96.

frequent rate cases.”³⁴ Portland also claims that *Kern River* is inapplicable because there was no finding that the pipeline regularly incurred Regulatory Commission Expenses.

Commission Determination

27. The Commission reverses the ALJ’s decisions to (a) allow Portland to include regulatory expenses not effective in the test period and (b) exclude expenses supported by invoices from the TransCanada service company, 9207670 Delaware, Inc. In addition, the Commission affirms the ID on the three-year averaging period.

28. The Commission’s regulations require that a pipeline’s rates be based on cost data adjusted to reflect known and measurable changes that become effective within a nine-month period following the base period, which is known as the adjustment period. Section 154.303(a)(4) of the Commission’s regulations requires that the changes a pipeline projects in its filing “become effective within the adjustment period.”

29. Accordingly, it is proper, and in accordance with our regulations, for Portland to include Regulatory Commission Expenses reflected in invoices received during the test period, as known and measurable changes to its reported costs.³⁵ Based on the requirement in section 154.303(a)(4) that cost adjustments must become effective in the test period, we find that Portland may not, however, include amounts that were billed and paid outside of the test period as Regulatory Commission Expenses and reverse the ALJ on this issue.³⁶

30. The Commission-approved methodology for determining a pipeline’s regulatory expenses only looks at historical regulatory expenses during the three years preceding the

³⁴ Portland Opposing Exceptions at 11 (citing Exh. No. PSG-123 at 34); Portland also cites Opinion No. 510, 134 FERC ¶ 61,129 at P 111, which used a three-year averaging period).

³⁵ *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 304 (2002) (*Enbridge*), *order on reh’g*, 102 FERC ¶ 61,310 (2003) (*Enbridge Rehearing*); *see also Williston Remand*, 87 FERC ¶ 61,265 at 62,021-22 (rejecting reliance on estimates that are not effective within the test period).

³⁶ *E.g.*, Exh. No. PNG-245 at 81 (9207670 Delaware, Inc., \$296.11, Dec. 21, 2010), 83 (9207670 Delaware, Inc., \$254,270.80, Dec. 21, 2010), 99 (Brown, Williams, Moorhead & Quinn, \$1350, Dec. 6, 2010), 101 (Concentric, \$2051.14, Dec. 29, 2010) and other amounts that are not effective within the test period.

end of the test period, not estimates of post-test period regulatory expenses.³⁷ The Commission has occasionally permitted the use of post-test period data to establish a pipeline's rates.³⁸ However, in doing so the Commission generally requires that the post-test period data demonstrate that projections based on the test period data will be seriously in error.³⁹ Portland has not shown that failure to consider the outlying invoices would impose a significant effect on the pipeline's rates such that would justify a departure from the Commission's policy and consideration of an out of test period adjustment for Regulatory Commission Expenses.

31. Further, Portland, as the applicant, gets to choose when it makes its NGA section 4 filing. As such, it gets to choose the base period (consisting of actual data) and adjustment period (consisting of known and measureable changes that will become effective within the adjustment period as of the time of filing) that will underlie its case. Base and adjustment periods are fixed time lines of 12 and 9 months respectively, for a total of 21 continuous months. The base period may not end more than four months prior to the time of filing, and the adjustment period must end no later than nine months from the date of filing.⁴⁰ Within these constraints, applicants have to evaluate what costs will be missed and what costs will be included within the 21 month time line when deciding which month file. Portland could have chosen a filing date that would have included these outlying invoices. But it chose not to. Portland must abide by the consequences of the decision it made with regard to its choice of base and adjustment periods.

32. We also approve the use of a three year averaging period. In calculating rates, the Commission allows pipelines to include in their cost of service a projection of their future regulatory expenses. To calculate this projection, the Commission prefers to project future regulatory expenses based on a three-year average of past expenses where possible.⁴¹ The Commission has generally based the projection of future regulatory

³⁷ Opinion No. 510, 134 FERC ¶ 61,129 at P 111.

³⁸ *Williston Remand*, 87 FERC ¶ 61,265 at 62,020-22 (citing *DistriGas of Mass Corp. v. FERC*, 737 F.2d 1208, 1220 (1st Cir. 1984) (*Distrigas*) and *National Fuel Gas Supply Corp.*, 51 FERC ¶ 61,122, at 61,334 & n.53 (1990). *Accord Enbridge Rehearing*, 102 FERC ¶ 61,310 at P 101; *Northwest*, 92 FERC ¶ 61,287 at 61,999-62,200.

³⁹ For Regulatory Commission Expenses, the Commission already relies on a departure from the test period figures in light of the fluctuating nature of such expenses, using the three-year historic average to project future costs.

⁴⁰ 18 C.F.R. 154.303(a) (2012).

⁴¹ *Enbridge*, 100 FERC ¶ 61,260 at P 359.

expenses on an average of the regulatory expenses incurred by the pipeline over the preceding three years, in recognition of the fact that these expenses fluctuate from year to year.⁴²

33. We reject PSG's proposal to project Portland's regulatory Commission expenses by averaging its costs incurred during the three-year, eleven-month period from January 1, 2007 through November 31, 2010 over a five-year period. PSG relies on *Kern River* as supporting its proposal, but we find *Kern River* is distinguishable. In that case, the pipeline concurred that it had a history of only filing rate cases every five years and no plans otherwise for the next five years. In addition, the pipeline did not provide any historical data concerning its Regulatory Commission Expenses before the test period.⁴³ Therefore, in calculating the five-year average, it was not possible to include costs from the entire past five-year period, consistent with the Commission's ordinary practice of using costs from the entire period being used to project average annual expenses. Here, by contrast, Portland has not indicated any intention to wait five years before filing another rate case, and Portland filed three rate cases during the 11-year period from its May 1, 1999 commencement of service to the filing of this rate case, or one every three and two-thirds years. Also, here, unlike in Opinion No. 486, Portland has provided historic data for the full three-year period being used to project average annual regulatory expenses, and the ALJ relied on that data in approving the use of a three year average.⁴⁴

34. The Commission also reverses the ALJ's decision to exclude costs for services performed by TransCanada employees in support of Portland's jurisdictional regulatory activities. Portland witness Sieppert's testimony indicates that he reviewed the invoices supporting these costs to confirm that they represented regulatory expenses for the appropriate time period, and that, while in general he relied on prior oversight by other TransCanada employees, he inquired into individual cost items as necessary.⁴⁵ Because the parties failed to raise a serious question that the TransCanada/9207670 Delaware, Inc. invoices did not represent work performed in connection with formal regulatory proceedings, we reject the finding in the ID that costs billed by TransCanada should be

⁴² *Id.* P 362; *Williston Basin Interstate Pipeline Co.*, 84 FERC ¶ 61,081, at 61,364-66 (1998).

⁴³ Opinion No. 486, 117 FERC ¶ 61,077 at P 277.

⁴⁴ ID, 137 FERC ¶ 63,018 at P 983.

⁴⁵ Tr. 941 (May 5, 2010).

wholly excluded.⁴⁶ In its Compliance Filing, Portland may include expenses for services performed by TransCanada on the same basis as the other Regulatory Commission Expense invoices.

2. Outside Services Employed (Account 923) (Outside Services)

35. Portland claimed \$6,936,438 in Outside Services costs, asserting that amount represents the costs it incurred through its fixed-rate contracts with two TransCanada service companies, 9207670 Delaware Inc. and 1120436 Alberta Ltd. Portland argues that Gaz Metro, Inc. (Gaz Metro), a 38.29 percent owner of Portland, approved the contract costs, and that its partnership agreement prohibited TransCanada from voting on the contracts.⁴⁷ Portland further claimed that the amounts charged under the contracts are lower than those it incurred when its own employees performed the services in 2004, and also lower than the costs it would have incurred had it still had its own employees performing those services.⁴⁸ According to Portland, the Commission had previously approved its arrangement with the TransCanada service companies in Opinion No. 510.⁴⁹

36. PSG and Trial Staff questioned Portland's reliance on Gaz Metro's acquiescence, noting a lack of evidence of arm's length bargaining and a lack of evidence that Gaz Metro reviewed the contracts before their execution. According to PSG and Trial Staff, certain management committee documents indicate that Portland had been directed to enter into the contracts by the management committee without mention of any recusal by TransCanada.

37. PSG and Trial Staff advocate basing Portland's outside services costs on the actual costs incurred to operate Portland's system and not the fixed fees established by its parent companies. They claim that the fixed fees are higher than the actual costs incurred by the

⁴⁶ Uniform System of Accounts, 18 C.F.R. Part 201, Account 928: "This account shall include all expenses (except pay of regular employees only incidentally engaged in such work) properly includible in utility operating expenses, incurred by the utility in connection with formal cases before regulatory commissions . . ."

⁴⁷ In support, Portland cited to Exh. Nos. S-4 at 11, PNG-48 at 8-9, PNG-242 at 2-3. Portland Initial Brief at 21.

⁴⁸ *Id.* at 21-22 (citing Exh. No. PNG-244).

⁴⁹ Opinion No. 510, 134 FERC ¶ 61,129 at PP 93-94.

service companies by some \$700,000.⁵⁰ In addition, both PSG and Trial Staff propose various other adjustments to the TransCanada costs.⁵¹

38. According to Trial Staff, the TransCanada service companies charged Portland \$6,991,144, while TransCanada charged the service companies only \$6,319,186 for the 12 months ending November 30, 2010.⁵² Trial Staff then made certain deductions and a correction to Portland's overhead expense to use the Modified Massachusetts Formula (or MMF) (\$96,971) to obtain what it asserts are the actual cost of the services performed by TransCanada's employees.⁵³

ALJ Decision

39. The ALJ found that Portland's operating costs should be adjusted to reflect its parent corporation's actual costs for operating the affiliated service companies, rather than the contractually determined amounts under the TransCanada service company agreements. The ALJ described Portland's relationship with the TransCanada service companies as follows:

Portland is TransCanada; it is substantially owned and operated by TransCanada, and TransCanada provides it with all of its necessary services. . . . I am convinced that, despite its attempt to shelter itself by use of the two shell corporations, TransCanada effectively is Portland and that

⁵⁰ ID, 137 FERC ¶ 63,018 at PP 901-05 (discussing PSG Initial Brief at 16).

⁵¹ *Id.* P 901 (PSG proposes a total of \$6,152,847 after eliminating charitable contributions, the Commission Annual Charge Adjustment, and Post-Employment Benefits Other than Pensions) and PP 903-05 (Trial Staff proposes a total of \$6,046,029 after eliminating non-recurring costs and the Annual Charge Assessment and correcting Portland's overhead allocation mechanism).

⁵² *Id.* P 905.

⁵³ *Id.* Staff proposed deductions for Post-employment Benefits Other than Pensions (\$40,632), charitable contributions (\$56,161), and Regulatory Commission Expenses that it reclassified to Account 928 (\$79,393).

TransCanada must comply on behalf of Portland with all of the Commission's recordkeeping and accounting requirements.⁵⁴

* * *

When all is said and done, the question presented here is whether Portland's customers should reimburse Portland for fees charged by two fictitious corporations created by its virtually sole parent, TransCanada, when those fictitious corporations have no employees and when all of the services that they have contracted to provide to Portland are sub-contracted to TransCanada. When one considers that these two fictitious corporations profited by about 10% and that, as they are wholly-owned by TransCanada, that profit is really TransCanada's, the question is transformed into whether the Commission can allow TransCanada to profit in this way at the expense of Portland's customers.⁵⁵

40. The ALJ sided with PSG and Trial Staff, finding that, the amount TransCanada charges the service companies, with appropriate adjustments, is the most just and reasonable value for the TransCanada service company services. The ALJ stated that Portland should exclude costs for: (1) Post-employment Benefits Other than Pensions, (2) charitable contributions, (3) reclassifying Regulatory Commission Expenses to Account 928, and (4) overhead expenses exceeding the value calculated under the Modified Massachusetts Formula.

41. The ALJ questioned the validity of the service agreement arrangement, under which Portland is billed by service companies having no employees, while costs are allocated separately to the service companies by the parent company at rates that are different than the fixed fee arrangement governing the costs billed to Portland. The ALJ expressed concern with the shell company arrangement, with TransCanada performing all the work, but the service companies billing Portland at different rates. The ALJ concluded that the service company arrangement permitted TransCanada to artificially profit from the raised rates to the detriment of Portland's customers and rejected Portland's proposal to develop a rate based on what the ALJ considered "excessive costs" paid to the service companies for work performed by TransCanada. The ALJ rejected

⁵⁴ *Id.* P 916.

⁵⁵ *Id.* P 909.

Portland's claim that Gaz Metro authorized the contracts, noting that Portland failed to call a witness representing Gaz Metro to establish that fact.

a. **Approval of Affiliate Transactions under *High Island Offshore System, L.L.C. (HIOS)***

Exceptions

42. Portland defends the contract costs claiming that the fixed rate contracts protect Portland from the risk of cost increases. Portland renews its claim that Gaz Metro's rights under the partnership agreement assure that the contracts were negotiated at arm's length and justify the higher charges. Portland claims that since the Commission's cross-subsidization rulemaking, the "no-profits to affiliates" rule is no longer good law.⁵⁶ Portland relies on a Commission statement in Order No. 707-A, stating that "captive customers are not harmed by the franchised public utility paying above-cost charges if those charges are no higher than what they would pay non-affiliates for the same non-power goods and services."⁵⁷

43. Portland claims that "its operating costs are no higher with the [service agreements] than they would have been had it retained its own employees whose costs reflected trends documented by the Bureau of Labor Statistics, and neither Trial Staff nor

⁵⁶ *Cross-Subsidization Restrictions on Affiliate Transactions*, Order No. 707, FERC Stats. & Regs. ¶ 31,264, *order on reh'g and clarification*, Order No. 707-A, 124 FERC ¶ 61,047 (2008) (Cross-Subsidization rule)

⁵⁷ Order No. 707-A, 124 FERC ¶ 61,047 at P 11. Portland variously argues that the service companies are not "centralized service companies" under the Commission's regulations, because they supply services (to the extent they perform any such services) only to Portland. Portland Brief on Exceptions at 17 n.81, Reply Brief at 17 (arguing that centralized service companies must provide services to "multiple companies" in a holding company, and arguing that the service companies are "like special purpose entities"). Portland further argues that it is exempt from the service company regulations because it is not an LDC and because the Commission has granted it exemptions available to exempt wholesale generators (EWG) and foreign utilities. Brief on Exceptions at 21 (citing exceptions from the PUHCA 2005 regulations granted in Docket Nos. HC09-1-000 and PH06-6-001).

PSG presented evidence indicating that an unaffiliated service provider could provide the same level of services at a lower cost.”⁵⁸

44. Portland claims that the fact that it paid its affiliate for services should suffice for inclusion in rates, claiming that there are substantial benefits of obtaining services from its affiliate in terms of access to experienced personnel, updated capabilities and shift of risk of “cost overruns” to an affiliate under fixed fee arrangement.⁵⁹ Portland acknowledges that it has no employees of its own (and neither do the affiliated service companies, for that matter). Portland argues that in *High Island Offshore System, L.L.C. (HIOS)*, the Commission accepted a fixed fee arrangement finding that the pipeline could not perform the services as efficiently as the service provider and the fee was based on historical cost data.⁶⁰ Portland contends that it submitted data to show that payments to the affiliated service companies would not meet costs in 2012, 2013, 2014 and 2015, and that the costs paid in 2005-10 were less than the cost that Portland incurred performing the services in 2002-04, using its own employees.⁶¹ According to Portland, TransCanada bills the service companies more than Portland pays, and Portland concludes that the affiliated services companies are losing money. Portland notes that no participant demonstrated that a non-affiliate would be able to provide the services at a lower cost or at what price Portland would have paid to obtain such services from a third party.⁶²

45. Portland also excepts to the ALJ’s finding in the ID that the affiliate expenses claimed by Portland were not representative of its costs. Portland claims its Witness Sieppert testified that TransCanada employees performing regulatory work for Portland kept time sheets and tracked the time worked for Portland, which is reflected in TransCanada’s invoices to Portland.⁶³ Portland argues that Trial Staff’s adjustment to its

⁵⁸ Portland Brief on Exceptions at 18 (citing Exh. Nos. PNG-48 (showing that contract costs are lower than 2004 costs adjusted for inflation), PNG-243 (Consumer Price Index) PNG-244 (operating costs history). PNG-348 at 1 (PSG witness Fink stating he did not compare service costs to market); Tr. 3150).

⁵⁹ Portland Brief on Exceptions at 13.

⁶⁰ *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043, at P 50 (2005) (*HIOS*).

⁶¹ Portland Brief on Exceptions at 17 (citing Exh. No. PSG-11 at 14).

⁶² *Id.* at 17-18 (citing Order No. 707-A, 124 FERC ¶ 61,047).

⁶³ *Id.* at 24 (citing Tr. 1006-11).

overhead expense is not needed. According to Portland, if a regulated utility provides a sufficient basis in support of the costs it seeks to include in its cost of service, the Modified Massachusetts Formula need not be applied.⁶⁴

46. Portland also objects to the ALJ's disregard for the fact that the fee arrangement was approved by a non-affiliated parent company, Gaz Metro, at arms length. Portland claims that the management committee authorization to enter into service agreements "on terms materially no less favorable than the services currently being provided" support its claim that the agreements were at arms length.⁶⁵

47. Portland also excepts to the ALJ's rejection of its allocation of corporate overhead costs in favor of Staff's use of the Modified Massachusetts Formula, resulting in a loss of \$96,971. Portland claims that the ALJ failed to discuss why its overhead allocation methodology was rejected. Portland notes that multiple allocation methodologies are acceptable and claims that Trial Staff failed to demonstrate that its own proposal is just and reasonable and that Portland's proposal is unreasonable.

48. Trial Staff opposes Portland's exception, claiming that it is improper, as recognized by the ID, that TransCanada be permitted to profit by performing services for Portland and billing the shell corporations different amounts than it charges Portland. Staff objects to TransCanada creating a service company with no employees to bill for the services, permitting it to collect a profit based on the difference between the amounts billed to the shell corporation and the amounts charged to Portland.⁶⁶

49. PSG and Trial Staff rebut Portland's reliance on *HIOS*, claiming that the fixed fee arrangement was not a "bargain" in light of the fact that fees under the contracts exceed TransCanada's actual costs by a significant amount, and arguing that Portland has not

⁶⁴ See *id.* at 15 (citing *Distrigas of Mass. Corp.*, Opinion No. 291, 41 FERC ¶ 61,205, at 61,554 (1987) (*Distrigas II*) (approving use of gross income in lieu of gross revenues based on finding that parent revenues were not representative of time and money on administration and other overhead activities for subsidiary); *Tennessee Gas Pipeline Co.*, Opinion No. 240, 32 FERC ¶ 61,086, at 61,233 (1985) (*Tennessee*) (acknowledging possibility of deviation from Modified Massachusetts Formula)). The Massachusetts Formula is a Commission-approved administrative and general cost allocator utilizing a combination of net revenues, gross payroll and gross plant.

⁶⁵ Portland Brief on Exceptions at 16.

⁶⁶ Trial Staff Brief Opposing Exceptions at 12, 19. Comparable cost data were not available in the *HIOS* proceeding.

demonstrated that the contract was negotiated at arm's length.⁶⁷ Responding to Portland, PSG and Trial Staff argue that Opinion No. 510 did not address the issues raised in this proceeding, and that the Commission's review in Opinion No. 510 was limited to scheduled fee increases under the contracts.⁶⁸ Trial Staff disputes the claim that any overage is offset by benefits to Portland, noting that Portland has failed to cite any Commission precedent recognizing such benefits and noting the lack of any such exception in the regulations.⁶⁹

50. PSG argues that *HIOS* is further distinguishable because there is no record in this proceeding of any actual negotiation between the non-affiliated partners, as was the case in *HIOS*.⁷⁰ PSG disputes Portland's claim that Gaz Metro's role ensured that the agreements were negotiated at arm's length. PSG claims that instead that, in a July 2004 directive, the Portland Management Committee (including majority owner, TransCanada) directed Portland to contract with the TransCanada service companies, which they did as of August 3, 2004.⁷¹ According to PSG, this directive demonstrates that TransCanada had a substantial role in the execution of the service agreements. PSG concludes that the directive precluded Portland from even seeking competitive bids from other service providers.

51. PSG also disputes Portland's claim that costs under the service agreements are lower when compared to Portland's costs of operating the system itself in 2003. PSG claims that Portland's alleged demonstration shows nothing about what Portland's costs would be following the dissolution of its separate operations. PSG concludes that the only plausibly reliable evidence of costs "actually incurred" in operating Portland is the TransCanada costs allocated to the TransCanada service companies.

52. PSG also defends the MMF methodology as well established Commission policy, and argues that Portland provided no justification for TransCanada's method, which excludes a revenue ratio.⁷² PSG claims that the use of a revenue ratio for allocation of

⁶⁷ Trial Staff Brief Opposing Exceptions at 18-19; PSG Brief Opposing Exceptions at 10 (noting that the issue of affiliate profits was not discussed in *HIOS*).

⁶⁸ Trial Staff Brief Opposing Exceptions at 17.

⁶⁹ *Id.* at 19-20.

⁷⁰ PSG Brief Opposing Exceptions at 10.

⁷¹ *Id.* at 8-10; PSG Initial Brief at 13.

⁷² Exh. No. S-1 at 15-16; Exh. No. S-3 at 9.

indirect overhead costs constitutes a “long-standing policy” of the Commission,⁷³ and claims that Portland has offered no reason to depart from the policy.

53. PSG further objects to Portland’s cost allocation methodology, noting that the service companies are single-purpose entities established to provide services to Portland. As such, PSG argues that the service companies should be directly assigning all costs to Portland. PSG states that, after such direct assignment is finished, the only remaining costs to be allocated should be residual costs, not profits for the parent company.⁷⁴

Commission Determination

54. The Commission affirms the ID on this issue. It is unjust and unreasonable for Portland to include in its rates the amount of outside service costs billed to it by the affiliated service companies in excess of those companies costs, when TransCanada actually performed those services and billed the service companies a lesser amount. We also agree with the ALJ’s finding that Portland failed to establish arm’s length bargaining. Finally, Portland’s comparison of 2010 expenses to 2003 costs fails to provide a meaningful comparison of costs to demonstrate that the costs are just and reasonable.⁷⁵

55. We affirm these findings and reject Portland’s arguments to the contrary, as discussed below. Portland should calculate its Outside Service Expense consistent with the ALJ’s findings. In addition, we reject Portland’s attempt to avoid application of the Modified Massachusetts Formula (MMF) to allocate overhead costs. As PSG notes, the Modified Massachusetts methodology is well established and comports with Commission policy and practice, which requires the use of net revenue, plant and labor ratios for

⁷³ *Distrigas II*, 41 FERC ¶ 61,205 at 61,557 (referencing the Commission’s “long-standing policy to use gross revenues for allocation of the indirect expenses” of a parent company); *see also, Tennessee*, 32 FERC ¶ 61,086 at 61,232-33 (rejecting proposal to use allocation based solely on plant and labor components and stating that arguments supporting exclusion of revenue component had been “laid to rest” in *Midwestern Gas Transmission Co.*, 32 FPC 1012, 1022-25 (1964); *aff’d in pertinent part* 32 FPC 993, 995 (1964)).

⁷⁴ PSG Brief Opposing Exceptions at 14.

⁷⁵ Tr. 837, 840 (ALJ finding Portland’s cost comparison to be “worthless for our purposes because there’s no accurate reflection of anything ... you can’t draw any conclusions based on those figures”).

overhead allocation purposes.⁷⁶ Portland cites the *Distrigas II* opinion, where the Commission approved a deviation from the Massachusetts Formula because one of the allocation factors, gross revenue, was not representative of the type of administrative activities to be performed for the subsidiary. Instead, in *Distrigas II* which predates *Williston II*, the revenue factor was skewed towards non-jurisdictional gas purchase activities. Even in that event, the alternate allocation methodology included a third factor to account for monies coming into the company, substituting net income for gross revenue. Portland fails to explain why the issue of gross revenues vs. net revenues is pertinent in this discussion, as in either case the methodologies allocate overhead costs to the subsidiaries or affiliates. The ID rejected Portland's proposed method to identify overhead costs using a non-standard allocation method, and adopted the MMF as consistent with Commission policy. Portland provides no reason why the MMF methodology is not appropriate for its circumstances and provides no justification for allocating an overhead allocation methodology that excludes a revenue ratio.

56. Portland essentially presents three reasons why the Commission should accept its proposal: (1) that Gaz Metro's approval rights ensured that the contract rates were fair to Portland, (2) that affiliate transactions are not a concern as Portland is not subject to cross-subsidization rules, which superseded the Commission's rate precedent, and (3) the contracts insulated Portland from cost increases, as shown by the comparison to Portland's 2003 costs. As discussed below, we reject these claims.

57. We agree with the ALJ that Portland failed to show that the existence of Gaz Metro's affiliate transaction approval rights demonstrated that the rate under the contracts was just and reasonable.⁷⁷ In *HIOS*, the Commission reviewed affiliate contracts between the pipeline and a parent owning 50 percent of the pipeline, GulfTerra Operating Co. (GTOC). The Commission noted that the other 50 percent owner, ANR Pipeline Co. (ANR), would have an incentive to keep rates and underlying cost structure at a competitive level because fifty percent of the money paid to GTOC would come out of ANR's pocket. Also, because a portion of the gas flowing through HIOS also flowed

⁷⁶ *Williston Interstate Pipeline Co.*, 95 FERC ¶ 63,008 (2001) (*Williston III*), *aff'd in relevant part*, 104 FERC ¶ 61,036, at PP 70-77 (2003) (justifying modification of gross revenue ratio to a net revenue ratio), *order on reh'g*, 107 FERC ¶ 61,164 (2004) (*Williston IV*); *see also*, *Distrigas II*, 41 FERC ¶ 61,205 at 61,555-57 (likewise employing revenue, plant and labor components); Exh. No. S-1 at 13-16. The allocation formula is used for indirect overhead costs that are incurred by and charged from parent companies and/or service companies to subsidiaries and affiliates.

⁷⁷ ID, 137 FERC ¶ 63,018 at P 182.

through ANR's system, ANR had an incentive to keep HIOS' rates and underlying cost structure at a competitive level.⁷⁸ Thus, in addition to the parity of bargaining power among the co-owners, the record in *HIOS* demonstrated that the co-owner had a financial stake in the operations of the subsidiary that is lacking here, where Portland failed to demonstrate that Gaz Metro took an active role in the operations of the pipeline.⁷⁹ Furthermore, Portland's position is belied by the Portland management committee's directive to Portland to enter into the contract.⁸⁰

58. Based on that arrangement, the Commission in *HIOS* found that a ten percent premium charge for non-routine operating services was based on the actual costs of providing the non-routine service, and thus concluded the fee is not a cost-plus arrangement whereby GTOC earns a profit by providing a service. However, in this proceeding, the ALJ found that the amounts TransCanada earned over its billings to the service companies turned a profit of 10 percent.⁸¹ The Commission rejects Portland's claim that Order No. 707 extinguished the affiliate contract policies developed in the rate context. The cross-subsidization rules are intended to prohibit in advance certain conduct by market participants. In Order No. 707, the Commission acknowledged its "long history of scrutinizing affiliate transactions for potential cross-subsidization" and thereafter explained its effort in that rulemaking to expand certain restrictions developed in the market-based rate and merger contexts to all utilities.⁸² The Commission's expansion of the restrictions developed in the market-based rate and merger contexts in Order No. 707, however, did not abrogate or diminish the Commission's long standing policies regarding scrutiny of affiliate transactions in the rate-making context.⁸³ Assuming that Portland's claim that TransCanada and the TransCanada service

⁷⁸ *HIOS*, 110 FERC ¶ 61,043.

⁷⁹ In addition, Gaz Metro, Quebec's primary gas distributor, doesn't operate an interconnected pipeline with gas flowing through Portland. Gaz Metro also owns the gas distribution system in Western Vermont, as well as Vermont's electric utilities Central Vermont Public Service and Green Mountain Power.

⁸⁰ Even Portland's rejoinder that this approval was to be under "terms no less favorable to Portland" than prior to the service company agreements cannot be relied upon, given Portland's failure to deliver comparative cost data.

⁸¹ *Id.*, 137 FERC ¶ 63,018 at P 909.

⁸² Order No. 707, FERC Stats. & Regs. ¶ 31,264 at P 3.

⁸³ *Id.* P 2: "the restrictions in this rule will supplement existing restrictions."

companies are not subject to Order No. 707 is valid, this does not mean that Portland is immunized from application of the Commission's concern with affiliate transactions in the rate context.

59. Based on this record, we find that the Participants in the hearing have raised a significant concern with respect to Portland's relation to its parent TransCanada, the affiliated TransCanada service companies and the affiliated transactions. Portland failed to demonstrate that its costs were justified based on historic outlays, on the basis of market data or on the basis that the transactions were truly negotiated at arms length. Some lowering of relative costs may be anticipated following TransCanada's business decision to dissolve Portland's independent operations, but due a dearth of record data, it is impossible to determine whether such is the case, or as Portland surmises, whether Portland's activities would have continued to cost it more following TransCanada's consolidation of operations after 2004. Accordingly, Portland has not shown its claimed costs are just and reasonable and an alternative cost allocation methodology must be employed.

b. Portland's Adherence to Commission Accounting Requirements

60. The ID concluded that Portland is required to maintain sufficiently detailed records, even though the records duplicate those maintained by TransCanada, for the Commission to be able to make the determinations required of it by the Natural Gas Act.⁸⁴ The ID cites *Highlands v. Nantahala Power & Light Co.*, 37 FERC ¶ 61,149, at 61,356 (1986) (*Nantahala*):

Treating Nantahala and its parent, Alcoa, as one entity in this proceeding is not the result of "piercing the corporate veil" in the common law sense. It is not necessary in this case for us to determine whether such a strategy is appropriate or whether the tests for doing so could be met. Our decision on this issue relies instead on the broad authority of an agency to look beyond a subsidiary to its owner to achieve the agency's statutory mandate and to assure that statutory purposes are not frustrated.

⁸⁴ ID, 137 FERC ¶ 63,018 at P 917.

Exceptions

61. Portland excepts to the ID's allegedly imposing a change in accounting practices performed by its parent company, in order to provide data for Portland's operations under the Commission's policies.⁸⁵ The ID stated that "TransCanada must comply on behalf of [Portland] with all of the Commission's recordkeeping and accounting practices," and that Portland "is required to maintain sufficiently detailed records, even though they be duplicates of those maintained by TransCanada[.]" Portland asks the Commission to find that Portland produced sufficiently detailed information of costs that the service companies incurred on behalf of Portland and that TransCanada is not required to modify its accounting practices.⁸⁶

62. Portland claims that it provided sufficiently detailed cost information under the Commission's policies, noting that Opinion No. 510 relied on those accounting practices and approved the fixed fee arrangement.⁸⁷ Portland objects to the ALJ's statements to the extent that the ID's holding would require TransCanada to modify its accounting practices. Portland states that modification of its accounting practices will result in cost increases.

63. According to Portland, its accounting practices provide sufficiently detailed information regarding costs incurred by the affiliated services companies on behalf of Portland. Portland concludes that, if the Commission's holding company and centralized service company regulations apply to TransCanada, Portland's practices are consistent with the requirement that service companies keep books of account with entries supported by "sufficient detailed information that will permit ready identification, analysis and verification of all facts relevant and related to the records."⁸⁸ Portland also claims it is exempt from the PUHCA 2005 regulations, as granted in Docket Nos. HC09-1-000 and PH06-6-001.⁸⁹ Portland disputes the ALJ's reliance on the

⁸⁵ Portland Brief on Exceptions at 18.

⁸⁶ *Id.* at 21.

⁸⁷ *Id.* at 19.

⁸⁸ *Id.* at 19-20 (citing section 367.3(a) of the Commission's Regulations for USofA for PUCHA 2005 service companies).

⁸⁹ *See* TransCanada, Holding Company Status Notification, Docket Nos. HC09-1-000 and PH06-6-001 (Dec. 3, 2008) (citing automatic exemptions from the books and records requirements of 18 C.F.R. § 366.2 and record retention, accounting and filing requirements of 18 C.F.R. §§ 366.21, 366.22 and 366.23 for TransCanada and its

Highlands/Nantahala case as not requiring a company with jurisdictional and non-jurisdictional segments to change accounting practices applicable to all business segments.⁹⁰

64. At the same time, Portland acknowledges that the ID did not require TransCanada to revamp its accounting procedures to provide data for its Commission-jurisdictional pipeline, but stated that Portland must maintain sufficiently detailed records in compliance with the Commission's regulations, and further acknowledged that such records "could be duplicates of those maintained by TransCanada."⁹¹

Commission Determination

65. As a jurisdictional natural gas company, Portland is required to maintain records sufficient to meet the Commission's accounting regulations and to provide cost support for its rate filings. Thus, the ID did not impose any additional obligation on Portland. As TransCanada executives all work for Portland, TransCanada must undertake the obligation to produce cost support necessary for Portland to defend its rate proposals in Commission proceedings. The Commission does not anticipate that this will require TransCanada to revise its accounting practices applicable to all business segments, nor does the record suggest that more is needed than time and salary accounting as has been demanded of jurisdictional natural gas companies since the Commission began to preside over natural gas company rates.⁹² However, TransCanada must provide documentation to Portland sufficient for Portland to meet its regulatory obligations and provide adequate cost support.

3. Pipeline Integrity Projects/Maintenance of Mains

66. In its hearing exhibits, Portland sought to recover \$790,806 in Pipeline Integrity Program/Maintenance of Mains (Acct. 863) (Pipeline Integrity Project or PIP) expenses,

Qualifying Facility (QF), Exempt Wholesale Generator (EWG) and Foreign Utility Company (FUCO) subsidiaries, including 701671 Alberta Ltd.). The filing did not mention Portland or 9207670 Delaware, Inc.

⁹⁰ Portland Brief on Exceptions at 21.

⁹¹ ID, 137 FERC ¶ 63,018 at P 917 ("Portland is required to maintain sufficiently detailed records . . . for the Commission to be able to make the determinations required of it by the Natural Gas Act").

⁹² *E.g., Connecticut Light and Power Co.*, 2 FPC 853 (1944).

based on an average of the Pipeline Integrity Project expenses for 2009 and 2010 with projected costs for 2011 through 2015.⁹³ Portland defended its proposal to use projected costs, claiming that costs increase over time and asserting that it based its projections on the services that a pipeline is required to perform under the Department of Transportation regulations.⁹⁴ In addition, Portland noted that Opinion No. 510 relied on projected amounts.

67. Both Trial Staff and PSG opposed Portland's proposal. Trial Staff proposed to average five years of historic calendar year data for 2004 through 2009 with test period data for the last eleven months of the test year consisting of data from January 1 through November 30, 2010. To obtain a full year cost figure from the data for the last 11 months of the test period, Trial Staff proposed an annualized cost of \$289,654 for Portland's Pipeline Integrity costs.⁹⁵ PSG supported using either Portland's \$532,556 in Pipeline Integrity Project expenses during the last twelve months of the test period ending November 30, 2010,⁹⁶ or a seven year average amount, similar to Trial Staff's proposal.⁹⁷

68. In the ID, the ALJ adopted the \$532,556 in test period expenses advocated by PSG and rejected Portland's and Trial Staff's proposals as not representative of Portland's test period costs and inconsistent with the Commission's test period regulations.⁹⁸

⁹³ ID, 137 FERC ¶ 63,018 at P 873; Exh. Nos. PNG-93 at 7-8; PNG-99. According to Portland, the 2009-10 period aligns closely with the base and test periods in this proceeding. Portland Initial Brief at 14; *see also* Exh. Nos. PNG-48 and PNG-99; Tr. 780, 784.

⁹⁴ ID, 137 FERC ¶ 63,018 at P 874; Exh. No. PSG-9 at 2; Tr. 786, 976-78.

⁹⁵ Trial Staff Witness Miller's testimony, Exh. No. S-1 at 8; Tr. 3114; *see also* Exh. No. S-24 at 16.

⁹⁶ Exh. No. PSG-1 at 17 (PSG Witness Fink testimony).

⁹⁷ ID, 137 FERC ¶ 63,018 at P 881. PSG substitutes the 2010 actual expense for Trial Staff's annualized test period figure in the seven year average and proposes \$299,759.

⁹⁸ *Id.* P 896.

Exceptions

69. Portland excepts to the ID, claiming that the ALJ did not account for the increasing costs it projects that it will experience over the program's seven year cycle. Portland claims that Opinion No. 510 adopted a Commission policy to establish a representative level of costs by incorporating projections of future costs.⁹⁹

70. Trial Staff excepts to the ID's rejection of its proposal to annualize Portland's expenses for the last eleven months in the test year and average the resulting expense with its historical costs during the period 2004 through 2009.¹⁰⁰ Trial Staff argues that Portland's test year PIP costs of \$532,556 are not representative of future costs, because Portland's costs have continued to fluctuate and this total is significantly higher than all but one year (2008) of Portland's recent annual PIP costs. In addition, Trial Staff notes that Portland's PIP costs have declined since Portland made its filing.¹⁰¹ Trial Staff agrees with the ID that Portland's projections of PIP expense for the three years following the test period are overestimated and cannot support a just and reasonable multi-year average. To calculate such a multi-year average, Trial Staff proposes a seven-year average, based on the requirement that a pipeline implement its PIP duties once every seven years.

Commission Determination

71. The Commission affirms the ID. In the ID, the ALJ approved \$532,556 in Pipeline Integrity Project test period expenses as just and reasonable, finding that figure to be supported by the preponderance of the evidence and consistent with the Commission's discussion in Opinion No. 510. Opinion No. 510 described the Commission's test period regulations as follows:

The Commission's regulations require that a pipeline justify any proposed rate increases 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," 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

⁹⁹ Portland Brief on Exceptions at 9.

¹⁰⁰ Trial Staff Brief on Exceptions at 73.

¹⁰¹ *Id.* at 75.

changes, including costs, which are “known and measurable” and “which will become effective within the adjustment period.”¹⁰²

72. In the absence of an agreement to make an adjustment similar to that approved in Opinion No. 510, the Presiding Judge rejected Portland’s reliance on projected costs as inconsistent with the Commission’s test period regulations. The Presiding Judge noted that the projected data were inconsistent with the test period data and that Portland’s past projections had previously overestimated PIP costs.¹⁰³

73. The ALJ in this proceeding also rejected the adjustments based on historic data advocated by PSG and Trial Staff. The ALJ found that the historic data was inconsistent with the test period data, and that the resulting calculations of approximately \$290,000 were not just and reasonable because that figure is far out of line with the \$532,556 that Portland actually expended during the base and test period. According to the ALJ, the historic data on which Trial Staff and PSG seek to rely incorporates cost data from the inception of Portland’s Pipeline Integrity project that is not representative of Portland’s costs going forward because the initial costs were lower than those incurred once the program was up and running and that Pipeline Integrity Project costs tend to increase over time.¹⁰⁴

74. As found by the ALJ, the record indicates that Trial Staff’s historic data and Portland’s projected costs did not reliably project costs going forward. Thus, in the absence of any agreed upon proposal by the parties to recognize costs from another period, we find that test period costs approved in the ID are just and reasonable and consistent with our regulations and Opinion No. 510.

¹⁰² Opinion No. 510, 134 FERC ¶ 61,129 at P 85 (citing 18 C.F.R. §154.303(a)(1) and (a)(4)) (note omitted).

¹⁰³ ID, 137 FERC ¶ 63,018 at P 891 (citing Opinion No. 510, 134 FERC ¶ 61,129 at PP 84, 87 (approving \$397,682 Pipeline Integrity Project costs, based on \$818,727 test period costs averaged with lower, projected figures for future time periods), *order on rehearing*, Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 40 (approving revised Pipeline Integrity Project costs of \$422,169)).

¹⁰⁴ ID, 137 FERC ¶ 63,018 at P 893 (citing \$714 in costs incurred in 2004 as not representative of future costs).

B. Ad Valorem Tax

75. In its 45-Day Update filing, Portland claimed that it incurred \$6,574,793 in *ad valorem* tax expense for the twelve months ending November 30, 2010.¹⁰⁵ Portland calculated this figure by totaling all of the tax assessments that were available at the time it made its filing and attributing a *pro rata* portion of the taxes due within the test period to each month.¹⁰⁶ After Portland filed its 45-Day Update on December 23, 2010, Portland filed a subsequent update to reflect all of the tax assessments that it had received during the year.¹⁰⁷ Portland adjusted its *ad valorem* tax calculation to incorporate certain tax assessments that were received during the test period but not reflected in the 45-Day Update filing.¹⁰⁸ The ID set Portland's *ad valorem* tax expense at \$6,640,383, finding that Portland included all of the assessments it claimed during the test year.¹⁰⁹ In doing so, the ALJ approved the later-filed adjustments to reflect all of the tax assessments that it received during the test year as recoverable expenses.

Exceptions

76. PSG objects to the *ad valorem* tax determination, claiming that it includes costs that were not known and measurable and/or did not become effective before the end of the test period. PSG asserts that the costs were either not invoiced and due or not paid for prior to the end of the test period and object to the ALJ's accrual justification.¹¹⁰ According to PSG, Opinion No. 510 and other Commission precedent require that

¹⁰⁵ See Exh. Nos. PNG-93 at 11 (Sieppert rebuttal test.), PNG-95, 45 Day Update filing at 62, Schedule H-4 (showing *ad valorem* tax accruals).

¹⁰⁶ Thus, Portland's costs are calculated on an accrual basis. Exh. No. PNG-93 at 13 (Sieppert rebuttal).

¹⁰⁷ Portland filed the 45-Day Update filing early to accommodate the procedural schedule.

¹⁰⁸ See Exh. No. PNG-97 at 7 (Gilead, Me. dated Nov. 23, 2010), 23 (Columbia, N.H. dated Nov. 15, 2010), 28 (Northumberland, N.H. payable Dec. 17, 2010), 31 (Stark, N.H. payable Dec. 2, 2010), 34 (State of New Hampshire dated Dec. 15, 2009).

¹⁰⁹ ID, 137 FERC ¶ 63,018 at PP 940-41 (citing Exh. Nos. PNG-93 at 15, PNG-97, PNG-98).

¹¹⁰ PSG Brief on Exceptions at 87 (citing *Williston I*, 76 FERC ¶ 61,066 at 61,384; *Panhandle*, 74 FERC ¶ 61,109 at 61,372).

adjustments to *ad valorem* tax costs be effective and paid during the test period in order to be reflected in rates.¹¹¹

77. PSG contests \$65,590 in Portland's updated expense figure as not known and measurable and/or not effective before November 30, 2010, the end of the adjustment period.¹¹² PSG seeks to exclude costs related to a November 16, 2010 tax bill from Northumberland, NH which was not paid by November 30, 2010 and was not due until thereafter. PSG also objects to a December 15, 2009 tax bill from the State of New Hampshire. PSG claims that the tax bill itself provides no support for an upwards adjustment, because, according to PSG, it should already have been included in the 45-day update expense figures if it had been paid.¹¹³

78. PSG notes that the three of the remaining tax assessments supporting the adjustment were actually decreases. PSG advocates retaining the downward adjustment for two invoices that were paid in the test period, though they were not due until thereafter, and a third which was due in the test period, but not paid until thereafter. PSG seeks an additional \$17,487 downward adjustment for amounts that were due or paid in the test period and propose that Portland's *ad valorem* tax be reduced overall from \$6,640,383 to \$6,557,306.

79. Portland supports the disputed tax amount, despite the fact that it was not paid in the test period, claiming that the case law focuses on when relevant costs were incurred and became effective, not when the amounts were paid. Portland disputes PSG's characterization of the December 15, 2009 bill, claiming that record evidence shows that, \$49,293 of the total \$817,748 assessment was not reflected in the 45-day update filing.¹¹⁴

¹¹¹ *Id.* at 87-88; Opinion No. 510, 134 FERC ¶ 61,129 at P 100; *Williston I*, 76 FERC ¶ 61,066 at 61,384, *aff'd*, *Williston Remand*, 87 FERC ¶ 61,265 at 62,024 (phase-in of higher *ad valorem* tax assessment during test period permitted cost adjustment based on assessment); *Panhandle*, 74 FERC ¶ 61,109 at 61,372; *Northwest*, 92 FERC ¶ 61,287 at 61,989; *Enbridge*, 100 FERC ¶ 61,260 at P 306 ("issuance of tax bills during the test period created an obligation to make the tax payments in the amount claimed ... and payment commenced during the test period with the payment of the first installment").

¹¹² PSG Brief on Exceptions at 86-88; ID, 137 FERC ¶ 63,018 at P 941.

¹¹³ *Id.* at 87 & n.219 (citing lack of indication in Exh. No. PNG-98 of payment of the increased *ad valorem* taxes claimed in Exh. No. PNG-97).

¹¹⁴ Portland Brief Opposing Exceptions at 12 (citing Exh. No. PNG-97, line 30).

Portland supports the \$65,590 adjustment as supported by the tax assessments received by Portland during the test period. Portland questions whether PSG applies a consistent methodology, given that they would count downward adjustments received in the test period, but not offsetting upward adjustments.

Commission Determination

80. The Commission affirms the ID. As noted by both Portland and PSG, section 154.303(a)(4) of the Commission's regulations states that costs established during the base period "may be adjusted" for changes in costs which are "known and measurable ... and ... which will become effective" during the Test Period.¹¹⁵ Although the Commission generally prefers the use of "actual test period *ad valorem* tax payments,"¹¹⁶ it has also permitted a pipeline to update its test year expense using revised tax allocations that were received in the test period.¹¹⁷ In *Enbridge*, the Commission accepted a calculation for *ad valorem* tax expense that included updated tax assessments that were received during the test period, but paid in installments, with half of the tax paid outside of the test period. The Commission's goal is to determine the amount of tax that is likely to be representative of costs incurred during the period that the rates are in effect. Consequently, the updated tax allocations represent the better projection of costs going forward.

81. Although Portland acknowledges that the revised amounts were not paid in the test period, the fact remains that the up-to-date assessments provide the most current projection of costs going forward. PSG failed to support through testimony or discovery

¹¹⁵ In Opinion No. 510, 134 FERC ¶ 61,129 at P 100, the Commission accepted amounts that reflected "actual *ad valorem* taxes that [Portland] was billed, and that it paid, during ... the test period" as in compliance with these regulations.

¹¹⁶ *Williston Remand*, 87 FERC ¶ 61,265 at 62,024, *aff'g*, *Williston I*, 76 FERC ¶ 61,066 at 61,384 ("the actual costs for any expense or tax during the test period generally reflects the best evidence of what the company can expect to incur in the future"). *See also Northwest*, 92 FERC ¶ 61,287 at 61,990 (noting that Commission made clear that pipeline is to include amounts for *ad valorem* taxes that have "actually been paid" during the test period, but noting that it would consider whether to accept calculation based on assessments at a later date).

¹¹⁷ *Enbridge*, 100 FERC ¶ 61,260 at P 304.

their assertion that the delay in updating the schedule of tax assessments demonstrates that a portion of the tax may not have been paid.¹¹⁸

C. Rate Base – Pre-paid Tax in Working Capital

82. Portland proposed to count \$373,936 in working capital, which it claims is its actual average balance during the test period, as prepaid tax expense.¹¹⁹ Portland objected to PSG's proposal to exclude the entire proposed Prepaid Taxes from working capital allowance and defended its proposal as being supported by record data.¹²⁰

83. Portland described its recordkeeping methodology as follows:

Portland maintains continuously updated records of the amount of taxes paid that apply to periods of time which have not yet come to pass (*i.e.*, prepaid taxes). For example, if Portland were to receive a tax assessment of \$120,000 for one calendar year due in March of that year, as of the end of March, Portland would have paid \$120,000 for the entire calendar year, but \$90,000 of that amount would be reflected as Prepaid Taxes for the 9 months that have yet to pass. This amount would be drawn down to \$0 by the end of the year. Accruals would have been booked for January through March and subtracted from the total tax bill to reflect the remaining amount that is prepaid as of the end of March.¹²¹

84. PSG objected to the proposed prepaid tax calculation methodology as inconsistent with the Commission's regulations.¹²² It disputed whether the calculation identified

¹¹⁸ In particular, PSG question the New Hampshire state tax assessment, which was issued in December 2009, but only added to the schedule of tax payments in the March 2011 supplemental update.

¹¹⁹ ID, 137 FERC ¶ 63,018 at P 962; Portland Initial Brief at 67.

¹²⁰ Portland Initial Brief at 67-68 (citing Exh. Nos. PSG-1 at 11, 14, PSG-2 at 5-6).

¹²¹ ID, 137 FERC ¶ 63,018 at P 963 (citing Portland Reply Brief at 55-56).

¹²² PSG Initial Brief at 41-42 (citing 18 C.F.R. Pt. 201 (2010)).

See Part 201, General Instruction No. 2(B) (Accounting on an Accrual Basis): When payments are made in advance for items such as insurance, rents, taxes or interest, the

(continued...)

actual tax payments, rather than “estimates of [Portland’s] *ad valorem* tax expense.”¹²³ PSG acknowledged that Portland maintains a cumulative monthly accrual account for the tax payments having terms extending in the future, but disputed whether these were prepayments of taxes.

85. The ALJ dismissed PSG’s objections as “specious.”¹²⁴ The ALJ found that the evidence supported Portland’s average monthly balance for the 13 months ending November 2010, or \$373,936, as Portland’s working capital allowance for inclusion in rate base.¹²⁵

Exceptions

86. PSG excepts to the ID’s approval of Portland’s proposal to include prepaid tax expenses resulting from accounting treatments as counter to Commission policy. According to PSG, Portland should limit Account 165 prepaid tax expense to tax prepayments due in and paid prior to the test period to which they applied.¹²⁶ PSG asserts that Portland has failed to establish that amounts charged to Account 165 represent tax prepayments required by the taxing jurisdiction, for tax due within the test period and made prior to the period in which they apply, as opposed to tax due in a prior period or voluntary pre-payments, which should be excluded.

amount applicable to future periods shall be charged to account 165, Prepayments, and spread over the periods to which applicable by credits to account 165, and charges to the accounts appropriate for the expenditure.

Account 165 (para. A) (Prepayments): This account shall include payments for undelivered gas and other prepayments of rents, taxes, insurance, interest, and like disbursements made prior to the period to which they apply.

¹²³ PSG Initial Brief at 42.

¹²⁴ ID, 137 FERC ¶ 63,018 at P 966.

¹²⁵ *Id.*

¹²⁶ PSG Brief on Exceptions at 83-85.

87. PSG objects to Portland's practice to accrue a certain amount each month as *ad valorem* tax expense, based on past obligations, and count any actual payments that exceed the amount accrued as a prepayment.¹²⁷

88. PSG objects that Portland's methodology is the result of Portland's decision to have under-accrued its tax expense instead of being based on a requirement to "prepay" for a future period. According to PSG, the Commission's tax pre-payment policies permit recording only of prepayments of taxes due prior to the period to which they apply, *not* amounts which a pipeline decides to accrue prior to the date tax expenses are recorded.¹²⁸

89. PSG also disputes Portland's detailed evidence supporting its Prepaid Taxes, claiming it does not contain *ad valorem* tax bills confirming prepayment requirements occurring in November 2009, or otherwise identify the taxing jurisdictions which received the purported tax prepayments.¹²⁹ PSG further claims that Portland failed to modify its methodology to exclude taxes paid prior to their due date, as approved in Opinion No. 510, claiming that the record contains 22 invoices for payments of tax obligations not due until after the end of the test period.¹³⁰ PSG concludes that Portland failed to prove by a preponderance of the evidence that the amounts recorded in its Account 165 reflect required tax prepayments, due within the test period, and made prior to the period to which they apply. Consequently, PSG requests the Commission to exclude Portland's claimed \$373,936 prepaid tax expenses from its Working Capital Allowance.

90. Portland defends its tax prepayments as adequately supported. Portland notes that it regularly updates its records of prepaid taxes and properly reflects payments of taxes made prior to the period to which they apply as prepaid tax.

91. Portland disputes PSG's identification of payments made before they were due, stating that it followed a routine business practice and is not required to wait until the last

¹²⁷ *Id.* at 83.

¹²⁸ PSG Brief on Exceptions at 84.

¹²⁹ Citing Exh. Nos. PNG-93 at 6, PNG-97 and PNG-98.

¹³⁰ PSG Brief on Exceptions at 85 (citing tax bills and payments from Exh. Nos. PNG-97 and PNG-98).

minute.¹³¹ Portland concludes that the preponderance of the evidence supports including the Prepaid Tax amount of \$373,936 in rate base as Portland's working capital allowance as determined in the ID and supported by Trial Staff.¹³²

Commission Determination

92. The Commission affirms the ID. In Opinion No. 510, the Commission reviewed Portland's support for its prepaid taxes amount to be included in its working capital allowance and found it adequately supported.¹³³ The Commission reviewed Portland's cost support consisting of a detailed listing of all prepaid taxes paid in the relevant time period, together with supporting documentation to show the prepayment requirement. The Commission described the materials as consisting of copious amounts of record evidence detailing the tax amounts and their due dates and the dates that Portland paid such taxes. Based on this showing, the Commission concluded that PSG's proposal to disallow all of Portland's proposed prepaid tax amounts would be unjust as Portland had clearly presented record evidence of properly included prepayments and PSG had not identified questionable invoices on exceptions.¹³⁴

93. We approve Portland's pre-paid tax expense on the same basis as in Opinion No. 510. The record here indicates that the claimed costs represent tax payments Portland made within the test period for taxes that apply to a term extending beyond the test period.

¹³¹ Portland Brief Opposing Exceptions at 23. Portland cites Exh. No. PNG-97 at 17 as reflecting a discount taken for early payment.

¹³² ID, 137 FERC ¶ 63,018 at PP 965-66.

¹³³ Opinion No. 510, 134 FERC ¶ 61,129 at P 155.

¹³⁴ Portland had previously agreed to adjust its originally proposed amount downward in response to PSG dispute of payments made outside of the test period.

IV. Levelized Rate Structure

Rate Base Calculations for use in the Levelized Process

Background

94. As noted above, on October 1, 2001, Portland filed a NGA section 4 rate filing as required by previous certificate orders on its system.¹³⁵ The Commission accepted and suspended the filing to be effective April 1, 2002, subject to refund.¹³⁶ Subsequently, on October 25, 2002, in Docket No. RP02-13-000, Portland filed an uncontested Stipulation and Settlement Agreement to resolve all issues in that docket (2002 Settlement).¹³⁷ The 2002 Settlement established a firm transportation (FT) maximum recourse rate effective April 1, 2002,¹³⁸ and stated that the Settlement Base Tariff Rates were “designed using rate levelization through March 31, 2020.”¹³⁹ The following provisions were included in the 2002 Settlement, Article III, section 3.1:

(a) The Settlement Base Tariff Rates are designed using rate levelization through March 31, 2020, as reflected in Appendix D (Levelization Schedule). *The levelization methodology used by [Portland] is the same as that approved in [Portland’s] certificate orders*, except that the remaining levelization period has been extended by approximately one year (to reflect the full period covered by all of [Portland’s] existing Long-term FT Contracts) and the cost-of-service has been modified consistent with Section 3.4 below.

(b) [Portland] shall continue to propose to design its FT rates

¹³⁵ See 1996 Certificate Order, 76 FERC ¶ 61,123 (1996); July 1997 Certificate Order, 80 FERC ¶ 61,134; September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345.

¹³⁶ *Portland Natural Gas Transmission System*, 97 FERC ¶ 61,131 (2001) (2001 Hearing Order), *settlement accepted*, 102 FERC ¶ 61,026 (2003) (letter order) (2002 Settlement Order).

¹³⁷ See Exh. No. PSG-19 (2002 Settlement).

¹³⁸ 2002 Settlement Order, 102 FERC ¶ 61,026 at P 3.

¹³⁹ *Id.* P 5.

based on the levelization methodology reflected in Appendix D for the entire period through March 31, 2020, subject to adjustments to the cost-of-service in accordance with this Settlement *or in future proceedings following termination of this Settlement in accord with Article VI below.*

(c) The Commission's order approving this Settlement in accord with Article VII shall constitute all necessary rate and accounting authority for [Portland] to continue to record and recover the deferred regulatory asset *in accordance with the levelization methodology approved as part of this Settlement, as reflected on Appendix D, for the entire period levelized rates are in effect.* [Emphasis added, footnote omitted].

The 2002 Settlement required Portland to file a general NGA section 4 rate case no sooner than, and no later than, April 1, 2008.¹⁴⁰

95. On April 1, 2008, Portland made the requisite filing in Docket No. RP08-306-000. The Commission accepted and suspended Portland's tariff sheets to be effective September 1, 2008, subject to refund, and established a hearing.¹⁴¹ Of specific interest here, in the Initial Decision following the hearing the Presiding Judge found that Portland must utilize an average rate base computation to derive its rates.¹⁴² Further, the Presiding Judge concluded that the 2002 Settlement also required that an iterative levelization methodology and model be used to establish rates as opposed to the Net Present Value (NPV) method proposed by Portland. The Presiding Judge found that only an iterative model could produce a schedule such as the one contained in Appendix D of the 2002 Settlement. The Presiding Judge reasoned that while the 2002 Settlement did not expressly use the term "iterative," the Settlement used an iterative process to derive the levelized cost-of-service.¹⁴³ Lastly, the Presiding Judge determined that a 21 year

¹⁴⁰ *Id.* P 7.

¹⁴¹ *Portland Natural Gas Transmission System*, 123 FERC ¶ 61,108 (2008) (Hearing Order on 2008 Rate Filing), *partial settlement accepted in*, 132 FERC ¶ 61,256 (2010).

¹⁴² *Portland Natural Gas Transmission System*, 129 FERC ¶ 63,027 at P 80 (2009) (Initial Decision on 2008 Rate Filing).

¹⁴³ *Id.* P 39. The Presiding Judge also stated that the fact that an iterative model may not replicate the deferred regulatory asset (DRA) balances in Appendix D of the 2002 Settlement was irrelevant. He noted that Footnote 2 in Appendix D to the

(continued...)

levelization period with an end date of March 31, 2020 best represented the original intent of the 2002 Settlement.¹⁴⁴

96. In Opinion No. 510, the Commission affirmed the Presiding Judge's levelized rate determination.¹⁴⁵ The Commission specifically reviewed two major issues regarding the consistency of Portland's proposed levelized cost-of-service rates with the requirements of the 2002 Settlement: (1) the appropriate rate levelization methodology and model for the proceeding and (2) the appropriate period over which levelization is to take place. The Commission affirmed the Presiding Judge's determinations on both these matters.¹⁴⁶ First, the Commission found that the Presiding Judge's determination that Portland must use an iterative method to derive its levelized rates in this proceeding is just and reasonable and that the record evidence revealed that Portland agreed in the 2002 Settlement to utilize a levelized rate design for future rate cases. The Commission also found that the 2002 Settlement states that Portland must use the same methodology used in the 2002 Settlement to design its rates for future proceedings. Because the record demonstrated that Portland used the iterative methodology to derive the levelized rates in the 2002 Settlement, the Commission reasoned that Portland must use that same iterative methodology in the 2008 rate proceeding.¹⁴⁷

97. The Commission in Opinion No. 510 also rejected Portland's argument that to require it to use an iterative methodology to derive levelized rates would elevate its risk. The Commission stated that the 2002 Settlement revealed that Portland agreed to this methodology and the risk allocation share. Therefore, the Commission reasoned that the Presiding Judge's finding that Portland must use an iterative methodology did not elevate Portland's risk level but merely held Portland to risk that Portland assumed when it agreed to the 2002 Settlement. The Commission further stated that permitting Portland to

Settlement states that the annual balances "are based on the Cost of Service" which, in turn, "is subject to change in accordance with the Settlement or in future proceedings." The Presiding Judge reasoned that logically the annual DRA balances will change as Portland's cost of service changes from its level established in the 2002 Settlement. Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at P 41 (citing Exh. No. PSG-5 in Docket No. RP08-306-000 at 30 n.2). .

¹⁴⁴ Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at P 64.

¹⁴⁵ Opinion No. 510, 134 FERC ¶ 61,129 at P 22.

¹⁴⁶ *Id.* P 11.

¹⁴⁷ *Id.* P 27.

derive its levelized rates in some manner other than that required by the 2002 Settlement would unfairly prejudice the other parties to the Settlement.¹⁴⁸ Accordingly, the Commission found that the Presiding Judge's determination was just and reasonable. The Commission also found that the Presiding Judge properly analyzed the 2002 Settlement and correctly determined that the appropriate levelization period was a 21-year period ending on March 31, 2020.¹⁴⁹

98. In its 2010 Rate Filing, Portland asserted that its rate base should be calculated as a point in time such as the end of the test period because this methodology would keep it revenue neutral between levelized rates and traditional rates and would allow it an opportunity to recover its allowed rate of return each year.¹⁵⁰

Initial Decision

99. In the ID in the current proceeding, the ALJ found that Portland obligated itself to the use of an average rate base during its certification proceeding and in the 2002 Settlement. Therefore, the ALJ held that Portland must continue to calculate its rate base for levelization purposes by using an average rate base. The ALJ also addressed arguments by Portland that the rate base, in a levelized environment, should be calculated at a point in time as opposed to a rate base average, and that Opinion No. 510 did not require that Portland use an average rate base.¹⁵¹ In ruling, the ALJ determined that the Commission in Opinion No. 510 only addressed the question of whether Portland was required to establish its levelized rates using an average rate base in general terms. However, the ALJ determined that the Initial Decision leading to the Commission's Opinion No. 510 did address the issue of rate base calculation and that Initial Decision rejected Portland's proposal that an end of levelization year balance be used for computing rate base, and held that the pipeline's certification proceeding and the 2002 Settlement in Docket No. RP02-13 required the use of an average rate base.¹⁵²

¹⁴⁸ *Id.* P 30.

¹⁴⁹ *Id.* P 47.

¹⁵⁰ ID, 137 FERC ¶ 63,018 at PP 976-78.

¹⁵¹ Opinion No. 510, 134 FERC ¶ 61,129.

¹⁵² ID, 137 FERC ¶ 63,018 at P 975 (citing Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at PP 71-80).

100. Accordingly, the ALJ found in the proceeding leading up to Opinion No. 510, that Portland had obligated itself to the use of an average rate base during its certification proceeding and in the 2002 Settlement.¹⁵³ Moreover, the ALJ found that in the instant proceeding, Portland was obligated to prove, by a preponderance of the evidence that good cause exists for altering the manner in which its rate base is calculated for levelization purposes and that it had failed to do so. Therefore, the ALJ found that Portland was required to continue to calculate its rate base for levelization purposes by using an average rate base and that such methodology provides a just and reasonable result.¹⁵⁴

Exceptions to the ALJ's Decision

101. In its Brief on Exceptions, Portland argues that the levelization process should establish rate base as of a point in time annually. Portland argues that Commission policy “traditionally provides for use of end of test period rate base balances [*i.e.*, a point in time] in natural gas pipeline Section 4 rate cases.”¹⁵⁵ Portland also asserts that neither its certificate proceeding nor the 2002 Settlement requires the use of average rate base. Accordingly, Portland argues that the ID erred and should be overturned to the extent it held that (1) Portland did not attempt to prove that good cause exists in support of a point in time rate base calculation and (2) Portland was obligated to use an average rate base approach.

102. Portland argues that the point in time method is the only calculation that provides Portland a reasonable opportunity to recover its allowed rate of return and that neither its certificate proceeding nor the 2002 Settlement requires the use of the average rate base. Portland argues that the ID erroneously relied upon the Presiding Judge's finding in Docket No. RP08-306 that Portland was obligated by settlement to use an average rate base approach. Portland claims that evidence the participants failed to agree to a specific calculation of rate base was first articulated in the instant docket.

¹⁵³ *Id.* P 977 (citing Initial Decision on 2008 Rate Filing at P 80).

¹⁵⁴ *Id.* P 978.

¹⁵⁵ Portland Brief on Exceptions at 45 (citing Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at P 80; *Order Amending Part 154, of the Regulations under the Natural Gas Act*, Order No. 488, 50 FPC 138 (1973) (reflecting Commission policy that natural gas pipelines should use a year-end rate base (*i.e.*, point in time rate base) to compute a return allowance)).

103. Portland also argues that the 2002 Settlement was a black box settlement designed to “embody only an overall cost-of-service and general rate level” and did “not reflect any agreement as to specific rate derivations,” such as the calculation of rate base. Portland argues that the 2002 Settlement neither endorsed any type of rate base calculation nor specified that rate base should be derived using an average rate base calculation.

104. Portland maintains that the ID also erred to the extent it failed to recognize that the 2002 Settlement prohibits any assertion that the settlement endorsed any type of rate base calculation. Portland asserts that, Article VIII of the 2002 Settlement states that it represents a negotiated resolution of only the specific matters addressed therein, and except as specifically provided in this Settlement, no participant shall be deemed to have waived any claim as to matters not addressed.

105. Further, Portland asserts that rates established in a NGA section 7 proceeding are not subject to the “just and reasonable” standard of NGA section 4 and instead, are to be reviewed under the public convenience and necessity standard of NGA section 7. Therefore, Portland argues that it cannot be said that the Commission found the use of average rate base to be “just and reasonable” in Portland’s certificate docket or that the certificate proceeding requires this approach going forward.

106. Lastly, Portland argues that the fact that the rate levelization model has been changed over time and now includes a calculated stub year and a pretax allowance and excludes a separate return and income tax allowances, as well as operating and maintenance expenses and taxes other than income, shows that neither Portland’s original certificate proceeding nor the 2002 Settlement required a fixed set of levelization practices.

Parties Opposing Exceptions

107. In its Brief Opposing Exceptions, Trial Staff supports the ALJ’s decision. Trial Staff asserts that although the Commission traditionally uses the end-of-test-period rate base balances in natural gas pipeline section 4 rate cases, the Commission, in levelized rate proceedings, has not expressed any preference for the use of “point in time” rate base balances across the levelization period. Trial Staff argues that to the contrary, the Commission recently accepted the use of average rate base balances in Opinion No. 486-E.¹⁵⁶

¹⁵⁶ Trial Staff Brief Opposing Exceptions at 40 (citing Opinion No. 486-E, 136 FERC ¶ 61,045 (2011)); Exh. No. KR-P2-4 in Docket No. RP04-274-023, at 11).

108. In response to Portland's contentions that neither its certificate proceeding nor the 2002 Settlement requires the use of average rate base, Trial Staff asserts that the Presiding Judge in Docket No. RP08-306-000 reviewed the 2002 Settlement and held that Portland should design its levelized rates using an average rate base methodology. Trial Staff claims the 2002 Settlement expressly obligates Portland to use the same levelization methodology the Commission approved in Portland's certification orders through March 31, 2020, and that the Commission approved the average rate base approach in Portland's certificate proceeding.¹⁵⁷ Trial Staff asserts that the Commission in Opinion No. 510 affirmed the Presiding Judge's holding regarding Portland's levelization methodology and, therefore, both the Commission in Opinion No. 510 and the Presiding Judge in Docket No. RP08-306-000 rejected Portland's argument that neither Portland's certificate proceeding nor the 2002 Settlement require the use of average rate base.

109. Trial Staff also opposes Portland's assertion that because rates established in a NGA section 7 proceeding are not subject to the NGA section 4 just and reasonable standard, no particular approach to calculating rate base used in a certificate proceeding can be binding on a prospective basis. Trial Staff argues the Commission applied the just and reasonable standard in Opinion No. 510 when it approved the Initial Decision's finding regarding the required use of average rate base methodology for Portland's levelization model. Therefore, Trial Staff maintains that Portland's claim in this proceeding that it may deviate from the rates adopted in an NGA section 7 proceeding because those rates are not subject to the "just and reasonable" standard is moot. PSG asserts that Portland's certificate proceedings employed a levelization methodology which utilized average rate base and that, in its first rate case following certification (Docket No. RP02-13), Portland agreed in the 2002 Settlement to continue to utilize that same levelization methodology through March 2020. PSG points out that the RP08-306-000 Initial Decision required Portland to continue to use an average rate base for levelization purposes, that Opinion No. 510 affirmed that holding, and that the ALJ in the instant case correctly agreed with these previous findings.¹⁵⁸

110. PSG also asserts that Portland's arguments that neither its certificate proceeding nor the 2002 Settlement requires it to use an average rate base are stale and effectively a collateral attack on Opinion No. 510. Further, PSG asserts that Section 3.1 of the 2002 Settlement clearly reflects Portland's ongoing obligations to use the methodology

¹⁵⁷ *Id.* (citing Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at PP 80-81).

¹⁵⁸ Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at P 80; Opinion No. 510, 134 FERC ¶ 61,124 at PP 2, 28; ID, 137 FERC ¶ 63,018 at PP 975, 977.

adopted in Portland's original certificate proceedings to design Portland's rates in the future.

111. PSG also challenges Portland's assertions that the 2002 Settlement, by its terms, has no precedential effect, and thus cannot obligate Portland to continue to use an average rate base calculation for rate levelization purposes. PSG argues that the Settlement allows for specifically delineated exceptions from the "no precedential effect" rule, and that the levelization methodology is one such provision. PSG also contests Portland's argument that the levelization model has changed over time, and that this negates the requirements of the 2002 Settlement to continue to use the specific settlement (and certificate) levelization methodology. PSG claims that this argument lacks merit because of the inconsequential nature of the changes noted by Portland.

112. PSG acknowledges that using an average rate base for levelized cost-of-service purposes will always produce a lower value than a traditional cost-of-service using an end of test period rate base. They argue, however, that it is not the use of an average rate base methodology that produces this result or places Portland at risk for cost recovery. PSG claims this fact is instead the result of Portland's agreement to continue to use the same levelization methodology it accepted in its certificate proceeding.¹⁵⁹

Commission Determination

113. The Commission finds that the ALJ properly found that "Portland shall continue to calculate its rate base for levelization purposes by using an average rate base and that such methodology provides a result which is just and reasonable."¹⁶⁰ Further, the Commission affirms the ALJ's finding that "Portland obligated itself to the use of an average rate base during its certification proceeding and in the [2002 Settlement]."¹⁶¹

114. Section 3.1(a) of the 2002 Settlement identifies the levelization methodology to be used to derive the Settlement rates, namely the methodology adopted in Portland's

¹⁵⁹ PSG cites Dr. Briden's observation: "If Portland's theory concerning earnings' inadequacy were true, it has always been true; and yet the use of average rate base is an essential element of the bargain Portland and the parties have struck concerning how Portland's rates would be levelized." Exh. No. PSG-63 at 17.

¹⁶⁰ ID, 137 FERC ¶ 63,018 at P 978.

¹⁶¹ *Id.* P 977.

original certificate proceedings.¹⁶² Section 3.1(b) of the 2002 Settlement requires the use of that same methodology to design Portland's rates in the future.¹⁶³ As we found in Opinion No. 510, Portland agreed in the 2002 Settlement to utilize a levelized rate design for future rate cases, and Section 3.1 of the 2002 Settlement expressly obligates Portland to use the same levelization methodology as approved in its certification orders.

115. Specifically, Portland's own witness testified that the 2002 Settlement utilized the same iterative methodology that was used in Portland's certificate proceedings¹⁶⁴ and the ALJ in Docket No. RP08-306 adopted a finding that an average rate base must be utilized for Portland's rate case.¹⁶⁵ Moreover, in its Brief on Exceptions, Portland now admits that the ALJ in the Docket No. RP08-306 proceeding "correctly recognized that the certificate proceeding and the [2002 Settlement] used an average rate base approach."¹⁶⁶

¹⁶² See Tr. 824-26. The 2002 Settlement identifies the original certificate proceedings at issue: 1996 Certificate Order, 76 FERC at 61,657-58; July 1997 Certificate Order, 80 FERC at 61,455; September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345.

¹⁶³ Opinion No. 510, 134 FERC ¶ 61,129 at P 27. See also Exh. No. PSG-19 at 6-7 (2002 Settlement, § 3.1(a) and (b)).

¹⁶⁴ Tr. 595-96; 882:16-20.

¹⁶⁵ Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at P 81.

¹⁶⁶ Portland Brief on Exceptions at 47. Indeed, the Presiding Judge in the 2008 Rate Filing proceeding was clear on this point, 129 FERC ¶ 63,027 at P 80 (emphasis added):

I agree with the arguments of PSG and Staff summarized above and thus adopt an average rate base for use in the levelization process. I agree with [Portland's] assertion that Commission precedent traditionally provides for the use of end of test period rate base balances in natural gas pipeline Section 4 rate cases. *However, it is clear on the record in the instant case that an average rate base computation was used in the [2002 Settlement]. See Ex. PSG-21; Ex. PSG-118; Tr. 817-18, 2071. Further, the record demonstrates that an average-rate-base approach was used in the levelization process in [Portland's] certificate proceeding, and Section 3.1(a) and Section 3.1(b) of the [2002 Settlement] expressly obligate [Portland] to use the same levelization methodology as approved in [Portland's] certification orders. See Ex. PSG-5 at 6-7; Tr. 821, 823.*

(continued...)

116. Portland now argues, however, that the ALJ erred in concluding that the “levelization methodology” in the 2002 Settlement required use of an average rate base going forward and asserts that no evidence was provided for this conclusion. Moreover, Portland argues that in the 2002 Settlement the participants did not agree to a specific calculation of the rate base and that the ID did not address the failure to identify the specific language in the certificate order or the 2002 Settlement that required the use of the average rate base.

117. Both the ALJ in this proceeding and the Presiding Judge in Docket No. RP08-306-000 reached the conclusion that the 2002 Settlement required the use of the average rate base going forward. The Commission finds that Portland’s certificate proceeding and the 2002 Settlement used an average rate base approach. The Commission also finds that Portland has acquiesced to this point. Therefore, the statement in the 2002 Settlement that “[Portland] shall continue to propose to design its FT rates based on the levelization methodology reflected in Appendix D *for the entire period through March 31, 2020, subject to adjustments to the cost-of-service in accordance with this Settlement or in future proceedings following termination of this Settlement in accord with Article VI below,*” compels a finding that Portland must utilize an average rate base methodology in the instant proceeding and in future rate proceedings. This finding is consistent with the Commission’s action in Opinion No. 510 where we found that to “permit[] Portland to derive its levelized rates in some other manner than that required by the 2002 Settlement would unfairly prejudice the other parties to the [2002] Settlement.”¹⁶⁷

The [2002 Settlement] states that the obligation extends through March 31, 2020. *See* Ex. PSG-5 at 6-7. *[Portland] is still bound by this obligation.*

In Opinion No. 510, 134 FERC ¶ 61,129, the Commission adopted this finding by the ALJ, and Portland did not request rehearing of that determination.

¹⁶⁷ Opinion No. 510, 134 FERC ¶ 61,129 at P 30. In both the instant proceeding and in Docket No. RP08-306, Portland has argued that it should no longer be held to various aspects of the 2002 Settlement to which it agreed. The Commission recently found in *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077 at P 44, in addressing issues related to the levelized rates on that system, that long term agreements must remain in place so that the parties might reap the benefit of their bargain.

The Commission examined the agreements reached by the parties in that proceeding, and following the relevant authority found that a company “is not typically entitled to be relieved of its improvident bargain” and, further, that “Despite recent cynicism, sanctity of contract remains an important civilizing concept;” moreover, “the general rule of freedom of contract includes the freedom to make a bad bargain.” The Commission

(continued...)

118. Portland also argues that no precedent exists that would require it to use an average rate base to calculate its levelized rates. Leaving aside for the moment the discussion above finding that Portland agreed to utilize such a methodology in the 2002 Settlement, the Commission has previously held in Opinion No. 486-A that a levelization methodology is “intended to be in effect for the life of a project . . . absent agreement by all parties to modify or eliminate that rate design.”¹⁶⁸ This is because that agreement as to the levelization reflects the underlying agreement regarding the allocation of risk initially reached by the parties that the “Commission will not lightly change.”¹⁶⁹

concluded that while the shipper may regret its service choice “wise or not, a deal is a deal,” and therefore, “people must abide by the consequences of their choices.”

Opinion No. 486, 117 FERC ¶ 61,077 at P 64 n.113 (quoting *Exxon Mobil Corp. v. FERC*, 430 F.3d 1166, 1177 n.7 (D.C. Cir. 2005) and *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 710 (D.C. Cir. 2000), *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 355 (1956), and *Morta v. Korea Ins. Corp.*, 840 F.2d 1452, 1460 (9th Cir. 1988)) (internal citations, quotations and editorial notes omitted).

¹⁶⁸ Opinion No. 486-A, 123 FERC ¶ 61,056 at P 25. Such findings and Portland’s agreement in the 2002 Settlement to utilize the same methodology in all future rates cases also belie Portland’s suggestion that the Commission routinely uses average rate base in certificate proceedings and then updates those numbers in a subsequent rate case. Portland attempts to bolster this contention by referring to cases such as *Iroquois Gas Transmission System, L.P.*, 84 FERC ¶ 61,086 (1998) (*Iroquois*), *order on reh’g*, 86 FERC ¶ 61,261 (1999). However, these proceedings only envisioned that the levelized cost of service would be in effect for the duration of the *initial rates* to address *temporary circumstances*.” 84 FERC at 61,445-46 (emphasis added).

¹⁶⁹ “Kern River’s existing levelized rate methodology is part of the risk sharing agreement among Kern River, its shippers and lenders underlying Kern River’s optional expedited certificate. . . . As a result, the Commission will not lightly change [that] allocation of risk” Opinion No. 486-A, 123 FERC ¶ 61,056 at P 357. As in the instant case, in the *Kern River* proceeding, the Commission attached great weight to the parties’ agreement regarding the appropriate allocation of the risks and stated that it would not lightly change this allocation of risk absent some overarching policy reason. This was an underlying theme of the Commission’s position in the Kern River proceeding. See Opinion No. 486, 117 FERC ¶ 61,077 at P 38; Opinion No. 486-A, 123 FERC ¶ 61,056 at P 19; Opinion No. 486-C, 129 FERC ¶ 61,240 at P 248; Opinion No. 486-D, 133 FERC ¶ 61,162 at P111 (2010).

119. The Commission has reviewed arguments by Portland that the nature and the specific language of the 2002 Settlement preclude it from governing the instant case and find that such arguments lack merit and cannot compel a finding that the ALJ in the instant proceeding erred in his determination that Portland must use a levelized rate methodology based on an average rate base in the instant rate case. Accordingly, we will not further address such assertions.

V. Depreciation and Negative Salvage

A. Depreciation Rate Increase

Background

120. Portland's last rate case provided for a composite transmission depreciation rate of 2.0 percent.¹⁷⁰ In the current proceeding, Portland proposed to increase the existing 2.0 percent depreciation rate to a 4.13 percent composite depreciation rate, reflecting a remaining economic life of 17.89 years based on the supposition that supplies will be unavailable to it after 2028. Trial Staff proposed a remaining economic life of 37 years and the resulting 2.20 percent depreciation rate. No other party proposed to change Portland's currently effective composite depreciation rate, and Trial Staff and PSG opposed Portland's proposal as unsupported.

Initial Decision

121. The ALJ rejected both Portland's and Trial Staff's proposed changes to Portland's existing depreciation rate, and thus determined that it should remain at the existing 2.0 percent. The ALJ found that Portland's depreciation study was insufficient to support Portland's proposed depreciation rate increase. The ALJ also rejected Trial Staff's proposed depreciation rate, finding that Trial Staff's production model was arbitrary and did not support its economic end-life conclusion.¹⁷¹

122. The ID found that Portland failed to support the two principal arguments upon which it relies for its proposal, namely that: (1) in 2028, Portland will no longer receive supplies from its traditional supply basin, the Western Canadian Supply Basin (WCSB), due to a decline in Canadian conventional production and an increase in Canadian

¹⁷⁰ The two percent rate was agreed to as part of the 2002 Settlement, and was maintained in Opinion No. 510, 134 FERC ¶ 61,129 at P 126.

¹⁷¹ ID, 137 FERC ¶ 63,018 at P 1086.

demand;¹⁷² and (2) an increase in production of Marcellus Shale¹⁷³ gas will lower the delivered cost of gas for other pipelines, making Portland uncompetitive in the Boston-area market.¹⁷⁴ In support of these claims, Portland offered a gas supply forecast for the WCSB, a study showing the cost of transporting gas on different pipeline paths, and an overview of pipeline capacity expansion projects in the northeast region.¹⁷⁵

123. Portland forecasted conventional WCSB gas supplies potentially available to its customers in the future, using a Hubbert model based supply study. That model uses historical production data and an estimate of ultimate recoverable resources to create a bell-shaped curve that predicts the level of future natural gas production from year to year.¹⁷⁶ Portland supplemented its Hubbert model result for conventional production

¹⁷² For the purpose of this proceeding, references to conventional gas production is to production using more traditional extraction methods, while unconventional gas production employs newer extraction methods, such as horizontal drilling and hydraulic fracturing. Exh. No. PNG-15 at 15-16; Tr. 2359-60. Unconventional gas sources include shale gas, coalbed methane and tight gas. Tr. 2681.

¹⁷³ Marcellus Shale is a recently-developing natural gas supply basin located in New York, Pennsylvania, Ohio, and West Virginia. Exh. Nos. PNG-38 at 26, PSG-89 at 33. It is closer to the Boston-area market than the WCSB and the United States Gulf Coast, both traditional supply basins for the northeast region. Exh. No. PNG-7 at 15, 21. The Participants agree that Marcellus Shale contains significant gas reserves. Exh. Nos. PNG-38 at 26-29, PSG-89 at 34, S-21 at 38-39.

¹⁷⁴ Portland serves the Boston-area market, along with the Tennessee Gas Pipeline Company, LLC, Texas Eastern Transmission, LP; Algonquin Gas Transmission, LLC; and Maritimes & Northeast Pipeline, L.L.C. pipelines. Exh. No. PNG-7 at 18-19. As noted by Maine Public Advocate Witness John A. Rosenkranz, Portland also has a sizable captive market north of the Boston area. Exh. No. MPA-1 at 6-7. According to the Maine Public Advocate, actual deliveries to Portland's captive markets averaged 42,313 Dth per day for the year ending August 31, 2010, while "the sum of the peak daily deliveries made by Portland at meters serving captive markets was 117,710 [Dth per day]." Maine Public Advocate Initial Brief at 5; Exh. No. MPA-2.

¹⁷⁵ ID, 137 FERC ¶ 63,018 at P 1068. The natural gas supply study relied upon by Portland to forecast gas supplies potentially available to its customers in the future is set forth in Exh. Nos. PNG-22 and PNG-59.

¹⁷⁶ See Exh. Nos. PNG-22 and PNG-59.

with other forecasts for unconventional production in the WCSB to arrive at Portland's total forecasted supplies.

124. The ID identifies several significant deficiencies in Portland's model related to whether the model adequately accounts for Canadian unconventional production. According to the ALJ, these deficiencies undermine the model's reliability as a reasonable estimate of future production in the WCSB.¹⁷⁷ First, the ALJ takes issue with Portland's unconventional production estimates that show Canadian Western Shale gas production plateauing starting in 2020.¹⁷⁸ The ID finds that estimate to be wholly unfounded, particularly given Portland's assumption that conventional production follows a bell-shaped curve.

125. Second, the ID finds that Portland should have incorporated unconventional production into its model rather than adding it on after the fact. According to the ALJ, by doing so Portland would have used a more reliable ultimate source recovery estimate that includes unconventional gas resources instead of the production estimate employed in the model.¹⁷⁹

126. Further, the ID finds unreasonable Portland's exclusions of large amounts of unconventional production from its model on the pretext that it requires the development of new technology. The ALJ notes that if, as Portland asserted, the production history used in the Hubbert model implicitly takes into account technological developments,¹⁸⁰ then the model should be able to take into account the technological developments that have led to the economic extraction of unconventional gas. The ID concludes, therefore, there is no reason why unconventional gas could not be directly incorporated into Portland's model.¹⁸¹

127. Third, the ID challenges the source of Portland's unconventional production data. According to the Presiding Judge, Portland failed to "show where it obtained its non-

¹⁷⁷ ID, 137 FERC ¶ 63,018 at PP 1071-84.

¹⁷⁸ *Id.* P 1072.

¹⁷⁹ *Id.* P 1073 & n.404.

¹⁸⁰ Portland Reply Brief at 82; Exh. No. PNG-22 at 6.

¹⁸¹ ID, 137 FERC ¶ 63,018 at P 1073.

conventional production estimates and provided little evidence showing that those estimates are reliable.”¹⁸²

128. The ID also finds Portland’s analysis flawed because it does not include the possibility of Utica Shale supplies ever reaching Portland’s system. The ID notes that record evidence shows that the Utica Shale has potentially large reserves in close proximity to Portland’s system. According to the ALJ, while Portland’s arguments for the exclusion of Utica supplies from its analysis may indicate that Utica Shale may not be producing any significant quantities of gas in the short term, it is unreasonable to conclude that there will never be any Utica Shale supplies available to Portland in the future.

129. The ID also finds fault with Portland’s argument that increasing levels of Marcellus Shale production will drive down demand for transportation service on Portland’s system. While acknowledging that it is reasonable to expect that Marcellus Shale production will significantly increase in the coming years, as argued by Portland,¹⁸³ the ALJ found unpersuasive Portland’s claims that this would cause a change in demand for Portland’s services to the Boston-area market.

130. In analyzing Portland’s argument, the ALJ reasoned that an increase in Marcellus Shale production would only cause a change in demand for service on Portland if Marcellus Shale gas can be transported to the Boston-area at a lower rate on other pipelines. Acknowledging that the study presented by Portland comparing the cost of transporting Marcellus Shale gas on Portland to the cost of transporting Marcellus Shale gas on competing pipelines¹⁸⁴ shows that Portland’s prices are substantially higher than the alternative paths, the ALJ reasoned that Portland’s higher prices might still be competitive so long as shippers face pipeline capacity constraints trying to ship Marcellus Shale gas into the Boston-area market on other pipelines. The ALJ further found that although expansion projects that might allow greater levels of Marcellus Shale gas to flow to the northeast region are in the planning stages, the actual impact of these expansion projects on Portland is questionable. The ALJ thus concluded that Portland had not provided sufficient evidence to support the conclusion that the incremental cost

¹⁸² *Id.* P 1074.

¹⁸³ Exh. No. PNG-38 at 26-29.

¹⁸⁴ Exh. No. PNG-85.

of expansion capacity going into the Boston-area market will be low enough to make Portland's rates uncompetitive.¹⁸⁵

131. Based on the findings that neither Portland nor Trial Staff demonstrated their proposed economic end lives are just and reasonable, the ALJ rejected both of their proposed depreciation rate changes and retained Portland's current 2 percent depreciation rate.¹⁸⁶ That ruling implicitly sets Portland's economic end-life at 2047, establishing a remaining economic life of 35 years.¹⁸⁷

Portland's Brief on Exceptions

132. On exceptions, Portland claims that the ALJ failed to discuss and properly analyze Portland's depreciation evidence, and thus reached erroneous conclusions concerning Portland's depreciation rates.¹⁸⁸ Specifically, Portland argues the ID failed to take into account that on November 22, 2010 the National Energy Board of Canada (NEB) set a truncation date of 2023 for TransQuebec & Maritimes' East Hereford Lateral, the primary receipt point for gas delivered to Portland at its northern inlet. According to Portland, that lateral is the sole source of supplies for Portland from the WCSB and from the lower 48 states via the Dawn Hub.

133. Portland contends that once the East Hereford lateral ceases operations, Portland's major supply conduit will be cut-off. Portland claims that the Commission in Opinion No. 510 rejected Portland's argument that the economic life of a downstream pipeline must mirror the remaining economic life of the upstream pipeline that is its primary source of supply because the Commission found the depreciation study in that proceeding to be stale. Portland contends, however, that Opinion No. 510 did not establish a blanket prohibition against tying the remaining economic life of a downstream pipeline to the life of its primary upstream supply source,¹⁸⁹ and that the fact that the NEB issued its ruling in this case just seven months prior to the hearing distinguishes the circumstances here from those addressed in Opinion No. 510. Portland argues that setting its system

¹⁸⁵ ID, 137 FERC ¶ 63,018 at PP 1079-83.

¹⁸⁶ *Id.* P 1087.

¹⁸⁷ Tr. 2386:1-6

¹⁸⁸ Portland Brief on Exceptions at 52.

¹⁸⁹ Portland Brief on Exceptions at 55 (citing *Iroquois Gas Transmission System, L.P.*, Initial Decision, 81 FERC ¶ 63,012 (1997), *aff'd Iroquois*, 84 FERC ¶ 61,086).

economic end life at 2028, five years after the NEB's ruling as to the Hereford Lateral's remaining economic life, is reasonable. Portland also argues the ALJ was wrong to ignore this evidence, which Portland claims supports its proposed depreciation rate increase even if its production model was flawed.

134. Portland also claims that the ALJ's contentions that it did not properly account for WCSB unconventional supplies is contrary to the evidence. Portland contends that contrary to the ALJ's suggestion, including non-conventional supplies in the Hubbert model would have produced an unrealistic forecast. Portland also claims that there was insufficient data to include unconventional supplies in the model due to the lack of production history and limited reserve knowledge regarding those resources. Portland further asserts that the source of its unconventional production is a non-issue because if anything, its inclusion favors the ratepayers, not Portland itself.

135. Portland also challenges the ID's finding regarding the exclusion of Utica Shale supplies from its gas supply study. Portland contends that it determined the potential for Utica Shale supplies to flow on Portland's system is speculative at best, and thus it properly excluded these "uneconomic and speculative reserves" in concert with Commission precedent.¹⁹⁰ Portland contends that Trial Staff's predictions of the levels of reserves in the Utica Shale in Quebec are vastly overestimated because they include reserves in New York as well, and fail to distinguish between "technically" and "economically" recoverable reserves.

136. Portland argues the ID also erred in finding that its evidence demonstrating the impact of expansion projects to bring Marcellus Shale gas to the Boston area was lacking. Portland claims that while it may be uncertain which of the projects will be built, there is no doubt that some projects will be built to bring Marcellus gas to the New England market. Portland contends the record is also replete with evidence that the delivered cost of Marcellus supplies to the Boston market will be substantially less on other pipelines than it will be on Portland.

137. Portland concludes that it produced substantial evidence to support its proposed depreciation rates of 4.10 percent for transmission plant and a 4.13 percent composite depreciation rate. According to Portland those rates were based on an economic end-life of 2028, which Portland contends is supported by the NEB truncation date for the Hereford Lateral and its gas supply forecast. Portland claims its supply study demonstrates that the projected remaining life estimate of 17.89 years is reasonable as it

¹⁹⁰ Portland Brief on Exceptions at 61 & n.374.

accounts for estimated production from both conventional and unconventional sources.¹⁹¹ Portland also asserts that its evidence shows that Marcellus Shale production threatens Portland's economic viability once its long term agreements with its shippers expire in 2019 because thereafter shippers will have a lower cost option to transport gas from the Marcellus Shale to the Boston area on Tennessee or Texas Eastern or Algonquin.

138. Finally, Portland argues that the ID failed to set "proper and adequate" depreciation rates as required by NGA section 9.¹⁹² According to Portland, even if its evidence in support of its revised depreciation rate was deficient, the Commission is still required under NGA section 9 to set a depreciation rate that allows Portland's investors to recover their investment over the useful life of Portland's system based upon "what the Commission expects will happen."¹⁹³ Portland argues that by defaulting to Portland's existing depreciation rate, the ID failed to satisfy that obligation.

PSG Brief Opposing Exceptions

139. In its Brief Opposing Exceptions, PSG contends that the ID correctly ruled that Portland has failed to meet its burden of proof for an increased depreciation rate.¹⁹⁴ PSG argues that the ID was correct to find that Portland had not supported any supply¹⁹⁵ or demand¹⁹⁶ related truncation of its remaining economic life. On the supply side, PSG argues that the ID was correct to conclude that a supply forecast that only accounted for conventional supplies and excluded non-conventional supplies was inherently unreliable. Portland claims the Commission has held that in determining a pipeline's remaining economic life for depreciation purposes, a model that ignores "vast unconventional

¹⁹¹ *Id.* at 70.

¹⁹² *Id.* at 53-57.

¹⁹³ *Id.* at 53 (citing *South Dakota Pub. Utils. Comm'n v. FERC*, 668 F.2d 333, 337 (8th Cir. 1981) (*South Dakota*)).

¹⁹⁴ PSG Brief Opposing Exceptions at 38-68.

¹⁹⁵ *See id.* at 39-50 (detailing Portland's failure to account for unconventional gas reserves in the WCSB and claiming that Portland's purported evidence fails to adhere to the Commission's gas supply modeling requirements).

¹⁹⁶ *See id.* at 51-62 (claiming that "changes in demand" criteria for adjusting depreciation rates applies to demand for natural gas generally in competition with other fuels, not between pipelines, and asserting that Portland's portrayal of its post-2019 circumstances is unduly pessimistic and speculative).

supplies ... does not produce a reasonable result.”¹⁹⁷ PSG claims that contrary to Opinion No. 510, Portland’s model fails to consider economic and technological factors. PSG contends the model also fails to take account of all gas supplies “potentially accessible” for transportation on Portland, particularly gas supplies sourced in the United States or eastern Canada, including the substantial Utica Shale reserves. PSG also argues that the record shows Portland will remain competitive currently and for the foreseeable future, because there is no evidence demonstrating that Portland’s competitors are expanding to serve Portland markets with Marcellus gas.

140. PSG also challenges Portland’s reliance on the NEB’s “ruling” that purportedly set the Hereford Lateral economic end life at 2023. According to PSG, the NEB “truncation” date was not a ruling but in fact only included in a draft report on depreciation submitted to the NEB in a rate settlement process, and was not mentioned in the NEB’s order approving the settlement. PSG argues that a proposed depreciation rate based on a purported truncation of the pipeline’s economic life cannot be sustained on the grounds that it supports settlement rates.¹⁹⁸ PSG further claims that Portland’s arguments that its economic life is dictated by the upstream Hereford Lateral fails because Trans-Quebec & Maritimes is not the only source of supply for Portland, and because Portland has not presented substantial evidence that it will lack adequate supplies in the future or that it will be unable to continue its current competitive service to the Boston market area.

141. Finally, PSG argues that Portland’s resort to NGA section 9 does not relieve Portland of its NGA section 4 burden to show that its proposed increase is just and reasonable. PSG states that contrary to Portland’s assertions, the Commission cannot approve a new depreciation rate even if Portland has failed to adequately support its supposed economic end life assertions. PSG claims that Portland’s argument regarding the potential under-recovery by investors fares no better because Portland has simply failed to prove that its useful life will end in 2028. PSG concludes that based on the lack of supporting evidence for Portland’s proposed change, the ID was correct to default to Portland’s existing depreciation rate.¹⁹⁹

¹⁹⁷ *Id.* at 42 (quoting *Williston IV*, 107 FERC ¶ 61,164 at P 37).

¹⁹⁸ *Id.* at 63.

¹⁹⁹ *Id.* at 64-68.

Commission Determination

142. The Commission affirms the ALJ's finding that Portland's depreciation rate should remain at 2 percent. As the ALJ correctly notes, Portland bears the burden to demonstrate that its proposed increase to its depreciation rate from 2 percent to 4.13 percent is just and reasonable. To make that demonstration, Portland must show that the average remaining physical life of its system should be truncated by an allegedly shorter economic life. Portland fails to satisfy that burden here.

143. The useful physical life of a pipeline is presumed to be the appropriate depreciation period unless the pipeline demonstrates that it will be forced out of business earlier, thereby shortening its economic life.²⁰⁰ The adequacy of gas supply is generally the dominating factor in the truncation analysis.²⁰¹ As discussed in detail by the Presiding Judge, Portland's study of its projected gas supplies is deficient to the extent that it does not reasonably support truncating Portland's economic end-life as proposed.

144. In determining depreciation rates for pipelines, the Commission "must estimate the *potential recoverable natural gas reserves* available to pipeline companies."²⁰² Therefore, the Commission has historically considered not only proven reserves, but also potential additional gas supplies, including probable and possible resources.²⁰³ Consistent with these principles, the Commission has previously held that a gas supply model that "ignored potentially vast unconventional resources" does not produce a reasonable result.²⁰⁴ That is the case with Portland's model, which, while it may not "ignore" unconventional resources entirely, significantly underestimates reserves of shale gas and other unconventional gas sources. As identified by the ALJ, the model's greatest deficiency is the estimate that unconventional gas production will remain static beginning in 2020. This projection appears wholly unsupported in the face of record evidence that

²⁰⁰ See *Memphis Light Gas and Water Division v. FPC*, 504 F.2d 225, 231 (D.C. Cir. 1974) (to justify depreciation rate change pipeline must show that "the exhaustion of natural resources has caused the useful life of [the pipeline] to be reduced to the extent that physical life ... is no longer an appropriate measure of useful life.").

²⁰¹ *Williston IV*, 107 FERC ¶ 61,164 at P 27 & n.23.

²⁰² *South Dakota*, 668 F.2d 333, 345 (D.C. Cir. 1981) (emphasis supplied).

²⁰³ *Trunkline Gas Co.*, Opinion No. 441, 90 FERC ¶ 61,017, at 61,054-5 (2000).

²⁰⁴ *Williston IV*, 107 FERC ¶ 61,164 at P 37.

WCSB shale gas will increase after 2020.²⁰⁵ As noted by the ALJ and argued by PSG, Portland should have included non-conventional gas production in its model instead of adding an unsupported and impractically low estimate of shale and other non-conventional gas reserves. In the absence of such reserves, Portland's study does not produce a reasonable result upon which the Commission can rely as the basis for a substantial increase in Portland's depreciation rate.

145. The NEB's purported "ruling" as to the economic end life of the Hereford Lateral does not help Portland's case. Contrary to Portland's assertions as to the precedential value of NEB's approval of a settlement application filed by Trans-Quebec & Maritimes, the depreciation analysis reviewed by the NEB was prepared by a consultant at the pipeline's request, and the NEB's only reference to the study in its approval letter was to chide Trans-Quebec & Maritimes for not having included it with its initial application.²⁰⁶ This reference to the necessity of including data that formed the basis of a settlement falls short of an endorsement of the merits of that analysis. It certainly is not a ruling by the NEB that Trans-Quebec & Maritimes' economic end-life is 2023.

146. Further, Portland has not established that Trans-Quebec & Maritimes is the only source of supply for Portland, and Portland has not presented substantial evidence that it will lack adequate supplies in the future. As the ALJ notes it is unreasonable to predict that supplies from the Utica Shale reserves will never flow on Portland's system. Moreover, as we stated in Opinion No. 510, our ruling in *Iroquois* did not establish a general Commission policy or rule requiring the use of an upstream pipeline's

²⁰⁵ Portland suggests that Dr. Lesser's incorporation of unconventional (*e.g.*, shale) gas in its WCSB Hubbert model "produces anomalous results." Portland Brief on Exceptions at 58-59. However, PSG witness Lesser asserts that this simply refers to the need to re-fit the model's preordained bell-shaped curve to accommodate the much higher gas reserves (reflected in the area below the curve) after including unconventional as well as conventional WCSB gas reserves in the model. The supposedly "anomalous" result (*i.e.*, the curve appears to show greater than historical gas production as additional gas reserves are added to the model) is generated by Portland itself. PSG points out that the fitted and smoothed curve are expected to deviate somewhat from actual production because the purpose of the curve is to show how long WCSB gas reserves are projected to last, not to estimate gas production in any given year. To the extent that the pace of gas production was overestimated, the period over which the reserves are projected to be depleted would be shortened (a result favoring Portland's position in this case). *See* PSG Brief Opposing Exceptions 39-41.

²⁰⁶ Exh. No. PNG-333 at 2.

depreciation rate or remaining life for all downstream pipelines.²⁰⁷ Portland's purported evidence in support of the remaining economic life of the upstream Hereford Lateral is no more reliable here than the TransCanada study the Commission rejected in Opinion No. 510.

147. In addition, the Commission affirms the ALJ's finding that Portland's assertion that it will be unable to compete in the Boston market in the future is speculative. As the ALJ states, there is record evidence Portland's higher prices might still be competitive so long as shippers face pipeline capacity constraints trying to ship Marcellus Shale gas into the Boston-area market on other pipelines.²⁰⁸ Further, potential expansion projects that might allow greater levels of Marcellus Shale gas to flow to the northeast region are currently in the planning stages, and thus too speculative to support a claim that Portland will be squeezed out of the market. Accordingly, Portland has not provided sufficient evidence to support the conclusion that the incremental cost of expansion capacity going into the Boston-area market will be low enough to make Portland's rates uncompetitive.

148. We also affirm the ALJ's finding that Trial Staff failed to demonstrate that Portland's currently effective depreciation rate is no longer just and reasonable.²⁰⁹ As noted by the ALJ, Staff's production model is based on an arbitrarily selected economic end life and Staff's witness does not explain how he arrived at the numbers that made up his end life recommendations. Therefore, Trial Staff's testimony is insufficient to satisfy the statutory requirement for a depreciation rate change.

149. Given that Portland had the burden to support its proposed depreciation rate change as just and reasonable and failed to carry that burden, and no other Participant supported an alternative just and reasonable depreciation rate, we find the ALJ was correct to retain Portland's existing depreciation rate of 2 percent for the test period in this proceeding.²¹⁰

150. All remaining depreciation rate issues raised on exceptions are dismissed.

²⁰⁷ See Opinion No 510, 134 FERC ¶ 61,129 at P 142.

²⁰⁸ ID, 137 FERC ¶ 63,018 at P 1080.

²⁰⁹ *Id.* P 1085.

²¹⁰ Portland's resort to NGA section 9 is unavailing. While NGA section 9 provides the Commission the authority to establish a proper and adequate depreciation rate for the pipeline, it does not vitiate the pipeline's obligation to demonstrate that the proposed rate is just and reasonable.

B. Negative Salvage

151. Net salvage value is the salvage value of retired property less the cost of removal.²¹¹ Negative net salvage refers to the cost of removal of an asset at the time of its retirement from service over the revenue realized from the sale of the retired asset. That is, when the revenue realized from the sale of the property is less than the cost of removal, the net salvage value is negative. In *Iroquois Gas Transmission System, L.P.*, the Commission established three criteria for approving a negative net salvage allowance: (1) the pipeline has a clearly discernable end-of-life; (2) the evidence is persuasive that interim retirements have been taken into account in computing negative salvage costs; and (3) sales and salvage values of abandoned or retired equipment are fully proven.²¹²

152. Pipelines may be allowed to include in their cost of service a charge for negative net salvage to compensate for costs to be incurred in the future retirement of facilities. Portland proposed in the 2010 Rate Filing a negative salvage rate of 0.55 percent to recover final abandonment estimates of approximately \$48.6 million.

Initial Decision

153. The ALJ determined that Portland is warranted a negative salvage value and adopted a blended negative salvage rate of 0.17 percent. The ALJ noted that the participants agreed with Portland witness Taylor's negative salvage analysis, with two exceptions: (1) the labor rates paid for decommissioning work; and (2) the appropriate price to use for the sale of linepack.²¹³ Based on a review of Portland's testimony and exhibits, and the lack of any disagreement among the participants, the ALJ concluded

²¹¹ 18 C.F.R. Part 201, Definition 23.

²¹² *Iroquois*, 84 FERC ¶ 61,086 at 61,440-41, *aff'd*, 86 FERC ¶ 61,261 at 61,941-44 (1999), *accord*, *Williston III*, 95 FERC ¶ 63,008 at 65,104-05, *aff'd in relevant part*, 104 FERC ¶ 61,036, *order on reh'g*, 107 FERC ¶ 61,164 (*Williston IV*) (applied in Opinion No. 510, 134 FERC ¶ 61,129 at P 117).

²¹³ Portland and Trial Staff briefly mentioned a third issue: that Trial Staff also made an adjustment for interim retirements in its negative salvage calculation. Portland opposed the adjustment, and noted that Trial Staff had not provided an explanation for why it made the adjustments. Because the ALJ found Trial Staff did not adequately explain their rationale for making the adjustment, the ALJ could not evaluate its reasonableness, and therefore rejected the adjustment.

that Portland's recommendations on negative salvage other than those related to labor rates or linepack price are reasonable, and adopted them.²¹⁴

154. The ALJ also adopted Trial Staff's estimate of decommissioning labor costs,²¹⁵ and Portland's negative salvage calculations for all other line items, including the projected sales price of line pack, and a remaining life of 37.25 years.

155. The 0.17 percent negative salvage rate will be added to Portland's depreciation rate and the ALJ reasoned those figures should permit Portland to recover sufficient funds during the life of the system to pay its net negative salvage expenses incurred in retiring its gas plant.

1. Decommissioning Labor Costs

Initial Decision

156. The ALJ accepted Trial Staff's labor wage rate figures, which consisted of a blended and weighted mix of union and non-union labor from across Portland's plant locations, for projecting the labor costs Portland will incur when it retires its plant.

Briefs on Exceptions and Opposing Exceptions

157. Portland takes exception to the ALJ's adoption of Trial Staff's proposal to use a blended and weighted mix of union and non-union labor wage rates. Portland proposed using union-only wage rates calculated from a proxy area consisting of Boston, Massachusetts. Portland states that, contrary to the ALJ's finding that Portland provided no actual contractual evidence to support its use of union-only labor rates or its Boston proxy area, it did provide such evidence, and that the ALJ failed to discuss Portland's evidence that: (i) supports use of labor wage rates from Boston, Massachusetts; and (ii) shows that Trial Staff used labor wage rates that understate the actual wages Portland will have to pay.

158. In its Brief on Exceptions, Portland argues that the ID erred by failing to adopt Portland's proposed overtime factor of 1.17. Portland claims that by adopting Trial Staff's labor rates, the ID implicitly and erroneously adopted Trial Staff's 1.10 overtime

²¹⁴ ID, 137 FERC ¶ 63,018 at P 1121.

²¹⁵ *Id.* PP 1122-27.

factor instead.²¹⁶ Portland contends that Trial Staff's 1.10 overtime factor assumes contractors will not work on Saturdays.²¹⁷ Portland's witness concluded that because harsh New England winter conditions can slow progress, a Saturday workday is necessary to meet the production requirements in support of the 1.17 overtime factor.²¹⁸ Portland further argues that its 1.17 overtime factor was also affirmed, and supported by Trial Staff, in Docket No. RP08-306.²¹⁹ Portland claims the ID erred by ignoring this evidence, not addressing the issue, disregarding that Opinion No. 510 adopted the 1.17 overtime factor, and not explaining the basis for reducing the overtime factor.²²⁰

159. In Trial Staff's Brief Opposing Exceptions, it argues that in the ID, the Presiding Judge implicitly and properly adopted Trial Staff's 1.10 overtime factor when he adopted Trial Staff's labor rates.²²¹ Trial Staff argues it is "unreasonable" to expect, as Portland did, that workers will perform their duties on a Saturday, especially when no abandonment task is expected to take more than 50 hours and employees are expected to work 10 hours each day.²²² Trial Staff further argues that if Saturday work is necessary, Portland's 10 percent contingency fund will cover this unlikely expense.²²³ Consequently, Portland's 1.17 overtime factor is inflated and therefore unjust and unreasonable.

²¹⁶ Portland Brief on Exceptions at P 75 (citing ID, 137 FERC ¶ 63,018 at P 1133; Exh. No. S-20 at 18, col. 4 (reflecting an overtime factor of 1.10)).

²¹⁷ Portland Brief on Exceptions at P 75 (citing Exh. No. S-19 at 11.)

²¹⁸ *Id.* at P 76 (citing Exh. No. PNG-16 at 2; Exh. No. PNG-184 at 9).

²¹⁹ *See* Opinion No. 510, 134 FERC ¶ 61,129, at PP 120-23 (noting that Portland proposed the 1.17 factor and affirming the ALJ's findings, which adopted Trial Staff's approach which also used a 1.17 factor); *see also* Trial Staff Witness Andrew M. Bieltz, Negative Salvage Workpapers filed in the 2008 Rate Filing proceeding, Docket No. RP08-306-000, Exh. No. S-3 at Schedule No. 10, col. 3 (Mar. 16, 2009) (reflecting an overtime factor of 1.17).

²²⁰ ID, 137 FERC ¶ 63,018 at PP 1121-27, 1133.

²²¹ Trial Staff Brief on Exception at 67 (citing ID, 137 FERC ¶ 63,018 at P 1127).

²²² *Id.*; Exh. No. PNG-18.

²²³ Trial Staff Brief on Exception at 67 (citing Exh. Nos. S-19 at 11-12, PNG-16 at 17).

160. In its Brief on Exception, Portland also pointed out two inconsequential mathematical errors of the ALJ, which when corrected result in the same negative salvage rate of 0.17 percent adopted in the ID and affirmed here.²²⁴

161. Trial Staff argued the ALJ was sound in holding that, in determining negative salvage, Portland's labor rates for union and non-union employees should be 8.6 percent and 91.4 percent respectively, in accordance with the Commission's finding in Opinion No. 510. Trial Staff also concurs that the ALJ properly adopted Trial Staff's 1.10 overtime factor when he adopted Trial Staff's labor rates.

Commission Determination

162. The Commission affirms the ALJ's findings concerning the proper mix of labor and the associated costs.

163. The ALJ relied on Trial Staff Witness testimony, which included a blended and weighted mix of union and non-union labor wage rates in the states that Portland bases its operations, updated from the previous rate case. The ALJ noted that in Opinion No. 510, the Commission adopted Trial Staff's mix of 6.9 percent union and 93.1 percent non-union labor rates weighted for the amount of Portland pipeline in Maine, Massachusetts, and New Hampshire.²²⁵ The Commission accepted Trial Staff's use of private construction data for its labor rates and stated that Portland made "no showing that non-union licensed contractors with similar labor skills could not perform the act of decommissioning Portland's pipeline in the same safe and skillful manner as union laborers."²²⁶ In the instant proceeding, the ALJ reasoned that Trial Staff's 8.6 percent union and 91.4 percent non-union labor rates are similar to the percentages the Commission accepted in Opinion No. 510.²²⁷ Furthermore, Trial Staff's use of private construction worker statistics in the instant proceeding is consistent with the Commission's decision in Opinion No. 510, as is its weighting the labor rates for the percentage of Portland's pipeline in Maine, Massachusetts, and New Hampshire.

164. Trial Staff's analysis, which the ALJ adopted, analyzed and rebutted Portland's evidence. According to Trial Staff, Portland presented no evidence that labor will have to

²²⁴ Portland Brief on Exception at 76.

²²⁵ Opinion No. 510, 134 FERC ¶ 61,129 at PP 123-24.

²²⁶ *Id.*

²²⁷ ID, 137 FERC ¶ 63,018 at PP 1123-24.

be hired from only the Boston area to perform these retirements. Nor does Portland make a showing that non-union licensed contractors with similar labor skills could not perform the act of decommissioning Portland's pipeline in the same safe and skillful manner as union laborers. Therefore Trial Staff's assumption that decommissioning a pipeline can utilize a significant proportion of local labor is still reasonable. This finding is consistent with Opinion No. 510.²²⁸

2. Line Pack Gas

Initial Decision

165. The ALJ accepted Portland's estimated sales price for line pack of \$5.22 per 1,000 cubic feet (Mcf) upon decommissioning of the pipeline for negative salvage estimates, which is based on the spot price for natural gas at Dracut on February 28, 2010.²²⁹

166. Trial Staff argued that Portland's line pack gas will sell for \$6.50 per Mcf at the time of Portland's final abandonment.²³⁰ This amount represents the average of the day-ahead Intercontinental Exchange gas price at Dracut, Massachusetts, which is the southern terminus of Portland, for December 2008, January, February, and December 2009, January, February, and December of 2010, and January 1 through January 14, 2011.²³¹ Trial Staff used a three-year average of winter gas prices because of the volatility of gas prices, and the belief that Portland will sell its gas when the prices are historically highest.²³²

167. The Presiding Judge selected Portland's proposed line pack price of \$5.22 per Mcf "because of the similarity between" Portland's proposed price and the average spot price during the year-long test period of \$5.16 per Dth.²³³ The ALJ also adopted Portland's

²²⁸ Opinion No. 510, 134 FERC ¶ 61,129 at P 124.

²²⁹ ID, 137 FERC ¶ 63,018 at P 1111 & n.451 (citing Exh. Nos. PNG-184 and PNG 187).

²³⁰ Trial Staff Brief on Exceptions at 92 (citing Exh. No. S-19 at 17).

²³¹ *Id.*

²³² Trial Staff Brief on Exceptions at 92.

²³³ ID, 137 FERC ¶ 63,018 at P 1132. In a certificate proceeding, pipeline capacity generally is stated in volumetric units. However, pipelines are required to state

(continued...)

position that Portland will sell its line pack at whatever time of year the Commission issues the abandonment order.²³⁴

Briefs on Exceptions and Opposing Exceptions

168. Trial Staff takes exception to the ALJ's adoption of Portland's proposed \$5.22 per Mcf price that line pack gas will sell for at the time of Portland's final abandonment.²³⁵ Trial Staff proposed \$6.50 per Mcf, a three-year average of winter gas prices at Dracut, Massachusetts, because of the volatility of gas prices — according to Trial Staff Portland delivers most of its gas during the winter when temperatures are coldest and demand is highest in the market area and historical natural gas prices tend to be highest in the winter.²³⁶

169. Portland's proposed line pack price of \$5.22 per Mcf is based on the spot price at Dracut, Massachusetts on a single day, February 28, 2010.²³⁷ Trial Staff argues that the Presiding Judge's confirmation of Portland's selection of the February 28, 2010 line pack price was arbitrary.²³⁸ Additionally, Trial Staff asserted that the line pack price on one date cannot accurately reflect the day-to-day or the year-to-year fluctuations in the line pack price; and the Presiding Judge should have, instead, adopted an average line pack price, taking into account daily and annual price variations.²³⁹ Trial Staff argued further,

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 applying a ratio based on the heating content of gas delivered by Portland into the Joint Facilities (1004 Btu) to Portland's volumetric capacity entitlement on the Joint Facilities (210,000 Mcf per day). Thus, for Portland, one Mcf provides approximately one Dth subject to Portland's conversion factor of 1.004 Btu/scf [standard cubic foot], based on the heating value of gas received at Pittsburg, N.H. *See* Exh. No. PSG-143 at 6 (Fink Supplemental Testimony).

²³⁴ ID, 137 FERC ¶ 63,018 at P 1130.

²³⁵ Trial Staff Brief on Exceptions at 92.

²³⁶ *Id.* (citing ID, 137 FERC ¶ 63,018 at P 1067).

²³⁷ *See* Exh. No. PNG-16 at 17.

²³⁸ Trial Staff Brief on Exceptions at 93 (citing ID, 137 FERC ¶ 63,018 at P 1131).

²³⁹ *Id.*

that the ALJ did not consider the fact that Portland will be able to select the date on which it sells its line pack after abandonment, which Trial Staff believes will likely be a date before the end of the winter season due to the higher prices at Dracut during the winter season.²⁴⁰

Commission Determination

170. The Commission affirms the ALJ's findings concerning the appropriate sales price estimate for Portland's line pack gas at decommissioning. The ALJ determined that Portland's argument that it will begin its abandonment process and sell its linepack at the point in time during the year that the abandonment order is issued is reasonable.²⁴¹ The ALJ further agreed with Portland's assertion that there is no evidence in the record showing that the monetary benefits of waiting until winter to sell linepack would outweigh the costs of delaying abandonment.²⁴²

171. In the ID, the ALJ determined that neither Portland's nor Trial Staff's linepack spot price data is manifestly representative of the price of gas throughout the year based on the sources and timing of the data.²⁴³ Based on data already in the record, the ALJ calculated the average spot price of gas at Dracut during the test period, from December 1, 2009, to November 30, 2010 of \$5.16 per Dth,²⁴⁴ close to Portland's recommended spot price of \$5.22 per Dth.

²⁴⁰ *Id.* at 94.

²⁴¹ ID, 137 FERC ¶ 63,018 at P 1130.

²⁴² In fact, Taylor testified that the total annual property taxes on the Portland system were approximately \$6 million. Tr. 2116. By comparison, Taylor calculated that the difference between Portland's and Trial Staff's total line pack salvage values (Trial Staff's being based on winter rates) was \$323,539. Exh. No. PNG-184 at 12-13.

²⁴³ ID, 137 FERC ¶ 63,018 at P 1131.

²⁴⁴ The ALJ performed this calculation by: (1) taking the average spot price for each of the trade dates for December 2009, January 2010, and February 2010 from Exh. No. S-20 at 25; (2) taking the average spot price for each of the trade dates for March 2010 through November 2010 from Exh. No. PNG-187 at 2-10; and (3) adding all of the spot prices from the first two steps and dividing by the total number of trade dates for the year. The result of this calculation is the average spot price of \$5.16 per Dth.

172. Because of the similarity between the two numbers, the ALJ concluded that Portland's recommended price is representative of the price it can expect to receive when it sells its linepack upon abandonment. Consequently, the ALJ adopted Portland's recommended linepack price of \$5.22 per Dth.²⁴⁵ The ALJ's adoption of the Portland number based on its similarity to a yearly average calculated from the evidence indicates that he analyzed the data and the testimony provided and made a reasoned decision based thereon.

3. Appropriate Recovery Period for Negative Salvage

173. The ALJ's findings and the exceptions for the appropriate recovery period of negative salvage are the same as those for depreciation rates. The Commission addresses that issue above, and finds that Portland should retain its existing depreciation rate of 2.0 percent. As the negative salvage allowance in a pipeline rate case recovers costs the pipeline will incur upon retirement of plant, negative salvage costs need to be recovered over a term consistent with the expected plant retirement date. In Portland's case, where there is a history of limited changes to gross plant and no interim retirements, the two percent depreciation rate provides a good estimate of the remaining life over which to recover negative salvage costs. The Commission finds that the appropriate recovery period for Portland's negative salvage costs is the same as its depreciable life determined above. This finding is also consistent with Opinion No. 510.²⁴⁶

VI. Rate Design

A. At-Risk Condition

Background

174. The Commission established Portland's "at-risk" condition in its certificate proceedings. In the July 1997 Certificate Order, the Commission directed Portland to revise its initial rates to reflect billing determinants based on capacity of 178,000 Mcf per day for the first year of service and, in subsequent years, 210,000 Mcf per day.²⁴⁷ Specifically, the Commission stated:

²⁴⁵ ID, 137 FERC ¶ 63,018 at P 1132.

²⁴⁶ Opinion No. 510, 134 FERC ¶ 61,129 at P 125.

²⁴⁷ July 1997 Certificate Order, 80 FERC ¶ 61,134 at 61,448.

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.²⁴⁸

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 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.²⁴⁹

175. Portland sought rehearing of the July 1997 Certificate Order. Among other things, Portland objected to 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 being 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 an order issued on September 24, 1997 (the September 1997 Certificate and Rehearing Order), the Commission granted Portland's rehearing request, agreeing with Portland that it was

²⁴⁸ *Id.*

²⁴⁹ *Id.*

premature, based on the current facts, to require Portland to revise its rates and to be placed at risk for 210,000 Mcf per day of capacity after its first year of operation.²⁵⁰ The Commission stated it would instead review the matter when Portland made its first NGA section 4 rate filing within three years of its in-service date.²⁵¹

176. Thereafter, on October 1, 2001, Portland made a section 4 rate filing in Docket No. RP02-13 as required by the certificate orders. The rate filing ended in the 2002 Settlement, an uncontested settlement which the Commission approved on January 12, 2003,²⁵² and thus that rate case did not resolve the issue of the appropriate level of Portland's at-risk condition.

177. On April 1, 2008, Portland made its 2008 Rate Filing in Docket No. RP08-306-000. There, Portland proposed to design its rates based upon billing determinants of 210,840 Dth per day, but 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 based on its design capacity during its first year of service. In Opinion No. 510, the Commission affirmed the ALJ's decision to establish Portland's at-risk condition at a level of 210,840 Dth per day.²⁵³ In Opinion No. 510-A, the Commission is granting PSG's request for rehearing regarding the level of Portland's at-risk condition. Upon further review, the Commission finds on rehearing that, as of the time of the Docket No. RP08-306-000 rate case, Portland's design capacity was at least 217,405 Dth per day, and therefore its at-risk condition should be set at that level.²⁵⁴ Opinion No. 510-A notes that in Opinion No. 510, the Commission had agreed with the ALJ 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. Opinion No. 510-A finds, however, that Portland's at-risk condition in the certificate proceedings was based on the winter-day design capacity of the Northern Facilities, not its capacity entitlement on the Joint Facilities. Accordingly, upon a further analysis of the record showing that Portland's winter-day design capacity during the test period for that proceeding was 217,405 Dth per

²⁵⁰ September 1997 Certificate and Rehearing Order, 80 FERC ¶ 61,345.

²⁵¹ *Id.* at 62,147.

²⁵² 2002 Settlement Order, 102 FERC ¶ 61,026.

²⁵³ Opinion No. 510, 134 FERC ¶ 61,129 at P 290 (basing at-risk finding of 210,840 Dth per day on Portland's Joint Facility capacity of 210,000 Mcf per day).

²⁵⁴ Opinion No. 510-A, 142 FERC ¶ 61,198 at P 59.

day, the Commission in Opinion No. 510-A established Portland's at-condition at that same level, 217,405 Dth per day.²⁵⁵

178. Since Portland made the 2008 Rate Filing, its capacity on its Northern Facilities has been reduced. In May 2006, Maritimes/Northeast filed an application in CP06-335 for its Phase IV Expansion project, which Maritimes/Northeast claimed was designed to provide the additional capacity necessary to accommodate supplies of regasified liquefied natural gas (LNG) from the proposed Canaport LNG import terminal to be located in Saint John, New Brunswick, Canada. According to the application, the Phase IV Project would increase the mainline capacity of the Maritimes/Northeast system from 415,480 Dth per day to 833,317 Dth per day. Maritimes/Northeast also proposed to expand the Joint Facilities by 393,000 Dth per day. Portland protested Maritimes/Northeast's application, claiming that the expansion was oversized, would unfairly benefit Maritimes/Northeast's shippers and its affiliate Algonquin pipeline to the detriment of Portland's shippers, and would result in a loss of capacity on Portland's Northern Facilities. Portland also claimed that Maritimes/Northeast failed to abide by the terms of the Definitive Agreements governing expansions. Portland also protested Maritimes/Northeast's proposed rate settlement in Docket No. RP04-360, which it claimed facilitated the Phase IV Expansion. The Commission ultimately ruled against Portland in the Phase IV Expansion proceeding,²⁵⁶ and approved the Docket No. RP04-360 Settlement over Portland's objections.²⁵⁷

179. Upon rejection of its challenges to Phase IV Expansion, Portland entered into the 2006 Settlement with Maritimes/Northeast that amended the Definitive Agreements to address future expansions and required Portland to withdraw its protest to the Phase IV application, which the Commission approved.²⁵⁸ Portland then filed a request for a Declaratory Order in Docket No. RP08-70, seeking an order stating that once the Phase IV facilities were placed in service, Portland's system-wide or "end-to-end" capacity (i.e. its ability to transport gas all the way from Pittsburg, NH to Dracut, MA) would be reduced to 168,000 Mcf per day on a year round basis. In June 2008, the Commission granted Portland's request, issuing an order finding that based on a review of the

²⁵⁵ *Id.* P 56.

²⁵⁶ Phase IV Certificate Order, 118 FERC ¶ 61,137 (2007).

²⁵⁷ *See Maritimes and Northeast Pipeline, LLC*, 115 FERC ¶ 61,176 (2006).

²⁵⁸ *Maritimes & Northeast Pipeline, L.L.C. and Portland Natural Gas Transmission System*, 118 FERC ¶ 61,193 (2007) (2006 Settlement Order). *See also* Exh. No. 281: settlement agreement filed Dec. 18, 2006 in Docket No. CP97-238-012

engineering information submitted, Portland would be incapable of transporting in excess of 168,000 Mcf per day all the way from Pittsburg to Dracut after Maritimes/Northeast placed its Phase IV Expansion into service.²⁵⁹

180. The Commission explained that Portland's capacity from Pittsburg, New Hampshire, to the interconnection of its Northern Facilities with the Joint Facilities at Westbrook, Maine, is dependent on both the receipt pressure from Trans-Quebec & Maritimes at Pittsburg and the minimum delivery pressure from Portland to the Joint Facilities at Westbrook. The Commission found that when the Maritimes/Northeast Phase IV Expansion is placed into service the minimum delivery pressure from Portland to the Joint Facilities will be higher than the current design pressure. These changes will reduce Portland's ability to transport gas all the way from Pittsburg to Dracut to 168,000 Mcf per day.

181. However, the Commission stated that this finding did not affect Portland's capacity rights of 210,000 Mcf per day in the Joint Facilities between Westbrook and Dracut as defined in the Definitive Agreements between Portland and Maritimes, and that Portland's capacity rights on the Joint Facilities would remain unchanged. The Commission in the Declaratory Order also reserved for Portland's next rate proceeding (i.e. the instant proceeding) the impact of the capacity finding on Portland's rates. On rehearing, the Commission expressly stated that the Declaratory Order "did not address or change the at-risk condition imposed on [Portland] by the certificate orders. The at-risk condition relates to the design of [Portland's] rates and is more appropriately addressed in [Portland's] next rate proceeding."²⁶⁰ Opinion No. 510-A reaffirmed this finding.²⁶¹

182. This rate case is Portland's first rate case since the in-service date of Maritimes/Northeast's Phase IV Expansion. In this rate case, Portland asserts that its at-risk condition should be reduced to 168,672 Dth per day. Through the testimony of its witness David J. Haag, Portland contends that in the Declaratory Order the Commission irrefutably declared the firm capacity of its system at the end of the test period to be 168,672 Dth per day. Portland states that figure was the one the Commission established

²⁵⁹ *Portland Natural Gas Transmission System*, 123 FERC ¶ 61,275 (Declaratory Order), *order on reh'g*, 125 FERC ¶ 61,198 (2008) (Declaratory Order Rehearing), *petition for review dismissed, PNGTS Shippers' Group v. FERC*, 592 F.3d 132 (D.C. Cir. 2010) (finding lack of standing).

²⁶⁰ 125 FERC ¶ 61,198 at P 20.

²⁶¹ Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 66.

in the Declaratory Order when it stated that Portland would be “incapable of transporting in excess of 168,000 Mcf per day on a firm year-round basis from Pittsburg to Dracut after Maritimes/Northeast’s Phase IV Expansion facilities are placed in service.”²⁶² According to Portland, the referenced Maritimes/Northeast’s expansion facilities were placed in-service on January 15, 2009.²⁶³ Portland contends that because there have been no additions or modifications to Portland’s wholly owned system or the Joint Facilities since the in-service date of the Phase IV Expansion, its current certificated capacity is 168,000 Mcf per day. Portland contends that consequently 168,000 Mcf per day is its at-risk condition.

Initial Decision

183. The ALJ held that Portland’s capacity at the end of the test period in this proceeding, (i.e., November 30, 2010), and hence its at-risk condition, is 168,672 Dth per day.²⁶⁴ The ALJ based this determination in part on the 2008 Declaratory Order’s finding that Portland’s system capacity once the Phase IV Expansion went into service would be 168,000 Mcf per day. The ALJ also recognized that in Opinion No. 510 the Commission found Portland’s at-risk condition in that proceeding was 210,840 Dth per day based on Portland’s capacity at the end of the test period in that case. According to the ALJ, the Commission in Opinion No. 510 clarified that its intention since the issuance of the certificate orders was to base Portland’s at-risk condition on its actual capacity, and that the pipeline would be at risk for any unsubscribed capacity up to that actual amount.²⁶⁵

184. In order to give effect to the 2008 Declaratory Order in light of Opinion No. 510, the ALJ reasoned it was necessary to establish Portland’s actual capacity as of the end of the test period in this proceeding. The ALJ determined that while Portland’s actual capacity was 168,672 Dth per day at the beginning of the test period, the record did not precisely establish Portland’s actual capacity on November 30, 2010. The ALJ thus found the best record evidence of Portland’s actually available firm year round capacity was Portland’s 45-day filing exhibit, which reflected that the full year contracted firm service entitlements on the system were 168,672 Dth per day. The ALJ thus concluded that Portland’s capacity at the end of the test year in this proceeding, and thus the at-risk

²⁶² Exh. No. PNG-1 at 9, lines 8-10 (Haag Direct Testimony).

²⁶³ *Id.*

²⁶⁴ *Id.*, 137 FERC ¶ 63,018 at P 1162.

²⁶⁵ *Id.* P 1150 (citing Opinion No. 510, 134 FERC ¶ 61,129 at P 290).

condition, was 168,672 Dth per day. The ALJ also stated that any party seeking to change that level carried the burden to establish by a preponderance of the evidence that the existing at-risk level, which Portland seeks to continue, is not just and reasonable.

185. The ALJ rejected PSG's assertions that the at-risk level ought to be at least 217,430 Dth per day, finding that the documents cited in support preceded the end of the test period in this case or relate to the Joint Facilities, which the ALJ considered irrelevant to the determination of Portland's capacity at the end of the test period. The ALJ found that the Commission had consistently determined that Portland's appropriate at-risk level should be established based on the pipeline's actual capacity at the end of the appropriate test period. Accordingly, the ALJ found all arguments regarding Portland's capacity levels at other time periods to be irrelevant.²⁶⁶

186. The ALJ also rejected as redundant or irrelevant arguments by PSG and Trial Staff that Portland was complicit by its conduct in the loss of its system capacity, and that Portland should have sought section 7 abandonment authority for the capacity reduction.²⁶⁷ Based on the finding in the Declaratory Order that Portland's certificated capacity was 168,672 Dth per day after the Phase IV in-service, the ALJ found that PSG's and Trial Staff's arguments as to alternative actions Portland may have pursued were conjecture and speculation. The ALJ also found that Trial Staff's claim that Portland should have filed an abandonment application was not ripe for decision.²⁶⁸

PSG's and Trial Staff's Briefs on Exceptions

187. PSG and Trial Staff except to the ALJ's holding with regard to the at-risk condition on several grounds. As a policy matter, PSG asserts that the ID shifts to Portland's customers the costs of unsubscribed capacity in direct contradiction of the Commission's at-risk policy. According to PSG, the decision in the ID "eviscerates the at-risk protections originally provided to Portland's shippers"²⁶⁹ and thus encourages pipelines to manipulate capacity to avoid the consequences of lost customer load. PSG asserts that the reasoning behind the at-risk policy is that because the pipeline is in a better position to evaluate whether and how large to build facilities, the pipeline should

²⁶⁶ *Id.* P 1160.

²⁶⁷ *Id.* PP 1170, 1190-91.

²⁶⁸ *Id.* P 1144 & n.497.

²⁶⁹ PSG Brief on Exceptions at 12.

bear the risk of under-recovery if that judgment turns out to be wrong.²⁷⁰ PSG contends that Portland built facilities that could accommodate over 210,000 Mcf per day of firm demand, yet that decision turned out to be wrong as Portland lost approximately 30 percent of that projected firm load. Trial Staff makes a similar argument that the ID contradicts Commission policy in its rulings regarding Portland's at-risk condition and billing determinants.

188. PSG and Trial Staff claim that the ID erroneously concluded the Declaratory Order was dispositive of Portland's at-risk condition. Specifically Trial Staff asserts that the ID was wrong to afford what it considers "concrete effect for rate purposes" to the Declaratory Order.²⁷¹ PSG argues that contrary to the findings in the ID, the Declaratory Order did not determine Portland's at-risk level for this case nor did it hold that Portland's "end to end" capacity, absent consideration of Portland's capacity on the Joint Facilities, is the appropriate measure of Portland's at-risk obligation.²⁷² PSG also argues that Portland was responsible for its own loss of capacity, and thus should not benefit therefrom. PSG claims that the ID's at-risk determination was erroneous because it ignored record evidence as to Portland's actual system receipt and delivery capabilities, as well as evidence of Portland's conduct and how that conduct created the circumstances giving rise to the capacity loss.

189. PSG asserts that the ALJ misapplied the determination of end-to-end capacity made in the Declaratory Order.²⁷³ PSG claims that contrary to findings in the ID, the Declaratory Order did not determine that Portland's "end-to-end" (Pittsburg, NH to Dracut, MA) was the appropriate measure of capacity for billing determinant and at-risk condition purposes, nor did it determine that Portland's capacity on the Joint Facilities is irrelevant to a determination of Portland's at-risk condition. According to PSG, the Declaratory Order did not establish the overall physical capacity of the Portland system to transport and deliver gas. PSG claims instead the 168,000 Mcf per day figure established in the Declaratory Order proceeding only established the capacity of Portland to transport volumes the entire length of its system from Pittsburg to Dracut. PSG contends that the Declaratory Order analysis does not account for the fact that Portland

²⁷⁰ *Id.* at 12 (citing ID, 137 FERC ¶ 63,018 at P 1177).

²⁷¹ Trial Staff Brief on Exceptions at 10.

²⁷² PSG Brief on Exceptions at 17 (citing Opinion No. 510, 134 FERC ¶ 61,129 at P 1170 & n.525).

²⁷³ *Id.* at 38-43.

has an alternate supply source from Maritimes' system at Westbrook, or that there are more delivery points than Dracut.²⁷⁴

190. PSG also argues that the Declaratory Order did not find that Portland's capacity on the Joint Facilities is irrelevant to its at-risk condition. According to PSG, the Commission in the Declaratory Order "simply observed that the Pittsburg-to-Dracut capacity determination made therein did not affect Portland's Joint Facility capacity rights of 210,000 Mcf per day" as set forth in the Definitive Agreements.²⁷⁵ PSG states that basing Portland's at-risk condition on only the 168,000 Mcf per day, as the ID does, would not hold Portland at risk for its 210,000 Mcf per day Joint Facility entitlement.

191. PSG further asserts that the ID ignored evidence establishing that Portland has capacity of at least 217,430 Dth per day, which it contends should be used as the at-risk figure.²⁷⁶ PSG asserts that the ALJ's conclusion in the ID that there is no support in the record for Portland having capacity of 217,430 Dth per day of capacity failed to consider extensive evidence supported by its Witness Fink that Portland has the physical capacity to receive, transport and deliver at least 217,430 Dth per day. According to PSG, flow diagrams and capacity studies submitted by Portland in the Maritimes/Northeast Phase IV Expansion proceedings show Portland has capacity to deliver and receive into the Joint Facilities at Westbrook 217,431 Dth per day at an inlet pressure of 1175 psig,²⁷⁷ and capacity studies submitted in the Declaratory Order proceeding show Portland having 217,430 Dth per day of Joint Facility capacity at Westbrook after the Phase IV Expansion.²⁷⁸ PSG further asserts that those studies were consistent with studies filed by Maritimes/Northeast with its amended Phase IV Expansion application. Further, PSG contends that an engineering analysis of those studies "confirmed" that Portland would have Joint Facility capacity of 217,430 Dth per day to 217,881 Dth per day that would not be affected by the Phase IV Expansion. PSG states that Portland's and Maritimes/Northeast's figures showing capacity levels of

²⁷⁴ PSG asserts that the volumes Portland receives from Maritimes at Westbrook (almost 37,000 Dth per day on average), in addition to the volumes received at Pittsburg, enable Portland to fully utilize its 210,000 Mcf per day base capacity entitlement on the Joint Facilities. PSG Brief on Exceptions at 39.

²⁷⁵ *Id.* at 41-42.

²⁷⁶ *Id.* at 43-52.

²⁷⁷ *Id.* at 45 (citing Exh. No. PSG-39 at 28).

²⁷⁸ *Id.* (citing Exh. Nos. PSG-50 and PSG-58).

217,000 Dth per day and above are based on Portland's volumetric Joint Facility capacity entitlement of 210,000 Mcf per day, converted to a thermal equivalent for operating purposes.²⁷⁹

192. PSG and Trial Staff both except to the ID's determination that purportedly extensive evidence as to Portland's own accountability for the loss of capacity discussed above was irrelevant to the level of Portland's at-risk condition and billing determinants.²⁸⁰ According to PSG, the Declaratory Order deferred consideration of issues concerning Portland's alleged conduct in creating its capacity loss to this proceeding. PSG argues that the ID's failure to even consider evidence of Portland's conduct in bringing about the system capacity loss was error and lead to unwarranted findings. Trial Staff likewise argues that the court decision reviewing the Declaratory Order, and the Declaratory Order itself, obligate the Commission to address the conduct issue in this case.²⁸¹

193. PSG also claims that facilities existed that would have enabled Portland to avoid at little to no cost the Joint Facility inlet pressure increase and purported loss of capacity. According to PSG, there was an alternate Phase IV design that could have avoided increasing Portland's inlet pressure. According to PSG, if Portland's Northern System had been connected upstream instead of between the two new compressors, Portland would have been able to maintain, or perhaps even increase its capacity of 210,000 Mcf per day. PSG concluded that Portland voluntarily chose to increase its pressure obligation and could have avoided its purported capacity loss at little to no cost if it had

²⁷⁹ *Id.* at 58. According to PSG, record evidence shows that Portland's capacity entitlement on the Joint Facilities on a thermal equivalency basis is determined by the heating value of the commingled stream received from both Portland and Maritimes. PSG claims Portland's capacity on the Joint Facilities is based on the comingled heating value of the gas. PSG contends that to ensure Portland receives its total volumetric entitlement at Dracut, Portland has the authority to increase deliveries of lower Btu gas into the Joint Facilities at Westbrook.

²⁸⁰ PSG Brief on Exceptions at 52-65. PSG and Trial Staff make a similar argument with regard Portland's failure to seek NGA section 7(b) abandonment authority for Portland's reduction in capacity. *Id.* at 65-68; Trial Staff Brief on Exceptions at 45-54.

²⁸¹ Trial Staff Brief on Exceptions at 18 (citing *PNGTS Shippers' Group v. FERC*, 592 F.3d 132).

not agreed to the pressure obligation increase and to the Phase IV Expansion design by withdrawing its opposition to the Phase IV Expansion project.²⁸²

194. PSG and Trial Staff also claim that the ALJ misconstrued the burden of proof as to the level of Portland's at-risk condition.²⁸³ PSG challenges the ALJ's statement that:

In its Initial Brief, relying solely on the Commission's 2008 [Declaratory Order] ruling, Portland is seeking a continuation of that [168,000 Mcf per day] level.... Therefore, even though it cited to no portion of the record supporting its position in either of its briefs, Portland has no burden of proof.

195. Finally, PSG and Trial Staff challenge the ID's finding that any party seeking a change in that capacity level bore the burden of proof to show it was not just and reasonable and that an alternate proposal is just and reasonable. PSG contends that as the proponent of an NGA section 4 general rate filing that seeks increased rates based in substantial part upon reduced billing determinants and a reduced at-risk level, Portland bore the burden to show that use of the capacity figures would result in just and reasonable rates. PSG claims Portland failed to make such a showing, and that the ALJ's assignment of burden of proof is wrong. Trial Staff also argues that the ID erred in relieving Portland from its NGA section 4 burden of proof with regard to the at-risk and billing determinant issues, as well as in its failure to address Portland's conduct with respect to the loss of system capacity. Trial Staff also argues that the ALJ erred by summarily dismissing the arguments that the Commission should initiate a section 5 proceeding or refer Portland to the Commission's Office of Enforcement.

Portland's Brief on Exceptions

196. Portland excepts to the ALJ's statement that the record in this case "does not establish precisely what Portland's actually available capacity was on November 30, 2010." According to Portland its engineering expert specifically testified that on a year round basis, Portland cannot transport more than 168,000 Mcf per day.²⁸⁴ Portland also notes that in the Declaratory Order the Commission determined Portland would not be able to transport more than that volume once the Maritimes/Northeast's Phase IV

²⁸² PSG Brief on Exceptions at 29-35.

²⁸³ *Id.* at 35-37; Trial Staff Brief on Exceptions at 40-45.

²⁸⁴ Portland Brief on Exceptions at 77 (citing Exh. No. PNG-134 at 11).

Expansion went into service. Portland thus concludes that the record does reflect its actual capacity at the end of the test period.

197. Portland also challenges the ID to the extent that the ALJ's reasoning regarding the at-risk condition is limited to the available capacity on a single day. Portland states that in paraphrasing Opinion No. 510's reference to the actual capacity of the pipeline, the ALJ states that the standard for the at-risk condition in this case should be Portland's "actually available capacity... on November 30, 2010." Portland states that to the extent the ALJ in the ID intended to set the at-risk condition or billing determinants based on the total capacity that may exist on one single day due to transitory factors, it excepts. Portland claims that although the Commission has recognized pipelines may be able to operate under certain conditions that would produce more capacity on a particular day than the system can reliably provide year-round, it is not appropriate to base one's billing determinants on the higher occasional levels.

Briefs Opposing Exceptions

Portland

198. Portland argues that the ID was correct to set its at-risk and billing determinant levels at 168,672 Dth per day consistent with the Commission's regulations.²⁸⁵ Portland asserts that finding leaves Portland at-risk for the difference between its "seasonally weighted" firm contract demand of 134,867 Dth per day and its maximum annual firm system capacity of 168,672 Dth per day. Portland argues that the Commission has held that the at-risk condition should apply to "actual capacity" based on the "pipeline as a whole," and thus, the finding in the Declaratory Order that Portland's post Phase IV actual system firm capacity is 168,672 Dth per day set Portland's at-risk condition. Portland further contends that setting the at-risk condition as the ID did at 168,672 Dth per day fully comports with the certificate orders, the Commission's case law, and the Commission's regulations. Portland states that the original certificate order held it at risk for unsubscribed seasonal capacity and that the at-risk condition in the ID continues to hold Portland responsible for those decontracted summer volumes. Portland claims those orders also recognized that level could change due to potential changes in Portland's capacity over time, and that the ID effectuates that intention.²⁸⁶

²⁸⁵ See Portland Brief Opposing Exceptions at 48-50.

²⁸⁶ See *id.* at 50-57 for the history of Portland's at-risk condition and alleged contributions of other parties to that history.

199. Portland also asserts that PSG and Trial Staff misunderstood the engineering circumstances and flow diagrams.²⁸⁷ Portland claims that as the Commission recognized in Opinion No. 510, the at-risk condition should be set on the basis of Portland's annual actual firm sustainable capacity and not on higher capacity figures that may be operationally possible on a transitory basis on certain days. Portland argues that PSG's contentions that flow diagrams submitted in the Phase IV Expansion proceedings show that Portland has capacity of at least 217,430 Dth per day are misplaced and based on a fundamental misunderstanding of the difference between design day capacity and transitory capacity reflecting changing operating conditions.²⁸⁸

200. Portland also claims that PSG's thermal value argument lacks merit. Portland asserts that contrary to PSG's claims, Portland cannot reliably sell a thermal equivalent of gas on a firm basis above its 210,000 Mcf per day volumetric entitlement on the Joint Facilities because it does not control Maritimes' tenders of gas at Westbrook and thus cannot rely on Maritimes to deliver higher Btu gas into the Joint Facilities on a regular basis.

201. Portland states that arguments it was responsible for the capacity loss are meritless, and that capacity reduction was a consequence of the action of many contributors, including the PSG members. Moreover Portland asserts that its adversaries' arguments ignore the fact that throughout the Phase IV proceeding Portland was exploring adding compression upstream of Westbrook even after September 2006, and that the 2006 Settlement gave Portland the opportunity to claim future inexpensive expansibility on the Joint Facilities. Portland claims by January 2008, however, that it was clear no shippers sought additional capacity on Portland, and that the Commission was likely to approve the Phase IV Expansion over Portland's objections. Portland states that it was shortly thereafter that it filed the petition in the declaratory order proceeding. Portland also argues that the PSG and Trial Staff positions ignore the recognized benefits of the Portland /Maritimes 2006 Settlement, as set forth in the ID.²⁸⁹

²⁸⁷ *Id.* at 65-72.

²⁸⁸ *Id.* at 66.

²⁸⁹ *Id.* at 40-41. According to Portland the Commission found that the settlement would "provide benefits to the shippers of both Maritimes and [Portland] because it removes uncertainty regarding various cost and ownership issues related to 'the Joint Facilities, as well as assisting in the certification of the Phase IV Expansion and the resolution of [that] docket.'" Portland further claims that PSG and Trial Staff fail to acknowledge that any diminution in capacity or deliverability on Portland's system as a

202. Portland argues that PSG and Trial Staff arguments regarding Portland's purported abandonment obligations are collateral attacks on the Declaratory Order, which made clear that Portland's certificated capacity as of the in-service date of the Phase IV Expansion would be 168,000 Mcf per day. Portland argues that arguments that it engaged in an unauthorized abandonment represent a misunderstanding and misapplication of law, and fail to recognize that Portland had pre-granted abandonment authority pursuant to our regulations to abandon service, and that no facilities were abandoned.²⁹⁰ Portland argues that while the D.C. Circuit stated that the parties would have an opportunity to present challenges to the Commission's failure to require Portland to file an abandonment application, the court did not hold that additional abandonment authority was required. Portland asserts that the Trial Staff and PSG have been given the opportunity to present their claims regarding abandonment and those claims do not show that additional abandonment authority was required.

203. Finally, as to the burden of proof issue, Portland states that Trial Staff and PSG misstate the ID's findings on the at-risk condition and billing determinants by alleging the ID held that Portland failed to meet its burden of proof. According to Portland, the ID actually stated that Portland failed in its brief to cite to the record for support of its claimed 168,672 Dth per day figure. Portland asserts that its witness testimony and accompanying exhibits establishes that Portland's actual capacity at the end of the test period in this case was 168,672 Dth per day. Portland further claims that its engineering expert specifically stated that Portland cannot transport more than 168,000 Dth per day from Pittsburg to Dracut on a firm, year-round basis, that the Commission determined the same in the Declaratory Order, and that PSG's Witness Smith agreed. Portland thus concludes that the record does reflect Portland actual capacity at the end of the test period in this proceeding, and accordingly it has met its burden of proof on this issue.

PSG

204. In its Brief Opposing Exceptions, PSG reiterates its claim that Portland's at-risk level and billing determinants should be set at no less than 217,430 Dth per day. PSG

result of the Phase IV Expansion is more than made up by the additional capacity made available on Maritimes as result of the expansion and thus that the 2006 Settlement benefitted the New England market as a whole. Portland asserts that due to the overall benefits of the Settlement, setting Portland's billing determinants at 168,672 Dth per day would achieve a fair apportionment of responsibility that reflects the actual end to end firm capacity of Portland's system.

²⁹⁰ Portland Brief Opposing Exceptions at 31-39.

agrees, however, with Trial Staff's claim that there should be an investigation into Portland's conduct.

205. PSG states that Trial Staff's acknowledgement that Portland has had a physical capacity of 168,672 Dth per day since the in-service date of the Phase IV Expansion ignores PSG arguments that the Declaratory Order only established Portland's end-to-end capacity, and that, when one takes into account Portland's second receipt point at Westbrook, any diminution in Portland's ability to transport gas end-to-end does not prevent Portland from utilizing its full capacity entitlement on the Joint Facilities. PSG further objects to Trial Staff's acknowledgement that Portland's capacity was 168,672 Dth per day after January 15, 2009. According to PSG, Trial Staff apparently failed to consider both (a) record evidence regarding pressures that PSG had described in its brief and (b) PSG's evidence regarding Portland's entitlement to thermal capacity in the Joint Facilities. PSG cites this evidence as indicting that thermal capacity in the Joint Facilities is calculated on the blended stream in the Joint Facilities, not solely on the heating value of gas that Portland receives at Pittsburg.

206. As noted, PSG claims that the evidence adduced in this case strongly supports the supposition that Portland deliberately withheld material facts in both the Phase IV Expansion and Declaratory Order proceedings, and thus it agrees that Trial Staff was correct to urge the Commission to conduct an independent investigation into Portland's conduct.

Commission Determination

207. For the reasons discussed below, we determine that the ALJ erred by establishing Portland's at-risk condition at a level of 168,672 Dth per day, and hereby determine that Portland's at-risk condition is 210,000 Mcf per day. It was error to find that Portland's capacity entitlements on the Joint Facilities were irrelevant to the at-risk condition, and to therefore disregard that capacity in the determination of Portland's at-risk condition.

208. The Commission's intent since it first established Portland's at-risk condition in the 1997 Certificate Order, as further clarified in Opinion Nos. 510 and 510-A, was to place Portland at risk for unsubscribed capacity on its Northern Facilities and its Joint Facilities.²⁹¹ The Commission did not limit Portland's at-risk condition solely to its end-to-end design capacity to transport natural gas the entire distance from Pittsburg, New Hampshire to Dracut, Massachusetts.

²⁹¹ Opinion No. 510, 134 FERC ¶ 61,129 at P 290; Opinion No. 510-A at P 173.

209. When the Commission initially established Portland's at-risk condition at 178,000 Mcf per day for the first year and at 210,000 Mcf per day thereafter in the 1997 Certificate Order, the Commission recognized that Portland would have greater capacity on its Northern Facilities than on the Joint Facilities during the first year. The Commission nevertheless established the at-risk condition for the first year based upon the higher capacity of 178,000 Mcf per day on the Northern Facilities, rather than the lower end-to-end capacity of 169,400 Mcf per day:

In the first year of service, PNGTS 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.²⁹²

210. In Opinion No. 510-A, the Commission is similarly establishing Portland's at-risk condition in the 2008 rate case at 217,405 Dth per day, reflecting Portland's ability in the test period there to transport a higher volume of natural gas on the Northern Facilities than the Joint Facilities. Thus, the Commission has not limited Portland's at-risk condition to its "end-to-end" capacity to move gas the entire distance from Pittsburg, NH to Dracut, MA.

211. In this case, we are presented with the reverse situation from the prior instances where we have addressed the level of Portland's at-risk condition. Portland now has greater capacity on the Joint Facilities than the Northern Facilities. In the Declaratory Order, where the Commission determined that Portland's year-round end-to-end annual certificated capacity on the in-service date of the Maritimes/Northeast' Phase IV Expansion project the entire distance from Pittsburg to Dracut would be 168,000 Mcf per day, it specifically noted that determination did not affect Portland's entitlements on the Joint Facilities, nor did it prejudice any impact of that decision on any rate issues, including the at-risk condition and the appropriate billing determinants. The Commission's at-risk policy requires that Portland's capacity on the Joint Facilities be

²⁹² 1997 Certificate Order, 80 FERC ¶ 61,134 at 61,448; *see also* July 1997 Certificate Order, 80 FERC 61,134 at 62,146 (“[W]e are conditioning the certificates issued herein to put both applicants at risk for their portion of the cost of the Phase II (Wells, Maine to Westbrook, Maine) joint facilities”).

included in establishing its at-risk condition, and record evidence shows that Portland has at least 210,000 Mcf per day capacity entitlements on the Joint Facilities from Westbrook to Dracut. Accordingly, it is appropriate to establish 210,000 Mcf per day as Portland's at-risk condition for the relevant period in this case to continue to hold Portland at risk for potential under-recovery of unsubscribed capacity and to prevent shifting costs to Portland's customers, as required in the 1997 Certificate Order.

212. Determining that Portland's at-risk condition is 210,840 Dth per day is consistent with the Declaratory Order's determination that Portland's certificated capacity from Pittsburg, NH to Dracut, MA, once the Phase IV Expansion project went in-service, is 168,000 Mcf per day. The Declaratory Order responded to Portland's request that, due to a reduction in capacity from the Phase IV Expansion, "(i) as of November 1, 2008 the firm year-round capacity across [Portland]'s system would be no more than 168,000 Mcf per day,... and (ii) [Portland may lawfully decline to enter into firm service requests which, ... would obligate PNGTS to transport volumes in excess of 168,000 Mcf per day on a year round basis beginning on November 1, 2008 from Pittsburg, New Hampshire to Dracut, Massachusetts."²⁹³ The Commission addressed that request directly in determining that Portland's certificated capacity from Pittsburg to Dracut as of the in-service date of the Phase IV Expansion would be 168,000 Mcf per day.

213. As PSG notes, however, the Commission did not state in the Declaratory Order that the Pittsburg to Dracut capacity determination was the appropriate measurement for establishing Portland's at-risk condition. To the contrary, in finding that Portland would be "incapable of transporting volumes in excess of 168,000 [Mcf per day] on a firm year-round basis from Pittsburg to Dracut after the in-service date of [Maritimes/Northeast's] Phase IV Expansion,"²⁹⁴ the Commission specifically noted that "this finding does not, however, 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," which rights remain unchanged.²⁹⁵ The Commission further deferred questions regarding the impact of the capacity decision on rate related issues, including the appropriate determinants to use to design Portland's rates, to its next

²⁹³ Portland Petition for Declaratory Order, Docket No. CP08-70-000 (Jan. 31, 2008), provided as Exh. No. PSG-222 at 1.

²⁹⁴ Declaratory Order, 123 FERC ¶ 61,275 at P 28.

²⁹⁵ *Id.* P 28 & n.30. *See also* Exh. No. PNG-262 at 136: Ownership Agreement between Portland and Maritimes, Section 10.1; Maritimes' Brief Opposing Exceptions at 5, 11 (the Phase IV Expansion preserved Portland's capacity entitlement of 210,000 Mcf per day delivered at Dracut).

rate case. Thus, contrary to the ALJ's finding, the Commission did not state that Portland's capacity on the Joint Facilities was irrelevant to establishing its at-risk condition but specifically recognized that Portland's Joint Facility entitlements were not affected by the Phase IV Expansion.

214. Establishing Portland's at-risk condition at 210,000 Mcf per day also preserves the Commission's intent underlying the at-risk policy applied in the 1997 Certificate Order and the reason for placing Portland at risk for unsubscribed capacity, namely, to prevent shifting of those costs from the pipeline to its customers. The rationale underlying the policy was that because the pipeline is in a better position to evaluate whether and how large to build facilities, the pipeline should bear the risk of under-recovery if that judgment turns out to be wrong.²⁹⁶ The Commission certificated Portland for 210,000 Mcf per day on the wholly-owned and the Joint Facilities, and while we recognized in the Declaratory Order that Portland's Pittsburg to Westbrook capacity would be reduced as a result of the Phase IV Expansion, Portland retained its 210,000 Mcf per day capacity entitlements in the Joint Facilities. Basing Portland's at-risk condition on only the 168,000 Mcf per day would not continue to hold Portland at risk for its 210,000 Mcf per day Joint Facility entitlement but would shift the costs of that capacity to Portland's shippers. Such a result contravenes the very purpose of the at-risk condition imposed by the 1997 Certificate Order and relied on by Portland's shippers when they decided to take service on Portland.

215. We find that the record evidence supports that Portland can, and has the right to, transport up to 210,000 Mcf per day on the Joint Facilities. As noted above, Portland's contractual capacity entitlement to 210,000 Mcf per day on the Joint Facilities remains unchanged despite the loss of actual capacity from Pittsburg to Westbrook. Moreover the flow diagrams submitted in the Declaratory Order proceedings show that Portland

²⁹⁶ 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 the 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.

retained its ability to transport up to 210,000 Mcf per day from Westbrook to Dracut on a firm basis,²⁹⁷ and Portland does not contest this fact.²⁹⁸

216. In setting Portland's at-risk condition at 210,000 Mcf per day, we determine that there is insufficient record evidence to support an at-risk level of 217,430 Dth per day as claimed by PSG. PSG asserts that flow diagrams and capacity studies submitted by Portland in the Maritimes/Northeast Phase IV Expansion proceedings show Portland has capacity to deliver and receive 217,431 Dth per day into the Joint Facilities at Westbrook at an inlet pressure of 1175 psig. PSG further asserts that capacity studies submitted in the Declaratory Order proceeding show Portland having 217,430 Dth per day of Joint Facility capacity at Westbrook after the Phase IV Expansion. PSG further asserts that those studies were consistent with studies filed by Maritimes/Northeast with its amended Phase IV Expansion application. PSG contends that an engineering analysis of those studies "confirmed" that Portland would have Joint Facility capacity of 217,430 Dth per day to 217,881 Dth per day that would not be affected by the Phase IV Expansion.

217. Yet, as Portland points out, PSG's claims are based on a misunderstanding of the difference between design day capacity and transitory capacity reflecting changing operating conditions. The record indicates that Portland has neither a contractual right, nor the operational ability, to transport more than 210,000 Mcf per day on the Joint Facilities. As held above, Portland's at-risk condition should be set at its actual capacity level, that is, at the level that it can sell firm capacity on a daily basis. The record evidence shows that Portland has contractual rights to only up to 210,000 Mcf per day on the Joint Facilities,²⁹⁹ and PSG presents no compelling evidence to refute that claim. As

²⁹⁷ "The flow diagrams attached as Exhibit E to the petition show that [Portland]'s capacity rights of 210,000 [Mcf per day] in the joint facilities remain unchanged by this petition." Declaratory Order, 123 FERC ¶ 61,275 at P 28 & n.30.

²⁹⁸ PSG and Trial Staff contend that the Presiding Judge misapplied the burden of proof and gave too much weight to the Declaratory Order's determination that Portland's capacity was 168,672 Dth per day. We agree that Portland had the burden of proof to establish that its at-risk condition should be set at 168,672 Dth per day on both the wholly owned and Joint Facilities. The effect of the ID's error, however, is essentially mooted by our determination that Portland's at-risk condition is 210,000 Mcf per day. As stated, the record demonstrates that Portland is entitled, and has the capability, to transport up to 210,000 Mcf per day the Joint Facilities.

²⁹⁹ The Definitive Ownership Agreement between Maritimes and Portland, which governs the Joint Facilities, states in section 10.1, that Portland has a "Capacity Entitlement Percentage ... of 33.240 percent" (estimated to be 210,000 Mcf per day).

(continued...)

we stated in Opinion No. 510-A, we reject PSG's claim 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).³⁰⁰ As we stated there, based on that average heating value of the gas tendered by Portland to the Joint Facilities, the Definitive Agreements specifically limit Portland's maximum capacity entitlement on the Joint Facilities to 210,840 Dth per day. For purposes of determining Portland's firm capacity entitlement on the Joint Facilities, therefore, the commingled heating value of all gas flowing on the Joint Facilities is irrelevant.

218. Further, the fact that daily operating conditions on the pipeline may at times allow Portland the ability to transport more than 210,000 Mcf per day on the Joint Facilities does not establish a right upon which Portland could sell capacity on a firm basis. That is particularly true here where Maritimes/Northeast operates the Joint Facilities, and thus Portland has no control over the daily operations of the system. Moreover, unlike in Opinion No. 510-A, where the Commission found that Portland's at-risk condition should be 217,405 Dth per day based in part on flow diagrams that showed Portland's ability to transport in excess of 210,000 Mcf per day on its wholly owned facilities prior to the Phase IV Expansion, those flow diagrams demonstrate that after the Phase IV Expansion Portland's capacity on its wholly owned facilities dropped to 168,000 Mcf per day, and thus do not support PSG's position.³⁰¹ It would not be reasonable to hold Portland at risk for unsubscribed capacity that it has no right to sell on a firm basis.

219. We find non-compelling PSG's claims that Portland voluntarily and intentionally gave up capacity on its wholly owned facilities, and from Pittsburg to Dracut, as part of a scheme to reduce its at-risk condition, though our determination that Portland's at-risk condition remains at 210,000 Mcf per day even after the Phase IV Expansion essentially renders that issue irrelevant. PSG asserts that Portland should not be rewarded with a

Exh. No. PSG-262 at 136. Moreover, in responding to PSG's suggestion that Portland could have demanded that Maritimes design its Phase IV Expansion in such a manner that it would not result in a loss of capacity on Portland's wholly owned system, Maritimes states that the "design of the Phase IV Project preserved [Portland's] Capacity Entitlement in the Joint Facilities of 210,000 [Mcf per day] delivered at Dracut." Maritimes Brief Opposing Exceptions at 11.

³⁰⁰ Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 55.

³⁰¹ See Exh. No. PSG-222 at 58: Portland Petition for Declaratory Order, Appendix E-8.

substantial reduction in its at-risk responsibilities as a result of the purportedly manipulative actions it allegedly took to create its capacity loss. Contrary to PSG's assertions, the record indicates that Portland repeatedly opposed the Maritimes' Phase IV Expansion that resulted in the subject loss of capacity until such point as further opposition appeared futile. At that point, without a market for the full amount of its capacity, Portland made a reasonable business decision to enter into a settlement that produced a variety of benefits, as recognized by the Commission, including allowing Maritimes to increase its capacity to meet increased demand.³⁰²

220. We also reject any argument that Portland was required to seek "additional" abandonment approval for its loss of capacity from Pittsburg to Dracut as a result of the Phase IV Expansion. First, our holding that Portland's at-risk condition is 210,000 Mcf per day recognizes that Portland did not "abandon" any capacity or facilities on the Joint Facilities. Second, we specifically held in the Declaratory Order that given the particular circumstances surrounding the uncertainty of Portland's system-wide certificated capacity, the Declaratory Order proceeding was an appropriate vehicle for resolving the matters at issue and that it was unnecessary for Portland to file an abandonment application.³⁰³ As we explained in denying PSG's request for rehearing on this issue, we evaluated Portland's petition for declaratory order under similar requirements set forth in section 7(c) of the NGA and considered all relevant factors in determining whether Portland's petition was consistent with the public convenience and necessity under that provision of the statute.³⁰⁴ Thus, we have already determined that Portland did not need to seek abandonment authorization outside the Declaratory Order proceeding, and PSG's and Trial Staff's arguments to the contrary are impermissible collateral attacks on our orders in that proceeding. PSG's contentions that the D.C. Circuit held that the abandonment issues could be re-visited herein fail because, by PSG's own argument, such action would only be necessary to consider a potential economic impact of a capacity reduction, such as an increase in rates. Our determination that Portland is at risk for 210,840 Dth per day alleviates any such concerns.

³⁰² See 2006 Settlement Order, 118 FERC ¶ 61,193 at P 5 (2007).

³⁰³ Declaratory Order, 123 FERC ¶ 61,275 at P 27.

³⁰⁴ Declaratory Order Rehearing, 125 FERC ¶ 61,198 at P 17.

B. Billing Determinants

Background

221. In its 2010 Rate Filing, Portland proposed that its rates be designed based on billing determinants of 168,672 Dth per day, consistent with its position that its at-risk condition should be reduced to that level. Portland also proposed to change from allocating costs to its interruptible services based upon a projection of interruptible billing determinants, and instead Portland proposed to credit its cost-of-service with the revenues it received from the provision of interruptible services during the test period (\$2,806,872). Finally, it proposed to credit \$2,861,800 against its cost of service as a means of accounting for its receipt of \$119,761,258 in the bankruptcy proceedings of Androscoggin and Rumford, which rejected their firm contracts in 2005 and 2006. Portland referred to this latter credit as the “2010 Rate Case Credit.” We will describe that proposed credit further below. In Opinion No. 510, the Commission required Portland to design rates based on the higher of the at-risk condition of 210,840 Dth per day, or billing determinant level. On rehearing, the Commission found that Portland’s at-risk condition should be 217,405 Dth per day instead of 210,840 Dth per day. Based on the comparison of the at-risk level and the calculated billing determinants, the Commission found that Portland must design its rates for that proceeding based on the level of the new at-risk condition, 217,405 Dth per day.³⁰⁵

Initial Decision

222. In the ID, the ALJ determined that, consistent with the establishment of Portland’s at-risk level at 168,672 Dth per day, Portland’s billing determinants should be set at 168,672 Dth per day, as it proposed.³⁰⁶ The ID recognized that in Opinion No. 510, the Commission held that, in cases like this, where the pipeline has an at-risk condition, Commission policy requires that the pipeline’s rates be designed based on the greater of its projected billing determinants or the volumetric level of the at-risk condition. The ID accepted Trial Staff’s calculation of Portland’s billing determinants totaling 186,631 Dth per day.³⁰⁷ However, the ID noted that Trial Staff’s calculation included discount-

³⁰⁵ Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 55.

³⁰⁶ ID, 137 FERC ¶ 63,018 at P 1182.

³⁰⁷ *Id.* PP 1180-81. *See also* Exh. No. S-27. For the calculation, Trial Staff’s Witness Steffy attributed 150,200 Dth per day for Portland’s winter demand, 9,347 Dth per day to Interruptible Transportation (IT) and Park and Loan (PAL) services, and 27,084 Dth per day to the contracts terminated by the Bankruptcy Court, as adjusted for discounts.

adjusted billing determinants associated with the rejected Androscoggin and Rumford contracts of 27,084 Dth. The ALJ stated that, because he was requiring Portland to provide an annual credit of \$8,544,375 against its cost-of-service,³⁰⁸ the billing determinants associated with the rejected contracts should not be included in the billing determinants used to design Portland's rates. Excluding those billing determinants leaves a balance of 159,547 Dth per day as projected determinants.³⁰⁹ Applying the "greater of policy for designing rates" as directed in Opinion No. 510, the ID sets that billing determinants at 168,672 Dth per day, the greater of the at-risk condition established therein and the 159,547 Dth per day projected billing determinants.³¹⁰

Briefs On and Opposing Exceptions

223. In its brief, Portland does not propose a specific billing determinant amount but cautions that because pipelines may operate in a manner that occasionally creates more capacity than the system can reliably provide year round, it is not proper to design rates on the transitory higher levels.

224. PSG makes the same arguments regarding Portland's billing determinants that it does with respect to the at-risk condition, namely, that based on Portland's alleged conduct, its complicity in the capacity reduction resulting from the Phase IV Expansion, and its failure to obtain abandonment authority, Portland should not be afforded a significant decrease in its billing determinants. PSG also argues that the finding in the ID that Portland's at-risk condition should be 168,672 Dth per day was based on the erroneous conclusion that the Pittsburg to Dracut capacity determination in the Declaratory Order was dispositive of the at-risk determination. PSG contends that establishing the billing determinants at 168,672 Dth per day would abrogate the at-risk condition established by the Commission and shift costs to Portland's customers. PSG asserts that the record supports billing determinants of up to 217,430 Dth per day and that

³⁰⁸ As described further below, the ALJ arrived at this credit by dividing the total bankruptcy proceeds by what he stated was the 14-year remaining terms of the contracts when they were rejected.

³⁰⁹ As discussed more fully below, the Presiding Judge in the ID found that the methodology established in Opinion No. 510 for addressing the proceeds Portland received for the bankrupt contracts "was no longer a possible resolution" because of the reduction in Portland's capacity from Pittsburg to Dracut. ID, 137 FERC ¶ 63,018 at P 950. Accordingly, the ID directs Portland to credit approximately \$8.5 million against its annual cost-of-service to account for the bankruptcy proceeds.

³¹⁰ ID, 137 FERC ¶ 63,018 at PP 1180-81.

the ID erred in not establishing the billing determinants at that level under the “greater of” analysis. PSG also argues that the ID’s treatment of the bankruptcy proceeds as an offset to the reduction in billing determinants is not a fair and equitable result and is contrary to the at-risk policy.³¹¹

225. Trial Staff also excepts to the ID’s setting the billing determinants at 168,672 Dth per day, claiming that result was based on the same misapplication of the Declaratory Order as discussed above. Trial Staff asserts the billing determinants should be set at 210,840 Dth per day, the same as the at-risk condition. Trial Staff asserts that in Opinion No. 510 the Commission required Portland to design rates based on the higher of the at-risk condition or billing determinant level, and specified the proper treatment of the bankruptcy proceeds as they related to the billing determinants. According to Trial Staff, its Witness Steffy calculated Portland’s billing determinants for this proceeding in accordance with the methodology developed in Opinion No. 510 (i.e. including the volumes attributable to the bankrupt contracts and to short term remarketing of that capacity).³¹² Trial Staff claims there is no basis for the ALJ’s decision to require Portland to credit the bankruptcy proceeds against its cost-of-service or to subtract those volumes from the billing determinant calculation, and that such findings were contrary to Opinion No. 510.

Commission Determination

226. We reverse the ALJ’s decision to establish Portland’s billing determinants at 168,672 Dth per day, and find that Portland must design its rates based on 210,840 Dth per day. As the Commission held in Opinion No. 510, and reaffirms in Opinion No. 510-A, Portland’s rates must be designed based upon the greater of its projected billing determinants or the volumetric level of the at-risk condition.³¹³ The ALJ’s decision was based on the determination that Portland’s at-risk level should be 168,672 Dth per day. However, as discussed above, we have reversed the ALJ’s finding and instead hold that Portland’s at-risk condition requires that its rates be designed based on billing determinants of at least 210,840 Dth per day. According to Trial Staff Witness Steffy’s billing determinant analysis, which was performed generally in accordance with the directives of Opinion No. 510, Portland’s billing determinants, even including the IT/PAL revenues and the volumes associated with the rejected contracts, are at most

³¹¹ PSG Brief on Exceptions at 71-72.

³¹² Staff Brief on Exceptions at 36-40.

³¹³ Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 61.

186,631 Dth per day.³¹⁴ Accordingly, as in its previous rate case, the Commission finds that Portland's projected billing determinants do not exceed the at-risk level, and Portland must design its rates based on the at-risk level.

C. IT /Park and Loan (PAL) Credits

Background

227. The Commission's policy for the treatment of interruptible services for rate design purposes requires a pipeline to allocate costs and volumes to such services or to credit its customers for interruptible transportation (IT) service revenues.³¹⁵ In Opinion No. 510, the Commission noted that Portland had proposed in that case to design its rates based upon its design capacity of 210,840 Dth per day without any express allocation of costs to its IT and PAL services, though previously Portland had allocated costs to its interruptible services (IT and PAL). In that proceeding, the ALJ had directed Portland to credit its IT/PAL revenues against its cost-of-service but the Commission reversed the ALJ, instead requiring Portland to allocate costs to its IT/PAL services based on a projected volume of interruptible services, consistent with the rate design underlying its preexisting rates, and subject to Portland's at-risk condition.³¹⁶

228. In Opinion No. 510-A, the Commission reaffirms that holding. In addition, the Commission rejects PSG's contention that Portland should also be required to credit its IT/PAL revenues against its cost of service. Opinion No. 510-A explains that a cost allocation based on projected billing determinants and an IT revenue credit against cost of service are mutually exclusive methods of allocating costs to IT services, and requiring both would unreasonably allocate costs to IT services twice.

³¹⁴ Trial Staff's witness arrived at this figure by adding together Portland's firm shippers' contract demands of 150,200 Dth, imputed interruptible and park and loan billing determinants of 9,347 Dth per day, and discount-adjusted billing determinants associated with the rejected contracts of 27,084 Dth per day. Trial Staff did not adjust the imputed interruptible and park and loan billing determinants for discounting because the projected total unadjusted billing determinants of 186,631 Dth per day were less than the at-risk level of 210,840 Dth per day. Exh. No. S-27.

³¹⁵ See, e.g., Opinion No. 510, 134 FERC ¶ 61,129 at P 294 (citing *Wyoming Interstate Co., Ltd.*, 121 FERC ¶ 61,135 (2007)); Opinion No. 510-A at P 111.

³¹⁶ Opinion No. 510, 134 FERC ¶ 61,129 at P 307.

Initial Decision

229. In the instant proceeding, Portland proposed to change from allocating costs to its interruptible services and proposed to credit its cost-of-service with the revenues it received from interruptible services during the test period (\$2,806,872). The ALJ, noting that all the parties agreed to the level of Portland's credit and that Commission policy allows for either revenue crediting or cost allocation, approved Portland's proposal to credit \$2,806,872 to its cost-of-service for interruptible service revenues.³¹⁷

Briefs On and Opposing Exceptions

230. On exceptions, Portland argues that the ALJ erred by accepting its proposal to credit interruptible revenues to its cost-of service and also allocating costs to those services by including projected volumes attributable to IT and PAL services in the billing determinant calculation.³¹⁸ Portland asserts that it first proposed its Rate Case Credit (\$2,861,800) and its IT/PAL credit of the bankruptcy proceeds (\$2,806,872) totaling \$5,668,672 in tandem to lower its cost-of-service by that amount. Portland claims that the ALJ erred by imposing a far larger credit of \$8,554,375 in lieu of the 2010 Rate Case Credit but not eliminating the IT/PAL credit. Portland contends that those findings create an insurmountable obstacle to Portland recovering its cost-of service. Portland states that instead of double-counting its IT and PAL revenues, the Commission should approve its initial proposal to credit the revenues to its cost of service.

231. PSG argues that Portland should be held to the IT/PAL revenue credit it proposed, and that the ID was entirely correct to accept that proposal. PSG contends that the credit amount reflects the total amount of IT and PAL revenue earned by Portland during the test period. PSG also asserts that unlike the holding in Opinion No. 510, where the Commission directed Portland to allocate interruptible costs because it had done so previously, here Portland sought to credit revenues when it filed its case, and thus the Opinion No. 510 prohibition on crediting is inapplicable. PSG also challenges Portland's claims that the IT/PAL revenues were double counted as "purely hypothetical."³¹⁹ According to PSG, the ALJ found that Portland had to design its rates on the higher at-risk level, as opposed to the lower billing determinants (including the IT/PAL volumes), because even with the interruptible volumes included Portland would not reach the at-risk

³¹⁷ ID, 137 FERC ¶ 63,018 at P 960.

³¹⁸ Portland Brief on Exceptions at 43-45.

³¹⁹ PSG Brief Opposing Exceptions at 33.

level adopted in the ID. Accordingly, PSG contends, the billing determinants were not affected by the inclusion of the IT/PAL revenues.

Commission Determination

232. We reverse the ALJ's decision to require Portland to credit IT and PAL revenues to its cost-of-service. As we explain in Opinion No. 510-A, because Portland 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."³²⁰ Accordingly in Opinion No. 510 we directed Portland to include in its billing determinants (1) an allocation of costs to its IT/PAL services based on a projected volume of interruptible transportation, and (2) 62,000 Dth per day of contract demand associated with the contracts rejected in bankruptcy and interruptible volumes associated with the remarketing of that capacity.

233. The Commission upheld that determination on rehearing, noting that requiring Portland to calculate its billing determinants enabled the Commission to determine whether Portland's billing determinants satisfied its at-risk condition. Based on Portland's statement that its recalculation of billing determinants in accordance with Opinion No. 510 showed that its projected billing determinants are less than the at-risk condition, the Commission determined that Portland must design its rates on the level of its at-risk condition. In Opinion No. 510-A, we also find that, because the at-risk billing determinants in that rate case exceeded Portland's total projected billing determinants including IT and PAL, the at-risk billing determinants reflect an allocation of costs to Portland's IT/PAL services. For that reason, it would be unjust and unreasonable to also require Portland to credit IT/PAL revenues against its cost of service, because that would result in a double allocation of costs to the IT/PAL services.

234. The circumstances in the instant proceeding are similar. Again, in this rate case, Portland's projected billing determinants, including IT and PAL volumes, are less than the at-risk level billing determinants, and therefore we are requiring Portland to design its rates based on the at-risk level. In these circumstances, the at-risk billing determinants reflect an allocation of costs to Portland's IT/PAL services. Therefore, crediting revenues to interruptible services, as the ID does, would double count those revenues in contravention of Commission policy.³²¹

³²⁰ Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 63 (citing *Kern River*, Opinion No. 486-A, 123 FERC ¶ 61,056 at P 86).

³²¹*Id.* P 89.

D. Androscoggin and Rumford Bankruptcy Proceeds**Background**

235. In addressing the treatment of the “bankruptcy proceeds” received by Portland, the ID considers whether Portland’s proposal to annually credit \$2,861,800 to its cost of service is an appropriate method for accounting for receipt of those proceeds.³²² Portland Witness Haag testifies that Portland properly accounted for the bankruptcy proceeds through the use of a \$2,861,800 credit against its cost of service (referred to as the “2010 Rate Case Credit”). According to Mr. Haag, this credit was calculated by using an engineering cost estimate for the expense that would have been incurred by Portland had it been required to maintain a level of firm system capacity sufficient to serve the additional 62,000 Dth per day of capacity to which it was formerly obligated under the bankrupt contracts. Portland further claims that this credit also serves as a proxy for any form of credit that may be appropriate, including any potential credit related to the bankruptcy proceeds received by Portland well before the base and test periods in this proceeding.

236. The ID states that Portland admitted receiving \$119,761,258 from the Androscoggin and Rumford bankruptcies but claimed that the value of the terminated contracts was \$273,715,685 based on transportation quantities of 18,000 Dth per day by Androscoggin and 44,000 Dth per day by Rumford. Portland thus claims that it was at risk for the lost revenues from those contracts from June 2005, the first date one of the contracts was terminated, until December 1, 2010, the effective date for the rates in this proceeding. The ID notes that Trial Staff claims Portland was entitled to \$91,753,825 from the bankruptcy proceeds during that time period, though Portland claims that only \$28,007,433 of the proceeds remain to credit against the remaining 10 years on the bankrupt contracts.

Initial Decision

237. The ID finds merit in Portland’s proposal to credit its cost-of-service with a portion of the proceeds received from the bankruptcy court.³²³ The ALJ disagrees, however, with Portland’s position that the entire \$91,753,825 should be attributed to services performed

³²² According to the ID, the term “bankruptcy proceeds,” as used by Portland, refers to \$119,761,258 that Portland received, net of legal expenses and before income tax liability, from the Androscoggin and Rumford bankruptcies. 137 FERC ¶ 63,018 at P 942 n.191.

³²³ ID, 137 FERC ¶ 63,018 at P 948.

prior to the end of the test period in this case, leaving only \$28,007,433 to be credited to Portland's cost-of-service over the next 10 years. Thus, the ALJ divides the bankruptcy proceeds by the 14 years remaining on the bankrupt contracts (2005 - 2019) to arrive at an \$8,544,375 annual credit to Portland's cost-of-service to account for the bankruptcy proceeds.³²⁴ In making this ruling, the ALJ acknowledges that in Opinion No. 510 the Commission required a different rate design methodology for addressing the bankruptcy proceeds, namely that Portland (1) include volumes attributable to the bankrupt agreements, subject to a discount adjustment, and any remarketed capacity, in its billing determinants and (2) reduce its rate base by the amount of the bankruptcy proceeds.³²⁵ In diverging from that methodology here, the ALJ stated that, because of the reduction in capacity as determined by the Commission in the Declaratory Order, there was no longer adequate capacity to which to allocate costs, and thus the Opinion No. 510 resolution was not possible in the current case. The ID also finds the rate base reduction is no longer necessary. The ID concludes that the cost-of service credit approach it mandates has an immediate impact on, and a greater reduction to, Portland's rates and "offers an absolute just and reasonable resolution" of the matter.³²⁶

Briefs On and Opposing Exceptions

238. Portland excepts to the ID, claiming that the ALJ's treatment of bankruptcy proceeds is illogical in that it recognizes that it carries risk but gives the benefits to ratepayers, and fails to provide Portland with an adequate opportunity to recover its cost of service. Portland contends the ID erred by failing to establish that a credit was required in the first place, and that it was wrong to adopt a \$8,554,375 credit instead of its proposed Rate Case credit. Portland argues that it was improper to impose a greater cost-of-service credit than it had proposed without determining that Portland had over-recovered its cost-of-service, and that the ALJ's methodology constitutes impermissible retroactive ratemaking because it credits the bankruptcy revenues to the cost-of-service in this case that are attributable to prior period costs and rates. Portland also asserts that the ALJ erred by failing to analyze its Rate Case Credit proposal, which Portland claims is a just and viable alternative to address the bankruptcy proceeds.

239. PSG also excepts to the ID on this issue, claiming that the cost-of service credit adopted therein fails to account for Portland's accelerated receipt of future revenues because it lacks a corresponding reduction to rate base, and is inconsistent with Opinion

³²⁴ *Id.* P 949 & n.198

³²⁵ *Id.* P 950.

³²⁶ *Id.*

No. 510 and the Commission's at-risk policy. PSG argues that the Commission in Opinion No. 510 recognized that Portland received two benefits from the bankruptcy proceeds – (1) recovery of a substantial amount of long term revenues to compensate it for future costs and cost-of-service and (2) an accelerated recovery of those revenues,³²⁷ – which is why it required Portland to account for receipt of the bankruptcy proceeds through both inclusion in rate design volumes and as a reduction to rate base. PSG states that the ID's remedy of a cost-of-service credit fails to account for the earning power of the unamortized proceeds due to the fact that Portland received the proceeds in a lump sum. PSG also argues that the ID compounds that error by establishing Portland's at-risk and billing determinant levels at post-Phase IV Expansion levels, thereby shifting the costs to Portland's shippers.

240. Trial Staff also excepts to the ID's treatment of the bankruptcy proceeds.³²⁸ With respect to the cost-of-service credit, Trial Staff contends that Portland and the ID fail to show any nexus between the bankruptcy proceeds and the alleged costs Portland would have had to spend on construction to maintain 210,840 Dth per day. Trial Staff claims that the Commission should reverse the ID's determination on the at-risk and billing determinant levels and adopt 210,840 Dth per day. If it does that, Trial Staff states that the Commission should also reverse the cost of service credit requirement because such a credit is not warranted if Portland's rates are designed on 210,840 per day or higher. Conversely, Trial Staff claims that if the Commission decides that Portland's rates should be designed on 168,672 Dth per day, then the ALJ's cost-of-service credit should be affirmed.

241. On the rate base reduction issue, Trial Staff asserts the finding in the ID that the issue was mooted by the cost-of-service credit and the capacity reduction is in error and contrary to Opinion No. 510. Trial Staff claims that the reasons underlying the inclusion of the bankrupt contracts' billing determinants and the rate base reduction are independent, and that the decrease in physical capacity upon which the ALJ relies as the basis for the inapplicability of the Opinion No. 510 methodology is wholly irrelevant to the factors leading to the adoption of the rate base reduction, namely to account for Portland's up-front lump sum payment.

³²⁷ PSG Brief on Exceptions at 73 (citing Opinion No. 510, 134 FERC ¶ 61,129 at P 356).

³²⁸ Trial Staff Brief on Exceptions at 83-90.

Commission Determination

242. The Commission reverses the ALJ's decision regarding the proper treatment of the bankruptcy proceeds. The ID's reason for adopting the proposed cost-of-service credit approach proposed by Portland, and thus diverting from the Commission's approach in Opinion No. 510, is the purported reduction in capacity resulting from the Phase IV Expansion. According to the ID, based on the Commission's capacity finding in the Declaratory Order, there was no longer adequate capacity to which to allocate costs, and thus the Opinion No. 510 resolution with regard to billing determinants was not possible in the current case. The ALJ also found that the adopted cost-of-service credit approach rendered the rate base reduction, ordered by the Commission in Opinion No. 510, unnecessary.³²⁹ As discussed above, however, the ID's findings with regard to Portland's capacity after the Phase IV Expansion are incorrect, and thus so are the ID's findings regarding the bankruptcy proceeds resulting from that presumption. Accordingly, we reverse the ALJ and direct Portland to account for the bankruptcy proceeds by including the volumes attributable to the rejected contracts in its billing determinants and to reduce its rate base by the amount received, in accordance with Opinion Nos. 510 and 510-A.

243. As to the billing determinants, as discussed above, Portland's situation is the same as in its 2008 rate case, that is, it must include its IT/PAL and rejected contract volumes in its billing determinants to evaluate whether it meets its at-risk condition. As shown, as in its previous rate case, the record evidence indicates that Portland's total billing determinants, including the bankruptcy and IT/PAL volumes, are less than its at-risk condition, and thus Portland must design its rate on the at-risk figure. The ID's supposition that there are inadequate volumes across which to allocate costs is simply incorrect. Further, because we are requiring Portland to include its bankrupt volumes, as adjusted for discounting, in its billing determinant calculation, requiring a cost-of-service credit for the bankruptcy proceeds would double count those revenues. Accordingly, Portland is directed to include in its rate design the 62,000 Dth per day of contract demand associated with the rejected agreements, subject to a discount adjustment, as we required in Opinion No. 510, and upheld in Opinion No. 510-A.

244. Additionally, we direct Portland to reduce its rate base by the amount of the bankruptcy proceeds in the manner described in Opinion No. 510-A. Specifically, we require Portland to reduce its rate base during each remaining year of the levelization period after the effective date of these rates 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. As discussed in Opinion

³²⁹ ID, 137 FERC ¶ 63,018 at P 950.

No. 510-A, to the extent the bankruptcy proceeds compensate Portland for payments Androscoggin and Rumford would have made under the rejected contracts in future periods, Portland may invest those proceeds as it sees fit and earn a return on the proceeds. Therefore, Portland's opportunity to earn an additional return by investing bankruptcy proceeds elsewhere should be reflected in a reduction to rate base.

245. This 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 rates, but not yet needed to pay current income taxes.³³⁰ 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.³³¹ 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 taxes 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

³³⁰ 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.

³³¹ 18 C.F.R. § 154.305(c) (2012). *See also Kern River*, Opinion No. 486, 117 FERC ¶ 61,077 at 228; 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).

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 (temporary) addition to the firm’s capital, because it was obtained by the company without cost.³³²

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.”³³³

246. Similarly, in this case, Portland has recovered from its customers, at no cost to itself, 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 elsewhere should be reflected in a reduction to rate base.

247. The credit to rate base will be reduced with each succeeding year of the levelization period (effectively, the same period remaining on the term of the rejected contracts), so as to remove from the credit that part of the bankruptcy proceeds which no longer constitutes a prepayment for future service. Thus, the Commission does not require Portland to include in the credit against rate base that portion of the bankruptcy proceeds related to earlier years of the levelization period. This permits Portland to receive the full benefit of the bankruptcy proceeds related to service in prior years without any reduction in rate base.

³³² *Distrigas*, 737 F.2d 1208 at 1213-14. On remand, the Commission stated that *Distrigas* could continue to include in rate base certain deferred tax liabilities that were at issue in the First Circuit case. *Distrigas of Massachusetts Corp.*, 31 FERC ¶ 61,276 (1985).

³³³ See *SFPP, L.P.*, 121 FERC ¶ 61,240, at P 140 (2007).

VII. Capital Structure

Initial Decision

248. The ID found that the appropriate capital structure for Portland was its end of test period capital structure comprised of 51.42 percent equity and 48.58 percent debt.³³⁴ Portland had proposed adjusting the debt component of its end of test period capital structure downward by \$12,751,317, by using the net proceeds rather than the gross proceeds of debt. The ID quoted Portland's testimony as follows:

A further adjustment is required to [Portland's] capitalization to assure that [Portland] has an opportunity to earn its return and recover the effective cost of debt. If a [Commission-] regulated utility's capitalization reflects its total debt outstanding at the end of the test period, a portion of the debt outstanding is not available to finance rate base because the debt is committed to finance capitalized debt issuance cost and in [Portland's] case, hedge costs. The *Northwest* approach would presume that these capital costs are financed through debt. Because these capitalized costs are not permitted in rate base, the debt used to finance the capitalized cost should be removed from debt outstanding in the capitalization.³³⁵

249. The ALJ was not convinced that varying from the end of test period capitalization as Portland advocated, i.e., using the net proceeds of debt, would result in a just and reasonable outcome for ratemaking regarding Portland's debt and equity ratios. The ID cited *Northwest*, noting the Commission held that pipelines are not permitted to include losses on reacquired debt in rate base but rather should amortize such costs over the remaining original life of the retired debt.³³⁶

³³⁴ ID, 137 FERC ¶ 63,018 at P 1305. As advocated by PSG.

³³⁵ *Id.* P 1304 (citing Exh. No. PNG-19 at 14; *Northwest Pipeline Corp.*, Opinion No. 396, 71 FERC ¶ 61,253 (1995)).

³³⁶ *Id.*

250. The ID noted that in *System Energy Resources, Inc.*, the Commission had previously held that a utility's total long-term debt should be included in its capital structure because it represents the utility's total obligation.³³⁷

251. The ID did not directly address a capital structure issue raised by Trial Staff and Portland, i.e., whether the equity component of Portland's capital structure should be adjusted by the removal of certain amounts in Account No. 219 (Accumulated Other Comprehensive Income).³³⁸ The ALJ reasoned it was unnecessary to address this issue because the crux of the capital structure issue was the adjustment to the debt balance.³³⁹

Briefs On and Opposing Exceptions

Trial Staff

252. Trial Staff supported the ID's rejection of Portland's proposal to adjust the debt component of its end-of-test-period capital structure downward by \$12,751,317 to reflect the net proceeds of the company's long-term debt.³⁴⁰ Trial Staff nevertheless stated that the ID incorrectly adopted the capital structure advocated by PSG, and advocated an adjustment to equity to correct an unrealized loss that was improperly reflected in the capital account.

253. Trial Staff opposed Portland's proposed net proceeds adjustment. Trial Staff explained that the adjustment is based on the value of the unamortized portion of the capital expenditures associated with Portland's sole debt issuance.³⁴¹ Trial Staff further stated that Portland's rationale is that subtracting the unamortized amounts from the long-term debt amount shows the true amount of debt capital Portland has available to finance rate base. Trial Staff argues that the Commission has already addressed this precise issue in *SERI* and explicitly held that the gross proceeds of debt belong in the capital structure

³³⁷ *Id.* P 1304 (citing *System Energy Resources, Inc.*, Opinion No. 446, 92 FERC ¶ 61,119 at 61,448-49 (2000) (*SERI*), *reh'g denied*, Opinion No. 446-A, 96 FERC ¶ 61,165 (2001)).

³³⁸ 18 C.F.R. Pt. 201 (2012).

³³⁹ ID, 137 FERC ¶ 63,018 at P 1303 n.715.

³⁴⁰ Trial Staff Brief on Exceptions at 95-96.

³⁴¹ Trial Staff Brief Opposing Exceptions at 88.

because this method reflects the company's total obligation with respect to long term debt.³⁴²

254. Trial Staff pointed out that the ALJ failed to address separately a second capital structure issue concerning the appropriate classification of realized losses.³⁴³ Thus, according to Trial Staff, the ID incorrectly ties the issue of the proper long-term debt issue with a separate amount involving realized losses.

255. Trial Staff explained that the realized loss amount at issue, \$10,415,581, stems from an interest rate swap agreement that Portland made to hedge the interest rate of its refinanced debt issued in 2003. Trial Staff claims this amount was improperly classified as an unrealized loss in Account No. 219 in Portland's FERC Form No. 2, when in fact it was a realized loss.³⁴⁴ Trial Staff's witness accordingly removed the Account No. 219 loss amounts from the equity component.³⁴⁵ This adjustment has the effect of increasing the equity component to \$198,670,418.³⁴⁶ Accordingly, Trial Staff asserts the ALJ erred in adopting the capital structure proposed by PSG, which does not reflect the Account No. 219 adjustment. Trial Staff urges the Commission to adopt Trial Staff's Account No. 219 adjustment to the equity component, as well as the ID's rejection of the net proceeds approach, and to approve the resulting capital structure of 52.84 percent equity and 47.16 percent debt.³⁴⁷

Portland

256. Portland states the ID erred in failing to make Portland's and Trial Staff's proposed adjustment to the end of test period equity and by using the gross proceeds of debt to calculate Portland's debt component. Portland states that if the ALJ had properly

³⁴² *Id.* at 89.

³⁴³ With this exception, Trial Staff adopted the capital structure submitted by Portland in response to a Trial Staff data request. Exh. Nos. S-18 at 1-2, S-16 at 5-6.

³⁴⁴ Exh. No. PNG-119 at 17 (original balance described in Portland's 2003 Form No. 2 at page 122.3; Exh. No. PNG-131 at 8).

³⁴⁵ Trial Staff Brief on Exceptions at 96 (citing Exh. Nos. S-16 and S-18).

³⁴⁶ *Id.*

³⁴⁷ *Id.* at 96-97.

made both of its proposed adjustments, Portland's capital structure would be 54.80 percent equity and 45.20 percent debt.³⁴⁸

257. Portland argues that \$12,751,317 of Portland's remaining unamortized debt costs should be removed from its end of test period debt balance of \$168,023,000. Portland asserts that applying the holding in *SERI* would not permit Portland to fully recover its debt cost. Portland argues that in the *SERI* case the Commission relied on the regulations for electric utilities, which state that the weighted cost of debt is to be computed by multiplying the cost of money by the principal amount outstanding, and that there is no similar requirement in the natural gas regulations.³⁴⁹

258. Portland states that the Commission has recognized that the debt cost calculation must use the net proceeds method to allow the pipeline to recover its underwriting costs. Portland cites to the Commission's regulations and a proceeding in which the Commission permitted use of the net proceeds basis to allow an opportunity to recover underwriting costs.³⁵⁰

259. Portland notes that the ID failed to address the Account No. 219 issue. According to Portland, the balance in Account No. 219 was a negative \$10,415,581 which represents an unamortized loss that remains from the settlement of Portland's forward interest rate swaps.³⁵¹ Portland agreed with Trial Staff that the losses from its swaps were realized. Portland explained that the losses were then deferred and are currently being amortized over the life of Portland's current debt issuance, and the unamortized portion is reflected in the Account No. 219 balance. Portland states that the unamortized balance in Account No. 219 has no relationship to the equity used to finance rate base and should be eliminated from the equity component of the capitalization.³⁵²

³⁴⁸ Portland Brief on Exceptions at 95.

³⁴⁹ *Id.* at 97.

³⁵⁰ *Id.* (citing 18 C.F.R. § 154.312(h)(5) (2011); *Michigan Gas Storage Co.*, 87 FERC ¶ 61,038, at 61,166 (1999) ("the Commission utilizes the net proceeds basis so that the pipeline has an opportunity to recover underwriting costs") (*Michigan Storage*); *SERI*, 92 FERC ¶ 61,119 at 61,448 (adopting the net proceeds method for debt costs as opposed to capitalization)).

³⁵¹ *Id.* at 96; Exh. No. PNG-119 at 17 (Lovinger rebuttal testimony).

³⁵² *Id.*

260. Portland states that \$188,254,838 is the correct equity balance after removing Account No. 219 from its end of test period figure.

PSG

261. PSG states the ID properly rejected Portland's proposed downward adjustment for the so-called hedging losses as well as debt issuance costs. PSG states that Portland acknowledges that the net proceeds methodology was already rejected by the Commission in the *SERI* case. PSG points out that use of the principal amount of debt outstanding for determining debt capitalization is consistent not only with the Commission's Uniform System of Accounts but also the Generally Accepted Accounting Principles (GAAP). PSG further notes that the major bond rating agencies, as well as investment advisory services such as Value Line Investment Survey, all account for debt obligations based upon principal amount outstanding.³⁵³ Further, PSG argues that the capitalization ratios considered by investors are ratios based on the total principal amount of debt outstanding.

262. PSG argues that the ID properly attributed \$177,839,356 of equity without making an adjustment for the Account No. 219 amounts. PSG construes these amounts as "so-called" hedging losses incurred in the trading of derivative instruments and states they are a liability to be borne by investors rather than ratepayers.³⁵⁴

Commission Determination

A. Gross v. net proceeds of debt

263. One issue before us is whether Portland should be permitted to reflect the net, rather than the gross, proceeds of debt in the debt component of its capitalization. As we held in *SERI*, it is the gross proceeds of a company's long-term debt, *i.e.*, the total principal outstanding, that belong in the capital structure analysis because that amount reflects the company's total obligation with respect to long-term debt. Although *SERI* concerned an electric utility, we did not confine our holding there to electric utility companies.³⁵⁵ In the *SERI* case, we stated:

³⁵³ PSG Brief Opposing Exceptions at 85; Exh. No. PSG-70 at 35.

³⁵⁴ PSG Brief Opposing Exceptions at 84.

³⁵⁵ Consequently, Portland's assertion that the Commission's natural gas regulations do not have parallel provisions does not affect our decision. In any event, we note that the section of the natural gas regulations which Portland cited simply identifies

(continued...)

[W]e reject SERI's proposal to compute the long-term debt ratio by using the net proceeds of debt (i.e., gross proceeds less unamortized premium, discount, expenses, and losses) instead of the gross proceeds of debt. SERI argues that the gross proceeds should not be used in the capital structure because it includes unamortized debt issuance costs and premium expenses that are not available to invest in rate base. Thus, SERI claims that the net proceeds, which excludes these costs, should be used instead. We disagree. It is the gross proceeds of a company's long-term debt, i.e., the total principal outstanding, that belong in the capital structure because this reflects the company's total obligation with respect to long-term debt. In addition, our regulations expressly provide that the weighted cost of debt capital is to be computed, in part, by "[m]ultiplying the cost of money . . . by the principal amount outstanding for each issue" of debt. The principal amount outstanding is the face value of the debt, which is the amount used under the gross proceeds method.³⁵⁶

We find that the holding in *SERI* applies here and, thus, Portland must use the gross proceeds method for its capital structure.

264. Portland's argument that it will not recover its cost of capital unless the net proceeds of debt method is used is incorrect. As stated above, the gross proceeds of debt amount reflect the exact outstanding debt of a company. Reducing this amount in the capitalization analysis would misrepresent Portland's total debt obligation and improperly weight the overall return.

265. Portland also argues that the higher amount of low cost debt capitalization leads to a lower percentage of capitalization attributable to equity and to a lower overall rate of return.³⁵⁷ The converse is that a lower percentage of debt (as compared to equity) in the

information that must be provided in Statement F-3 – Debt Capital in a pipeline's section 4 rate filing. We note that the *Michigan Storage* case cited by Portland predates our decision in *SERI*.

³⁵⁶ *SERI*, 92 FERC ¶ 61,119 at 61,448-49 (citing 18 C.F.R. § 35.13(h) (22) (ii)) (emphasis in original, footnote reference omitted).

³⁵⁷ Portland Brief on Exceptions at 98. *See also SERI*, Opinion No. 446-A, 96 FERC ¶ 61,165 at 61,740.

capital structure means less lower cost capital and more higher cost capital and a higher overall return. As we stated in *SERI*, using the total principal outstanding, or gross proceeds, accurately represents the amount of debt outstanding and allows for a more accurate picture of a company's capital structure, and, in turn, results in the correct calculation of a company's cost of capital. Our holding there noted that the company was obligated to pay, and its debt holders expect to receive, a return of and on the full face amount of the debt that they hold, and not on some lesser amount.³⁵⁸ Further, regardless of the level of the overall return, the allowed rate of return on the equity component of the capitalization will not decrease. Portland will still have the opportunity to earn its allowed equity return.

B. Account No. 219

266. Although the ALJ did not rule on the issue, we find that Trial Staff was correct to make an adjustment to remove Portland's realized losses from its interest swaps (\$10,415,581) from Account No. 219. That amount in Account No. 219 represents the unamortized portion of realized losses and should be deducted from the equity component of the capitalization.³⁵⁹

267. In view of the foregoing determinations, we find that Trial Staff has supported the appropriate capital structure for Portland, which it calculates as 52.84 percent equity and 47.16 percent debt, and we hereby adopt that structure for this proceeding.

VIII. Cost of Debt/Interest Rate Swaps

268. To hedge against interest rate declines, a borrower may agree to pay a variable interest rate on a stipulated principal to another party in exchange for receiving a fixed interest rate on the same stipulated principal.³⁶⁰ Such agreements are known as interest rate swaps. Typically, payments are made at intervals dictated by the terms of the swap agreement, and the relative payments owed by each party are netted against each other. By this method, the borrower's actual debt interest payments are offset by the fixed interest received under the swap and the borrower's outlay is closer to the variable interest rate.

³⁵⁸ Opinion No. 446-A, 96 FERC ¶ 61,165 at 61,740.

³⁵⁹ Backing out the loss results in an increase in the equity figure to \$188,254,838.

³⁶⁰ The principal amount can be stipulated because there is no need to exchange actual amounts of principal.

269. In the instant proceeding, Portland entered into interest rate swap agreements in order to hedge against interest rate increases with regards to its construction loans, which were required to be refinanced in early 2003.³⁶¹ Portland reports that, when it executed the swap agreements in October of 2001, Treasury bond yields were near their lowest rate in ten-years, and it was feared that rates would rise.³⁶² Portland reports that it chose to hedge against possible rising interest rates, rather than refinance in 2001, because its cost of debt was already low.³⁶³ However, as it came to pass, despite near ten-year lows, interest rates did not rise. As a result, Portland incurred the debt swap expenses at issue in this proceeding when it came time for the required refinancing of its construction loans.

270. At hearing, Portland and Trial Staff proposed to calculate Portland's cost of debt at 7.09 percent, which includes costs attributable to debt swaps.³⁶⁴ PSG calculated the cost of debt as 5.99 percent by excluding such costs attributable to debt swaps.³⁶⁵ Portland argued that the Commission in *Kern River* indicated that interest rate swap expenses are an appropriate cost of debt and may be amortized over the life of the issue to which they relate.³⁶⁶ Portland contends that *Kern River* characterized swap cancellation fees as "the costs of reacquiring debt."³⁶⁷ Citing Commission precedent,³⁶⁸ Portland submitted an

³⁶¹ Portland Initial Brief at 169-73; Exh. No. PNG-131 (FERC Form No. 2-A).

³⁶² Portland Initial Brief at 172.

³⁶³ *Id.* (describing effective cost of debt under the construction loan as only 5.63 percent, or nearly 2.4 percent lower than prevailing on Public Utility debt yields for Baa- rated companies).

³⁶⁴ Portland Initial Brief at 167; Reply Brief at 158; Trial Staff Initial Brief at 121; Reply Brief at 107.

³⁶⁵ PSG Initial Brief at 105.

³⁶⁶ *Kern River*, Opinion No. 486, 117 FERC ¶ 61,077 at PP 179-209.

³⁶⁷ *Kern River*, Opinion No. 486-A, 123 FERC ¶ 61,056 at P 242.

³⁶⁸ *SERI*, 92 FERC ¶ 61,119 at 61,448-49, *reh'g denied*, 96 FERC ¶ 61,165; *Michigan Storage*, 87 FERC ¶ 61,038 at 61,166; *Minnesota Power & Light Co.*, 16 FERC ¶ 63,012, at 65,053 (1981).

alternative calculation of its debt cost in accordance with a yield to maturity methodology using the net proceeds per unit outstanding in that calculation, of 6.825 percent.³⁶⁹

271. Portland stated that its forward interest rate swaps were intended to hedge against its expected 2003 debt refinancing, and to insulate it from a variable interest rate risk prior to the refinancing.³⁷⁰ Portland claimed that because it “designated the swaps as cash flow hedges” pursuant to Financial Accounting Standards Board (FASB) Statement 133 the swaps were considered to be 100 percent effective hedges. Portland also claimed that its interest rate swaps were authorized by the Commission’s Uniform System of Accounts.³⁷¹

272. Portland challenged PSG’s accusation that engaging in interest rate swaps was gambling rather than engaging in valid transactions. Portland claimed that if it had not entered into the swaps “it would have been placing a bet (on its own or its ratepayers’ behalf) with the entire refinancing obligation” that interest rates would not rise between October 2001 and when it refinanced its debt in 2003.”³⁷² Moreover, in response to the PSG complaint that it could have refinanced in 2001, Portland declared that this would have increased its debt cost because it would have foregone a low interest rate for a higher rate before it needed to do so.³⁷³ It also explained that it would have increased its debt costs had it gone ahead, as PSG suggested too, and implemented the swaps.³⁷⁴

273. PSG asserted that a company’s hedging losses are the owner’s responsibility and not recoverable from its customers under GAAP. It suggested that Portland accounted for its hedging losses in a manner consistent with this responsibility until 2008.³⁷⁵ PSG

³⁶⁹ Exh. No. PNG-124 at 5; Portland Initial Brief at 174-75. Portland reports that this figure is the same debt cost rate used for the 2008 Rate Filing. Citing Initial Decision on 2008 Rate Filing, 129 FERC ¶ 63,027 at PP 639-43.

³⁷⁰ Exh. No. PNG-119 at 169-70 (Lovinger rebuttal).

³⁷¹ In support, Portland referred to 18 C.F.R. Pt. 201, General Instructions 23 (C), (E) (2011). Portland Reply Brief at 160.

³⁷² Reply Brief at 160.

³⁷³ *Id.* at 161.

³⁷⁴ *Id.*

³⁷⁵ PSG Initial Brief at 105 (citing Tr. 1492-93, 1537-38).

indicated that Portland could have avoided or mitigated its losses by going forward with its swap agreements rather than locking in a \$20.3 million loss through settlement or by refinancing in 2001.

274. Trial Staff did not join PSG in questioning the prudence of Portland's interest rate swap transactions.

275. In the ID, the ALJ sided with Portland and Trial Staff. It found that PSG's argument was speculative, and that by arguing contrary to the end result of the swaps, PSG's arguments were "built more on fantasy than on fact." In siding with Portland, the ALJ permitted the pipeline to include the costs resulting from the interest rate swaps in its cost of debt. According to the ALJ, PSG attempted to shift the burden of proof onto Portland,³⁷⁶ and the ALJ found based on a preponderance of the evidence that Portland's cost of debt is 7.09 percent.

Briefs On and Opposing Exceptions

276. Portland excepts to the ID for its alleged inconsistent approaches to establishing the amount of debt used to compute debt costs and to establish debt capitalization. According to Portland, this inconsistency thwarts a reasonable opportunity for Portland to recover its authorized return.

277. PSG objects to any debt cost adjustment attributable to trading in derivative instruments, including the forward interest rate swaps. PSG claims that GAAP support assigning such costs to a charge against equity, and excluding hedging costs from debt calculations. PSG objects to Portland's initial calculation of 7.09 percent and its revised calculation applying the Commission's Yield to Maturity (YTM) methodology of 6.825 percent as including debt-swap costs. PSG calculates 5.99 percent using Portland's initial methodology, and 6.046 percent using the YTM methodology. PSG defends the 5.99 percent figure as consistent with the Commission's approved alternative to the YTM calculation provided for in *SERI*.³⁷⁷

278. Portland disputes PSG's characterization of its actions as being investment related, noting that all financial instruments are investment related.³⁷⁸ Portland claims that in *Kern River* the Commission denied an equity return on swap cancellation fees, but

³⁷⁶ ID, 137 FERC ¶ 63,018 at P 1291.

³⁷⁷ *SERI*, 92 FERC ¶ 61,119 at 61,447-48 & n.37.

³⁷⁸ Portland Brief Opposing Exceptions at 81.

explicitly included the amortization of the swap cancellation fees over the life of the previous issue, because the fees were a cost of reacquiring debt. Portland also argues that the Initial Decision in *SFPP* supports the inclusion of swap fees in debt costs for cost of capital purposes.³⁷⁹ Portland notes that GAAP determinations are not binding on Commission regulatory policy.³⁸⁰

279. According to PSG, Portland abandoned the debt cost calculation methodology that it initially presented in this case, which divides its debt costs by net loan proceeds, yielding a debt cost rate of 7.09 percent (including amortization of hedging losses), and reverted instead to the Commission's preferred YTM methodology that Portland used in its previous rate case, which produces a lower debt cost rate of 6.825 percent (including amortization of hedging losses).³⁸¹ PSG states that because each of Portland's debt cost calculations in this case improperly includes hedging losses, neither of Portland's debt cost calculations could properly be adopted in this case.

280. PSG advocates its own debt cost calculation of 5.99 percent claiming that it properly excluded hedging losses and properly divided remaining debt costs by gross loan proceeds. PSG claims that Portland only took issue with its calculation for excluding hedging losses and because it did not reflect the Commission's preferred YTM method of calculation.³⁸² However, PSG justified its witness's use of the alternative embedded cost methodology because Portland initially used a version of that methodology.³⁸³ PSG reports an alternate figure using the YTM formula while still eliminating hedge losses of 6.046 percent for Portland's debt rate cost.

³⁷⁹ *Id.* at 83 (citing *SFPP L.P.*, Initial Decision, 134 FERC ¶ 63,013 at PP 94, 97 (2011) (*SFPP*); *Transok, Inc.*, 70 FERC ¶ 61,177, at 61,555 (1995)). The Commission addressed the *SFPP* Initial Decision in *SFPP, L.P.*, Opinion No. 522, 140 FERC ¶ 61,220 (2012) (addressing issue whether parent swap activities supported capital acquisition of subsidiary).

³⁸⁰ *SFPP, L.P.*, 111 FERC ¶ 61,334 at P 66 (2005) ("Although the Commission is not bound to follow GAAP, it generally does so provided that it does not conflict with sound regulatory principles"), *aff'd*, 113 FERC ¶ 61,277, at P 65 (2005).

³⁸¹ According to PSG, Portland's initial debt cost calculation methodology (dividing debt costs by net rather than gross loan proceeds) sought more than allowed by the Commission's YTM methodology. PSG Brief on Exceptions at 92; Tr. 1578-79.

³⁸² Citing Portland Initial Brief at 174.

³⁸³ Citing Exh. No. PNG-21 at 2; Tr. 1577-78, 1579.

281. PSG describes its 5.99 percent debt cost rate using the embedded cost methodology (amortizing debt costs over the life of the loan) as quite close to the comparable YTM debt cost rate of 6.046 percent. PSG states that the embedded cost methodology was approved by the Commission as an alternative to the YTM methodology (as producing essentially the same results) in *SERI*.³⁸⁴ According to PSG, the *SERI* rehearing clarified that the total principal amount of debt (gross loan proceeds) should be used in the denominator of the embedded cost calculation as PSG Witness Neri did.³⁸⁵ PSG concludes that the 5.99 percent debt cost rate is just and reasonable.

282. In its brief opposing exceptions, Portland acknowledges that it provided YTM calculations “as an alternative proposal if the ID or the Commission accepted PSG’s contentions concerning the inclusion of Swaps.”³⁸⁶

Commission Determination

283. The Commission affirms the ALJ’s finding that Portland may incorporate the costs of settling interest rate swaps established to hedge its construction loans in anticipation of the required 2003 refinancing. However, we reverse the ALJ on the finding that Portland’s higher 7.09 percent calculation is supported by the preponderance of the evidence and require Portland to adopt its alternative 6.825 percent figure, consistent with the reasons Portland described in its Initial Brief.

³⁸⁴ *SERI*, Opinion No. 446, 92 FERC ¶ 61,119 at 61,447-48 & n.37, *reh’g denied*, Opinion No. 446-A, 96 FERC ¶ 61,165.

³⁸⁵ *SERI*, Opinion No. 446-A, 96 FERC ¶ 61,165 at 61,740-41 (stating that the Commission’s regulations “expressly provide that the weighted cost of debt capital is to be computed, in part, by ‘[m]ultiplying the cost of money ... by the principal amount outstanding for each issue’ of debt,” which means “the face value ... *i.e.*, the gross proceeds ... of the debt...,” adding that “the purpose of the cited regulation is to derive the weighted cost of debt” rather than “the percentage of debt in the capital structure.” *Id.* at 61,740-41 (citations omitted) (distinguishing in note 79 a case relied on by Portland as predating the relevant regulations). The YTM method similarly “provides for recovery of the par value of the bond, *not just recovery of the net proceeds.*” *Enbridge*, 100 FERC ¶ 61,260 at P 207 (emphasis added). *See also id.* PP 206 & n.195, 208. Portland’s reliance in this regard on *Michigan Storage*, 87 FERC ¶ 61,038 at 61,166, is misplaced because the YTM methodology was apparently used and endorsed in that case.

³⁸⁶ Portland Brief Opposing Exceptions at 86.

284. Portland entered into a hedging arrangement that was specifically directed at its construction financing – financing that was secured by substantially all of the pipeline assets.³⁸⁷ In order to lock in benefits at a time when rates were at an all time low, Portland entered into the hedging arrangement, until it was required to refinance the expiring construction loan. Because interest rates were low, Portland took a position such that it would be protected if rates rose. However, the opposite occurred and Portland was exposed to losses when rates remained low. Consequently, when it came time to settle the debt swap agreements in order to carry out the refinancing, Portland incurred losses under the swap agreements. Under these circumstances, the debt swap costs are properly counted as part of the cost of Portland’s current debt financing, as the costs were incurred in service of the temporary construction financing, and thus were specifically incurred to maintain the financing necessary to construct the pipeline. The construction loan was required to be reacquired and replaced with the longer term permanent financing. That is, the 2003 debt issue was facilitated by reacquiring the construction loan and incurring the debt swap settlement costs. Consequently, we find in this proceeding, as in Opinion No. 486, that it is proper for Portland to amortize the debt swap premiums and other costs of reacquiring the construction debt as premiums or other expenses for refinancing debt, to be collected over the life of the 2003 debt issue.³⁸⁸

285. Portland reports its resulting effective debt cost calculated using the YTM methodology using net proceeds as 6.825 percent. This calculation aligns with the effective debt cost rate reported in Docket No. RP08-306-000 in relation to the 2008 Rate Filing.³⁸⁹ In light of that fact, the Commission approves Portland’s calculation incorporating the debt swap settlement costs resulting in an overall effective debt cost of 6.825 percent.

³⁸⁷ Exh. No. PNG-131 at 4 (Portland 2002 FERC Form No. 2-A).

³⁸⁸ Opinion No. 486, 117 FERC ¶ 61,077 at PP 202, 209; Opinion No. 486-A, 123 FERC ¶ 61,056 at PP 251, 256.

³⁸⁹ Portland Initial Brief at 174-75; Portland Exh. No. PNG-83 at 8, Docket No. RP08-306-000, Schedule F-3, Cost of Long Term Debt Outstanding.

IX. Return On Equity

A. Derivation of ROE

286. As discussed in the Commission's *Policy Statement on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return On Equity*,³⁹⁰ 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. 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."³⁹¹ In order to attract capital, "a utility must offer a risk-adjusted expected rate of return sufficient to attract investors."³⁹² In theory, this requires an evaluation of the regulated firm's needed return compared to other regulated firms of comparable risk.

287. Most natural gas pipelines 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. 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."³⁹³ With simplifying assumptions, the DCF model results in the investor using the following formula to determine share price:

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

³⁹⁰ *Policy Statement on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return On Equity*, 123 FERC ¶ 61,048 (2008), *reh'g dismissed*, 123 FERC ¶ 61,259 (2008) (Policy Statement).

³⁹¹ *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

³⁹² *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001) (*CAPP v. FERC*).

³⁹³ *Id.*

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.³⁹⁴

288. Unlike investors, the Commission uses the DCF model to determine the return on equity (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:

$$R = D / P + g$$

The Commission uses a two-step procedure for determining the constant growth of dividends, averaging short-term and long-term growth estimates. Security analysts’ five-year forecasts for each company in the proxy group (discussed below), as published by 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).³⁹⁵ 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.³⁹⁶ The DCF methodology produces a zone of reasonableness in which the pipeline’s rates may be set based on specific risks.³⁹⁷

289. Here, the parties and Trial Staff have not disputed this basic methodology. The ROE issues litigated by the parties and Trial Staff are limited to: (1) the composition of the proxy group; (2) the appropriate methodology for calculating dividend yield for one member of the proxy group; (3) the appropriate derivation of the long-term growth

³⁹⁴ *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).

³⁹⁵ *Northwest Pipeline Corp.*, Opinion No. 396-B, 79 FERC ¶ 61,309, at 62,383 (1997); *Williston II*, 79 FERC ¶ 61,311 at 62,389, *aff’d in relevant part*, *Williston v. FERC*, 165 F.3d 54 at 57.

³⁹⁶ *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.

³⁹⁷ *Williston v. FERC*, 165 F.3d 54, 57.

estimate; and (4) the appropriate placement of Portland in the range of reasonable returns developed using the Commission's constant growth DCF model.

290. The returns for the proxy group adopted by the ALJ range from 8.69 percent to 11.53 percent, with a median of 10.28 percent.³⁹⁸ The ALJ determined that Portland's ROE should be placed at the median of the proxy group adopted in the ID, that is, 10.28 percent.

B. Composition of the proxy group

Initial Decision

291. The ID found that all participants agreed that Boardwalk Pipeline Partners, L.P., Southern Union Company, Spectra Energy Corporation, Spectra Energy Partners, L.P., and TC Pipelines, L.P. should be included in the proxy group.³⁹⁹ The ID noted that these five companies also comprised part of the proxy group approved by the Commission in Opinion No. 510.⁴⁰⁰ Based on the evidence presented during the proceeding, the ALJ concluded that nothing had changed since the issuance of Opinion No. 510 that would suggest that any of these five companies were no longer appropriate for inclusion in the proxy group for Portland.⁴⁰¹

292. The ID found that the only remaining dispute was whether to include El Paso Pipeline Partners, L.P. (El Paso Partners) in the proxy group.

293. Trial Staff is the only participant that objected to the inclusion of El Paso Partners. Trial Staff objected on the grounds that the company has a non-investment grade credit rating (BB) from Standard & Poor's (S&P). Trial Staff acknowledged that the Commission had included El Paso Partners in the proxy group in Opinion No. 510, but suggested that the Commission might have been unaware of the company's non-investment grade rating when it made that decision. The ALJ assumed for the sake of argument that the Commission was unaware of El Paso Partners' credit rating.

³⁹⁸ ID, 137 FERC ¶ 63,018 at P 1228.

³⁹⁹ *Id.* P 1205.

⁴⁰⁰ *Id.* (citing Opinion No. 510, 134 FERC ¶ 61,129 at P 169). No party sought rehearing of the Commission's decision regarding the appropriate proxy group. *See* Opinion No. 510-A at P 184.

⁴⁰¹ ID, 137 FERC ¶ 63,018 at P 1205.

294. The ID found that Trial Staff did not cite any Commission precedent indicating that a non-investment grade rating alone should disqualify a company from inclusion in the proxy group, other than a statement the Commission made in a footnote to Opinion No. 510. In that footnote, the Commission stated that it “agree[d] with the ALJ’s decision to exclude El Paso Corporation [from the proxy group] on the grounds that its credit rating was not investment grade during the relevant time period.”⁴⁰² The ALJ reasoned that while the Commission stated that it agreed with the ID to exclude a company based on its credit rating, the footnote did not establish that a company with a non-investment grade rating must be excluded in all cases. The ALJ found that, given the various criteria for proxy group inclusion that the Commission had explicitly spelled out,⁴⁰³ it seemed odd that it would establish a new requirement in a footnote near the end of a long proxy group discussion.⁴⁰⁴

295. The ID recognized that while El Paso Partners is rated non-investment by S&P, the other two rating agencies, Moody’s and Fitch, rate the company as investment grade.⁴⁰⁵ The ID noted one way in which Portland and El Paso Partners are comparable – in that both companies have non-investment grade S&P ratings.⁴⁰⁶

296. The ID pointed out that the Commission included El Paso Partners in the proxy group in Opinion No. 510 after discussing at length its assets, operations, income, and distribution history which made it a suitable comparable company to Portland. The ALJ concluded that the evidence in the instant proceeding indicates that El Paso Partners’ situation has not changed significantly since Opinion No. 510.⁴⁰⁷

297. The ID noted that in Opinion No. 510, the Commission concluded that the advantage of including in the proxy group a firm whose business activities are so similar

⁴⁰² Opinion No. 510, 134 FERC ¶ 61,129 at P 222 n.301.

⁴⁰³ *See id.* PP 164, 166-67.

⁴⁰⁴ ID, 137 FERC ¶ 63,018 at P 1207.

⁴⁰⁵ *Id.* P 1208 (citing Portland’s Initial Brief at 154).

⁴⁰⁶ The ID also referred to both companies having investment grade ratings from Moody’s and Fitch. 137 FERC ¶ 63,018 at P 1208. On exceptions, Portland points out that it does not have an investment grade rating from Moody’s and Fitch as those agencies have not provided Portland with a rating. Portland Brief on Exceptions at 78.

⁴⁰⁷ ID, 137 FERC ¶ 63,018 at P 1208.

to Portland's outweighed any concern about the relatively short period El Paso Partners had been organized as a master limited partnership.⁴⁰⁸ In the same vein, the ID found that the similarity between Portland and El Paso Partners outweighed El Paso Partners' non-investment grade rating from S&P and found it appropriate to include El Paso Partners in the proxy group.

Briefs On Exceptions

Trial Staff

298. Trial Staff excepted to the ID's inclusion of El Paso Partners in the proxy group.⁴⁰⁹ Trial Staff argues that El Paso Partners has a S&P rating of BB and is not investment grade.⁴¹⁰

299. Trial Staff argues that the ALJ admitted that in Opinion No. 510, the Commission agreed with the "ALJ's decision to exclude El Paso Corporation from the proxy group on the grounds that its S&P credit rating was not investment grade during the relevant time period." Trial Staff rejects the ID's finding that Opinion No. 510 did not establish that a company with a non-investment grade rating must be excluded from all cases." Trial Staff argues that in the prior Portland case, a proxy group candidate was plainly excluded for no other reason than it was not investment grade.

300. Trial Staff also argues that the ID ignores the contention of Trial Staff Witness Keyton that Portland is not as risky as portrayed by the S&P report and should be upgraded back to BBB-.⁴¹¹ Trial Staff took the position that the bankruptcy proceeds should be reflected in the current and future revenue levels used in calculating the debt

⁴⁰⁸ In Opinion No. 510, one issue was that El Paso Partners had been in operation less than five years. That timeframe has been met in this case. In any event, the Commission noted in Opinion No. 510 that the constituent pipelines of El Paso Partners had been in business for many years.

⁴⁰⁹ No party excepted to the composition of the proxy group.

⁴¹⁰ Trial Staff Brief on Exceptions at 94.

⁴¹¹ *Id.* at 95.

service coverage ratio⁴¹² for Portland.⁴¹³ According to Trial Staff, the S&P report did not consider the bankruptcy proceeds in the debt service coverage ratio calculation.⁴¹⁴

301. Finally, Trial Staff asserts that the ID ignored testimony that El Paso Partners has a lower credit rating than Portland even if Portland is considered non-investment grade.

Commission Determination

302. As we discussed in Opinion No. 510,⁴¹⁵ 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.’”⁴¹⁶ It is thus 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.”⁴¹⁷

303. In Opinion No. 510, we explained in detail why El Paso Partners qualified to be a member of the proxy group in that proceeding. The company more than satisfied the 50 percent test as its assets are composed nearly 100 percent of interstate natural gas facilities and nearly 100 percent of its operating income is derived from those

⁴¹² In general terms, a debt service coverage ratio is used to determine if a company has enough cash to pay off its items associated with debt. The ratio consists of some measurement of cash flows in the numerator and repayment of debt, to include principal and interest expenses, in the denominator. Exh. No. S-16 at 41, lines 16-19.

⁴¹³ Exh. No. S-16 at 46, lines 4-9, and 49, lines 2-11.

⁴¹⁴ It is unclear how this argument affects El Paso Partners’ suitability to be a proxy group member. In any event, we will not consider Trial Staff’s debt coverage argument, since it is purely speculative as to what effect consideration of the bankruptcy proceeds would have had on the S&P report.

⁴¹⁵ 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*)).

⁴¹⁶ *Petal v. FERC*, 496 F.3d at 697 (quoting *CAPP v. FERC*, 254 F.3d 289 at 293).

⁴¹⁷ Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 211.

facilities.⁴¹⁸ It follows that an investor would view an investment in El Paso Partners as an investment in a company in the same line of business as Portland.

304. Trial Staff argues that El Paso Partners' non-investment credit rating disqualifies it as a proxy group member and notes that in Opinion No. 510 we excluded a proxy group candidate (El Paso Corporation) on the sole basis that it had a non-investment grade rating. In that opinion, we stated that the "record is unclear as to whether any party still proposes El Paso Corporation as a proxy group member in this case. In any event, we agree with the ALJ's decision to exclude El Paso Corporation on the grounds that its credit rating was not investment grade during the relevant time period."⁴¹⁹

305. Given the many candidates for inclusion in the proxy group in the Opinion No. 510 proceedings, we determined to exclude El Paso Corporation. However, as the ALJ perceived, our decision there should not be construed to establish a binding standard. We note that El Paso Corporation has extensive gas production and development lines of business which are inherently more risky and thus affect its credit ratings. Further, these functions make it less comparable to Portland.

306. We note that El Paso Partners has been rated by all three ratings agencies. It has two investment grade ratings (Moody's and Fitch) and one non-investment grade rating. It is reasonable, therefore, to conclude that El Paso Partners is primarily of investment grade.

307. S&P downgraded El Paso Partners in part on account of its assessment of the risk of El Paso Partners' parent, El Paso Corporation. As noted above, El Paso Corporation has exploration and production functions which make it more risky than a natural gas pipeline. In contrast, El Paso Partners consists of several natural gas pipeline companies, all of which have been in business for many years. As we found in Opinion No. 510, the advantage of including in the proxy group a firm whose business activities are so similar to Portland's outweighs other factors, such as a non-investment rating from one of the three ratings agencies.⁴²⁰

308. Based on the foregoing, we find that El Paso Partners is an appropriate proxy group member and affirm the ID.

⁴¹⁸ Opinion No. 510, 134 FERC ¶ 61,129 at PP 200-01.

⁴¹⁹ *Id.* P 222 n.301.

⁴²⁰ *Id.* P 201.

C. DCF Analysis

Initial Decision

309. For purposes of the DCF analysis, the ID adopted the Trial Staff's discounted cash flow calculations,⁴²¹ which included the IHS Global Insight long-term growth forecast and a one-half long-term growth rate for master limited partnerships.⁴²²

310. As Trial Staff did not propose El Paso Partners as part of its proxy group, the ID added El Paso Partners' discounted cash flow result as calculated by CAPP to Trial Staff's DCF calculations.⁴²³ The ID acknowledged that CAPP did not include IHS Global Insight's estimates in its long-term growth rate, but found that CAPP's resulting 2.28 percent long-term growth rate for master limited partnerships was extremely similar to Trial Staff's 2.29 percent long-term growth rate. The ALJ concluded that it was appropriate to use CAPP's discounted cash flow result for El Paso Partners.⁴²⁴

311. The ID's discounted cash flow analysis, reflecting the calculations above, resulted in a range of returns for the proxy group from 8.69 percent to 11.53 percent, with a median of 10.28 percent.⁴²⁵ Trial Staff's DCF returns for each company are:

Company	DCF Result (%)
Boardwalk Pipeline Partners, L.P.	10.32
Southern Union Company	8.69
Spectra Energy Corp.	10.24
Spectra Energy Partners, L.P.	10.23
TC Pipelines, L.P.	10.69
El Paso Pipeline Partners, L.P.	11.59 ⁴²⁶

⁴²¹ Exh. No. S-67 at 2.

⁴²² ID, 137 FERC ¶ 63,018 at P 1228. The ID approved the use of the IHS Global Insight long-term growth forecast and a one-half long-term growth rate for master limited partnerships. No participant excepted to these determinations of the Presiding Judge.

⁴²³ Exh. No. CAP-22.

⁴²⁴ ID, 137 FERC ¶ 63,018 at P 1228 n.597.

⁴²⁵ *Id.* P 1228.

Briefs On and Opposing Exceptions

Portland

312. Portland excepts to the ALJ's use of CAPP's DCF results for El Paso Partners in the DCF analysis. Portland notes that the ID acknowledged that CAPP's analysis used the wrong GDP data, but determined the difference was inconsequential. Portland disagrees and asks the Commission to reject El Paso Partners' DCF results containing the incorrect data.⁴²⁷

313. Instead, Portland urges use of the DCF for El Paso Partners as calculated by Trial Staff in its updated return on equity calculations.⁴²⁸ That analysis uses the GDP data that the ID ruled should be included in the DCF.⁴²⁹ Portland states that Trial Staff's analysis calculates a return for El Paso Partners of 11.59 percent and thereby raises the top of the range to 11.59 percent, as opposed to 11.53 percent under the ID. Portland asserts that the ID erred by relying on CAPP's evidence, rather than Trial Staff's.⁴³⁰

314. Portland also noted that the DCF returns differ due to the distribution yields used by Trial Staff (4.96 percent) and CAPP (4.90 percent). Portland noted that the difference was due to the distribution recorded for January 2011. Portland states that its witness also calculated a dividend yield for El Paso Partners of 4.96 percent.⁴³¹

CAPP

315. CAPP states that Trial Staff incorrectly calculated the dividend yield figure for El Paso Partners. CAPP asserts that the annualized distribution for the first four months of the six-month period was \$1.64, and that the distribution was increased to \$1.74 for the months of February and March 2011.⁴³² CAPP states that Trial Staff incorrectly imputed

⁴²⁶ Exh. No. S-67 at 3.

⁴²⁷ Portland Brief on Exceptions at 79.

⁴²⁸ Exh. No. S-67 at 3, 12.

⁴²⁹ Exh. No. S-67 at 3, col. "GDP," 4, 12.

⁴³⁰ Portland Brief on Exceptions at 78-79.

⁴³¹ *Id.* at 79 n.506.

⁴³² CAPP attached an Appendix to its Brief on Exceptions which summarizes El Paso Partners' distribution history for the time period in question.

the payment date of the higher distribution figure to January 2011, which distorted the computation of the actual yield. CAPP argues that Trial Staff's figure is thus the "incorrect" figure and CAPP's DCF for El Paso Partners should be used in the DCF analysis.⁴³³

316. CAPP does not address Portland's argument that CAPP's analysis used incorrect GDP data.

Commission Determination

317. The only issue with regard to the appropriate DCF analysis concerns whether the return for El Paso Partners should be calculated using Trial Staff's method or CAPP's. The ID decided to use CAPP's analysis, presumably because Trial Staff did not advocate that El Paso Partners should be included in the proxy group. The ID recognized that CAPP's analysis did not use IHS Global Insight's estimates in deriving the long-term growth estimate, although its final result approximated Trial Staff's.

318. CAPP's long-term growth rate reflects the average of two long-term estimates of United States Gross Domestic Product (GDP).⁴³⁴ Although Trial Staff did not propose to include El Paso Partners in the proxy group, it did include El Paso Partners in its updated return on equity calculations. Trial Staff used three estimates of long-term growth – IHS Global Insight, Energy Information Administration (EIA), and the Social Security Administration's Federal Old Age and Survivors Insurance and Disability Insurance Trustees Report.⁴³⁵

319. The Commission has standardized the inputs to the DCF formula as applied to interstate gas and oil pipelines.⁴³⁶ The long-term growth estimate is based on forecasts of long-term growth of the economy as a whole,⁴³⁷ as reflected in the GDP, which are drawn

⁴³³ CAPP Brief on Exceptions at 12. CAPP also asserts that Portland raised a factual issue not taken up in the hearing. Because the exact composition of the proxy group could not be known until the ID was issued, there was no opportunity for Portland to raise this precise issue before the filing of briefs on exceptions.

⁴³⁴ *Id.* at 4-5; Exh. Nos. CAP-9 at 23, lines 12-13; CAP-13.

⁴³⁵ Exh. No. S-16 at 34-35.

⁴³⁶ Policy Statement, 123 FERC ¶ 61,048 at P 6.

⁴³⁷ Opinion No. 396-B, 79 FERC ¶ 61,309 at 62,383. *Williston II*, 79 FERC ¶ 61,311 at 62,389, *aff'd*, *Williston v. FERC*, 165 F.3d 54, 57.

from three different sources.⁴³⁸ Trial Staff's alternative analysis for El Paso Partners correctly reflected the use of three sources for long-term growth estimates. CAPP's analysis used only two estimates.

320. The difference between the two long-term growth estimates is one percent. Although the difference is *de minimus*, we conclude that Trial Staff's DCF return analysis should be used since it correctly reflects our long-standing requirement for determining the long-term growth estimates in the DCF methodology.

321. We will accept Trial Staff's calculation of the dividend yield for El Paso Partners. Trial Staff correctly used the declared date of January 21, 2011 for the dividend. A reasonable investor would factor a change in dividend (here, an increase) into its risk assessment of a company as of the date the dividend is declared, not the date it is paid. We further note that Trial Staff consistently used the declared date in its six-month analysis.⁴³⁹

322. In view of the foregoing discussions, we adopt Trial Staff's calculation of the DCF return for El Paso Partners. Accordingly, we reverse the ID and increase the top of the zone of reasonableness to 11.59 percent.

D. Portland's place in the Proxy Group

323. The ID cited the Commission's long-standing approach that, in determining the appropriate return on equity, the presumption is that "pipelines generally fall into a broad range of average risk, absent highly unusual circumstances that indicate an anomalously high or low risk as compared to other pipelines."⁴⁴⁰ The ALJ noted that the pipeline has

⁴³⁸ The three sources identified by the Commission in the Policy Statement are Global Insight: *Long-Term Macro Forecast – Baseline (U.S. Economy 30-Year Focus)*; Energy Information Agency, *Annual Energy Outlook*; and the Social Security Administration. Policy Statement, 123 FERC ¶ 61,048 at P 6 n.7. The ID determined that since IHS Global Insight was the successor of Global Insight and also forecasted 30 years into the future, it was reasonable to include IHS Global Insight it as a source for calculating long-term growth. ID, 137 FERC ¶ 63,018 at P 1226.

⁴³⁹ Exh. No. S-67 at 12.

⁴⁴⁰ ID, 137 FERC ¶ 63,018 at P 1273 (citing *Transcontinental Gas Pipeline Corp. (Transco)*, 90 FERC ¶ 61,279, at 61,936 (2000)). The Commission reiterated this standard in Opinion No. 510, 134 FERC ¶ 61,129 at P 265; Opinion 486-B, 126 FERC ¶ 61,034 at P 140; and the Policy Statement, 123 FERC ¶ 61,048 at P 7).

the burden of making “a very persuasive case” in support of deviating from the median – if it does not, “the Commission will set the pipeline’s return at the median.”⁴⁴¹ Because Portland argued that its return on equity should be set at the high end of the range of returns, the ID found that it has the burden of showing it faces “anomalously high . . . risk” and “highly unusual circumstances” when compared with other pipelines.⁴⁴²

324. The ID found that Portland relied primarily on three areas of risk in support of its request for a higher return on equity: (1) a decrease in its supply of natural gas and a decline in demand for long-term firm transportation service; (2) its non-investment grade credit rating from S&P; and (3) a comparison between Portland and the proxy group companies showing Portland’s greater risk.

325. Portland argued that its supply and demand problem resulted from a combination of declining exports of gas from Canada and competition from increased gas production from Marcellus Shale. With regard to Canadian gas supplies, Portland presented evidence from the EIA and the NEB which indicated that exports from Canada are expected to decrease in the future.⁴⁴³

326. The ID noted, however, that the development of shale gas in the Western Canadian Sedimentary Basin and Utica Shale (generally located in southern Quebec) may produce additional supplies that would be available to Portland.⁴⁴⁴ The ALJ concluded that while Portland faced some risk that Canadian supplies and exports to the United States will decline, Canadian shale gas development might mitigate or eliminate that risk.⁴⁴⁵

327. Portland also provided evidence that it was the most expensive path for shipping gas produced from Marcellus Shale. Portland provided an analysis of the transportation costs of shipping gas on several paths from the Dawn market hub to Boston, showing that Portland was the most expensive path for shipping gas.⁴⁴⁶ Portland’s analysis showed

⁴⁴¹ ID, 137 FERC ¶ 63,018 at P 1273.

⁴⁴² *Id.*

⁴⁴³ Exh. No. PNG-38 at 8-9.

⁴⁴⁴ ID, 137 FERC ¶ 63,018 at P 1275 (citing Exh. Nos. CAP-1 at 3-8, PSG-89 at 54-56; S-21 at 43-45).

⁴⁴⁵ *Id.*

⁴⁴⁶ Exh. Nos. PNG-38 at 14-16, PNG-100 at 27.

that Marcellus Shale gas will travel on Portland's system only if there is not a cheaper, more direct route available with sufficient capacity. Portland acknowledged that capacity to support Marcellus Shale production may not be currently available, though it expected that expansions will be built in the future to increase capacity.⁴⁴⁷

328. The ID acknowledged that if these expansions are built, and the incremental cost of expansion does not bring transportation costs above Portland's, then Portland does face risk in that other pipelines will be able to deliver Marcellus Shale gas more cheaply than Portland can. However, the ALJ found that the risk is not absolute because whether sufficient expansion capacity is built is uncertain, as is the ultimate cost of such expansions and the exact point in time when they will be built.⁴⁴⁸

329. The ID found that this risk depended on whether pipeline expansions which could transport Marcellus gas at a price more competitive than Portland's price would be built within a relevant timeframe.

330. The ID acknowledged that Portland's non-investment credit rating was an indication of its level of risk and was appropriately considered in the risk analysis.⁴⁴⁹ However, the ALJ found that Portland's credit rating was not highly unusual. While the credit rating might indicate that Portland has a higher level of business risk than a company with an investment grade rating, the ID found that it was not so unusual that it alone would justify deviation from the median.

331. For this proceeding, Portland provided a comparison between itself and the proxy group members. The ID found that in a number of categories Portland was less favorably situated than the proxy group, noting that the participants disagreed over the validity of some of Portland's conclusions.

⁴⁴⁷ Tr. 2243-44.

⁴⁴⁸ Additionally, the Maine Public Advocate pointed out that actual deliveries to Portland's captive markets averaged 42,313 Dth per day for the year ending August 31, 2010, while "the sum of the peak daily deliveries made by Portland at meters serving captive markets was 117,710 [Dth per day]." Maine Public Advocate Initial Brief at 5; Exh. No. MPA-2. This evidence shows that Portland has a fairly significant captive market, even if it may not be successful at contracting with these customers on a long-term firm basis. *See* Portland Reply Brief at 154.

⁴⁴⁹ ID, 137 FERC ¶ 63,018 at P 177 (citing Opinion No. 510, 134 FERC ¶ 61,129 at P 267; Opinion No. 486, 117 FERC ¶ 61,077; Opinion 486-B, 126 FERC ¶ 61,034 at P 137).

332. The ID acknowledged that the three areas of risk identified by Portland indicated that the company faces some risk, although the ALJ found that Portland had failed to show anomalously high risk or highly unusual circumstances. In the end, the ALJ chose to focus on the fact that through 2019 most of Portland's capacity is either subscribed under long-term transmission contracts or is compensated for in the disposition of the bankruptcy proceeds, which significantly reduces Portland's risk. Until then, the ID concluded that Portland did not face much risk at all. Any risk Portland has in comparison to the proxy group is offset by these factors. Because Portland did not show that its risk is anomalously high or that it faces highly unusual circumstances, the ALJ adopted a rate of return set at the median discounted cash flow result, 10.28 percent.⁴⁵⁰

Briefs On and Opposing Exceptions

Portland

333. On exceptions, Portland asserts that the ID erred by concluding that Portland's risk is not clearly anomalously high and that it does not face highly unusual circumstances. Portland states that a median return is particularly unjust and unreasonable given the ALJ's rulings concerning the treatment of the bankruptcy proceeds, IT/PAL revenue crediting, and depreciation rates. According to Portland, these rulings increase its risk and exacerbate its under recoveries.

334. Portland argues that it cannot contract for its unsubscribed capacity, it faces a declining supply situation, it has a non-investment grade credit rating, and its comparative analysis shows that it is more risky than the proxy group companies. Portland states the ID's rulings to credit the Bankruptcy Proceeds and the IT/PAL revenues and to adjust the depreciation exacerbate its under recovery.

335. Portland asserts that it has a significant amount of capacity unsubscribed on a long-term basis, contrary to the findings in the ID that through 2019, most of Portland's capacity is subscribed under long-term contracts. Portland states that, on an annual revenue adjusted basis, approximately 20 percent of its capacity is unsubscribed which is significant.⁴⁵¹ Portland argues that this unsubscribed capacity leads to an under recovery of its cost of service and thus its risk remains high.

⁴⁵⁰ The DCF results for the ID's proxy group range from 8.69 percent to 11.53 percent, with a median of 10.28 percent. ID, 137 FERC ¶ 63,018 at P 1228.

⁴⁵¹ Portland states that from April through October, over 50 percent of its firm system capacity is unsubscribed under long term firm contracts. From November through March, about 11 percent of its capacity is unsubscribed.

336. Portland states that the fact that all of its system capacity is subject to an at-risk condition also elevates its risk. Portland states that Trial Staff has not identified any pipeline other than Portland whose entire capacity is subject to an at-risk condition.

337. Portland states the ID erred when it found that Portland's unsubscribed capacity is "accounted for in the disposition of the Bankruptcy Proceeds" and therefore failed to consider the additional risk placed on Portland due to these rulings. Portland argues that as a result of the rulings, Portland will amortize exclusively for the ratepayers benefit the bankruptcy proceeds, rather than using any part of that amount to offset the under recoveries due to its unsubscribed capacity. Portland claims the rulings exacerbate its risk of under recovery and increase the chance Portland will not realize its Commission-approved return on equity.

338. Portland asserts the ID erred by failing to compare the length of Portland's long term contracts to the length of the proxy group members' long term contracts. Portland states that the ID's reliance on Portland's long-term firm contracts as a significant mitigating factor to its risk is unfounded and reflects inadequate analysis. Portland argues that this finding fails to follow Opinion No. 510 which called for a comparison of a pipeline's risk to that of the proxy group members.

339. Portland rejects the comparative analysis of the proxy group members' long-term contracts performed by CAPP and PSG.⁴⁵² Portland states that CAPP's analysis included pipelines not owned by proxy group members, excluded pipelines owned by proxy group members, and ends six months before the end of the DCF study. Portland states that because it has been unable for the past five years to contract any of its capacity on a long term firm basis, its contract length is constantly decreasing as time passes. In contrast, Portland asserts that the proxy group members have been able to recontract their capacity and hence their contract length will not decrease at the same rate as Portland's contract length, and potentially may not decrease at all.

340. Portland argues that even if the analyses of CAPP and PSG were combined, the data would produce an average contract term for proxy group members of 9.64 years. Portland argues that since its long term firm contracts are on average shorter than those of the proxy group members, Portland's contracts cannot significantly mitigate Portland's relative risk.

341. Portland takes issue with the ID's reliance on the *Mojave* and *Iroquois* cases.⁴⁵³ First, Portland states that both these cases were decided prior to the Commission's

⁴⁵² Portland Brief on Exceptions at 82.

⁴⁵³ *Id.* at 84 (citing *Mojave*, 81 FERC ¶ 61,150 (1997), *reh'g denied*, 83 FERC

mandate in Opinion No. 510 that a pipeline's risk must be compared to the proxy group members' risks. Portland states that the length of its long term contracts is not a mitigating risk factor when compared to the proxy group. Second, the ID underemphasized the undepreciated nature of Portland's system. Portland cites *Northwest*, which stated that capital recovery risk is an important risk consideration.⁴⁵⁴ Portland argues that its long-term contracts do not remotely cover its remaining depreciable life. Under the ID's depreciation rates, Portland says it has 29 years of capital recovery risk after its last contract expires.

342. Portland avers that *Mojave* had contracts that were longer than average, was 98 percent subscribed, had rates that produced a built-in over recovery of its cost of service and would have recovered over 70 percent of rate base when its contracts expired. As for *Iroquois*, Portland argues that Iroquois had contracts for a substantial portion of its capacity, increasing throughput, and served growing demand with long-lived supplies.⁴⁵⁵

343. In contrast, Portland states that it cannot sell its current unsubscribed capacity, and has a shorter contract life than the proxy group. Portland states that it is only 80 percent subscribed, and will under recover its cost of service in the future due to its unsubscribed capacity and the ID's treatment of the Bankruptcy proceeds and IT/PAL revenues. When its contracts expire, approximately 56 percent of its plant will be unrecovered using the ID's depreciation rates in 2019. Portland avers its decreasing utilization, declining market, and limited supplies severely threaten its investors' recovery.⁴⁵⁶

344. Portland states that the ID erred in concluding that Portland's non-investment credit rating was not highly unusual relative to the proxy group members. Portland argues that the ID also erred in finding that one of the proxy group members, El Paso Partners, had a lower credit rating. Had the ALJ recognized the Moody's and Fitch's investment grade ratings for El Paso Partners, Portland would instead have the lowest rating of the proxy group members. Moreover, S&P's rating was based on El Paso Partners' parent, El Paso Corp., and Portland contends the parent's exploration and production operations influenced El Paso Partners' rating.

¶ 61,267 (1998); *Iroquois*, 84 FERC ¶ 61,086).

⁴⁵⁴ Citing *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 (1999).

⁴⁵⁵ Portland Brief on Exceptions at 85.

⁴⁵⁶ *Id.* at 85-86.

345. Portland also states that the ID erred to the extent it relied on the various attacks on Portland's credit rating by Trial Staff, PSG, and CAPP. Portland cites the Commission's previous holdings that credit ratings are an appropriate part of the risk analysis. Portland also criticizes the Trial Staff's attempt to recalculate Portland's debt service coverage ratio in order to raise its credit rating to investment grade.⁴⁵⁷

346. Portland claims that the ID erred in failing to assess whether two challenges to Portland's comparative risk analysis had any merit.

347. PSG argued that Portland's basis differentials study was misleading because it reflected annual data and asserted that Portland's rate was competitive during the winter. Portland asserts that its maximum recourse rate is not competitive during winter. As an example, Portland states that the highest rate at which it sold winter capacity on a short-term basis during the test period was at a 67 percent discount from the current maximum rate. It states that its average winter interruptible sales were discounted between 21-79 percent. Portland's actual test period experience demonstrates that its maximum recourse winter rates are above market and do not make up for the loss of demand in the summer months. Furthermore, Portland's reliance on recovering its cost of service through the sale of capacity solely in winter creates higher risk. Portland says that the other pipelines in the proxy group have the opportunity to make up their lost revenues in summer.

348. Trial Staff opposed Portland's claim that Portland experienced the largest percentage decrease in contracted firm transportation compared to the proxy companies since the start of 2008. Trial Staff argued that the loss was due to the bankruptcies. Portland contends this position has zero merit since the bankrupt shippers defaulted in 2005 and 2006.

349. Portland reiterates that its comparative risk analysis establishes that its circumstances are highly unusual relative to the proxy group. Portland identifies the following factors: Portland has had the least success renewing existing contracts for firm service and attracting new firm contracts; it has a higher concentration than the proxy companies (i.e., top five customers as a percentage of total contracted capacity is 78.01 percent for Portland); Portland has been unable for the last five years to enter into long-term contracts for its unsubscribed capacity; and it has a larger proportion of capacity expiring in any given year (89.3 percent) than any proxy company. Portland states that it is "fully at the mercy" of market conditions in one 12-month period, as opposed to the more diverse market conditions that would obtain during staggered

⁴⁵⁷ *Id.* at 88.

contract terminations over multiple years. Moreover, Portland states it is smaller than any proxy company (in terms of total assets) and has higher business concentration risk than the proxy group.

350. Portland states the ID erred in concluding that Portland's supply analysis did not demonstrate an increase in risk. Portland faults the ID for not applying the Commission's definition of risk found in its 1982 order on the generic rate of return for electric utilities. Portland focuses on the language which defines risk "in an investment context...as the chance that expected returns will not be realized or, alternatively, as the chance of realizing returns less than expected."⁴⁵⁸

351. Portland asserts that its supplies are currently declining and will decrease further due to lower production from its primary supply basin [in Canada] together with increased demand for those supplies in Canada. Portland argues that these forces will reduce exports to the US and will make Canada a net gas importer by 2028. Portland states that as the most marginal export pipeline, it will be the first to be affected by future reductions in exports.

352. Portland argues that the economics that support expansions of pipelines to serve the Northeast undermine any expectation of demand for long-term firm transport service on Portland because existing or new shippers have no economic incentive to renew or enter into long term firm transportation contracts with Portland.

353. Portland notes that Utica shale is not a viable source of supplies, and in any event, its development is purely speculative.

354. Portland expects that Marcellus gas supplies will also displace Canadian supplies and eliminate demand for firm transportation on Portland. Portland disagrees with the ID's conclusion that Marcellus shale production does not affect its risk because the production's flow path is uncertain and states the ID seems to think that until Portland is actually harmed by the production, it does not have risk. Portland contends that it is the least economic route to ship Marcellus gas to the Boston market. Moreover, Marcellus gas will reduce the price of gas and eliminate whatever basis differential existed on Portland.

355. Portland contends the ID also erred by failing to consider the decrease in demand in Portland's market area. It asserts that aggregate demand in New England will decrease

⁴⁵⁸ Portland Brief on Exceptions at 91 & n.608 (citing *Generic Determination of Rate of Return on Common Equity for Electric Utilities*, 47 Fed. Reg. 38,332, 32,218 (1982)).

through 2019, when Portland's long-term contracts expire. Portland states that its competitors are expanding, offering service from competitive supply sources, and decreasing the market value of Portland's transportation such that it cannot sell new firm transportation even to its few captive customers.

356. Portland states that it is the least competitive pipeline on a delivered cost basis serving New England. Its ratio of pipeline basis differential to firm transportation rate, 0.0 percent, is lower than for any proxy company. Portland states that approximately 95 percent of its firm contract commitments can bypass Portland and that its utilization rates have plunged from 40 percent to 10 percent in 2009. Portland states that it had the second lowest annual load factor for 2009 of the proxy companies.

357. In sum, with regard to its comparative risk vis-à-vis the proxy group members, Portland declares that it is in a very risky position and that its ability to withstand a negative event in the future is limited. Coupled with supply uncertainty, Portland believes its circumstances are highly unusual and that its investors should be compensated for the risks they face with a return on equity at the top of the range.⁴⁵⁹

Trial Staff

358. Trial Staff opposes Portland's exceptions and urges the Commission to uphold the ALJ's ruling that the return on equity should be set at the median of the zone of reasonableness, or 10.28 percent.⁴⁶⁰ Trial Staff states that Portland only describes its dire business situation but does not offer any game plan detailing what steps it may undertake to meet these challenges. Trial Staff states that Portland also failed to explain why, if it truly has these financial problems, it distributed the bankruptcy proceeds to its parent companies. Trial Staff points to Portland's witness testimony that Portland did so "because there was no use that Portland has for that kind of money."⁴⁶¹

359. Trial Staff discounts Portland's arguments concerning its risk, e.g., the seasonality aspect of the pipeline, that its unsubscribed capacity translates into under recovery of its cost of service, its at-risk condition, and that its risks will increase if the at-risk condition and billing determinants are set at a level beyond Portland's physical capacity.

⁴⁵⁹ Based on the adjustment Portland urged to the ID's DCF methodology, its top of the range is 11.59 percent, as opposed to the ID's 11.53 percent.

⁴⁶⁰ Trial Staff Brief Opposing Exceptions at 68.

⁴⁶¹ *Id.* at 73.

360. Trial Staff points out that it was the Commission's intention from the time it issued the initial certificate order to place the pipeline at risk for any unsubscribed capacity. Similarly, it was clear from the beginning that Portland was a seasonal pipeline and thus it would certainly have unsubscribed capacity in the summer and possibly even during the winter months. Trial Staff cites the language of Opinion No. 510 which explained that neither the seasonal nature of Portland's system nor the fact that it lost subscribed capacity due to the bankruptcies "are hardly unique to Portland and are also faced by other interstate pipelines."⁴⁶² Trial Staff states the pipeline could have chosen not to accept its certificate in 1997 and should not be heard to complain now.

361. Trial Staff also disagrees with Portland regarding the effect of the ID's rulings regarding the bankruptcy proceeds and interruptible revenues. Portland argues that these rulings will exacerbate its risk level. Trial Staff points out that although Portland seeks to transfer \$16.3 million in costs to shippers based on the proposed billing determinants of 168,672 Dth day (which represents a 20 percent reduction in its certificated capacity), it then asserts that its risk level will be raised if it has to pay the \$8.5 million cost of service credit ordered by the ALJ.

362. Trial Staff submits that, contrary to Portland's contentions, the ALJ adequately compared Portland to the proxy group members. Trial Staff believes that Portland skewed its analysis toward an outcome showing Portland with greater risk and focused only on two aspects for comparison – retention of long-term contracts and credit ratings. As a result, Trial Staff posits Portland has failed to demonstrate that it is far riskier than other members of the proxy group.

363. With respect to the long-term contracts, Trial Staff argues that Portland focused on proxy group contracts expiring by 2020 in order to portray Portland as riskier than the other proxy group members. Trial Staff points out that even Portland's witness' analysis shows that other proxy group members have over 90 percent of their firm contracts expiring by 2020. Simply because Portland has all of its contracts expiring does not demonstrate "anomalously high" risk, according to Trial Staff.

364. Trial Staff argues that it makes little sense to require Portland's existing shippers to pay rates for a time period commencing December 1, 2010 based on a return on equity at the top of the range because Portland may lose customers eight and a half years into the future. Trial Staff notes that Portland can always file for a section 4 rate increase if it should fail to renew or replace its existing contracts by 2019.⁴⁶³

⁴⁶² *Id.* at 74.

⁴⁶³ *Id.* at 78.

365. Trial Staff contests Portland's analysis of the *Mojave* case. In that case, the Commission specifically rejected an above median return on equity for a pipeline which had long-term contracts reserving a high percentage of its capacity. Portland claimed that *Mojave* did not control because it was issued before Opinion No. 510's direction that a pipeline's risk be compared to the proxy group members' risks. Trial Staff argues that even before Opinion No. 510, the Commission required pipelines to show highly unusual circumstances indicating anomalously high or low risk as compared to other pipelines (citing *HIOS*). Trial Staff also dismissed Portland's claim that 56 percent of its plant will remain unrecovered in 2019 under the depreciation rate in the ID. Trial Staff believes that this risk can be addressed by a section 4 rate case and that Portland accepted this risk under the at-risk condition.

366. Trial Staff disagrees with Portland's argument that its low credit rating justifies a return on equity at the top of the range. It states that Portland's citation of a 1993 *Transco* case is no longer controlling precedent for determining adjustments to the return on equity. In the *Transco* case, the Commission held that because the pipeline's business and financial risks were higher than that of the average natural gas pipeline and its credit ratings were downgraded, it placed the return on equity at the top of the range. Trial Staff argues that Portland ignores the fact that more recently the Commission has determined that it is presumed that existing pipelines fall within a broad range of average risk and a pipeline must demonstrate highly unusual circumstances to justify an adjustment to the median return on equity.

367. With regard to Portland's credit rating, Trial Staff points out that one of the reasons why S&P downgraded Portland was due to the company's low debt service coverage ratio. Trial Staff argued that the bankruptcy proceeds should be reflected in the current and future revenue levels used in calculating the debt service coverage ratio for Portland. Trial Staff proposed that \$119,761,258 be amortized over the number of years remaining on the Androscoggin and Rumford contracts at the time they went bankrupt. Trial Staff argues that if this approach were adopted, Portland would satisfy the requirements of its debt service coverage and thereby would mend or ameliorate S&P assessment. Trial Staff notes that the S&P report states that it could raise the rating if Portland were allowed to raise rates such that expected debt service coverage ratio would exceed 1.4x consistently through the debt's remaining term.

CAPP

368. CAPP asserts that Portland's arguments are not valid and warrant no adjustment to the ID's findings or any deviation from the median return on equity.⁴⁶⁴

⁴⁶⁴ CAPP Brief Opposing Exceptions at 2.

369. With regard to Portland's contract life, CAPP believes that the evidence supports a downward adjustment from the median.⁴⁶⁵ Although CAPP believes that Portland's analysis of the other proxy group members' contract terms in Appendix A of its BOE is deficient, it chose to accept the data used in the analysis. CAPP states that its witness computed an average contract for Portland of 8.44 years, which Portland did not rebut. CAPP argues the median contract life figure for the proxy group pipelines is 8.05 years. CAPP believes that certain pipelines were double-counted, and if this were corrected, the median contract life drops to 7.68 years. CAPP argues that the comparisons it draws from the proxy group analysis all indicate that Portland has average or lower than average risk when compared to the proxy group.⁴⁶⁶

370. CAPP states that Portland's assertion that the average contract length for proxy group members is 9.64 years is distorted by the inclusion of Elba Express Pipeline (Elba) which is owned by El Paso Partners. Elba is a new pipeline with a single customer which has contracted for all of its capacity under a negotiated rate. If Elba is removed from the contract life analysis, CAPP's calculations show that the average contract life of the proxy group approaches that of Portland's and that some proxy group members would have contract lives lower than Portland.⁴⁶⁷

371. CAPP rejects Portland's argument that it is unusually risky because of the high proportion of its capacity that is subject to a renewal risk. CAPP says Portland offers no comparison to other pipelines' unsubscribed capacity.⁴⁶⁸

372. CAPP argues that Portland is well positioned to take advantage of new sources of natural gas from the Marcellus and Utica gas shale fields. CAPP believes that Utica shale gas offers an important new source of supply for Portland. It cites remarks made by an officer of TransCanada, Portland's corporate parent, to the effect that if Utica shale developed, the volumes produced would exceed local demands making movement into the continental market likely. CAPP also argues that Marcellus gas could be delivered to TransCanada in Western New York for distribution through the TransCanada system.⁴⁶⁹

⁴⁶⁵ *Id.*

⁴⁶⁶ *Id.* at 4-5.

⁴⁶⁷ *Id.* at 7.

⁴⁶⁸ *Id.*

⁴⁶⁹ *Id.* at 8-9.

373. CAPP argues that Portland's argument that its credit rating is the lowest of the proxy group members does not support any adjustment to the median. This is because Portland's evidence compares the S&P issuer ratings for the proxy group pipelines with the S&P instrument rating of Portland's long-term debt, i.e., specific bonds. CAPP argues that Portland does not have a long-term S&P issuer rating. CAPP points out that the S&P credit rating explicitly describes the risks to lenders as declining over the term of the bonds.⁴⁷⁰

PSG

374. PSG states that even accepting Portland's argument at face value, a long-term FT subscription level of 80 percent of capacity hardly indicates "anomalously high" risk relative to the proxy group companies, particularly considering that the ID found that the remaining 20 percent is already substantially paid for through Portland's receipt of proceeds from the Androscoggin/Rumford bankruptcies, which compensated Portland for the future revenue stream under long-term contracts covering 62,000 Dth day of Portland capacity but which Portland chose to distribute to its owners.⁴⁷¹ Moreover, the maximum FT recourse rate applicable to Portland's winter-only contracts was originally set at 2.4 times the rate under its year-round contracts, such that on an annual revenue-adjusted basis (relevant for an investor's risk analysis), a 100 percent subscription level under Portland's winter-only contracts would amount to the same revenue as a 100 percent subscription level under its year-round contracts.⁴⁷²

375. PSG points out that it was Portland's choice to reduce its maximum FT recourse rate for its winter-only contracts to 1.9 times the rate under its year-round contracts, and the Commission permitted this only on the condition that Portland would bear the risk of any resultant reduction (e.g., from 89 percent to 80 percent) in its revenue-adjusted level of long-term subscription to its FT service capacity. Accordingly, Portland should not be heard to argue that a reduction in its winter rate, made at its own request, supports an enhanced return on equity.

⁴⁷⁰ PSG Brief Opposing Exceptions at 71.

⁴⁷¹ ID, 137 FERC ¶ 63,018 at P 1280. Portland presents no corresponding figures for the proxy group companies.

⁴⁷² This formula rate is derived by dividing 12 months per year by the five winter months ($12 \div 5 = 2.4$) such that Portland's maximum long-term FT recourse rate for winter-only (5-month) service would be sufficiently high to generate the same level of revenue as Portland's corresponding rate for year-round service.

376. PSG rejects Portland's argument that because the ID has ruled that the bankruptcy proceeds and the IT/PAL revenues should be credited to its cost of service, it cannot use those monies to offset under recoveries resulting from unsubscribed capacity. PSG argues that this situation results from Portland's own actions, i.e., Portland chose to distribute the bankruptcy proceeds and to lower its winter rate to accommodate its decision to enter into most-favored nation (MFN) clauses. Further, PSG claims that Portland's request for an enhanced ROE in this case is barred by (among other reasons) policy parameters set by the Commission, which preclude consideration of purported business or financial risks of a pipeline that are effectively the result of its own business decisions. PSG also argues that Commission policy precludes any adjustment to return on equity based on Portland's purported risks flowing from "regulatory uncertainty."⁴⁷³

377. PSG argues that Portland's long-term contracts mitigate its risk. PSG claims that Opinion No. 486-E clarified that the Commission will focus on the five year period used in forecasting the growth of proxy companies because any evaluation of future risk declines after five years.⁴⁷⁴ Based on this interpretation, PSG argues that Portland has contracts extending beyond five years into 2019 for at least 80 percent of its capacity and the remaining 20 percent is substantially paid for through the bankruptcy proceeds. PSG notes that Portland will have an opportunity to file another rate case, if circumstances arise that may justify a rate increase.⁴⁷⁵

378. PSG believes that if the Utica shale is developed, it will create additional opportunities for Portland. PSG argues that any risk arising from the increased production of Marcellus gas would arise only after the expiration of Portland's contracts in 2019. In the meantime, Portland's customers are locked into their contracts.⁴⁷⁶

379. PSG states that Portland misrepresented its basis differentials analysis. Had Portland calculated its basis differentials for the winter months, the ratio would have been positive, thus reflecting a competitive winter rate. Similarly, PSG notes Portland's assertion that it suffered a decline between 2007 and 2009 in fourth-quarter short-term contracts as a percentage of capacity. PSG states Portland did not fully account for all of

⁴⁷³ PSG Brief Opposing Exceptions at 74.

⁴⁷⁴ The Commission's reference in Opinion No. 486-E to a five year time period was to the period used by financial analysts in forecasting the growth prospects of individual firms, not to any Commission standard.

⁴⁷⁵ PSG Brief Opposing Exceptions at 75.

⁴⁷⁶ *Id.* at 76-77.

its winter contracts between 2007 and 2009 since it did not count contracts beginning after the start of a quarter and thus ignored contracts running from November through March.

380. PSG dismisses the S&P 2010 credit rating downgrade as a reason for granting Portland a premium return on equity.⁴⁷⁷ PSG argues that the downgrade was due primarily to S&P recognition of the rate decrease ordered in the RP08-306 Initial Decision and its perception of regulatory uncertainty. PSG argues that this is not a permissive risk factor under Commission policy. PSG points out that S&P concluded that otherwise Portland had a satisfactory business profile reflecting long-term contracts with investment grade shippers.⁴⁷⁸ PSG also argues that S&P did not consider Portland's receipt of \$120 million from the bankruptcy proceedings and may have been unaware of it. PSG believes that since Portland has no plans to incur further debt, and the debt will be retired in 2018, Portland will have attained 100 percent equity investment.

381. PSG avers that Portland's currently below investment grade rating does not indicate "highly unusual" risk considering that a proxy group member, El Paso Partners, received a lower credit rating from S&P.

Commission Determination

382. The Commission's traditional assumption with regard to relative risk is that natural gas pipelines generally fall into a broad range of average risk absent highly unusual circumstances that indicate an anomalously high or low risk as compared to other pipelines. Thus, unless a pipeline makes a very persuasive case in support of the need for an adjustment and the level of the adjustment proposed, the Commission will set the pipeline's return at the median of the range of reasonable returns.⁴⁷⁹ However, the Commission permits parties to present evidence to support any return on equity that is within the zone of reasonableness, and the Commission has recognized that an examination of the risk factors specific to a particular pipeline may warrant setting its ROE either higher or lower than the middle of the zone of reasonableness established by the proxy group.⁴⁸⁰ In this case, for the first time since Opinion No. 414-A established

⁴⁷⁷ *Id.* at 82.

⁴⁷⁸ *Id.*

⁴⁷⁹ *Transco*, 90 FERC ¶ 61,279; Opinion No. 486-B, 126 FERC ¶ 61,034 at P 140; Policy Statement, 123 FERC ¶ 61,048 at P 7.

⁴⁸⁰ Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,427.

our current policies concerning the assessment of a pipeline's risk as compared to the proxy group, we must determine the ROE for a pipeline with a below investment grade credit rating. We find that Portland's below investment grade credit rating, combined with its inability to reflect its unsubscribed capacity in its rate design, present highly unusual circumstances justifying setting Portland's ROE at the top of the range of reasonable returns.

383. In Opinion Nos. 510 and 510-A, we determined that Portland had failed to overcome the presumption of average risk and determined that its return on equity should be set at the median of the zone of reasonableness.⁴⁸¹ Portland argued that numerous factors such as favored nations clauses, decontracting options, free off-peak transportation provisions, and the use of joint facilities supported its request for a higher return on equity. We found that those factors were the consequence of Portland's own business decisions and not an appropriate basis for adjusting Portland's ROE upward. We also found that Portland had failed to present a comprehensive analysis comparing its risk to each proxy group member.

384. Portland's current rate case in Docket No. RP10-729-000 necessarily presents different facts and circumstances from those existing in the previous rate case. Thus, to determine the appropriate return on equity, we must answer the question: has Portland presented evidence of highly unusual circumstances which demonstrate that it has anomalously high risk which would warrant an upward adjustment to the median.

385. In Opinion No. 510, the Commission denied Portland's request for official notice of S&P's post-record downgrade of Portland's senior secured credit rating.⁴⁸² The

⁴⁸¹ Opinion No. 510, 134 FERC ¶ 61,129 at P 270, *aff'd* Opinion No. 510-A at P241-50.

⁴⁸² Opinion No. 510, 134 FERC ¶ 61,129 at P 271. Portland filed a motion on August 20, 2010 to request that the Commission take official notice under Rule No. 508 (18 C.F.R. § 385.508(d) (2012)) of a confidential, July 22, 2010 S&P report that downgraded its BBB- corporate credit rating to BB+ Stable. According to Portland, S&P specifically identified the rates approved in the Initial Decision in Docket No. RP08-306-000 as the main factor in the downgrade. Portland argued that the S&P downgrade was relevant to Portland's risk compared to the proxy group and stated the credit rating could be used to determine whether the rates approved in the Initial Decision provide a rate of return that Portland suggested is constitutionally-required to maintain its credit standing. Portland Motion at 3 (citing *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1994) (*Hope*); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923) (*Bluefield*)).

Commission found that the downgrade had occurred nearly 21 months after the close of the test period in that proceeding and was irrelevant to the determinations of Portland's return on equity there. In particular, the Commission noted that Portland had filed a new rate case (i.e., Docket No. RP10-729-000) and that the downgrade could be addressed in that proceeding.⁴⁸³

386. Credit ratings are an appropriate consideration in determining a pipeline's relative risk within the range of ROEs established by the proxy group.⁴⁸⁴ The Commission has previously taken into account below investment grade credit ratings when determining a pipeline's return on equity, and set a pipeline's ROE at the top of the range because of its below investment grade credit rating.⁴⁸⁵

387. The July 2010 S&P report lowered Portland's senior secured credit rating to BB+ from BBB-. According to that report, the BB+ rating reflected the following risks: Portland's litigated rate cases increase the risk of future revenue reductions and threaten Portland's competitive position with shippers; strong competition from other interstate pipelines in the Northeast and the Boston area; Portland's higher cost structure than regional competitors which weakens its ability to attract new shippers; and Portland's capacity use may decline significantly due to reduced availability of natural gas from Canada.⁴⁸⁶

388. When compared to the six proxy group members, Portland's non-investment grade credit rating places it below all of the other proxy group members with the possible exception of El Paso Partners. That company also has a non-investment grade rating from S&P. However, as discussed above, El Paso Partners also has investment grade ratings from the other two ratings agencies. Thus, El Paso Partners can be construed to have an investment grade credit rating given this is the consensus rating from two out of

⁴⁸³ Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) at P 212 ("It is most efficient to ... consider in Portland's next rate case whether its return on equity should be modified in light of subsequent developments occurring long after the close of the test period" in Docket No. RP08-306-000).

⁴⁸⁴ Opinion 486-B, 126 FERC ¶ 61,034 at P 137 (a pipeline's credit rating is "an appropriate part of the risk analysis"). See *Transco*, 90 FERC ¶ 61,279 at 61,937; Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,427-4 – 61,427-5 (1998).

⁴⁸⁵ *Transcontinental Pipeline Corp.*, 60 FERC ¶ 61,246, at 61,826 (1992) (*Transco II*), *reh'g denied*, 64 FERC ¶ 61,039, at 61,348 (1993).

⁴⁸⁶ Exh. No. PNG-113.

the three major credit rating agencies. The same cannot be said of Portland, which has only the S&P non-investment grade rating. Thus, when compared to the other proxy group members, Portland ranks at the bottom. A potential investor could reasonably reach the conclusion that Portland is the most risky of the comparable companies.⁴⁸⁷

389. In terms of Portland's business risk, Trial Staff's witness compared S&P business risk profiles and financial risk profiles, in addition to issuer credit ratings.⁴⁸⁸ The witness noted that Portland had a S&P risk profile of "satisfactory,"⁴⁸⁹ but that the three other proxy group companies with business risk ratings had more favorable "strong" ratings. This supports Portland's argument that it has higher risk than the proxy group companies. The witness noted that Portland itself had not been given a financial risk rating. In terms of issuer credit ratings, the three proxy group members that have such ratings, Southern Union, Boardwalk, and Spectra Energy Corp, are rated BBB-, BBB, and BBB+, respectively.⁴⁹⁰

390. In its last rate case, Portland did not have a non-investment credit rating. However, as of 2010, it has been rated as non-investment grade. Such a rating tends to make financing more difficult and costly to obtain. A reasonable investor would likely consider Portland to be a very risky company, especially when compared to the other proxy group members. Such a reasonable investor would require a premium to invest in a company with a non-investment grade credit rating.

391. The Commission has previously found that a pipeline should be afforded an equity return commensurate with an investor's perception of the pipeline's risk.⁴⁹¹ Portland's non-investment credit rating represents a significant change in its circumstances since its last rate case. When compared to the six proxy group members on several bases, Portland ranks last.

392. We also take into account the fact the at-risk condition included in Portland's certificate prevents it from designing its rates based on less than its design capacity,

⁴⁸⁷ In one sense, there are no comparable natural gas companies to Portland since only Portland has a non-investment credit rating.

⁴⁸⁸ Exh. No. S-30 at 11.

⁴⁸⁹ Exh. No. S-16 at 52.

⁴⁹⁰ Exh. No. S-30 at 11.

⁴⁹¹ *Transco II*, 60 FERC ¶ 61,246 at 61,826.

despite the fact its projected billing determinants are about 20 percent less than its design capacity. None of the pipelines owned by the members of the proxy group are subject to such an at-risk condition,⁴⁹² and thus those pipelines would be free to propose to increase their rates sufficiently to recover their entire cost of service, despite having unsubscribed capacity. We recognize that Portland agreed to the at-risk condition, by accepting the certificate with that condition. However, the shippers benefited from that decision, because otherwise the pipeline would not have been built. Moreover, while the shippers negotiated levelized rates during the certificate proceeding, Portland retained the flexibility to propose a revised ROE in any section 4 rate case. Therefore, the fact Portland agreed to the at-risk condition does not foreclose taking it into account in determining its relative risk compared to the proxy group. We find that the fact of Portland's non-investment grade credit rating, combined with the at-risk condition, warrants an upward adjustment from the median to Portland's return on equity.

393. The parties and Trial Staff have presented other arguments as to why Portland's return on equity should remain at the median. These arguments raise many of the same concerns as presented in Docket No. RP08-306-000.

394. Some of the factors which led us to conclude in Opinion No. 510 that Portland should be given a return on equity at the median still exist.⁴⁹³ We have carefully considered all arguments raised by the parties and Trial Staff. However, we believe that Portland's non-investment credit rating represents a very significant change in circumstances affecting return on equity that was not present in the last proceeding.

395. Based on Portland's particular circumstances as reflected in the record in this proceeding, we determine that Portland has made the very persuasive case necessary to overcome the presumption that its ROE should be set at the median of the proxy group. Portland's non-investment grade credit rating supports the conclusion that Portland is of above average risk when compared to the proxy group. Portland's non-investment grade credit rating, together with the at-risk condition, constitutes a highly unusual circumstance which warrants an upward adjustment to the return on equity. Accordingly,

⁴⁹² As stated previously, in 1999 two years after issuing Portland's certificate, the Commission modified its certificate policy and no longer imposes at-risk conditions based upon a pipeline's design capacity.

⁴⁹³ For example, factors such as favored nations clauses, decontracting options, free off-peak transportation provisions, and the use of joint facilities are still attributable to Portland's own actions.

we determine that Portland's return on equity should be set at the top of the range of reasonable returns as defined earlier, or 11.59 percent.

X. Compliance

396. Within 30 days of the date of this order, Portland is required to file *pro forma* recalculated rates consistent with the terms of this order.⁴⁹⁴ Portland is required to provide work papers in electronic format, including formulas, reflecting each of the adjustments required by this opinion. Portland is also required to compare the revised rates to those required by Opinion No. 510-A. If Portland files requests for rehearing, it is required to also provide recalculated rates identifying the rate impact of each item at issue, with supporting work papers in electronic format, including formulas.

397. Parties to this proceeding should file any comments they may have on Portland's compliance filing within 30 days of the date of the filing.

398. The Commission will issue an order addressing Portland's tariff and refund obligations at a later date.

The Commission orders:

(A) The Initial Decision is affirmed and modified as discussed in the body of this order.

(B) Within 30 days of the issuance of this order, Portland must file revised *pro forma* rates, including proposed accounting and workpapers, reflecting the Commission's rulings, as discussed in the body of this order.

By the Commission.

(S E A L)

⁴⁹⁴ Portland should make this compliance filing utilizing the Commission's eFiling system and designating Docket No. RP10-729.

Nathaniel J. Davis, Sr.,
Deputy Secretary.