150 FERC ¶ 61,107
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Portland Natural Gas Transmission System

Docket Nos. RP10-729-001
RP10-729-000

OPINION NO. 524-A

OPINION AND ORDER ON REQUEST FOR REHEARING AND COMPLIANCE FILING

Issued: February 19, 2015

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Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

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OPINION NO. 524-A

OPINION AND ORDER ON REQUEST FOR REHEARING
AND COMPLIANCE FILING

(Issued February 19, 2015)

1. This order addresses requests for rehearing of Opinion No. 524, issued on March 21, 2013 in the captioned docket,[1] and Portland Natural Gas Transmission System's (Portland) filing in compliance with that order.[2] Opinion No. 524 addressed briefs on and opposing exceptions to an Initial Decision issued on December 8, 2011 regarding a general Natural Gas Act (NGA) rate proceeding filed by Portland in May 2010.[3] As discussed below, the Commission denies the requests for rehearing of Opinion No. 524.

I. Background

A. Portland's Facilities

2. Portland's interstate pipeline system was authorized by a series of Commission orders, which approved Portland's initial and amended applications and issued

[1] *Portland Natural Gas Transmission System*, Opinion No. 524, 142 FERC ¶ 61,197 (2013) (Opinion No. 524).

[2] *See* Portland's filing to comply with Opinion No. 524, dated April 23, 2013.

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

certificates of public convenience and necessity pursuant to NGA section 7(c), 15 U.S.C. § 717f (c).[4] As it exists today, Portland's 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-Québec & Maritimes Pipeline Inc. (TQM) 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). Portland shares the Joint Facilities with another interstate pipeline, Maritimes & Northeast Pipeline, LLC (Maritimes).

3. Portland has capacity rights of 210,000 Mcf per day on the Joint Facilities. On January 15, 2009, Maritimes placed into service a major expansion of its system through the installation of additional compression on its upstream facilities and on the Joint Facilities (Phase IV Expansion). While the Phase IV Expansion did not affect Portland's capacity on the Joint Facilities, as described in more detail below, it did reduce Portland's ability to transport natural gas over its Northern Facilities to the Joint Facilities from at least 210,000 Mcf per day to 168,000 Mcf per day.

B. Procedural Background

4. As stated, this case involves a general NGA section 4 rate proceeding filed by Portland on May 12, 2010 (2010 Rate Filing). Portland used a test period consisting of a base period of the 12 months ending February 28, 2010, as adjusted for known and measurable changes occurring through a nine month adjustment period ending November 30, 2010.[5] In the 2010 Rate Filing, Portland sought an increase in its base

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[4] *See Portland Natural Gas Transmission System*, 76 FERC ¶ 61,123 (1996) (issuing preliminary determination on Portland's initial certificate application) (1996 Certificate Order); 80 FERC ¶ 61,134 (1997) (issuing preliminary determination on all aspects of Portland's amended certificate application except for construction of Phase I Joint Facilities) (July 1997 Preliminary Determination Order); 80 FERC ¶ 61,136 (1997) (certificating Portland's construction of Phase I Joint Facilities) (July 1997 Phase I Construction Certificate Order); and 80 FERC ¶ 61,345 (1997) (granting certificate authority and addressing requests for rehearing of the July 1997 Preliminary Determination Order) (September 1997 Certificate and Rehearing Order).

[5] The rates proposed in the 2010 Rate Filing 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

(continued…)

transportation rates based on its claims of increased business risks, unsubscribed capacity, and changes in the pipeline infrastructure affecting its market area. Among other things, Portland contended that its at-risk condition and billing determinants should be reduced to 168,672 Dth per day to reflect its reduced ability to transport natural gas across the Northern Facilities. The Commission accepted and suspended Portland's proposed rate increase until December 1, 2010, subject to refund, and established a hearing before an ALJ.[6]

5. On December 8, 2011, the ALJ issued the ID. The ID addressed numerous issues relating to the 2010 Rate Filing, including the treatment of certain bankruptcy proceeds and the appropriate level for Portland's at-risk condition and its billing determinants.

6. On March 21, 2013, the Commission issued Opinion No. 524. In Opinion No. 524, the Commission reversed the ID with respect to several rate design issues, including the appropriate at-risk level for Portland and the proper calculation to determine the billing determinants for designing Portland's rates. The Commission held that Portland's at-risk condition and billing determinants should be set at the 210,000 Mcf level of its capacity on the Joint Facilities. The Commission also approved the ALJ's findings regarding the composition of the proxy group to determine Portland's return on equity but reversed the ALJ's placement of Portland at the median of the zone of reasonableness and placed Portland at the top of the range of reasonable returns instead. The Commission found that Portland's non-investment grade credit rating, combined with the fact that its at-risk condition prevents it from designing rates based on less than its design capacity, warranted the upward adjustment from the median of the zone of reasonableness. The Commission also rejected Portland's proposal to increase its depreciation rate from 2 percent to 4.13 percent.

7. On April 19, 2013, Portland filed a request for rehearing of Opinion No. 524 (Portland Rehearing Request) and on April 22, 2013 the Indicated PNGTS Shippers

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the ALJ's initial decision in that rate case (*Portland Natural Gas Transmission System*,Opinion No. 510, 134 FERC ¶ 61,129 (2011)) (Opinion No. 510), and subsequently we generally denied rehearing of Opinion No. 510 in Opinion No. 510-A (*Portland Natural Gas Transmission System,* Opinion No. 510-A, 142 FERC ¶ 61,198 (2013)) (Opinion No. 510-A).

[6] *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).

(Indicated Shippers),[7] and the Canadian Association of Petroleum Producers (CAPP) each filed a request for rehearing of Opinion No. 524. Portland asserts that the Commission erred in its holdings concerning (1) Portland's at-risk condition; (2) the level of billing determinants; and (3) Portland's depreciation rate. Indicated Shippers request rehearing of the Commission's rulings (1) rejecting Portland's proposal to credit interruptible transportation (IT) revenues; and (2) placing Portland at the top of the range of reasonable returns, and thereby establishing an ROE of 11.59 percent. CAPP also seeks rehearing of the placement of Portland at the top of the zone of reasonableness.

II. <u>Discussion</u>

8. For the reasons discussed below, the Commission denies rehearing on all issues.

A. <u>Portland's At-Risk Condition</u>

9. On rehearing, Portland contends that the Commission erred in rejecting its proposal to reduce its at-risk condition and billing determinants to 168,000 Dth per day consistent with its reduced ability to transport gas across its Northern Facilities and instead require the at-risk condition and billing determinants to be based on the 210,000 Mcf per day level of its capacity on the Joint Facilities. Among other things, Portland contends that (1) the orders certificating its system do not require that it be placed at-risk for the full amount of its capacity on the Joint Facilities, in light of the fact Maritimes' Phase IV Expansion has reduced the capacity of its Northern Facilities to 168,000 Dth per day, (2) it would not have built a system with capacity in excess of 178,000 Dth absent pressure from the Commission, and (3) therefore, the policy underlying at-risk conditions, namely to place the risk of overbuilding on the pipeline because "the pipeline is in a better position to evaluate whether and how large to build facilities," is inapplicable to its situation.

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[7] Indicated Shippers state that the Indicated PNGTS Shippers are a subset of the PNGTS Shippers' Group (PSG) that participated in the Docket No. RP10-729 hearing proceeding and are referenced in Order No. 524. Indicated Shippers state that each member of the PSG and Indicated Shippers groups has held a long-term firm transportation agreement with Portland. The filing further states certain intervening events since the submission of briefs in the proceeding have affected PSG's membership such that the Indicated Shippers represent the contracted firm transportation interests of Northern Utilities, Inc., DTE Energy Trading Inc., H.Q. Energy Services (U.S.) Inc., Wausau Paper Mills, L.L.C., and Mead and New Page on the Portland system.

10. As background for addressing the merits of Portland's request for rehearing on this issue, we describe below: (1) the Commission's at-risk policy as in effect during Portland's certificate proceeding, (2) the various Commission orders establishing Portland's at-risk condition, and (3) the subsequent events affecting its capacity on the Northern facilities. We then discuss the relevant holdings of Opinion No. 524 and our reasons for denying Portland's request for rehearing on this issue

1. <u>At-Risk Condition Policy</u>

11. At the time of Portland's certificate proceeding, the Commission's policy was to place a pipeline "at-risk" for recovery of costs related to a new project, if it could not satisfy the traditional *Kansas Pipe Line*[8] standard for demonstrating market support for the project.[9] That standard required the pipeline to show that it had long-term contractual commitments for 100 percent of the project's capacity.[10] The Commission found that the at-risk condition functioned as an adequate substitute for a showing of market demand. The condition serves as a signal that the pipeline had not made the market showing customarily required for traditional NGA section 7(c) certificate applications, and therefore that the pipeline is not entitled to the presumption regarding inclusion in rates that has traditionally accompanied such certificated facilities. An at-risk condition is not a permanent rate condition. It can be removed if the pipeline is able to demonstrate in a NGA section 4 rate case that the new capacity was fully subscribed under long-term firm contracts for at least ten years or that project revenues would exceed costs on a long-term basis.[11]

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[8] *Kansas Pipe Line & Gas Co.*, 2 FPC 29 (1939).

[9] 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 Certificate Policy's requirement that a pipeline must be prepared to financially support the project without relying on subsidization from its existing customers obviated that need for an "at-risk" condition because it accomplished the same purpose, namely making the pipeline responsible for the costs of new capacity that is not fully utilized. *Id*. at 61,747.

[10] *CNG Transmission Corp.*, 80 FERC ¶ 61,137, at 61,501 (1997) (Generally, the Commission considered contracts with terms of 10 years or longer to be long-term contracts.).

[11] *See, e.g.*, *ANR Pipeline Co.*, 82 FERC ¶ 61,145, at 61,537-38 (1998) (*ANR*).

12. An at-risk condition requires that a pipeline's initial rates be designed based on the assumption that all capacity is subscribed at maximum recourse rates even if some or all of it is not. This is accomplished by establishing billing determinants at a level that reflects the full annualized capacity of the pipeline system.[12] In terms of a pipeline's cost-of-service, this means that each unit of the pipeline's annualized capacity would be assigned a *pro rata* share of the pipeline's cost-of-service and if the pipeline fails to achieve revenues equal to its capacity times its maximum rate, the pipeline would not recover its full cost-of-service.

13. The purpose of an at-risk condition was to guard against shifting the costs of potentially underutilized facilities to existing customers who do not benefit from the project and to protect future customers from rate increases if the new facilities were underutilized.[13] The Commission reasoned that, because the pipeline proposing to build the new facilities was in the best position to evaluate whether and how large to build its facilities, it was appropriate that the pipeline, not its customers, shoulder the financial risk in the event that its judgments turned out to be wrong.[14] The at-risk condition, thus, operates as a floor on a pipeline's billing determinants used to assign revenue responsibility among services.

2. <u>Commission Orders Imposing At-Risk Condition on Portland</u>

14. On March 14, 1996, Portland filed its initial application to construct and operate import facilities at the United States-Canada border near North Troy, Vermont and construct and operate approximately 242 miles of pipeline from the border facilities to an interconnection with Tennessee Gas Pipeline Company, L.L.C. (Tennessee) near Haverhill, Massachusetts.[15] Portland's proposed pipeline was designed for a firm, winter-day design capacity of 178,000 Mcf per day[16] and Portland based its proposed

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

[13] *See Koch Gateway Pipeline Co.*, 79 FERC ¶ 61,115 (1997).

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

[15] *See 1996* Certificate Order, 76 FERC at 61,649.

[16] *Id.* at 61,650, 61,664.

rates upon its firm, winter-day design capacity of 178,000 Mcf per day.[17] With the exception of the gas to be delivered to Northern Utilities in Maine, all deliveries were to be made into Tennessee's system at the Haverhill, Massachusetts interconnect.[18]

15. The 1996 Certificate Order made a preliminary determination on Portland's application, subject to the outcome of a review of environmental matters.[19] The Commission directed Portland, among other things, to revise its initial rates to reflect billing determinants of 178,000 Mcf per day, even though Portland only had firm contracts for 167,400 Mcf per day during the winter (November-March) and 66,000 Mcf per day during the summer (April-October).[20] The Commission found that Portland's proposed billing determinants were too low "and, combined with its proposed levelization approach," shifted costs to customers in later years.[21] Recognizing that Portland would have unsubscribed capacity for both the winter and summer months, the Commission expressly placed Portland at-risk for the recovery of costs based on 178,000 Mcf per day, stating:

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

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[17] *Id.* at 61,651.

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

[19] *Id.* at 61,649

[20] *Id.* at 61,649-50, 61,660.

[21] Earlier in the order, the Commission expressed concern that Portland's rate proposal had the effect of shifting a significant amount of the costs of service in the initial years to the later years of the project. 1996 Certificate Order, 76 FERC at 61,659-60.

> Accordingly, the Commission will place [Portland] at risk for the recovery of the off-peak costs. The billing determinants used to calculate the initial rates should be based on the total capacity.[22]

16. Because the southern portion of Portland's proposed pipeline would run along essentially the same route as pipeline facilities being proposed by Maritimes and Northeast Pipeline, LLC (Maritimes) in a separate docket,[23] the Commission also urged Portland to consider the feasibility of constructing a single pipeline with Maritimes or constructing two separate pipelines sharing the right-of-way. The Commission stated:

> Many commenters suggested that only one pipeline, large enough to meet the needs of both [Portland] and Maritimes, should be constructed where the routes converge. Both [Portland] and Maritimes have expressed interest in exploring the feasibility of a jointly owned and operated pipeline where routing permits. The Commission, as part of its environmental review, considers alternatives to any construction proposal. A jointly owned pipeline for the congested and environmentally sensitive area between Haverhill, Massachusetts and Portland, Maine will be one such alternative that the Commission will explore. We, therefore, urge [Portland] and Maritimes to study the feasibility of constructing a single pipeline where possible or constructing two separate pipelines sharing the right-of-way. Additionally, we encourage the pipelines to consider the expansion potential for their projects so that a single pipeline, if constructed, is sized large enough to avoid the need for looping the pipeline in the foreseeable future.[24]

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

[23] *See Maritimes & Northeast Pipeline, L.L.C.*, 76 FERC ¶ 61,124 (1996) (*Maritimes*). Maritimes proposed to construct a new pipeline extending from a proposed point of interconnection with the existing facilities of Tennessee near Dracut, Massachusetts to a proposed point of interconnection with the facilities of Granite State Gas Transmission, Inc. (Granite State) near Wells, Maine. The proposed pipeline would be 24-inches in diameter, 64 miles in length, and have a capacity of 60,000 MMBtu per day.

[24] 1996 Certificate Order, 76 FERC at 61,655-56.

17. After several months of negotiations with Maritimes, Portland subsequently amended its certificate application in Docket Nos. CP96-248 and CP96-249 and, in addition, filed another construction application jointly with Maritimes in Docket No. CP97-238-000. Under the amended application, Portland proposed to construct and operate: (a) import facilities at the United States/Canada border at Pittsburg, New Hampshire; (b) 142 miles of mainline from the border crossing facilities to Westbrook, Maine; and (3) two laterals off the mainline (collectively, Northern Facilities).[25] Portland's import facilities connected with facilities in Canada constructed by TQM.[26]

18. The 142-mile mainline of the Northern Facilities interconnected at its downstream end at Westbrook, Maine with mainline facilities that Portland proposed jointly with Maritimes in Docket No. CP97-238-000. The proposed joint facilities (collectively, Joint Facilities) consisted of 101 miles of pipeline, including 35 miles of 30 inch diameter mainline from Westbrook to Wells, Maine and one lateral (Phase II Joint Facilities) and 66 miles of mainline from Wells, Maine to Dracut, Massachusetts and two laterals (Phase I Joint Facilities).[27] The Joint Facilities interconnected with Tennessee at Dracut, Massachusetts, and interconnected with Maritimes' affiliate, Algonquin Gas Transmission, LLC (Algonquin), near Beverly, Massachusetts.

19. Separately, Maritimes proposed to construct a 247-mile pipeline to transport up to 440,000 MMBtu of Canadian gas produced by the Sable Gas Offshore Energy Project from Maine's border with Nova Scotia, Canada to Westbrook, where Maritimes' solely-owned facilities would interconnect with the Joint Facilities. We will refer to these facilities as the Maritimes Upstream Facilities. These facilities were not expected to go into service until a year after Portland's Northern Facilities and the Joint Facilities went into service. During the first year of operation, the Northern Facilities would have a capacity of 178,000 Mcf per day, and the Joint Facilities would have a capacity of 229,000 Mcf per day (169,000 Mcf per day for Portland and 60,000 Mcf per day for Maritimes).[28] During the second and subsequent years, after the Maritimes upstream

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

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

[27] September 1997 Rehearing and Certificate Order, 80 FERC at 62,145. The Phase I facilities interconnected with Granite State Pipeline at Wells, Maine, and Maritimes intended to use those facilities to serve certain customers located on Granite State before the Phase II facilities were completed. *Id.* at 61,472.

[28] July 1997 Preliminary Determination Order, 80 FERC at 61,447

facilities went into service, Portland's Northern Facilities were expected to have a capacity of 210,000 Mcf per day, and the Joint Facilities to have a capacity of 650,860 Mcf per day, with Portland having 210,000 Mcf per day of that capacity and Maritimes the remainder. The increased capacity of the Joint Facilities would result from increased pressure provided by compressors on the Maritimes Upstream Facilities. The increased capacity on Portland's Northern Facilities would result from additional compression to be added by TQM on its Canadian facilities upstream of Portland's Northern Facilities, and that compression was necessary to increase pressure on the Northern Facilities sufficiently to allow gas to be delivered into the Joint Facilities when Maritimes' Upstream Facilities went into service.[29]

20. Seven shippers executed precedent agreements with Portland for service on the Northern and Joint Facilities. The volumes under those firm agreements totaled 170,200 per day (on a winter peak day).[30] Portland's proposed rates were calculated based on a winter-day design capacity of 178,000 Mcf per day.

21. On July 31, 1997, the Commission issued two orders on Portland's certificate applications. In the first order, issued in Docket Nos. CP97-238-000, *et al.*, the Commission issued to Portland a certificate to construct, and to Maritimes a certificate to operate, the Phase I Joint Facilities, subject to Portland and Maritimes being "at risk for their portion of the cost of the Phase I Joint Facilities."[31] In the second order,[32] issued in Docket Nos. CP96-248-000, *et al.*, the Commission issued a preliminary determination on the basis of all pertinent non-environmental issues, that the public convenience and necessity required issuance of a certificate to Portland to provide service using its capacity on the Phase I Joint Facilities, to construct facilities and provide service using its capacity on the Phase II Joint Facilities, and to construct and operate the Northern Facilities.[33] The July 1997 Preliminary Determination Order also granted and denied certain requests for rehearing of the 1996 Certificate Order.[34] Neither the July 1997 Preliminary Determination Order nor the July 1997 Phase I Construction Certificate

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[29] *Id.* at 61,477-78.

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

[31] July 1997 Phase I Construction Certificate Order, 80 FERC at 61,477.

[32] July 1997 Preliminary Determination Order, 80 FERC ¶ 61,134.

[33] *Id.*

[34] *Id.*

Order took any action with respect to Maritimes' application for a certificate for its Upstream Facilities.

22. The July 1997 Preliminary Determination Order required Portland to revise its rates to reflect billing determinants based on 178,000 Mcf per day for the first year and an estimated increased capacity of 210,000 during subsequent years.[35] Specifically, the Commission stated:

> In the first year of service, [Portland] will have a capacity of 178,000 Mcf per day on its 24-inch mainline and 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.[36]

23. Recognizing that Portland would have unsubscribed capacity for both the winter and summer months based on these figures, the Commission also 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

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

[36] *Id.*

> place [Portland] at risk for the recovery of costs for the unsubscribed capacity.[37]

24. The July 1997 Preliminary Determination Order also required Portland to make a NGA section 4 rate filing within three years of the in-service date of its system "so that rates may be effective no later than the third anniversary of its in-service date."[38]

25. Following the July 1997 Preliminary Determination Order, Portland sought rehearing of the Commission's decision to require Portland to revise its rates to reflect 210,000 Mcf per day of capacity after the first year of operation and be placed at-risk for the increased unsubscribed capacity.[39] Portland argued that it was uncertain when additional compression to be installed by TQM would go into service or the actual amount of increased compression and its effect on the capacity of the Portland system. Portland asserted that the increase in pressure and the increased capacity capability associated therewith would occur only when TQM installed new compression on its system, but TQM would not do so until the compression was needed to match the line pressures created by Maritimes' deliveries into the Joint Facilities.[40] Portland asserted that it was possible that these events would occur more than 12 months after Portland's operations began, and even when TQM increased compression, the new compression might not increase the peak day capacity to 210,000 Mcf per day. Portland did not seek rehearing of the Commission decision to require Portland to revise its rates to reflect 178,000 Mcf per day of capacity during the first year of operation.

26. In the September 1997 Certificate and Rehearing Order, the Commission granted final certificate authorizations for the Northern and Phase II Joint Facilities after completing its environmental review, subject to conditions, and addressed Portland's request for rehearing of the July 1997 Preliminary Determination Order.[41] Among other things, the Commission again conditioned the certificates issued in the order for the Joint Facilities "to put both applicants [Portland and Maritimes] at risk for their portion of the

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[37] *Id.*

[38] September 1997 Certificate and Rehearing Order, 80 FERC at 62,147 (clarifying July 1997 Preliminary Determination Order, 80 FERC ¶ 61,134 at Ordering Paragraph (C)).

[39] September 1997 Certificate and Rehearing Order, 80 FERC at 62,146.

[40] *Id.*

[41] *Id.*

cost of the Phase II Joint Facilities.[42] With respect to Portland's rehearing request, the Commission found that it was premature, based on the current facts, to require Portland to revise its rates and to be placed at-risk for higher capacity after its first year of operation, stating:

> Based on the facts before us, we find that it is premature to require [Portland] to revise its rates or to be placed at risk for higher capacity after its first year of operation. It is not certain at this time when the additional compression will go into service or the actual amount of increased compression and its effect on the capacity of the [Portland] system. We will instead review this matter when [Portland] makes its section 4 filing.[43]

27. In October 1997, Portland and Maritimes executed an Ownership Agreement and Engineering and Construction Management Agreement, and an Operating Agreement (collectively the Definitive Agreements) governing the construction, maintenance, and operation of the Joint Facilities. In November 1997, the Commission approved these agreements.[44]

28. Before Portland commenced construction of its pipeline the Commission reaffirmed that, as a condition of its certificate, Portland was at-risk for its unsubscribed capacity. In 1998 Portland requested a waiver of the condition in the July 1997 Preliminary Determination Order that Portland may not commence construction of the involved facilities until it had executed firm contracts equal to the capacity to which its customers committed themselves in signed precedent agreements. The Commission granted the request, stating:

> The other shippers, moreover, will be protected from having to subsidize the cost of any unsubscribed capacity resulting from any possible failure of PNGTS to negotiate a firm transportation contract with Mead inasmuch as PNGTS is already at risk for any unsubscribed capacity. Although we

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[42] *Id.* at 62,146. As described above, the Commission placed Portland at-risk for its portion of the cost of the Phase I Joint Facilities in the July 1997 Phase I Construction Order.

[43] *Id.*

[44] *Maritimes and Northeast Pipeline, LLC*, 81 FERC ¶ 61,166 (1997).

> will waive the contract volume execution condition here insofar as Mead's capacity is concerned, we emphasize that PNGTS will be at risk for this additional 8,000 Mcf a day of unsubscribed capacity as well as the unsubscribed capacity described in our July 31, 1997 preliminary determination order.[45]

29. Portland completed construction of its pipeline in 1999.[46] As completed, Portland had capacity of at least 210,840 Dth on both the Northern Facilities and the Joint Facilities.[47]

30. On October 1, 2001, Portland made a NGA section 4 rate filing in Docket No. RP02-13 as required by the certificate orders. The rate filing ended in an uncontested settlement, which the Commission approved on January 14, 2003.[48] Among other things, the 2002 Settlement required Portland to file a general NGA section 4 rate case no sooner than, and no later than, April 1, 2008.[49]

31. In September 2003, Portland filed to decrease the maximum recourse reservation rate for its firm seasonal (Winter-only) transportation service from 2.4 times the firm non-seasonal transportation maximum recourse reservation rate to 1.9 times the non-seasonal rate, which raised shipper concerns regarding the continued viability of the certificate at-risk condition. In response, the Commission stated that the shippers' concerns were "unfounded" and that "Portland's at-risk condition prevents the shifting of costs due to under-collection." The Commission also pointed out that "Portland has indicated that it will respect the at-risk condition imposed by the Commission in

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[45] *Portland Natural Gas Transmission System, et al.*, 83 FERC ¶ 61,080, at 61,388 (1998).

[46] Portland provided notice that both its Northern Facilities and Joint Facilities would commence operations on March 10, 1999. March 5, 1999 notice by Portland in Docket No. CP96-248-000 and CP96-249-000. The remainder of the Joint Facilities was placed into service on December 1, 1999. Ex. S-14 at 26.

[47] Ex. PSG-24 at 18 (Deposition of David J. Haag, Manager of Rates and Regulatory Affairs for Portland).

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

[49] *Id.* P 6.

Portland's initial certification authorization" if its proposed rate reduction was accepted by the Commission.[50]

3. Maritimes' Phase IV Expansion of the Joint Facilities

32. The 30-inch diameter of the Joint Facilities mainline allows for the capacity of those facilities to be increased relatively cheaply through the installation of compression, without the need for any other additional pipeline facilities.[51] After the Portland and Maritimes systems went into service, a number of terminals for the importation of liquefied natural gas (LNG) were proposed in Quebec, Nova Scotia, New Brunswick, and Maine. Both Portland and Maritimes saw these projects as opportunities to make use of the cheap expansibility of the Joint Facilities to provide the transportation capacity required to move regasified LNG to New England markets.[52] Terminals in Quebec would use the Portland system, while terminals in the other locations would use the Maritimes system.

33. In early 2005, Maritimes proposed the Phase IV Expansion of the Joint Facilities. Maritimes' open season for this expansion resulted in long-term, binding precedent agreements with two shippers to transport natural gas from two LNG import terminals located in New Brunswick and Nova Scotia, Canada over both Maritimes' upstream facilities and the Joint Facilities to delivery points in Massachusetts with service to commence by the end of 2008. On April 5, 2005, Maritimes notified Portland of its planned expansion project, as required by the Definitive Agreements.[53] Portland opposed the planned expansion, fearing that it would allow Maritimes to capture all the cheap expansibility inherent in the Joint Facilities.[54] Portland also elected, pursuant to its rights under the Joint Facilities Ownership Agreement, to participate in the expansion project, and notified Maritimes on June 3, 2005, that it desired 150,000 Dth per day of expansion capacity on the Joint Facilities.[55] Portland did this both to protect its proportionate

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[50] *Portland Natural Gas Transmission System*, 109 FERC ¶ 61,225, at PP 42, 45 (2004).

[51] Ex. PNG-142 at 16-17.

[52] *Id.* at 16.

[53] Ex. S-14 at 1-2.

[54] Ex. PNG-142 at 17; Ex. S-14 at 3-4.

[55] *Maritimes & Northwest Pipeline, L.L.C.*, 115 FERC at 61,069, at P 7 (2006) (Maritimes Declaratory Order); Ex. S-14 at 3-4.

interest in the cheap expansibility of the Joint Facilities and to be in a position to serve potential additional market needs arising from proposed LNG facilities in Quebec.[56]

34. In June 2005, Portland received bids in a non-binding open season for long-term capacity on its system[57] but did not succeed in obtaining firm commitments from those bidders. Also in June 2005, Portland was informed that its firm contract with Androscoggin Energy LLC (Androscoggin) was being rejected and terminated through bankruptcy.[58]

35. From June to October 2005, Maritimes, Portland and the operator of the Joint Facilities (M&N Operating Company, LLC), held discussions concerning the most economical engineering design for the Phase IV Expansion based on the requirements of each of the co-owners. Among the issues discussed was how to add compression at Westbrook, where Portland's Northern Facilities interconnect with the Joint Facilities. The Joint Facilities ownership agreement originally provided that the maximum inlet pressure at Westbrook that Portland and Maritimes could be required to satisfy in order to deliver gas from their respective wholly-owned facilities into the Joint Facilities was 1110 pounds per square inch gauge (psig).[59] So long as the inlet pressure did not exceed that level, Portland could deliver at least 210,000 Mcf from its Northern Facilities into the Joint Facilities.[60] However, the addition of compression upstream of where the Northern Facilities interconnect with the Joint Facilities at Westbrook, for example on Maritimes' Upstream Facilities, would increase the inlet pressure that Portland must satisfy to deliver gas into the Joint Facilities. This would reduce the amount of gas Portland could deliver into the Joint Facilities unless it added compression on its system or TQM added compression upstream of the Northern Facilities.[61] Nevertheless, in 2004, as part of negotiations between Portland and Maritimes involving swaps of ownership interests in certain laterals on the Joint Facilities, Portland requested, and Maritimes agreed, to modify the Ownership Agreement so that effective November 1, 2005 the maximum

[56] Ex. PNG-142 at 17.

[57] Ex. S-15 at 149.

[58] Ex. S-7 at 5.

[59] Ex. PSG-24 at 35, 53; Ex. S-14 at 12.

[60] Ex. PSG-24 at 18.

[61] *Id.* at 110.

pressure that each pipeline could be required to satisfy to make deliveries into the Joint Facilities would increase to 1250 psig.[62]

36. During their discussions concerning the design of the Phase IV Expansion, Portland proposed, and Maritimes agreed, that one of the two compressor units proposed at Westbrook would be located on Maritimes' Upstream Facilities, upstream of the interconnection of Portland's Northern Facilities with the Joint Facilities, and the other compressor unit at Westbrook would be located on the Joint Facilities, downstream of the Northern Facilities' interconnection. The parties anticipated that this configuration of the compressor units would increase the inlet pressure that Portland had to satisfy to enter the Joint Facilities from 1110 psig to about 1174 psig.[63] However, this configuration also removed the compressor unit to be located on Maritimes' Upstream Facilities from Portland's financial responsibility.[64] The operator provided its final engineering proposal reflecting this agreement to the co-owners on October 27, 2005.[65]

37. On the same day, an e-mail was circulated within Portland stating that, if the Joint Facilities were operated so as to require Portland to deliver gas to the Joint Facilities at Westbrook at the higher 1250 psig contract pressure permitted by the Ownership Agreement as of November 1, 2005, Portland would not be able to make any deliveries into the Joint Facilities, absent an increase in pressure on Portland's Northern Facilities.[66] The e-mail discussed various options for addressing this situation, including negotiating with Maritimes for a lower delivery pressure at Westbrook, having TQM install additional compression on its upstream system, or Portland installing compression on the Northern Facilities. The e-mail outlined plans by TQM to install additional compression by November of 2006 or 2007 before the Phase IV Expansion would go into service. The e-mail also indicated that, if Maritimes agreed to limit the increase in the inlet pressure requirement at Westbrook to 1175 psig instead of 1250 psig, Portland would be able to

[62] Ex. S-15 at 155; Ex. S-14 at 1; Maritimes Request for Declaratory Order in Docket No. CP06-32, Exhibit D-2 at 4.

[63] Ex. S-15 at 154.

[64] Maritimes Request for Declaratory Order in Docket No. CP06-32, Exhibit D at 2-3 and Exhibit D-2 at 13, Exhibit D-3 at 2.

[65] Maritimes, Declaratory Order, 115 FERC ¶ 61,069 at P 8.

[66] Ex. S-14 at 12-13.

deliver 176,000 Mcf per day into the Joint Facilities at existing pressure levels on the Northern Facilities.[67]

38. Portland did not raise any concerns with Maritimes about the final engineering design proposed by the operator. Nevertheless, Portland indicated that it would not vote to approve the proposed final engineering design until certain contract issues were resolved, including indemnification of Portland by Maritimes for its use of a disproportionate share of the cheap expansibility of the Joint Facilities, expected cash flow projections, and cost sharing in case a co-owner changed its level of participation.[68]

39. In November 2005, although it had not yet submitted a certificate application for the Phase IV Expansion, Maritimes filed a request for the Commission to make a preliminary determination that the final engineering design was appropriate for that expansion. Maritimes stated that Portland's refusal to approve the operator's final engineering design for the expansion threatened to delay the proposed completion of the project for the winter of 2008. Maritimes stated that it was only requesting preliminary approval of the design of the project, and was not requesting the Commission to resolve the contractual issues raised by Portland, which could be left to the courts to resolve.[69] Maritimes noted that the final engineering design was substantively identical to the design Portland had proposed in October.

40. Portland opposed Maritimes' request for a declaratory order.[70] Portland did not raise any concerns about a potential loss of capacity on its system as a result of the increased inlet pressure to the Joint Facilities at Westbrook. Rather, it asserted that approval of the engineering design was premature before its contractual issues with Maritimes, including its request for indemnification for Maritimes' disproportionate use of the cheap expansibility of the Joint Facilities, were resolved. Portland also stated that the proposal could unfairly benefit downstream pipelines, including Maritimes' affiliate Algonquin, by increasing pressure on those systems.

[67] Ex. S-13 at 9; Ex. S-14 at 12-13; Ex. PSG-24 at 232-233.

[68] Maritimes Request for Declaratory Order in Docket No. CP06-32, Exhibit I and L.

[69] Maritimes Declaratory Order, 115 FERC ¶ 61,069 at P 13; Ex. S-14 at 21-22.

[70] Ex. S-14 at 63-91.

41. In January 2006, Portland responded to a Commission staff request in the Docket No. CP06-32-000 proceeding that it describe its proposed 150,000 Dth expansion of its system, including the Joint Facilities, as part of the Phase IV Expansion. Portland stated that it was then evaluating two possible designs, including either TQM modifying its facilities to increase Portland's receipt pressure at its interconnection with TQM or the addition of compression on Portland's Northern Facilities.[71] Portland also stated that "both designs incorporate current unsubscribed excess capacity and do not reflect possible turnback capacity. [Portland's] market intelligence suggests that there will be both sufficient upstream supply and the correct market incentives for the [Portland] capacity to be used to meet the growing demand for natural gas in New England." In response to staff's question whether it disputed any of the pressures, flows, and compressor information in the final engineering design agreed to in October 2005, Portland stated that it was "in general agreement with the pressures, flows, and compressor information" and that "the diagram correctly depicts the appropriate pressures at interconnects (Westbrook and Dracut) such that they do not unfairly benefit the upstream and downstream interconnecting pipelines at the expense of the [Portland] shippers."[72]

42. TQM informed Portland in late 2005 and early 2006 that it was unable at that time to provide increased compression, because of uncertainty about demands on its system.[73]

43. In April 2006, the Commission granted Maritimes' request for declaratory order. The Commission found that the facilities represented in a flow diagram reflecting the operator's final engineering design would increase the capacity of the Joint Facilities by about 1,050,000 Dth per day, while meeting the flow and pressure requirements of both Portland and Maritimes.[74] The Commission also pointed out that Portland had agreed in its data response that the flow pressures at Westbrook and Dracut would not unfairly benefit upstream and downstream pipelines at the expense of Portland's shippers.[75] The Commission did not reach the contractual disputes between Portland and Maritimes, stating those could be addressed in state courts.

[71] Portland January 27, 2006 data response in Docket No. CP06-32-000.

[72] *Id*.

[73] Ex. PSG-24 at 93.

[74] Maritimes, Declaratory Order, 115 FERC ¶ 61,069.

[75] *Id.* P 26.

44. In April 2006, Portland learned that its firm contract with Rumford Power Associates, LP (Rumford) was being rejected and terminated through bankruptcy.[76] The Androscoggin and Rumford contracts together accounted for 62,000 Dth per day of contract demand on Portland's system.[77] Their loss reduced Portland's 20 year winter firm obligations from 212,000 Dth per day to 150,200 Dth per day.[78] On May 15, 2006, the Commission approved, over Portland's objections, a settlement of Maritimes' general NGA section 4 rate case filed in 2004.[79] Among other things, that settlement provided for Maritimes to file a new rate case within six months of the in-service date of a mainline expansion, if the roll-in of the costs of the expansion would lower its system-wide rates.

45. In May 2006, Maritimes filed an application in Docket No. CP06-335 for its Phase IV Expansion project. Maritimes proposed a smaller expansion than the Commission had addressed in the Maritimes Declaratory Order, because one of the shippers who had executed precedent agreements decided not to participate in the expansion. Maritimes stated the project as proposed would (1) increase the capacity of the Joint Facilities by 393,000 Dth in order to transport for the remaining shipper regasified liquefied natural gas (LNG) from the proposed Canaport LNG import terminal (Canaport) to be located in Saint John, New Brunswick, Canada[80] and (2) increase the capacity of the Joint Facilities by an additional 150,000 Dth per day for Portland. Maritimes proposed to add five new compressor stations. These included two new compressor stations at Westbrook, each with 13,333 horsepower (HP), one located on the Maritimes Upstream Facilities and one on the Joint Facilities, and a new compressor station at Eliot, Maine on the Joint Facilities. Maritimes stated that the design inlet pressure to the Joint Facilities at Westbrook was 1174 psig.[81] Maritimes stated that this was consistent with the design of the facilities the Commission approved in the Maritimes Declaratory Order.[82] Maritimes also stated that it expected that rolling in the costs of the Phase IV Expansion would

[76] Ex. S-7.

[77] Ex. PSG-24 at 87.

[78] *Id.* at 88-89.

[79] *Maritimes & Northeast Pipeline, L.L.C.*, 115 FERC ¶ 61,176.

[80] Maritimes stated that the other shipper had delayed the development schedule of its LNG import project and therefore would no longer participate in this expansion.

[81] Ex. S-14 at 106.

[82] *Id.* at 9.

reduce its recourse rates, and therefore the settlement of its 2004 rate case would require it to file a new rate case lowering its rates within six months of the in-service date of the expansion.[83]

46. On June 16, 2006, Portland protested Maritimes' certificate application.[84] Portland again did not raise any concerns about a potential loss of capacity on its system as a result of the increased inlet pressure to the Joint Facilities at Westbrook. Rather, Portland's objections focused on its contention that Maritimes was improperly seeking to capture for itself a disproportionate share of the cheap expansibility of the Joint Facilities. Portland objected to the size of Maritimes' proposed compressor at Eliot, arguing that the compressor included 15,738 HP, when only 8,500 HP was necessary to provide the service requested by the participants in the project, including Portland. Portland stated that the excess horsepower would increase capacity by 115,000 Dth per day more than required for the project. Portland contended that the excess horsepower would increase the construction cost by $5 million, as well as require more fuel to operate than necessary, imposing an additional annual cost on Portland's customers of about $4 million.[85] Finally, Portland contended that Maritimes' affiliate, Algonquin, would reap the benefit of the extra horsepower on the Eliot compressor, because the additional pressure produced thereby would increase capacity on Algonquin. Portland raised various other procedural objections to Maritimes' proposal.

47. On June 19, 2006, Portland responded to a staff request that it describe any facilities it would need to construct on its Northern Facilities in order to transport its requested 150,000 Dth of expansion capacity. Portland described the same two design options it had described in response to staff's similar data request six months earlier in the Docket No. CP06-32-000 proceeding.[86] Portland also again stated that its market intelligence suggested that there would be sufficient market demand for the additional capacity. Portland stated it anticipated an in-service date for its expansion in late 2009.

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[83] *Id.* at 7.

[84] *Id.* at 147-162.

[85] June 16, 2006 Portland protest in Docket No. CP06-335 at 8-10.

[86] Ex. S-14 at 172.

48. During the first eight months of 2006, it appeared less and less likely to Portland that it could obtain contractual commitments for an expansion of its system.[87] In early September, Portland determined that it would not proceed with the 150,000 Dth per day expansion of its facilities.[88] Several days later, on September 8, 2006, Maritimes amended its certificate application to remove the proposed 150,000 Dth per day capacity for Portland, stating that Portland was not able to make a definitive commitment to the new capacity on the Joint Facilities in the necessary time frame. Maritimes proposed to accomplish the reduction in the expansion capacity by reducing the horsepower at the Eliot compressor station from 15,800 HP to 5,700 HP.[89] Maritimes did not propose any other changes to the design of the Phase IV Expansion. Thus, the design inlet pressure to the Joint Facilities at Westbrook continued to be 1174 psig, with the resulting reduction in Portland's capacity on the Northern Facilities to around 170,000 Dth absent TQM or Portland adding compression.[90]

49. On September 29, 2006, Portland protested Maritimes' amended certificate proposal, while also stating that it was in discussions with Maritimes to settle their differences concerning the expansion of the Joint Facilities.[91] In its protest, Portland again did not raise any concerns about a potential loss of capacity on its system as a result of the increased inlet pressure to the Joint Facilities due to the new compressor unit at Westbrook on Maritimes' Upstream Facilities. Portland again contended that the proposal would improperly allow Maritimes to capture the benefits of the cheap expansibility of the Joint Facilities, without compensation to Portland. Portland argued that the expansion was oversized and created subsidies for the downstream facilities of Tennessee and Maritimes' affiliate, Algonquin, because increased pressure on the Joint Facilities would also increase capacity on the downstream facilities. Portland contended that the proposal would adversely affect Portland and its shippers by increasing operation and maintenance (O&M) and fuel costs, if the necessary compression was added on the Joint Facilities. While Portland objected to the increased pressure at the downstream interconnection of the Joint Facilities with Tennessee at Dracut, Portland did not object to the increased inlet pressure to the Joint Facilities at Westbrook as a result of the proposed

[87] Ex. PSG-24 at 203.

[88] *Id.* at 96, 200-201; Ex. S-14 at 200.

[89] Ex. PSG-24 at 208. The Eliot compressor station change was the only change.

[90] Ex. S-14 at 106; Ex. PNG-24 at 16.

[91] Ex. S-15 at 1-6.

location of one of the two Westbrook compressors on Maritimes' Upstream Facilities.[92] Nor did Portland inform either the Commission or its customers that the proposal would reduce its capacity on its Northern Facilities.[93] Portland also did not tell Maritimes, and Maritimes was unaware of this effect of its expansion until Portland filed its request for declaratory order in January 2008.[94]

50. Some Portland shippers intervened in the Phase IV Expansion certificate proceeding and stated their support of Maritimes' expansion and stated they might participate in that expansion.[95] Given this fact and the Commission's approval of Maritimes' earlier request for declaratory order, Portland believed there was significant momentum toward approval of Maritimes' certificate application, despite Portland's opposition to the project.[96]

51. In October and November 2006, Portland entered into two agreements with Maritimes which permitted Maritimes to proceed with its Phase IV Expansion as proposed in its amended September 8, 2006 certificate application.[97] First, on October 23, 2006, Portland and Maritimes executed an agreement to amend the Joint Facilities ownership agreement to provide that the maximum inlet pressure to the Joint Facilities at Westbrook would be 1175 psig, as compared to the 1110 psig maximum inlet pressure in the original Ownership Agreement.[98] This meant that Maritimes' addition of a compressor unit on its Upstream Facilities increasing the inlet pressure to the Joint Facilities to 1174 psig, as proposed in its amended Phase IV Expansion certificate application, would not violate the Ownership Agreement.

52. Second, on November 29, 2006, Portland and Maritimes entered into a settlement which (1) modified the Definitive Agreements to resolve their disputes concerning future expansions of the Joint Facilities using their cheap expansibility and (2) required Portland

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[92] Ex. PSG-24 at 114.

[93] *Id.* at 105-106, 190, 214-216, 229-234.

[94] *Id.* at 217-220.

[95] *Id.* at 27-28.

[96] *Id.* at 27-29.

[97] Ex. PNG-100.

[98] Ex. PSG-24 at 19-22.

to withdraw its protests to Maritimes' Phase IV Expansion certificate application within three days (Expansion Settlement).[99] The Expansion Settlement established the parties' rights and obligations with respect to the construction of the next 750,000 Dth per day of capacity on the Joint Facilities (referred to in the Settlement as the "Initial Expansibility"). The Expansion Settlement provided that Maritimes' share of the Initial Expansibility would be 500,000 Dth per day and Portland's share would be 250,000 Dth per day. The Expansion Settlement also provided that the 393,000 Dth per day which Maritimes intended to construct in its Phase IV Expansion would be credited against its 500,000 Dth per day share, leaving it with the right to an additional 107,000 Dth per day of the Initial Expansibility after the Phase IV Expansion goes into service. The Expansion Settlement also provided for the rights of the parties with respect to expansions in excess of the Initial Expansibility amounts.[100] As required by the Expansion Settlement, Portland withdrew its opposition to Maritimes' Phase IV Expansion certificate application on December 1, 2006.[101] The Commission approved the Expansion Settlement in March 2007.[102]

53. Portland was aware when it entered into these agreements that an increase in the inlet pressure to the Joint Facilities to 1174 psig would reduce Portland's capacity on the Northern Facilities to about 170,000 Dth, unless it also arranged with TQM for an increase in pressure at its interconnection with TQM.[103] Moreover, TQM had informed Portland in late 2005 and early 2006 that it was unable at that time to provide increased compression, because of uncertainty about demands on its system.[104] Nevertheless, for several reasons, Portland proceeded with these agreements permitting Maritimes to add a compressor unit to its Upstream Facilities, with a corresponding increase of the inlet pressure to the Joint Facilities to 1174 psig, rather than pursuing other options.

54. First, Portland's loss of the Androscoggin and Rumford contracts had reduced Portland's 20-year winter firm obligations from 212,000 Dth per day to 150,200 Dth per day. As a result, Portland was relatively certain that a decrease in the capacity of its

[99] Ex. S-15 at 78-122.

[100] *Id.* at 73-73; Ex. PSG-12 at 184.

[101] Ex. S-15 at 76-122; Ex. PSG-24 at 102-103.

[102] *Maritimes & Northeast Pipeline, L.L.C.*, 118 FERC ¶ 61,193 (2007).

[103] Ex. PSG-24 at 90-91, 99-100, 104.

[104] *Id.* at 93.

Northern Facilities to 170,000 Dth would not jeopardize its ability to meet its reduced firm system contract demand.[105]

55. Second, Portland did not pursue alternatives that could have avoided the loss of capacity on its Northern Facilities, because there was no market demand for the lost capacity or any increased capacity that might result from the alternatives.[106] One option would have been for either TQM to add compression on its upstream facilities or for Portland to add compression on its Northern Facilities.[107] However, Portland "had no contractual underpinning to support or necessitate any capital spending for the addition of facilities, compressors or other equipment to maintain its historical capacity." In addition, Portland believed it was "not required to construct facilities in the absence of firm transportation contracts."[108]

56. The other alternative would have been to locate both Westbrook compressors on the Joint Facilities downstream of the interconnection with Portland's Northern Facilities.[109] If this had been done, the inlet pressure Portland had to satisfy would have been reduced to about 900 psig or less, increasing Portland's ability to deliver gas into the Joint Facilities significantly above 210,000 Mcf.[110] However, Portland did not see any market demand or need for that additional capacity as of the time it entered into these agreements.[111] Also, the Joint Facilities Operating Agreement required Portland to share the O&M cost of any compressors located on the Joint Facilities.[112] The O&M costs

[105] *Id.* at 91, 184.

[106] Ex. PNG-100 at 10, 11.

[107] Ex. PSG-24 at 154-155.

[108] Ex. S-15 at 123.

[109] *Id.* at 157.

[110] Ex. PSG-24 at 51-52, 61-62, 63, 240, 289-292; Ex. PNG-142 at 52; Ex. PNG-100 at 6.

[111] Ex. PSG-24 at 44-45, 50; Ex. PNG-142 at 52-53; Ex. PNG-100 at 4-5, 7, 10.

[112] Ex. PSG-24 at 56-57, 59-60, 77-78, 98; Ex. S-15 at 157.

associated with each compressor are about $200,000 to $300,000.[113] Therefore, if both Westbrook compressor units had been placed on the Joint Facilities, Portland and its shippers would have had to share the O&M costs associated with both compressor units. By contrast, while locating one of those compressor units on Maritimes' Upstream Facilities reduced the capacity of Portland's Northern Facilities, it also enabled Portland to avoid bearing any of the $200,000 to $300,000 annual cost of operating that compressor unit.[114] Placing both compressor units on the Joint Facilities also could have required modifications to further downstream compressors, but neither Portland nor Maritimes studied that issue.[115] Both Portland and Maritimes believed that, given the parameters of Maritimes' proposed expansion, locating one of the Westbrook compressor units on Maritimes' Upstream facilities and one on the Joint Facilities was the most economic and efficient configuration of the compressor units.[116]

57. Third, Portland believed that the Expansion Settlement provided future benefits to Portland and its shippers by preserving its ability to take advantage of the cheap expansibility of the Joint Facilities when market opportunities arise in the future.[117]

58. In February 2007, the Commission approved Maritimes' certificate application for the Phase IV Expansion.[118] Among other things, the Commission found that the project would not adversely affect Maritimes' existing customers or other pipelines and their customers. The Commission also stated that there was no evidence that service on other

[113] Ex. PSG-24 at 63-64, 82. After the Commission issued a certificate for the Phase IV Expansion, the Commission held that Portland was not responsible for the fuel costs incurred to operate compressors added to the Joint Facilities as part of the Phase IV Expansion, because that expansion did not increase Portland's capacity on the Joint Facilities. *Portland Natural Gas Transmission System*, 126 FERC ¶ 61,317 (2009), *reh'g denied*, 132 FERC ¶ 61,033 (2010).

[114] Ex. PSG-24 at 46-47, 248; Ex. PNG-100 at 4.

[115] Ex. PSG-24 at 119; Ex. S-15 at 158.

[116] *Id*. Ex. PNG-100 at 10.

[117] Ex. PSG-24 at 97-98.

[118] *Maritimes & Northeast Pipeline, L.L.C.*, 118 FERC ¶ 61,137 (2007) (Phase IV Certificate Order).

pipelines would be displaced or bypassed and no pipeline company objected to the project.[119]

59. In June 2007, an e-mail circulated within Portland stating that the increase in inlet pressure to the Joint Facilities from 1110 psig to 1175 psig agreed to by Portland with Maritimes would decrease Portland's capacity from 210,000 Mcf per day to 168,000 Dth per day.[120] The e-mail stated that, in order to restore Portland's capacity to 210,000 Mcf per day, compression would have to be added. This could be accomplished by TQM adding sufficient compression to increase its delivery pressure into Portland from 1255 psig to 1300 psig or by Portland adding compression on its system. The e-mail estimated costs of various options for TQM to add compression ranging from $5 to $20 million and costs of Portland adding compression on its system ranging from $20 to $30 million.

60. In early to mid-2008, Portland again asked TQM whether it would be able to provide increased pressure at its interconnection with Portland, and TQM answered that it could not.[121] In January 2008, Portland filed a request for a Declaratory Order in Docket No. RP08-70-000, 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, New Hampshire to Dracut, Massachusetts) would be reduced to 168,000 Mcf per day on a year round basis.[122] Portland stated that it would still have more than enough capacity to meet all its contractual obligations for service after the Phase IV Expansion went into service and that it "was not aware of any interest for additional FT contracts that would exceed the 168,000 Dth/day capacity level."[123] Therefore, it was not seeking to abandon any facilities or any contractual commitments. Rather, it was simply seeking a determination that it has no obligation to enter into future commitments of capacity from Pittsburg to Dracut that, together with existing commitments that continue in effect past October 31, 2008, would exceed 168,000 Dth per day. Portland also stated that any rate implications from its reduced capacity would be addressed in a future rate case, and it was not seeking any resolution of those issues in its request for a declaratory order.

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[119] *Id.* P 27.

[120] Ex. S-15 at 124-125.

[121] Ex. PSG-24 at 93-94.

[122] Ex. S-15 at 132-148.

[123] *Id.* at 133.

61. In June 2008, the Commission granted Portland's request, issuing an order finding that Portland would be incapable of transporting in excess of 168,000 Mcf per day all the way from Pittsburg to Dracut after Maritimes placed its Phase IV Expansion into service.[124] The Commission found that the Maritimes' Phase IV Expansion would increase the minimum delivery pressure from Portland to the Joint Facilities above the current design pressure, thereby reducing Portland's ability to transport gas all the way from Pittsburg to Dracut to 168,000 Mcf per day. 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. In its Declaratory Order 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."[125] According to Portland, Maritimes' Phase IV Expansion was placed in-service on January 15, 2009.[126]

62. At the hearing in this case, Portland stated there continues to be no market demand for service on its system in excess of 168,000 Mcf per day. Its witness, David Haag, testified, "Neither Portland, nor any of its shippers have a need for any capacity in excess of 168,000 Mcf per day."[127] There are no shippers interested in contracting for additional capacity on Portland.[128] Portland also stated that it has the physical ability to deliver 168,000 Dth from its Northern Facilities into the Joint Facilities and at the same time receive 42,000 Dth from Maritimes and transport that amount over its portion of the Joint Facilities, but "the market economics would never support those transactions."[129] Haag

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[124] *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).

[125] Declaratory Order Rehearing, 125 FERC ¶ 61,198 at P 20. The D.C. Circuit relied on this statement in dismissing PSG's appeal of the Declaratory Order on the ground that they had not shown that they were aggrieved by the Declaratory Order.

[126] Ex. PNG-1 at 9:10-12.

[127] Ex. PNG-142 at 67.

[128] *Id.* at 67-68.

[129] Ex. PSG-24 at 124-125, 150.

stated that increased costs to shippers, if Portland's at-risk condition was lowered, is about $16 million.[130]

4. Opinion Nos. 510, 510-A and 510-B

63. As required by the settlement in Portland's 2001 rate case, Portland filed a rate case in Docket No. RP08-306-000 on April 1, 2008, and the Commission suspended the proposed rates until September 1, 2008. The rates determined in that proceeding were effective only for a locked-in period from September 1, 2008 until November 30, 2010, when the rates in the instant case took effect.

64. Among the issues raised in Portland's 2008 rate proceeding was the appropriate level of its at-risk condition. The test period in that rate case predated the in-service date of Maritimes' Phase IV Expansion.[131] Accordingly, the parties and the Commission in that proceeding addressed the issue based on Portland's configuration and capacity before the Phase IV Expansion. While Portland proposed to design its rates based on billing determinants of 210,840 Dth per day (equivalent to 210,000 Mcf per day, Portland's capacity entitlement on the Joint Facilities), it asserted that its at-risk condition should remain at the 178,712 Dth per day (178,000 Mcf per day) level established in its certificate proceeding.[132] Portland argued that the "Commission's 178,000 Mcf/day at-risk condition was the final determination of this matter in the certificate proceedings."[133]

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[130] *Id.* at 159.

[131] The 2008 Rate Filing's test period ended September 30, 2008 (*Portland Natural Gas Transmission System*, 123 FERC ¶ 61,108, at P 4 (2008)), whereas Maritimes' Phase IV Expansion went into service January 15, 2009 (Ex. PNG-1 at 9:10-12).

[132] In a certificate proceeding, pipeline capacity generally is stated in volumetric units. However, pipelines are required to state their rates in thermal units. *See Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs*, Order No. 582, FERC Stats & Regs. ¶ 31,025, at 31,392 (1995). Therefore, Portland's proposed billing determinants are stated in thermal units (Dth) and derived by multiplying the heating content of gas delivered by Portland into the Joint Facilities (1004 Btu per cubic foot of gas) by Portland's volumetric capacity entitlement on the Joint Facilities. 1 MMBtu equals 1 Dth.

[133] *Portland Natural Gas Transmission System*, Initial Decision on the 2008 Rate Filing, 129 FERC ¶ 63,027, at P 304 (*citing* the 2008 Rate Filing's Ex. PNG-1 at 6) (2008 Rate Filing ID).

Trial Staff recommended that the at-risk condition be set at 210,840 Dth per day (210,000 Mcf per day). PSG, on the other hand, argued that the capacity of Portland's Northern Facilities was 217,405 Dth per day, somewhat greater than its capacity on the Joint Facilities and therefore the at-risk condition should be established at a level of 217,405 Dth per day. Opinion No. 510 affirmed the ALJ's decision to establish Portland's at-risk condition at a level of 210,840 Dth per day.[134] The Commission agreed with the ALJ that, in both the July 1997 Preliminary Determination Order and September 1997 Certificate and Rehearing Order, the Commission intended to base Portland's at-risk condition on the actual capacity of the pipeline and to place Portland at-risk for any unsubscribed capacity.[135] The Commission found that the actual capacity of Portland's system was 210,840 Dth per day.

65. PSG sought rehearing of the Commission's determination in Opinion No. 510 that Portland's at-risk condition be based on a capacity level of 210,840 Dth per day. PSG contended that the Commission erred in ignoring certain record evidence establishing that Portland's firm capacity on the Northern Facilities during the Test Period year exceeded 210,840 Dth per day and was at least 217,405 Dth per day.

66. In Opinion No. 510-A, the Commission granted PSG's rehearing request. Upon further review, the Commission found that the level of Portland's at-risk condition should be 217,405 Dth per day, instead of 210,840 Dth per day. The Commission interpreted the July 1997 Preliminary Determination Order as requiring that the at-risk condition be based on the capacity of the Northern Facilities, if that capacity was greater than Portland's capacity entitlements on the Joint Facilities. Based on its analysis of the record in the 2008 rate proceeding, the Commission found that during the relevant test period the capacity of Portland's Northern Facilities was at least 217,405 Dth per day. In light of this evidence, the Commission concluded that Portland's at-risk condition should be based on 217,405 Dth per day, as opposed to its capacity entitlement on the Joint Facilities.

67. Portland sought rehearing of Opinion No. 510-A, contesting the Commission's decision to increase the at-risk condition to 217,405 Dth per year for reasons similar to those it raises on rehearing of Opinion No. 524's rulings on the at-risk condition issue. However, in a contemporaneous order, the Commission is denying Portland's request for rehearing of Opinion No. 510-A on the ground that the issue of whether the at-risk condition applicable in the 2008 proceeding should be 210,840 Dth per day as held in Opinion No. 510 or 217,405 Dth as held in Opinion No. 510-A is moot. In its filing to

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

[135] *Id.*

comply with Opinion No. 510-A, Portland calculated a $0.8048 per Dth 100 percent load factor rate using billing determinants of 217,405 Dth. However, the refund floor for the locked-in period at issue in the 2008 rate proceeding is $0.85 per Dth. Accordingly, Portland only made refunds based on a $0.85 per Dth rate, and the Commission has approved its refund report.

68. Even if the Commission were to grant rehearing of Opinion No. 510-A and allow Portland to recalculate its rates based upon the 210,840 Dth per day billing determinants it proposed in that rate proceeding, the recalculated rates would only rise to approximately $0.8298 per Dth. This would not reduce the refunds Portland has already provided in that proceeding, because $0.8298 per Dth is still below the applicable refund floor. Moreover, the rates we approve in this proceeding are approximately $0.85 per Dth, which is above any possible refund floor for this proceeding that might be established based on the final rates determined in the 2008 rate proceeding. In these circumstances, no purpose would be served by a final resolution of Portland's at-risk condition in the 2008 rate proceeding based on a stale record that does not reflect Portland's current capacity levels as a result of Maritimes' Phase IV Expansion, and its reduced ability to transport gas across the Northern Facilities. Because we are not making a final resolution of the at-risk condition issue in the 2008 rate proceeding, we will not treat the discussions of this issue in either Opinion No. 510 or Opinion No. 510-A as precedential, and will instead resolve this issue based on Portland's current capacity levels as reflected in the record of this proceeding without reference to Opinion Nos. 510 and 510-A.

5. Opinion No. 524

69. Opinion No. 524 reversed the ALJ's finding that Portland's capacity at the end of the test period in this proceeding (November 30, 2010), and hence its at-risk condition, was 168,672 Dth per day, and held instead that Portland's at-risk condition for the test period is 210,000 Mcf per day.[136] The Commission noted that the ALJ had based his finding that the at-risk condition should be 168,672 Dth per day in part on the finding in the Declaratory Order that Portland's system capacity once the Phase IV Expansion went

[136] The Commission rejected PSG's claims that the appropriate at-risk level should be 217,430 Dth per day, finding there was insufficient record evidence to support that claim. The Commission noted that while the operating conditions on the pipeline may allow Portland to transport more than 210,000 Mcf per day on occasion, it only has contractual rights to 210,000 Mcf per day on the Joint Facilities, and thus it cannot sell more than that amount on a firm basis. Opinion No. 524, 142 FERC ¶ 61,197 at PP 216-218. Indicated Shippers have not sought rehearing of Opinion No. 524's ruling on this issue.

into effect would be 168,000 Dth per day. The Commission also stated that the ALJ had relied on Opinion No. 510's holding that Portland's at-risk condition was 210,000 Mcf per day based on Portland's capacity at the end of the test period in that case, which he took as an indication of the Commission's intent that Portland's at-risk condition should be based on Portland's actual system capacity, and that the pipeline should be at-risk for any unsubscribed capacity up that actual amount.[137]

70. The Commission found that it was error for the ALJ 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.[138] The Commission stated that its intent since it first established Portland's at-risk condition in the July 1997 Preliminary Determination Order, as further clarified in Opinion Nos. 510 and 510-A, was to place Portland at-risk for unsubscribed capacity on both its Northern Facilities and its Joint Facilities.[139] The Commission found that it had not limited 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, and that by initially establishing Portland's at-risk condition at 178,000 Mcf per day for the first year despite the fact the capacity of the Joint Facilities would be only 169,000 Mcf per day during that year. The Commission recognized that Portland would have greater capacity on its Northern Facilities than on the Joint Facilities during the first year of operation. The Commission nevertheless established Portland's at-risk condition for the first year at the higher 178,000 Mcf per day capacity on the Northern Facilities rather than the 169,400 Mcf per day end to end capacity. The Commission also noted that in Opinion No. 510-A, the Commission similarly established Portland's at-risk condition 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 concluded that it had not limited Portland's at-risk condition to its "end-to-end" capacity to move gas as argued by Portland.

71. The Commission recognized that during the test period in the instant proceeding, Portland had greater capacity on the Joint Facilities than on the Northern Facilities. The Commission found that its at-risk policy requires that Portland's capacity on the Joint Facilities be included in establishing its at-risk condition, and that according to record evidence, Portland had at least 210,000 Mcf per day capacity entitlements on the Joint

[137] Opinion No. 524, 142 FERC ¶ 61,197 at P 183.

[138] *Id.* P 207.

[139] Opinion No. 510, 134 FERC ¶ 61,129 at P 290, *order on reh'g* Opinion No. 510-A, 142 FERC ¶ 61,198 at P 173.

Facilities from Westbrook to Dracut. The Commission thus found it 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 July 1997 Preliminary Determination Order.[140]

72. The Commission found the determination that Portland's at-risk condition is 210,840 Dth per day to be consistent with the Declaratory Order's determination that Portland's certificated capacity from Pittsburg, New Hampshire to Dracut, Massachusetts, once the Phase IV Expansion project went in-service, would be 168,000 Mcf per day. The Commission noted that it 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, but to the contrary, 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." These rights remain unchanged.[141] The Commission thus concluded that 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.

73. The Commission also found that establishing Portland's at-risk condition at 210,000 Mcf per day preserved the Commission's intent underlying the at-risk policy applied in the July 1997 Preliminary Determination 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 Commission found that establishing an at-risk condition of 168,000 Mcf per day would not leave Portland at-risk for its 210,000 Mcf per day capacity on the Joint Facilities but would shift the costs of that capacity to Portland's shippers in contravention of the very purpose of the at-risk condition.

6. <u>Commission Decision</u>

74. On rehearing, Portland contends that the Commission erred in establishing Portland's at-risk condition and billing determinants at 210,000 Mcf per day. In its rehearing request, Portland focuses on the circumstances surrounding both the original certification of its system and the subsequent Phase IV Expansion of Maritimes' system to argue that its at-risk condition should be set at either (1) the 178,000 Mcf capacity of

[140] Opinion No. 524, 142 FERC ¶ 61,197 at P 211.

[141] *Id.* P 213 (*quoting* Declaratory Order, 123 FERC ¶ 61,275 at P 28 n.30).

the pipeline it proposed to build in its original certificate application in 1996 or (2) the 168,000 Mcf capacity of its Northern Facilities following the in-service date of Maritimes' Phase IV Expansion.

75. For the reasons discussed below, the Commission continues to find that the level of Portland's at-risk condition and billing determinants for the time period covered by this proceeding should be 210,000 Mcf per day and therefore, we deny Portland's request for rehearing. Below, we first address Portland's contentions related to the initial certification of its system. We find that our September 1997 Certificate and Rehearing Order reasonably required that Portland be at-risk for the full amount of its capacity once all the construction authorized by the orders in that certificate proceeding had been completed and placed into service. It is undisputed that, as completed, Portland's system, including both the Northern Facilities and the Joint Facilities, had capacity of at least 210,000 Mcf per day.[142]

76. We next address Portland's contentions related to Maritimes' Phase IV Expansion and the resulting reduction in Portland's capacity on its Northern Facilities. We find that this reduction in capacity does not justify reducing Portland's at-risk condition below 210,000 Mcf. As Portland's own evidence demonstrates, this reduction in capacity was the direct result of reduced market demand for capacity on Portland's Northern Facilities and thus also on its share of the Joint Facilities. This is the very risk that the at-risk condition was intended to require Portland to bear and to protect its customers from incurring. In addition, a reduction in Portland's at-risk condition below its 210,000 Mcf per day share of the capacity of the Joint Facilities would be contrary to the express requirement in the July 1997 Phase I Construction Certificate Order and the September 1997 Certificate and Rehearing Order that Portland be at-risk for its share of the capacity of the Joint Facilities.

a. At-Risk Condition Established in Original Certificate Proceeding

77. As stated earlier, at the time of Portland's certificate proceeding, the Commission's policy was to place a pipeline "at-risk" for recovery of costs related to a new project, if it could not satisfy the traditional *Kansas Pipe Line*[143] standard for demonstrating market support for the project. That standard required the pipeline to show that it had long-term contractual commitments for 100 percent of the project's

[142] PSG contended earlier in this proceeding and in the preceding 2008 rate case in that Portland had capacity of over 217,000 Dth. However, it is no longer arguing for an at-risk condition in excess of 210,000 Mcf in this proceeding.

[143] *Kansas Pipe Line & Gas Co.*, 2 FPC 29 (1939).

capacity.[144] An at-risk condition required that a pipeline's initial rates be designed based on the assumption that all capacity is subscribed at maximum recourse rates even if some or all of it is not. This is accomplished by establishing billing determinants at a level that reflects the full annualized capacity of the pipeline system.[145]

78. It is undisputed that at the time of the September 1997 Certificate and Rehearing Order giving final certificate authorization for Portland's Northern Facilities and the Joint Facilities, Portland could not satisfy the traditional *Kansas Pipe Line*[146] standard for demonstrating market support for those facilities. Nevertheless, Portland contends that its at-risk condition should be no higher than the 178,000 Mcf per day capacity of the pipeline it originally proposed to build in its initial 1996 certificate application for a stand-alone pipeline, rather than the higher capacity of the facilities certificated by the September 1997 Certificate and Rehearing Order. Portland argues that, while generally the Commission establishes at-risk conditions to discourage pipelines from constructing unnecessary capacity, that justification is not applicable here because Portland did not voluntarily propose to construct 210,000 Mcf per day of capacity. Rather, it proposed a stand-alone pipeline with a capacity of 178,000 Mcf, based on its assessment of market demand. Portland contends that the subsequent design changes that resulted in the increases in capacity above 178,000 Mcf per day came as a result of the Commission's urging, rather than an increase in Portland's projection of market demand.

79. Portland points out that it made these and other contentions in its request for rehearing of the July 1997 Preliminary Determination Order's requirement that its at-risk condition increase to 210,000 Mcf per day after its first year of operation, and the September 1997 Certificate and Rehearing Order granted that rehearing request, finding that it was premature to require any increase in Portland's at-risk condition after its first year of operation and instead the Commission would review that issue in Portland's next section 4 rate case. Portland states that, in its request for rehearing of the July 1997 Preliminary Determination Order, it argued that imposing the 210,000 Mcf per day at-risk condition would not serve the Commission's at-risk policy objectives. Portland states

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[144] *CNG Transmission Corp.*, 80 FERC at 61,501 (Generally, the Commission considered contracts with terms of 10 years or longer to be long-term contracts.).

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

[146] *Kansas Pipe Line & Gas Co.*, 2 FPC 29 (1939).

that it explained that the design changes that increased its capacity over the proposal in its original certificate application were the result of the 1996 Certificate Order's request that Portland consider a jointly owned pipeline with Maritimes. Portland contends that the design changes:

> were prompted by the Commission's suggestion that a joint facility be constructed; they were not based on an assessment of an increase in the market demand for [Portland] capacity. Thus, this is not a case where a pipeline is increasing capacity to meet projected market demand, and hence might be expected to bear the risk of its projections.[147]

80. Portland also asserts in its rehearing request that the Commission had encouraged Portland to consider the expansion potential for its pipeline so that if a joint facility was built it would be "sized large enough to avoid the need for looping the pipeline in the foreseeable future."[148]

81. Portland states that, in its request for rehearing of the July 1997 Predetermination Order, it also argued that it was premature to require it to increase its billing determinants to 210,000 Mcf per day, because it was not yet clear when or whether its capacity would increase to 210,000 Mcf per day. Portland explained that its capacity would not increase until TQM installed the planned new compression on its system in Canada, and TQM might not do that until more than a year after Portland commenced service. Portland states that the September 1997 Certificate and Rehearing Order granted its request for rehearing.

82. Portland also points out that in a subsequent 1998 order in the Maritimes' certificate proceeding the Commission stated its intent that owners of the Joint Facilities should not "be penalized … for following the Commission's suggestion that [Portland] and Maritimes construct jointly-owned facilities."[149] Portland concludes that, consistent

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[147] Portland Rehearing Request at 28 (citing Request of Portland Natural Gas Transmission System for Rehearing and Clarification, Docket No. CP96-248-000, *et al.* at 9 (filed Sept. 2, 1997)).

[148] Portland Rehearing Request at 3-4, 13, 19-20 (citing 1996 Certificate Order, 76 FERC at 61,656).

[149] Portland Rehearing Request at 3, 13, 19 (citing *Maritimes & Northeast Pipeline, L.L.C.*, 84 FERC ¶ 61,130, at 61,448 (1998)).

with this intent, the Commission should limit the at-risk condition to the 178,000 Dth per day capacity of its originally proposed stand-alone pipeline.

83. The Commission rejects these contentions. As discussed below, we find that the circumstances surrounding Portland's business decision to proceed with its proposed project approved in the September 1997 Certificate and Rehearing Order did not justify a departure from the applicable at-risk policy, and that order imposed an at-risk condition consistent with Commission policy. Contrary to Portland's suggestion in its instant rehearing request, the September 1997 Certificate and Rehearing Order made no finding that Portland's at-risk condition should be limited to the proposed design capacity of its originally proposed stand-alone pipeline based on the "historical factors" described by Portland. To the contrary, the intent of that order was to place Portland at-risk for the full amount of its capacity once all the construction authorized by that order, as well as the July 1997 Phase I Construction Certificate Order, had been completed and placed into service. Portland accepted its certificate as so conditioned by the Commission. Therefore, capping Portland's at-risk condition at the 178,000 Mcf per day capacity of its originally proposed stand-alone pipeline would be contrary to the reasonable expectations of the parties when they decided to proceed with the project after the September 1997 Certificate and Rehearing Order.

84. Contrary to Portland's claims, this is not a case where the Commission simply directed Portland and Maritimes to construct a jointly owned pipeline, such that Portland's decision to proceed with the project as authorized by the September 1997 Certificate and Rehearing Order without contracts for the full capacity should be treated as a matter outside Portland's control. Rather, before the Commission issued the 1996 Certificate Order on Portland's original stand-alone pipeline proposal, both Portland and Maritimes expressed interest in the idea of a jointly owned pipeline. They did this after commenters on the two pipelines' original certificate applications suggested that idea as means of addressing environmental concerns that the proposed pipelines ran along essentially the same route from the vicinity of Westbrook, Maine to Massachusetts.[150]

85. After these expressions of interest by Portland and Maritimes, the Commission urged the two pipelines in separate orders to consider the feasibility of constructing *either* a single pipeline *or* constructing two separate pipelines sharing the right-of-way, thus

[150] *See Maritimes & Northeast Pipeline, L.L.C.*, 76 FERC ¶ 61,124 (*Maritimes*). Maritimes originally proposed to construct a new pipeline extending from a proposed point of interconnection with the existing facilities of Tennessee near Dracut, Massachusetts to a proposed point of interconnection with the facilities of Granite State near Wells, Maine. Maritimes proposed a 64 miles 24-inch diameter pipeline with a capacity of 60,000 MMBtu per day.

providing the option for each pipeline to construct stand-alone pipelines.[151] Specifically, in Portland's 1996 Certificate Order, the Commission stated:

> Many commenters suggested that only one pipeline, large enough to meet the needs of both [Portland] and Maritimes, should be constructed where the routes converge. *Both [Portland] and Maritimes have expressed interest in exploring the feasibility of a jointly owned and operated pipeline where routing permits.* The Commission, as part of its environmental review, considers alternatives to any construction proposal. A jointly owned pipeline for the congested and environmentally sensitive area between Haverhill, Massachusetts and Portland, Maine will be one such alternative that the Commission will explore. We, therefore, urge [Portland] and Maritimes to study the feasibility of constructing *a single pipeline where possible or constructing two separate pipelines sharing the right-of-way*. Additionally, we encourage the pipelines to consider the expansion potential for their projects so that a single pipeline, if constructed, is sized large enough to avoid the need for looping the pipeline in the foreseeable future.[152]

86. Following the 1996 Certificate Order, the Director of the Commission's Office of Pipeline Regulation (Director) sent Maritimes and Portland a letter reiterating that the 1996 Certificate Order urged Portland and Maritimes to study the feasibility of *either* constructing a single pipeline *or* sharing a single right-of-way with two separate pipelines and asked the parties to meet and file with the Commission a status report on their negotiations.[153] The parties filed three status reports with the Commission indicating that

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[151] *See* 1996 Certificate Order, 76 FERC at 61,655-56 and *Maritimes*, 76 FERC at 61,674.

[152] 1996 Certificate Order, 76 FERC at 61,655-56 (emphasis added).

[153] Letter from Kevin P. Madden, Director, Office of Pipeline Regulation, Portland Natural Gas Transmission System, Docket No. CP96-248-000 (filed Oct. 11, 1996). Time was of the essence with respect to these negotiations given that Portland had requested Commission certification by August 31, 1997 for an in-service date of November 1, 1998. *See* Portland's Supplement to Amended Application for a Certificate of Public Convenience and Necessity, Docket No. CP96-249-003, at 7 at 7 (filed March 18, 1997).

the parties were in discussions regarding a joint pipeline south of Portland, Maine, including the joint pipeline route, environmental and other regulatory permitting and cost sharing. The Director responded urging the parties to continue their efforts and offered for the parties' consideration an alternative single pipeline route.[154] After additional negotiations with Maritimes, Portland voluntarily amended its original certificate application in Docket Nos. CP96-248 and CP96-249 to construct and operate the Northern Facilities and filed a joint application with Maritimes in Docket No. CP97-238-000 to construct and operate the Joint Facilities.

87. As evidenced by the 1996 Certificate Order and the subsequent correspondence, the Commission did not require Portland to construct a single, jointly-owned pipeline with Maritimes to the exclusion of a stand-alone project by Portland, as Portland suggests. Nor did the Commission specify how large the jointly-owned or stand-alone pipeline needed to be. Portland's decision to construct joint facilities with Maritimes from Westbrook Maine to Dracut, Massachusetts rather than a stand-alone pipeline and to obtain capacity of 210,000 Mcf per day on the joint facilities was its own business decision. The fact that Portland's final decisions on these matters may have been influenced by the need to respond to various concerns raised by affected parties, including environmental concerns, does not sufficiently distinguish this project from any other major pipeline project to justify deviating from the at-risk policy in effect at the time the September 1997 Certificate and Rehearing Order was issued. The originally proposed designs of major pipeline projects typically are modified to address concerns raised with the original proposal, but ultimately the pipeline remains in the best position to determine whether the project, as so modified, is economically viable and should be built.[155]

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[154] Letter from Kevin P. Madden, Director, Office of Pipeline Regulation, Portland Natural Gas Transmission System, Docket No. CP96-248-000 (filed Dec. 10, 1996).

[155] Portland states that in *Maritimes & Northeast Pipeline, LLC*, 84 FERC ¶ 61,130, at 61,693 (1998), the Commission granted Maritimes' request to defer its recovery of its Joint Facility costs until its overall project, including its upstream facilities, were placed into service, even though Portland was commencing service on the relevant Joint Facilities earlier. The Commission recognized that, in order for Portland and Maritimes to jointly construct a portion of their respective systems, some timing issues would arise, and this was one. The Commission further stated, "We do not think Maritimes should be penalized *in this instance* for following the Commission's suggestion that [Portland] and Maritimes construct jointly owned facilities [emphasis supplied]." This statement did not suggest that the circumstances leading to the construction of the Joint Facilities justified a departure from the Commission's at-risk

(continued…)

88. In any event, and contrary to Portland's suggestion in its instant rehearing request, we find that the September 1997 Certificate and Rehearing Order did in fact place Portland at-risk for the full amount of its capacity once all the construction authorized by that order, as well as the July 1997 Phase I Construction Certificate Order, had been completed and placed into service. We reject Portland's interpretation of the September 1997 Certificate and Rehearing Order as having capped the at-risk condition at the 178,000 Mcf per day capacity of its originally proposed stand-alone pipeline or left that issue open. Portland relies on the fact that an order granted rehearing of the July 1997 Preliminary Determination Order's requirement that the at-risk condition be increased to 210,000 Mcf per day after its first year of operation. However, the September 1997 Certificate and Rehearing Order granted rehearing of that requirement solely on the ground that such a requirement was premature because it was uncertain when and by how much Portland's capacity would increase after its first year of operation, not to permit the at-risk condition to be less than Portland's actual design capacity.

89. As described above, Portland had requested rehearing of the July 1997 Preliminary Determination Order on two grounds: (1) that such a requirement was premature because it was uncertain when and by how much Portland's capacity would increase above its initial level of 178,000 Dth per day on the Northern Facilities and 169,400 Mcf per day on the Joint Facilities and (2) that it should not be placed at-risk for capacity in excess of the 178,000 Dth per day it proposed in its original certificate application for a stand-alone pipeline. The September 1997 Certificate and Rehearing Order granted rehearing based solely on the first ground, and not the second. Specifically, the Commission found in that order:

> Based on the facts before us, we find that it is premature to require [Portland] to revise its rates or to be placed at risk for higher capacity after its first year of operation. It is not certain at this time when the additional compression will go into service or the actual amount of increased compression and its effect on the capacity of the [Portland] system. We

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policy, so as not to hold the two pipelines at risk for their share of the costs of the Joint Facilities, as required by their certificate orders. Rather, the Commission was recognizing the difficulties that could arise in coordinating the two projects during their construction.

> will instead review this matter when [Portland] makes its section 4 filing.[156]

The September 1997 Certificate and Rehearing Order did not address any other arguments that Portland raised in its rehearing request.

90. Moreover, other actions taken by the Commission in the September 1997 Certificate and Rehearing Order demonstrate it did not intend to limit Portland's at-risk condition to the 178,000 Dth per day capacity of its originally proposed stand-alone pipeline. As described above, that order not only addressed Portland's request for rehearing of the Preliminary Determination Order, but also granted final certificate authorization, following environmental review, for Portland to (1) provide service using its capacity on the Phase I Joint Facilities from Wells, Maine to Dracut, Massachusetts, (2) construct and provide service on the Phase II Joint Facilities from Westbrook to Wells, Maine, and (3) construct and operate its Northern facilities. The September 1997 Certificate and Rehearing Order also granted Maritimes final certificate authorization to construct and operate the Phase II Joint Facilities. In granting both Portland and Maritimes certificates for the Phase II Joint Facilities, the Commission expressly stated that it was "conditioning the certificates issued herein to put both applicants at risk for their portion of the cost of the Phase II joint facilities."[157] Previously, the July 1997 Phase I Construction Certificate Order, which was issued contemporaneously with the July 1997 Preliminary Determination Order, expressly placed both Portland and Maritimes "at risk for their portion of the cost of the Phase I Joint Facilities."[158] Thus, the final certificate orders for both the Phase I and Phase II Joint Facilities placed Portland at-risk for its share of the costs of the Joint Facilities.

91. If the Commission had intended in the September 1997 Certificate and Rehearing Order to limit Portland's at-risk condition to the 178,000 Mcf per day capacity of its originally proposed stand-alone pipeline, there would have been no reason for the Commission to place Portland at-risk for its share of the costs of Joint Facilities. These are the very facilities which Portland contended in its request for rehearing of the July 1997 Preliminary Determination Order it had not voluntarily chosen to build and thus it should not be held at-risk for recovery of their costs. Further, if the Commission had intended to cap Portland's at-risk condition at 178,000 Mcf per day, there would have

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

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

[158] July 1997 Phase I Construction Certificate Order, 80 FERC at 61,477. Portland did not seek rehearing of this order.

been no need for the Commission to revisit the issue of Portland's at-risk condition in its next rate case so that the at-risk condition could be based on its actual capacity after all the construction authorized by the orders in that certificate proceeding were placed into service. Portland did not seek rehearing or appeal the September 1997 Certificate and Rehearing Order, on these or any other grounds. Nor did Portland seek rehearing of the same at-risk requirement imposed in the July 1997 Phase I Certificate.

92. We thus interpret our September 1997 Certificate and Rehearing Order as requiring that Portland be at-risk for whatever the full amount of its capacity turned out to be once all the construction authorized by the orders in that certificate proceeding had been completed and placed into service. This interpretation is buttressed by the fact the Commission and Portland itself have subsequently interpreted the at-risk condition in that manner, rather than being limited to the capacity of Portland's originally proposed stand-alone pipeline.

93. For example, in a 1998 order issued in those same certificate proceedings, the Commission affirmed that Portland was still at-risk for all its unsubscribed capacity on the Northern facilities and the Joint Facilities, stating:

> The other shippers, moreover, will be protected from having to subsidize the cost of any unsubscribed capacity resulting from any possible failure of [Portland] to negotiate a firm transportation contract with Mead inasmuch as [Portland] is already at risk for any unsubscribed capacity. Although we will waive the contract volume execution condition here insofar as Mead's capacity is concerned, we emphasize that [Portland] will be at risk for this additional 8,000 Mcf a day of unsubscribed capacity as well as the unsubscribed capacity described in our July 31, 1997 preliminary determination order.[159]

94. The unsubscribed capacity described in the July 1997 Preliminary Determination Order was the capacity Portland proposed in its revised certificate application, not its original certificate application for a stand-alone pipeline.

95. Similarly, in Portland's Docket No. RP08-306-000 rate case, its witness Haag testified that "[Portland] is held at risk to the level of our firm system capacity."[160]

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[159] *Portland Natural Gas Transmission System, et al.*, 83 FERC at 61,388.

[160] Docket No. RP08-306 hearing record, Tr. 1023:23-24.

96. We recognize that Portland contends in its request for rehearing of Opinion No. 524 that the fact the September 1997 Certificate and Rehearing Order deferred a decision on the level of Portland's at-risk condition after its first year of operation until Portland's actual capacity was determined indicates that the final at-risk condition could be less than Portland's 210,000 Mcf per day share of the capacity of the Joint Facilities. Portland asserts that at the time of the September 1997 Certificate and Rehearing Order it was already known that Portland would have capacity of 210,000 Mcf per day on the Joint Facilities. The only uncertainty was whether TQM would provide sufficient compression to increase the capacity of the Northern Facilities to 210,000 Mcf per day. Thus, Portland argues, there would have been no reason to defer the issue of whether the at-risk condition should increase to 210,000 Mcf per day, unless the September 1997 Certificate and Rehearing Order contemplated that the at-risk condition could be set below 210,000 Mcf if TQM failed to provide sufficient compression to increase the capacity of Northern Facilities to 210,000 Mcf per day.

97. The uncertainties that led the Commission to defer a final decision concerning an increase in Portland's at-risk condition related more to the timing of any increase in Portland's capacity, than the exact amount of that increase. Interpreting the September 1997 Certificate and Rehearing Order as indicating that the at-risk condition might be set at a level significantly below Portland's 210,000 Mcf per day share of the capacity of the Joint Facilities would be inconsistent with that order's express requirement that Portland be at-risk for its share of the costs of the Joint Facilities.

98. In any event, it is undisputed that, as completed, Portland's system, including both the Northern Facilities and the Joint Facilities, had capacity of at least 210,000 Mcf per day. In a deposition, Portland's witness Haag responded to a question concerning Portland's capacity before the Phase IV Expansion as follows: "[W]hen the pressure at Westbrook was 1110 psi and given the operating pressures we were receiving from our upstream pipeline, in the past, yes, we were able to deliver 210,000 Mcf of firm system capacity end to end on our system." [161] Therefore, the condition for increasing Portland's at-risk condition to 210,000 Mcf per day set forth in the September 1997 Certificate and Rehearing Order was satisfied. Thus, we conclude that prior to the Phase IV Expansion, the at-risk condition established by the September 1997 Certificate and Rehearing Order was at least 210,000 Mcf per day, not the lower 178,000 Mcf per day capacity of Portland's originally proposed stand-alone pipeline, and Portland accepted the certificate with that condition. In the next section, we address the issue of whether the subsequent reduction in the capacity of Portland's Northern Facilities due to the Phase IV Expansion,

[161] Ex. PSG-24 at 18:14-19.

which could not have been anticipated in September 1997, justifies a reduction in the at-risk condition established in the September 1997 Certificate and Rehearing Order.

b. Effect of the Phase IV Expansion

99. Portland contends that Order No. 524 failed to adequately consider the reduction in the capacity of its Northern Facilities as a result of the Phase IV Expansion. Portland states that in the Declaratory Order the Commission determined that as of the in-service date of the Phase IV Expansion, Portland's certificated capacity from Pittsburg, New Hampshire to Dracut, Massachusetts would be 168,000 Mcf per day on a year round basis, and found that there was nothing in the record indicating that Portland would need to operate its system at a capacity level greater than 168,000 Mcf per day to be able to satisfy its current or anticipated firm customer load. Portland further notes that it has not turned down a maximum rate request for firm service since the Phase IV expansion went into effect, and that during the test period in this case it did not need the full 210,000 Mcf per day allocated to it on the Joint Facilities because 62,000 Mcf per day of that capacity was associated with the bankrupt related agreements, which were served by downstream delivery points on Portland's wholly owned facilities. Portland also contends that there are no markets or sources of supply at Portland's interconnection with Maritimes at the northern end of the Joint Facilities to fill the added capacity. Thus, claims Portland, it should not be held at-risk for capacity it cannot sell that is available only on the jointly owned and not its wholly owned facilities.

100. The Commission finds that the reduced capacity on Portland's Northern Facilities as a result of the Phase IV Expansion does not justify a reduction in the at-risk condition approved in the September 1997 Certificate and Rehearing Order. As described above, both the July 1997 Phase I Construction Certificate Order and the September 1997 Certificate and Rehearing Order granting Portland certificates for the Phase I and Phase II Joint Facilities expressly placed Portland at-risk for its portion of the costs of the Joint Facilities. Portland still has capacity of 210,000 Mcf per day on the Joint Facilities. To reduce its at-risk condition and billing determinants to 168,000 Mcf per day would shift the risk of the 42,000 Mcf per day unsubscribed and unutilized capacity on the Joint Facilities (about 20 percent of the total capacity) from Portland to its firm shippers. This would impose approximately $16 million in additional costs on those shippers, contrary to the requirement of the certificate orders that Portland be at-risk for the recovery of those costs. The fact that the certificate orders set forth a separate at-risk condition specifically applicable to the Joint Facilities indicates that those orders did not limit the at-risk condition to Portland's end-to-end capacity.

101. In addition, the record clearly indicates that Portland's loss of capacity on the Northern Facilities was the direct result of reduced market demand for service on its system as originally certificated, the precise possibility the at-risk condition is intended to protect shippers against. Until June 2005, Portland had contracts with shippers for winter firm service with total contract demands of 212,000 Dth per day. However, in June 2005

and 2006, while the Phase IV Expansion was under consideration, Portland lost two winter firm contracts with total contract demand of 61,800 Dth per day, thus reducing the total contract demand of its shippers to 150,200 Dth per day. Portland's witness testified that it agreed with Maritimes to the increase in the inlet pressure to the Joint Facilities, reducing the capacity of its Northern Facilities, because the reduction in its capacity would not jeopardize its ability to meet its reduced firm system contract demand.[162] In addition, it did not pursue alternatives to avoid a loss of capacity because it "had no contractual underpinning to support or necessitate any capital spending for the addition of facilities, compressors or other equipment to maintain its historical capacity."[163] In its request for a declaratory order that its end-to-end capacity after the Phase IV Expansion was 168,000 Dth per day, Portland stated that it "was not aware of any interest for additional FT contracts that would exceed the 168,000 Dth/day capacity level."[164] At the hearing in this case, Portland stated there continues to be no market demand for service on its system in excess of 168,000 Mcf per day. Its witness, David Haag, testified, "Neither Portland, nor any of its shippers have a need for any capacity in excess of 168,000 Mcf per day,"[165] and there are no shippers interested in contracting for additional capacity on Portland.[166] Portland also stated that, while it has the physical ability to deliver 168,000 Dth from its Northern Facilities into the Joint Facilities and at the same time receive 42,000 Dth from Maritimes and transport that amount over its portion of the Joint Facilities, "the market economics would never support those transactions."[167]

102. If Portland had not lost 20 percent of its contract demand, the Commission could not have approved the Phase IV Expansion as proposed, because such an adverse effect on existing shippers on the Portland system could not have been found to be in the public convenience and necessity. However, with the loss of that contract demand and the lack of market demand for the unsubscribed capacity, Portland did not consider the reduction in capacity on the Northern Facilities, with the resulting underutilization of Portland's share of the Joint Facilities, to be an adverse effect even worth mentioning to the Commission during the Phase IV certificate proceedings. At such time as market demand

[162] *Id.* at 91:14-19.

[163] Ex. S-15 at 123.

[164] *Id.* at 133.

[165] Ex. PNG-142 at 67.

[166] *Id.* at 67-68.

[167] Ex. PSG-24 at 124-125, 150.

redevelops for transportation of natural gas along the TQM-Northern Facilities- Joint Facilities path to New England markets, Portland can restore its lost capacity through the addition of compression on its system and/or TQM; Portland also has the rights to use the cheap expansibility of the Joint Facilities, which it bargained to retain during the Phase IV Expansion certificate proceedings. However, during the interim, the cost of the unsubscribed capacity on the Joint Facilities must be borne either by Portland or its shippers.

103. The July 1997 Preliminary Determination Order authorizing the Phase I Joint Facilities and the September 1997 Certificate and Rehearing Order authorizing the Phase II Joint Facilities both allocate the risk that those facilities will not be fully subscribed to Portland. As the Commission has previously held, the purpose of certificating a new pipeline with an at-risk condition was "to guard against unwarranted increases in the rates to customers who use the new facilities in the event that the new capacity is substantially underutilized."[168] All parties having proceeded with the project pursuant to orders setting forth that risk allocation, the Commission finds that risk allocation should continue to be enforced. Accordingly, the Commission will not permit Portland to shift that risk to its remaining shippers, thereby imposing an approximate 20 percent rate increase on the shippers for a risk which they reasonably believed they would not be required to bear.

104. Portland points out that in *Tennessee Gas Pipeline Co.*,[169] the Commission stated that an at-risk condition is not a permanent rate condition and the allocation of the costs and risks of the subject facilities will be considered in the pipeline's rate cases. However, the Commission also stated in *Tennessee* that an at-risk condition "is intended to put the pipeline on notice that it can only rely on the recovery of costs for that portion of capacity that has been subscribed to under firm contracts at the time it seeks to recover the costs."[170] Consistent with that purpose, the Commission subsequently explained in *ANR* that, in order for an at-risk condition to be permanently removed in a subsequent rate case, the pipeline must demonstrate that the subject capacity was fully subscribed under long-term firm contracts for at least ten years or that project revenues would exceed costs

[168] *ANR*, 82 FERC at 61,537-38 (citing *CNG Transmission Corp.*, 81 FERC ¶ 61,031 (1997)).

[169] 61 FERC ¶ 61,194, at 61,723 (1992) (*Tennessee*).

[170] *Id.*

on a long-term basis.[171] Portland has not contended that it has satisfied that condition for removal of the at-risk condition.[172]

105. In *ANR*, the Commission did state that a pipeline may propose to seek to include the costs of facilities subject to an at-risk condition in its rates in a general NGA section 4 rate case, even though it cannot justify removal of the at-risk condition.[173] However, in that circumstance, the pipeline must show that the costs of the at-risk facilities it proposes to include in its rate will produce just and reasonable rates to its customers. In particular, the Commission stated that "the pipeline has the burden of showing that the concerns about . . . unwarranted increases to the project's customers are satisfied."[174] The Commission pointed out that, while permanent removal of the at-risk condition requires a showing of long-term, 10-year contracts or other long-term guarantees against cost shifts, rate cases examine the reasonableness of rates based on a shorter-term examination of facility use and current test period experience.[175] Therefore, the test period in a particular rate case could reflect sufficient shorter term firm contracts or interruptible volumes, such that the full costs of the at-risk facilities could be included in rates without causing unwarranted rate increases to the project's customers, even though the conditions for permanent removal of the at-risk condition could not be satisfied.[176] The test period in this case, however, does not reflect any such shorter term firm contracts or interruptible volumes that would protect Portland's shippers from an unwarranted rate increase if its rates were designed based upon volumes less than the 210,000 Mcf per day at-risk condition approved in its certificate proceeding. To reduce Portland's at-risk condition from 210,000 Mcf per day to the current 168,000 Mcf per day capacity of its Northern Facilities, or design its rates based on that reduced volume, would shift to Portland's customers the entire cost of the unutilized twenty percent of its 210,000 Mcf per day

[171] *ANR*, 82 FERC at 61,537-38.

[172] While Portland had contracts for 212,000 Dth for its winter firm service, it was not fully subscribed for summer service.

[173] *ANR*, 82 FERC at 61,536-37.

[174] *Id*. at 61,537.

[175] *Id*. at 61,538.

[176] *Id*.

capacity on the Joint Facilities – "thereby causing the very cost-shifts that the at-risk condition is intended to prevent."[177]

106. Portland contends that Opinion No. 524's determination that Portland's at-risk condition is 210,000 Mcf per day failed to properly recognize the Declaratory Order's determination that Portland's certificated capacity across its system from Pittsburg, New Hampshire to Dracut, Massachusetts, once the Phase IV Expansion project went in-service, is 168,000 Mcf per day. Portland states that, in making that determination, the Commission did not break Portland into parts and issue separate certificated capacity levels for each. 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 [Portland] 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."[178] 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.

107. The Declaratory Order's determination of Portland's Pittsburg to Dracut certificated capacity in response to Portland's request for a determination of its end-to-end certificated capacity did not establish that Portland's end-to-end certificated capacity should also be its at-risk level. In fact, on rehearing of the Declaratory Order, the Commission expressly stated that the Declaratory Order "did not address or change the at-risk condition imposed on [Portland] by the Commission's certificate orders. The at-risk condition relates to the design of [Portland's] rates and is more appropriately addressed in [Portland's] next rate case."[179] As discussed above, in Portland's certificate orders for both the Phase I and Phase II Joint Facilities, the Commission expressly put Portland "at risk for [its] portion of the cost of the" relevant phase of the "joint facilities." Moreover, when the Commission established Portland's at-risk condition for its first year of operation when Portland had capacity of 178,000 Dth on its Northern Facilities and

[177] *Id.*

[178] Portland Petition for Declaratory Order, Docket No. CP08-70-000 (January 31, 2008), provided as Ex. PSG-222 at 1.

[179] Declaratory Order Rehearing, 125 FERC ¶ 61,198, at P 20 (2008). The Declaratory Order Rehearing also stated that the Declaratory Order did not prejudge the impact of that decision on Portland's rates or the appropriate billing determinants to use in designing its rates. *Id.*

capacity of only 169,400 Dth per day on the Joint Facilities, the Commission based the at-risk condition on the 178,000 Dth per day capacity of the Northern Facilities, rather than the then end-to-end capacity of 169,400 Dth per day. Thus, we find no evidence of any intent in the certificate orders establishing Portland's at-risk condition to limit that condition to Portland's end-to-end capacity. In the Declaratory Order, while the Commission found Portland's end-to-end certificated capacity would be limited to 168,000 Mcf per day, 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." The certificate orders having placed Portland at-risk for its share of the costs of the Joint Facilities, it follows that its at-risk condition should be set at the 210,000 Mcf per day capacity on the Joint Facilities which the Declaratory Order recognized that Portland would retain after the in-service date of the Phase IV Expansion.

108. Portland also argues that Opinion No. 524 fails to adequately recognize that the Declaratory Order rejected contentions that Portland needed to create or acquire capacity above 168,000 Mcf per day on the Northern Facilities because there is no evidence that there was firm demand above this amount.[180] Portland argues that the at-risk condition implemented in Opinion No. 524 indirectly does what the Commission's regulations and the NGA bar it from doing directly, namely compelling Portland to enlarge its facilities.

109. Portland's arguments here fail as well. Whether and when to restore or increase the capacity of the Northern Facilities is a business decision for Portland to make based on its assessment of the market demand for such increased capacity. Portland accepted certificates that placed it at-risk for the costs of the Joint Facilities, and Portland's obligation under those certificates did not change because of a decrease in market demand for transportation service across Portland's system rendered approximately twenty percent of the capacity of the Joint Facilities unutilized. To allow Portland to design its rates on capacity lower than Portland's total capacity on the Joint Facilities would result in shifting the costs of the unutilized Joint Facilities to Portland's customers in contravention of the Commission's policies. Whether or not the Declaratory Order "rejected" the idea that Portland needed to acquire or create capacity above 168,000 Mcf per day because it had no firm demand above that level is irrelevant to the question of its appropriate at-risk level. The very purpose of the at-risk condition is to hold Portland accountable for the difference in amount of firm capacity it has available and the amount it is able to sell on a firm basis.

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[180] Portland Rehearing Request at 33-34.

110. Portland states that a reduction of the at-risk condition to 178,000 Mcf per day would still hold it at-risk for its unsubscribed summer capacity. Portland notes that on an annualized basis, it currently has year-round subscribed capacity of only 134,867 Dth per day. However, Portland's certificate orders placed it at-risk for the full amount of its capacity on the Joint Facilities, not simply the difference between the capacity subscribed on a firm basis in the winter and the summer. Thus, reducing its at-risk condition to a level that is close to the amount of its capacity that is currently subscribed for winter firm service would be inconsistent with the at-risk condition established in the certificate orders.

111. Portland also argues that Opinion No. 524 is inconsistent with the Commission's actions in other cases. First, Portland contends that in *Cities Service Gas Co./Northwest Central Pipeline Corp.*[181] and *Lear Petroleum Corp.*[182] the Commission held, when it has required a pipeline to design its rates based upon a minimum percentage of its capacity, "the raw volume" necessary to satisfy that condition decreases if the pipeline's capacity decreases, although the percentage figure remains the same.[183] In *Cities Service/Northwest Central*, the Commission authorized Cities Service to construct a pipeline with an annual capacity of 67,000,000 Mcf if all proposed 11 compressors were built, and the Commission required that the pipeline's rates be designed based on a minimum throughput level of at least 90 percent of its design capacity or 60,000,000 Mcf per year. Cities Service built nine of the compressors, creating a pipeline with capacity of 47,800,000 Mcf per year. It then filed an application to amend its certificate to remove the two unbuilt compressors on the ground that market conditions had changed and the additional capacity to be created by those two compressors was no longer needed. Cities Service also requested removal of the minimum throughput condition. The Commission granted the request for authorization not to build the two compressors. However, the Commission denied the request for removal of the minimum throughput condition, and instead required that Cities Service's rates be designed based on 90 percent of the reduced capacity level, or 43,000,000 Mcf per year. The Commission found that removing the at-risk condition would improperly relieve Cities Service of the market risk it agreed to bear when it accepted the certificate. In *Lear*, the Commission cited its *Northwest Central* order denying rehearing of the *Cities Service* order in support of its

[181] 23 FERC ¶ 61,193, at 61,409 (1983), *reh'g denied sub nom.*, *Northwest Central Pipeline Corp.* 26 FERC ¶ 61,372 (1984) (*Cities Service/Northwest Central*).

[182] 42 FERC ¶ 61,015, at 61,054-55 (1988) (*Lear*).

[183] Portland Rehearing Request at 33.

requirement that Lear design its rates based upon at least 90 percent of its design capacity.[184]

112. Our ruling concerning Portland's at-risk condition in Opinion No. 524 is not inconsistent with *Cities Service/Northwest Central* or *Lear*. In *Cities Service/Northwest Central*, the pipeline did not construct two of the compressors included in its originally certificated facilities pipeline, and thus the costs of those two compressors were not reflected in its rates. Thus, the revised throughput condition continued to place Cities Service/Northwest Central at-risk for the same percentage of all the costs of the facilities that it actually built as required in the original certificate proceeding, based on the principle that the allocation of risks approved in the original certificate proceeding should be maintained. Here, Portland, unlike Cities Service/Northwest Central, constructed all of the facilities authorized in its certificate proceeding and all those costs are reflected in its cost-of-service, including the costs of its 210,000 Mcf per day capacity on the Joint Facilities. Therefore, a reduction of Portland's at-risk condition below 210,000 Mcf per day would alter the allocation of risks approved in its certificate proceeding by requiring its customers to bear the costs of the twenty percent of its currently unsubscribed capacity on the Joint Facilities. This would be contrary to the holdings of *Cities Service/Northwest Central* and *Lear* maintaining the originally approved allocation of risks.

113. Second, Portland cites *East Tennessee Natural Gas Co.*[185] and *Weaver's Cove Energy, LLC*,[186] as holding that, where specific operational constraints prevent the pipeline from having a reasonable opportunity to recover its cost-of-service using actual capacity for billing determinants, the Commission has allowed the use of a lower capacity level to derive rates. However, these cases are also distinguishable from the instant case, because neither involves a post-construction loss of market demand such as is at issue here. In *Weaver's Cove*, the Commission granted rehearing of its initial certificate order in order to allow Weaver's Cove to design its initial rates based upon the lower capacity of the only downstream pipeline able to receive gas from Weaver's Cove, rather than

[184] The Commission based the throughput conditions in *Cities Service/Northwest Central* and *Lear* on 90 percent of design capacity, because the rates at issue there were volumetric rates which could not be collected when service was interrupted for necessary maintenance. No such issue arises here, where Portland has Straight Fixed Variable (SFV) rates under which all fixed costs are included in reservation charges paid based on contract demand rather than actual throughput.

[185] 114 FERC ¶ 61,122 (2006) (*East Tennessee*).

[186] 114 FERC ¶ 61,058 (2006) (*Weaver's Cove*).

requiring the pipeline to design its rates based upon the higher capacity of its two laterals leading to the downstream pipeline. Thus, that case involved a situation in which, from the date that Weaver's Cove expected to go into service and for the indefinite future, a physical constraint on a downstream pipeline owned by a different company, rather than market conditions, would prevent Weaver's Cove from selling the full amount of its capacity on a firm basis. Here, by contrast, there are no physical constraints on separate, downstream pipelines that would prevent Portland from selling the full 210,000 Mcf per day of capacity on its Joint Facilities.[187] In fact, when Portland went into service, it was able to enter into firm winter contracts for its full 210,000 Mcf per day capacity. As discussed above, the subsequent reduction in the capacity of Portland's Northern Facilities was the direct result of reduced market demand for service on its system as originally certificated. This is the precise risk the at-risk condition included in its certificate orders was intended address.

114. In *East Tennessee*, the Commission's order certificating the construction of a new lateral recognized that East Tennessee's use of a 20-inch diameter pipeline, rather than a 16-inch diameter pipeline, increased the capacity of the new lateral from 210,000 Dth per day to 235,000 Dth per day and that it might take the pipeline time to market the additional capacity. Accordingly, the Commission gave East Tennessee the option of designing the lateral rates based on 210,000 Dth for the first two years of operation and thereafter designing the rates based on the full capacity of 235,000 Dth. Thus, in *East Tennessee*, the Commission simply allowed a short delay after the lateral's in-service date before requiring the pipeline to design its rates based on the full design capacity of the subject lateral. That requirement was comparable to the Commission's decision in the September 1997 Certificate and Rehearing Order to permit Portland to delay the increase in its at-risk condition until after Portland went into service and its actual capacity could be determined. *East Tennessee* did not involve a subsequent loss of market demand as has occurred in this case.

115. Portland contends that, by setting the at-risk condition at the 210,000 Mcf per day capacity of the Joint Facilities, the Commission improperly requires rates for service on both the Joint Facilities and the Northern Facilities to be designed based on 210,000 Mcf per day, despite the fact the Northern Facilities have capacity of only 168,000 Mcf per day. Portland contends that it is arbitrary to reduce its recovery of the Northern Facilities' costs based upon the proportion of unsubscribed capacity on the larger Joint

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[187] Ex. PSG-24 at 124-125, 150 (Portland has the physical ability to deliver 168,000 Dth from its Northern Facilities into the Joint Facilities and at the same time receive 42,000 Dth from Maritimes and transport that amount over its portion of the Joint Facilities.).

Facilities. Portland contends that this is inconsistent with *Northern Border Pipeline Co.*,[188] in which the Commission permitted an at-risk condition to be reduced based on the proportionate amount of total capacity that is not utilized under the contracts originally expected for the capacity.

116. The at-risk condition reasonably requires Portland to design its rates based upon 210,000 Mcf per day for service on the Northern Facilities, as well as the Joint Facilities, so long as Portland retains its existing postage stamp rate design. Under that rate design, shippers pay a single system-wide rate for transportation service anywhere on Portland's system, regardless of the length of haul or the facilities used. As a result, placing Portland at-risk for its 210,000 Mcf per day capacity on the Joint Facilities requires that its single system-wide rate be designed based on volumes of 210,000 per day. If Portland were to modify its rates to use rate zones, with one zone for the Northern Facilities and a separate zone for the Joint Facilities, the Commission could permit it to design the rates for each zone based on the capacity of that zone, but that is not the way Portland currently designs its rates.[189]

117. In any event, it does not follow that designing Portland's rates based on 210,000 Mcf per day would automatically lead to an under-recovery of the costs of the lower capacity Northern Facilities. As the postage stamp rate design does not use length of haul as a factor for calculating billing determinants, short haul transactions using just the Joint Facilities are allocated the same costs as long haul transactions which use the Joint Facilities and Northern Facilities. The higher design capacity of the Joint Facilities permits Portland to enter into transactions using just that capacity, in addition to transactions on and through the Northern Facilities, to recover its costs. In fact, Portland did engage in services performed only on the Joint Facilities, including reverse flow services, during the test period in this case.[190] Because Portland has postage stamp rates, it has the ability to offer short haul, long haul and reverse flow services on any part of its system and that provides it with an opportunity to recover its full cost-of-service.

[188] 52 FERC ¶ 61,272 *Northern Border, reh'g granted in part*, 53 FERC ¶ 61,138 (1990) (*Northern Border II*).

[189] During the certificate proceedings, Central Maine Power Company did suggest separate zones for the Northern Facilities and the Joint Facilities. The Commission rejected the proposal to require Portland to engage in zoning, however, in part because doing so might have upset the rate structure agreed to by Portland and shippers that had executed precedent agreements or service contracts. July 1997 Preliminary Determination Order, 82 FERC at 61,451.

[190] Ex. S-21 at 39-40:15-2. Ex. S-22 at 27-28.

118. Portland contends that Opinion No. 524 ignores that there are no viable markets or sources of supply to fill capacity only on Portland's portion of the Joint Facilities. Noting that Maritimes also has postage stamp rates, Portland asserts that it would not make economic sense for a shipper to pay Maritimes' rate to transport gas from Canada to Westbrook, Maine, and then switch and pay Portland's rate to transport from Westbrook, Maine to Dracut, Massachusetts because that customer would have been entitled to transport all the way to Dracut on Maritimes' joint facility capacity paying only Maritimes' rate. Portland also argues that Opinion No. 524 places it at a competitive disadvantage because Maritimes' Joint Facility unit rate is less than any reasonable calculation of Portland's rates under Opinion No. 524.

119. Portland's arguments on this point lack merit. Portland was fully aware of the configuration of its own and Maritimes' facilities when it accepted its certificate, and thus the at-risk condition. Portland's ability to reach different supply markets has not changed.

120. Portland also claims that in *Northern Border II* the Commission used an at-risk approach to direct the elimination of the cost of the capacity proportionate to the extent an increment of capacity is not utilized under the contracts originally expected for that capacity.[191]

121. Portland's reliance on *Northern Border II* is misplaced as it involved an entirely different situation from that in the present case. In *Northern Border II*, the pipeline proposed to expand its system by adding compression. That pipeline, unlike Portland, had formula rates, which it adjusted each year. Assuming the expansion shippers contracted for service as anticipated, the expansion would add more rate design volumes to the system than costs, and therefore would lower the pipeline's formula rates for the existing shippers. However, there was a risk that the expansion shippers would not contract for service at the anticipated levels. Therefore, the Commission conditioned its issuance of a certificate for the expansion on Northern Border including the anticipated contract volumes in the design of its formula rates, even if the expansion shippers ultimately did not contract for all of that service. However, on rehearing, Northern Border pointed out that this at-risk condition would guarantee the existing customers a rate reduction as a result of the expansion. Northern Border accordingly requested that the Commission limit the at-risk condition, so as only to protect the existing customers from incurring any rate increase under the pipeline's formula rates, and the Commission granted rehearing in order to so limit the at-risk condition.

[191] Portland Rehearing Request at 24 (citing *Northern Border II*, 53 FERC ¶ 61,138 (1990).

122. Unlike *Northern Border II*, the instant case involves the certification of an entirely new pipeline, not an expansion of an existing pipeline. Thus, the issue of an at-risk condition potentially guaranteeing a rate reduction to existing customers, as opposed to just protecting against a rate increase, does not arise. Here, the Commission imposed the at-risk condition in order to require the pipeline to be at-risk for any underutilization of its newly constructed facilities, and the shippers were entitled to rely on that condition when deciding whether to take service on the new pipeline. Limiting Portland's at-risk condition to solely the capacity of the Northern Facilities would be contrary to the shippers' expectations when they agreed to take service on the pipeline.

123. Finally, Portland claims that Opinion No. 524 did not meet the burden to establish that Portland's final rate would be just and reasonable, would maintain the pipeline's credit and ability to attract capital, and would produce returns comparable to other pipelines in the region.[192] According to Portland, the Commission unlawfully modified how it determines an appropriate at-risk condition by rejecting its previous determination that its at-risk condition should be based on the pipeline's system wide capacity and arbitrarily basing it on Portland's capacity on just the Joint Facilities. Portland claims that by erroneously interpreting the certificate orders to mean that the at-risk condition should be set at the highest capacity level that Portland is able to transport over only a portion of its facilities, the Commission guaranteed that Portland will not be able to recover its cost-of-service in contravention of Commission policy that requires a pipeline to be given a reasonable opportunity to recover its costs and earn an adequate return on its investment.[193]

124. Portland's assertions and unsupported statements are unavailing. As explained above, the certificate orders and Opinion Nos. 510 and 510-A made clear that Portland's at-risk condition was to be set at the higher of its capacity on either the joint or the wholly owned facilities in order to hold Portland responsible for any unsubscribed capacity. With respect to the claim that Opinion No. 524 guarantees that Portland will not be able to recover its cost-of-service or earn an adequate return, Portland ignores the fact that possibility always existed because of the admitted lack of a market and the at-risk condition Portland accepted that was intended to protect its customers from Portland

[192] Portland Rehearing Request at 36 n.90 (citing *See Duquesne Light Co. v. Barasch*, 488 U.S. 299, 312 (1989); *In re Permian Basin Area Rate Cases*, 390 U.S.747, 792 (1968); *Federal Power Comm'n. v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1994); *Bluefield Water Works & Improvement Co v. Pub. Serv. Comm'n of W. Va*, 262 U.S. 679, 692-93 (1923)).

[193] Portland Rehearing Request at 37.

shifting costs of unsubscribed capacity to existing customers. Opinion No. 524 placed Portland at the high end of reasonable returns, in part because the Commission recognized the anomalous risk that Portland faces relative to the other proxy group members because of its at-risk condition. Thus contrary to Portland's claims, the Commission specifically considered Portland's particular circumstances and found that "the fact Portland agreed to the at-risk condition does not foreclose taking it into account in determining its relative risk…."[194] As discussed below, the Commission herein affirms Portland's placement at the top of the zone.

B. Billing Determinants

1. Opinion No. 524

125. Based on the finding that Portland's at-risk condition should be 210,000 Mcf per day, the Commission reversed the ALJ's decision to establish Portland's billing determinants at 168,672 Dth per day and found that Portland must design its rates based on 210,840 Dth per day.[195] The Commission noted that based on its underlying certificates and the holdings in Opinion Nos. 510 and 510-A, Portland's rates must be designed based upon the greater of its projected billing determinants or its at-risk condition. The Commission found, based on the billing determinant analysis in the record, the most the record could support for billing determinants was 186,631 Dth per day.[196] Accordingly, because Portland's projected billing determinants did not exceed Portland's at-risk level, the Commission found that Portland must design its rates based on the higher at-risk level.

2. Portland's Request For Rehearing

126. Portland argues that because Opinion No. 524 erred in determining that 210,000 Mcf per day was the appropriate at-risk condition, it also erred in determining that Portland's billing determinants should be set at 210,000 Mcf per day. Portland claims that the billing determinants should be based on an at-risk condition of at most 178,000 Mcf per day or on the contracted service discount–adjusted billing determinants, which it claims is less than the 186,631 Dth calculated in Opinion No. 524. According to Portland the Commission routinely sets the billing determinants at the level of capacity at which

[194] Opinion No. 524, 142 FERC ¶ 61,197 at P 392.

[195] *Id.* P 226.

[196] *Id.*

the pipeline can operate the system 365 days a year,[197] and claims that the record is clear in this case that Portland cannot provide long term firm service at that level. Portland further claims that Opinion No. 524 is also inconsistent with Commission policy that billing determinants should be based on the capacity of the facilities or on contractual volumes but not a combination of both.[198] Portland asserts that Opinion No. 524 runs afoul of this policy because the at-risk condition incorporates the rejected (bankruptcy) contracts that it claims were sold as IT/PAL.

3. <u>Commission Decision</u>

127. Portland makes arguments similar to those it raised with regard to continuing the at-risk condition, namely that Opinion No. 524 fails to adequately consider the impact of its determination upon resulting rates and thereby deprives Portland of the reasonable opportunity to recover its cost-of-service. The Commission fully addressed the appropriateness of continuing the at-risk condition above. Portland states that its proposed billing determinants are consistent with the Commission's normal policy for general rate cases filed pursuant to Part 154 that permit pipelines to recover its revenue requirement based upon projected units of service. Part 154 of the Commission's regulations require pipelines filing a general rate case to provide 12-months of actual data (base period) plus 9-months of projected data that reflect known and measurable changes (adjustment period).[199]

128. Opinion No. 524 did not ignore Portland's projected units of service data in this proceeding. Opinion No. 524 explicitly reviewed that data.[200] However, regulations and policy do not over-rule explicit Commission findings, in this case the at-risk condition required by the certificate orders. Opinion No. 524 applied our standard policies to Portland's projected units of service. Those policies provide for the recognition of every billing determinant for which revenue was received by Portland, as adjusted for discounts. The record showed that Portland had no more than 186,631 Dth per day in billing determinants. This level was below the at-risk level of 210,000 Mcf per day. Therefore, as stated by Opinion No. 524, the applicable billing determinant level in this

[197] Portland Rehearing Request at 38 (*quoting Gulfstream Natural Gas Sys.*, 98 FERC ¶ 61,349, at n.10 (2002)).

[198] *Id.* (*quoting Missouri Interstate Gas, LLC*, 127 FERC ¶ 61,011, at 60,060 (2008)).

[199] 18 C.F.R. § 154.303(a) (2014).

[200] Opinion No. 524, 142 FERC ¶ 61,197 at P 226.

proceeding was the at-risk level of 210,840 Dth per day, not the lower level based on projected units.[201] If the Commission were to permit Portland to use some billing determinant level below 210,000 Mcf per day, costs would be shifted to existing customers. Such a shift in costs would be inconsistent with the understanding Portland's firm customers had when they entered into their long term agreements with Portland and to which Portland agreed when it accepted the at-risk condition. The Commission's finding is consistent with the standard set forth in *Hope/Bluefield*, as Portland had and has the opportunity to find additional markets, including short term firm, long term firm, interruptible and reverse flow transportation.[202] Further, the Commission has recognized the impact of the at-risk condition by providing a return on equity taken from the top of the zone derived from the proxy group used in this record.

129. We also reject Portland's contention that the Commission failed to satisfy the burden of proof required of it to act under section 5 of the NGA to support its requirement that Portland design its rates based upon billing determinants below the at least 210,840 Dth per day amount found to be reasonable by Opinion No. 510-B. In this NGA section 4 rate case, Portland has proposed to increase its rates above the just and reasonable level established in its preceding rate case, in part based on its proposal to decrease the billing determinants used to design its rates below the 210,840 Dth per day amount it used to design its rates in its last rate case. NGA section 4 places the burden on Portland to justify its proposed rate increase, including the proposed reduction in billing determinants underlying that rate increase. In Opinion Nos. 524 and 524-A, we find that Portland had not satisfied its section 4 burden to support its proposed reduction in its billing determinants and therefore it has not supported its full proposed rate increase. However, we are approving a smaller rate increase than Portland proposed. Accordingly, we are not requiring any rate reduction that would require us to satisfy a NGA section 5 burden.

130. The Commission's longstanding policy as reiterated in Opinion Nos. 510 and 510-A is that "pipelines with an at-risk condition must design rates based upon the greater of the pipeline's projected billing determinants or the volumetric level of its at-risk condition."[203] In the preceding sections, we have reaffirmed Opinion No. 524's determination that Portland's at-risk condition must be set at 210,000 Mcf per day. Therefore, it follows that its rate design billing determinants must also be set at that level.

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[201] *Id.*

[202] Ex. S-21 at 39-40:15-2. Ex. S-22 at 27-28.

[203] Opinion No. 510-A, 142 FERC ¶ 61,198 at P 61.

C. IT/Park and Loan (PAL) Credits

1. Opinion No. 524

131. In this proceeding, Portland proposed to change its method for treating interruptible service for rate design purposes from allocating costs to its interruptible services to crediting its cost-of-service with the revenues generated by interruptible services during the test period. The ALJ, relying on the Commission's policy that for rate design purposes a pipeline may either allocate costs and volumes to such services or credit its customers for interruptible services revenues, approved Portland's proposal to credit its interruptible revenues to its cost-of-service.

132. In Opinion No. 524 the Commission reversed the ALJ. The Commission explained that when a pipeline is subject to an at-risk condition, it must design its rates upon the greater of its projected billing determinants or its at-risk volumetric level.[204] Thus we found that in order to enable the Commission to determine whether Portland's total billing determinants satisfied its at-risk condition, it was necessary to require Portland to project billing determinants for all its services, rather than to project billing determinants only for firm services and then credit interruptible revenues to the cost-of-service.[205] The Commission further explained that in the situation where the projected billing determinants are less than the at-risk level billing determinants, the at-risk level billing determinants, upon which the pipeline must design its rates, already reflect an allocation of costs to the pipeline's interruptible services. Thus, it would be unjust and unreasonable to credit the pipeline's interruptible revenues to its cost-of-service because that would result in a double allocation of costs to interruptible services in contravention of Commission policy. [206]

2. Indicated Shippers' Request for Rehearing

133. Indicated Shippers argue that the Commission erred by reversing the ALJ's requirement that Portland credit its IT/PAL revenues against it cost-of service.[207] Indicated Shippers contend that the Commission's decision to reject Portland's crediting proposal and to require Portland to allocate IT/PAL costs on the basis that Portland did

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[204] Opinion No. 524, 142 FERC ¶ 61,197 at P 232.

[205] *Id.* P 233.

[206] *Id.* P 234.

[207] Indicated Shippers' Rehearing Request at 8-18.

not have sufficient billing determinants and throughput to satisfy its at-risk condition is contrary to the rate design conditions and elections imposed on Portland in the certificate orders and Commission policy and unreasonably dilutes the protections provided by the at-risk condition.

134. Indicated Shippers contend that contrary to the finding in Opinion No. 524 that Portland's rate design issues in this and its previous rate proceeding were "similar" (i.e., Portland's billing determinant projections were less than its at-risk condition),[208] there is a critical difference here with respect to the treatment of IT/PAL revenues, namely that here Portland sought in its NGA section 4 filing to design its rates by crediting its IT/PAL revenue to its cost-of-service.[209] Indicated Shippers note that Portland's election to credit revenues was consistent Commission rate design policy regarding interruptible services, and that the determination in Opinion No. 524 directing it to allocate costs was contrary to those orders. Indicated Shippers state that "by …effectively imputing an allocation of costs to IT/PAL services simply because Portland's projected billing determinants did not meet or exceed the billing determinant level set by its at-risk condition, the Commission materially changed the dual requirements of Portland's certificate orders mandating that Portland design its rates i) on a capacity-based billing determinant level, *and also* ii) on the basis of the pipeline's own rate design election to allocate costs to IT services or credit IT revenues."[210] Indicated Shippers claim the Commission's finding in Opinion No. 524 effectively melds these two requirements together such that Portland is now required to elect an allocation of costs or crediting of IT revenue only if its projected billing determinants reach or exceed its at-risk condition.

135. Indicated Shippers claim that Portland made the decision not to include IT/PAL revenues in billing determinants and to credit revenues instead. According to Indicated Shippers, Portland was permitted to do so under the original certificate orders and it is not "the Commission's place to protect the pipeline from the consequences of its own NGA Section 4 rate design election."[211] Indicated Shippers contend that the Commission's at-risk policy and policy requiring pipelines to allocate costs to a service or credit revenues from that service were implemented to protect customers. They argue that by imputing an IT/PAL allocation that Portland did not propose into the 210,000 Mcf per day at-risk

[208] *Id.* at 19.

[209] *Id.* at 11.

[210] *Id.* at 11-12.

[211] *Id.* at 14.

condition, the Commission diluted the protections that should have been afforded by those policies.

136. Indicated Shippers argue further that the Commission's basis for requiring Portland to allocate costs instead of credit IT/PAL revenues was flawed because it was not necessary to allocate costs to determine whether Portland's billing determinants would satisfy its at-risk condition. Indicated Shippers assert that Portland chose not to include IT/PAL revenues in its rate design and that compliance with its at-risk condition could have been determined by simply assessing Portland's projected billing determinants for its firm and other services, with revenue credited for IT/PAL throughput.[212] According to Indicated Shippers, if determination of whether Portland had satisfied its at-risk condition were impossible under an IT/PAL revenue crediting approach, the certificate orders would not have offered Portland that option in the first place.

3. Commission Decision

137. We deny rehearing. Indicated Shippers raise the same argument here that they did in their brief opposing Portland's exceptions to the ID's requirement that it credit IT/PAL revenues to its cost-of-service.[213] The Commission found that it was necessary for Portland to allocate costs to all its services on the basis of billing determinants as a means of determining whether the minimum billing determinant level required by the at-risk condition had been met.[214] As we stated in Opinion No. 524, because the at-risk condition billing determinants are greater than 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. Therefore, as explained by Opinion No. 524, including an IT/PAL revenue credit in addition to allocating costs on the basis of billing determinants that include IT/PAL services would result in allocating costs to IT/PAL services twice.

138. The Commission rejects Indicated Shippers' contention that the underlying certificate orders nevertheless required the Commission to accept Portland's original proposal in this case to credit its IT/PAL revenues against its cost-of-service. The Commission's order on Portland's initial application for a certificate for a stand-alone pipeline required Portland either "to credit 100 percent of the IT revenues, net of variable

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[212] *Id.* at 15.

[213] Opinion No. 524, 142 FERC ¶ 61,197 at P 231.

[214] *Id.* P 233.

costs, to its firm shippers, or propose an allocation of costs to interruptible service."[215] When Portland amended its certificate application to reflect the Joint Facilities, Portland proposed to allocate costs to its IT service. Accordingly, in the July 1997 Preliminary Determination, the Commission "allowed Portland to retain its Rate Schedule IT revenues, and not credit them to firm shippers."[216] That same order also required Portland to design its rates for its first year of service based upon the level of billing determinants required by its at-risk condition, because its capacity was undersubscribed. Thus, contrary to the Indicated Shippers' contention, the Commission's orders issuing Portland a certificate to construct its Northern Facilities and the Joint Facilities did not require Portland to both (1) design its rates based upon an at-risk condition level that exceeded its total billing determinants for all services and (2) credit IT/PAL revenues to its cost-of-service, as Indicated Shippers request here. Rather, those orders required Portland to design its rates based upon an at-risk level that exceeded its total billing determinants without crediting any IT/PAL revenues against its cost-of-service. That is exactly what Opinion No. 524 also did.

139. The certificate orders were concerned that Portland was under-subscribed, and those orders imposed an at-risk provision in order to ensure that the costs of the under-subscription were not shifted to the shippers. Our actions in Opinion No. 524 carry out this intent and thus we have not deprived the shippers of any of the protections afforded them by the underlying certificate orders. Further, allocating costs twice to interruptible services would have reduced the costs allocated to firm services. The Commission's certificate orders did not contemplate or require that firm shippers' rates be subsidized by IT/PAL services.

140. As the Indicated Shippers point out, in this rate case Portland initially proposed to credit $2,861,800 of IT/PAL revenues and a small portion of the Androscoggin and Rumford bankruptcy proceeds it received to its cost-of-service. However, that proposal was made in the context of Portland's proposal to design its rates based on total billing determinants of 168,672 Dth per day.[217] Portland's crediting proposal effectively recognized that its proposed rate design volumes of 168,672 Dth per day could not be considered to include an allocation of costs to IT/PAL service and properly account for its receipt of bankruptcy proceeds. However, we have rejected Portland's proposal to design its rates using billing determinants of 168,672 Dth per day and instead required it to design its rates based on billing determinants to 210,840 Dth per day. As Opinion No.

[215] 1996 Certificate Order, 76 FERC at 61,661.

[216] July 1997 Preliminary Determination Order, 80 FERC at 61,451.

[217] Opinion No. 524, 142 FERC ¶ 61,197 at P 221.

524 found, Portland's actual projected billing determinants including all services and volumes associated with the rejected Androscoggin and Rumford contracts are at most 186,631 Dth per day.[218] Therefore, the rate design volumes we have required Portland to use do include an allocation of costs to IT/PAL services. For that reason, it would be unjust and unreasonable to 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.

D. **Depreciation**

1. **Opinion No. 524**

141. In Opinion No. 524, the Commission affirmed the ALJ's determination that Portland had not supported its claim for an increase from its existing 2.0 percent depreciation rate to 4.13 percent.[219] The Commission noted that pursuant to longstanding policy 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.[220] The Commission agreed with the ALJ that the adequacy of gas supply is generally the dominating factor in the truncation analysis, and that Portland's gas supply study was so deficient so as to not reasonably support truncating Portland's economic life as it had proposed.

142. The Commission stated that determining the adequacy of gas supply involves estimating the potential recoverable natural gas reserves available to the pipeline, both proven and probable. Thus a supportable gas supply model must consider both conventional and unconventional sources of natural gas,[221] and a gas supply model that ignores "potentially vast unconventional resources" does not produce a reasonable result.

[218] *Id.* P 226.

[219] *Id.* P 142.

[220] *Id.* P 143 n.200 (citing *Memphis Light Gas and Water Division v. FPC,* 504 F.2d 225, 231 (D.C. Cir. 1974)).

[221] 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. Ex.PNG-15 at 15-16; Tr. 2359-60. Unconventional gas sources include shale gas, coal bed methane and tight gas. Tr. 2681

The Commission found this to be the case with Portland's depreciation study because it significantly underestimated reserves of shale gas and other unconventional resources.[222]

143. The Commission agreed with the ALJ's determination that the greatest deficiency with Portland's model was the estimate that unconventional gas production will remain static in 2020, which the Commission found to be contrary to record evidence indicating that shale gas production will increase after 2020. Based on Portland's "impractically low estimate of shale and other non-conventional gas reserves", the Commission found that Portland's study did not produce a reasonable result upon which the Commission could rely as the basis for a significant depreciation rate increase. Accordingly, because Portland had not met its burden to support its proposed depreciation rate increase, and no other party supported an alternative just and reasonable depreciation rate proposal, the Commission concluded that the ALJ was correct to retain Portland's existing 2 percent depreciation rate.

2. Portland's Request for Rehearing

144. Portland claims the Commission erred in rejecting Portland's proposal for an increased depreciation rate and thus determining that Portland's depreciation rate should remain at 2 percent.[223] According to Portland, the Commission failed to consider the substantial evidence that Portland produced supporting the just and reasonableness of its proposed increased depreciation rate. Portland argues that its gas supply study was not deficient and that it properly excluded speculative unconventional supplies. Portland also contends that the Commission failed to adequately address evidence of the economic life of its upstream supply pipeline in rejecting its truncation analysis. Portland further claims that Opinion No. 524 fails to properly apply the NGA section 9 standard to set "proper and adequate" depreciation rates.

3. Commission Decision

145. We deny Portland's request for rehearing. Portland bears the burden in this NGA section 4 proceeding 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 was required to show that the average remaining physical life of its system should be truncated by an allegedly shorter economic life. Portland fails to make such a showing.

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[222] Opinion No. 524, 142 FERC ¶ 61,197 at P 144.

[223] Portland Rehearing Request at 41.

146. Portland's proposed depreciation increase is premised on Portland's claim that the economic end life of its system is 2028. In support of its proposal, Portland claimed that in 2028, it would no longer receive supplies from its traditional supply source, the Western Canadian Supply Basin (WCSB),[224] due to a decline in Canadian conventional production and an increase in Canadian demand. Portland also argued that an increase in production of Marcellus Shale[225] gas will lower the delivered cost of gas for other pipelines, making Portland uncompetitive in the Boston-area market.[226] In support of these claims, Portland offered a gas supply forecast for the WCSB and a study showing the cost of transporting gas on different pipeline paths, and an overview of pipeline capacity expansion projects in the northeast region.[227]

147. Portland argues on rehearing that it used a gas supply forecast that was largely based on a forecasting model that was consistent with Commission precedent, that recognized changes in technology, and that properly evaluated potential gas supplies. In short, Portland argues that because it used a gas supply study that largely comports with models previously accepted by the Commission, the Commission must affirm the results of that model. The Commission disagrees. If the results of a model are not reasonable given other evidence in the record, the credibility of the model is suspect.

148. Opinion No. 524 found that the record evidence in this proceeding shows that Portland's depreciation analysis fails to support its requested change to its existing depreciation rate. Portland's application of the Hubbert model produced an inaccurate result because it failed to properly account for unconventional gas sources. The result of this deficient study was an unreasonably low estimated remaining life of 18 years.

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[224] WCSB underlays parts of Alberta, British Columbia, and Saskatchewan, Canada. Ex. S-21 at p. 22:11-12.

[225] The Marcellus Shale is a recently-developing natural gas supply basin located in New York, Pennsylvania, Ohio, and West Virginia. Ex. PNG-38 at 26. Ex. 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. Ex. PNG-7 at 15, 21. The Participants agree that Marcellus Shale contains significant gas reserves. Ex. PNG-38 at 26-29. Ex. PSG-89 at 34. Ex. S-21 at 38-39.

[226] Portland serves the Boston-area market, along with the Tennessee, Algonquin; and Maritimes pipelines.

[227] 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 Ex. PNG-22 and PNG-59.

Further, Portland's arguments regarding the purported economic life of its upstream supply pipeline failed to support its truncation claims. Finally, Portland's analysis conflated market demand with competitive business risks, and attempts to improperly include mitigation of competitive business risks into its depreciation evaluation, though such considerations are already addressed through the return on equity analysis.

a. Portland's Gas Supply Model

149. 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.[228] The adequacy of gas supply is generally the dominating factor in the truncation analysis.[229] As discussed in detail by the Commission in Opinion No. 524, Portland's study of its projected gas supplies is deficient as it does not reasonably support truncating Portland's economic end-life.

150. Portland based a significant component of its proposed depreciation rate on a Hubbert model to forecast production and discovery of conventional natural gas in the WCSB. The Hubbert model is a discovery rate extrapolation model that attempts to use known geologic or historical supply data to generate forecasts. The Hubbert model is based on aggregate historical production data and the premise that there is a fixed amount of fossil fuel in the ground that will be produced in a manner that resembles a bell-shaped curve. The model projects that production will be small in the beginning, rise to a peak, and decline at the inverse rate at which it was produced. The model presumes that production declines because discovery results are constantly declining while the effort to discover the resource constantly increases. Thus, eventually discoveries will be zero or too uneconomical to produce. By fitting the historical data into the bell curve, the model has been used to predict peak production and the subsequent decline.

151. Portland acknowledges that the Hubbert methodology does not explicitly incorporate factors such as price, technology, demand, and changes in extraction costs, but asserts that these factors are implicit in the model. Because the Hubbert model finds a trend for production across time (with an assumption that production will ultimately fit a bell-shaped curve), time is a proxy for the changes of all other relevant variables. This

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[228] *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").

[229] *Williston Basin Interstate Pipeline Co.*, 107 FERC ¶ 61,164 at P 27 n.23 (2004).

means, Portland claims, the fitted curve will reflect any trend for price, technology, demand, and other variables, which are reflected in the historical data used to find the fitted curve.[230] Portland nevertheless admits that shortcomings of the Hubbert model include that it presumes that aggregate production will follow a bell shaped curve and that, while the curve may be reasonable if these variables follow their historic trend, an uncharacteristically large change in price or technology can potentially shift the bell-shaped curve.[231]

152. In its application of the Hubbert model to determine ultimate potential marketable natural gas from the WCSB, Portland used production, historical reserve and estimates of ultimate recoverable resources of conventional gas from several sources.[232] Portland excluded unconventional sources of natural gas, including coal bed methane and shale gas, from its Hubbert model analysis, claiming that historical data was lacking so as to render any recovery estimate of such reserves too speculative to include in its Hubbert model, and that unconventional production had not as yet contributed significantly to historical production.[233]

153. For the Hubbert model, the date of peak production and amount of fixed supply are important in determining the shape of the bell curve. In Portland's version of the model, Portland states that the data shows that conventional WCSB production reached a maximum during the years of 2001-2006, and it examined the production bell curves that would result from those years. For Portland's estimate of WCSB ultimate conventional resource production, Portland states that it used two studies: a TransCanada study that estimated 277,000 Bcf and a National Energy Board (NEB) study that estimated 290,000 Bcf. Portland states the results of its curve fitting exercise was that the year 2002 (labeled Scenario 1) corresponds with the TransCanada prediction, and the year 2003 (labeled Scenario 2) corresponds with the NEB prediction.[234] Portland states that it chose as its preferred model the lower estimate, the TransCanada study and Scenario 1, as the

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[230] Ex. PNG-22 at 5-6; Tr. 1093-1094:24-8, 1142:12-19.

[231] Ex. PNG-22 *at* 6-7.

[232] *Id.* at 9.

[233] Ex. PNG-59 at 33:7-8.

[234] Ex. PNG-22 at 12, 15.

data was more recent than the NEB study and the bell curve fit the data more closely than the Scenario 2 curve.[235]

154. Portland argues that the Hubbert model, while not explicitly including variables such as technological change, does contain a proxy for such variables. By not including unconventional production data in its version of the Hubbert model, however, Portland undermines its validity. Unconventional production, the parties agree, is partially or largely due to changes in technology. As such, unconventional production data are the very data that are supposed to be the proxy for the variables that the model is supposed to be able to capture.

155. The Hubbert model has been used previously to predict ultimate resource recovery.[236] According to Portland, its Hubbert model analysis projected its ultimate recoverable conventional resources.[237] Portland's application of the model, however, did not produce this result. Portland imposed inaccurate constraints on its application of the model thereby leading to an unreliable determination of the end of production date. First, Portland assumed that WCSB conventional peak production occurred between 2001-2006. The explicit imposition of a peak production figure on the calculation of the bell curve removes one of the two variables that the model has been used to solve for. As noted by PSG, Portland's selection of the peak production year has no relationship to what is actually occurring in the WCSB, where over-all production is continuing to increase by significant amounts.[238]

156. Second, in selecting a scenario that it would proffer, Portland imposed a requirement that the model could not predict an ultimate conventional resource production figure greater than a fixed figure provided by another source: the TransCanada study. Trial Staff took issue with Portland's choice of the TransCanada study. That study estimated the WCSB's ultimate conventional resource production at 277,000 Bcf. Trial Staff noted that a more recent NEB study identified 121,000 Bcf in additional conventional WCSB reserves beyond the 277,000 Bcf estimated in the earlier

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[235] *Id.* at 13.

[236] Portland notes that Trial Staff's use of the Hubbert model in other cases has been to predict ultimate resource recovery. Tr. 2307:19-22.

[237] Tr. 2307-8:19-2.

[238] Ex. PSG-89 at 60, Fig. 4.

study.[239] With inaccurate constraints on the peak year and a constraint on the ultimate production, the remaining variable for the Hubbert model, the end of production end date, will inevitably be unreliable. If the fixed gas supply is understated, as Trial Staff contends, the projected end of production date would be too early. Further, as argued by Trial Staff[240] and PSG,[241] Portland, by imposing limits on the peak year production level and on total ultimate conventional resource production, essentially converted the Hubbert model into Portland's "effectiveness of exploration" model. That model has been previously rejected by the Commission.[242]

157. Portland reiterates its argument that it would have been an error to include the WCSB unconventional supplies in Portland's Hubbert conventional gas supply model.[243] Noting that the Commission has previously found the Hubbert model to be an accurate forecasting tool, Portland claims the bell curve produced by its model provides a "good fit" to actual production data of conventional supplies from the WCSB.[244] Portland argues that including unconventional sources to the model would produce unrealistic results. Portland also contends that the lack of historical production history and limited reserve knowledge demonstrates that there was insufficient record data to include unconventional sources in the Hubbert model. Portland claims including speculative unconventional gas estimates would skew the Hubbert model and produce errors of up to 20 percent.

158. Portland argues on rehearing that the original Hubbert model did not consider unconventional gas as it was not known at the time, implying that Portland was correct in

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[239] Ex. S-21 at 70:13-18 (citing a 2009 NEB study). The NEB study cited by Portland is dated 2005. Ex. PNG-22 at 9:5-7.

[240] Ex. S-21 at 23-24:12-3.

[241] Ex. PSG-89 at 58.

[242] Opinion No. 510, 134 FERC ¶ 61,129 at PP 138-140.

[243] Portland Rehearing Request at 44-47.

[244] Portland's argument that use of the Hubbert model is appropriate here because the Commission has previously accepted it as accurately modeling conventional WCSB production (Portland Rehearing Request at 41 and n.116), is unavailing. Those orders were issued prior to the shale gas boom and none of them address the issue of incorporating unconventional supplies into the model.

not considering unconventional gas in its version of the model. Presumably Portland is referring to Hubbert's statement as follows:

> Therefore, as an essential part of our analysis, we can assume with complete assurance that the industrial exploitation of the fossil fuels will consist in the progressive exhaustion of an initially fixed supply to which there will be no significant additions during the period of our interest.[245]

159. There is nothing in Hubbert's statement, however, that indicates the model is only applicable to a single type of natural gas production. Rather, his statement says that the progressive exhaustion is of a "fixed supply." As the record in this proceeding has shown, there are multiple estimates of what the WCSB fixed supply is – and those estimates include unconventional gas. While Portland argues that the Hubbert model is not applicable to WCSB unconventional gas, there is also no showing by Portland that the Hubbert model was premised on WCSB's conventional natural gas supply. Trial Staff's criticism of the Hubbert model demonstrates that the Hubbert model is generally interpreted to be applicable to fossil fuels in general, not to a specific production basin.[246]

160. As Portland notes, it did supplement the results of its Hubbert model by adjusting the results of that model to reflect a separate projection of unconventional WCSB supplies. Portland estimates that three sources of WCSB unconventional gas would result in an additional 2.4 to 2.5 Bcf per day of production.[247] Portland based these figures on TransCanada estimates. Portland believes these estimates are reasonable, as it compared TransCanada's estimates with estimates from another source, Bentek, which projected daily production figures significantly less than TransCanada's figures. Portland stated that the TransCanada data were the most "optimistic" of which it was it was aware.[248] Portland then took those unconventional daily production estimates and added

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[245] Ex. S-21 at 56:6-9 (citing Hubbert's 1956 presentation at the "Spring Meeting" of the American Petroleum Institute entitled *Nuclear Energy and the Fossil Fuels* at page 4).

[246] Ex. S-21at 56-68.

[247] Tr. 2350:9-14. *See also* Ex. PNG-7 at 56-57:3-12. The three unconventional sources are coal bed methane, Monterey Shale Hybrid, and the Horn River Shale. Review of Portland's Ex. 23, Sch. 15, which lists the projected production numbers for each of the three unconventional sources, shows that Portland actually projected as much as 4.82 Bcf per day of unconventional gas production in the WCSB by 2020.

[248] Tr. 2350:5-16.

them to the daily production estimates for conventional WCSB gas production that its Hubbert model bell curve projected.[249]

161. PSG questioned the validity of Portland's claim that its projected daily gas production from WCSB unconventional sources of 2.4 to 2.5 Bcf per day was in excess of the most optimistic data it could find. PSG noted that Canadian Association of Petroleum Producers report that in 2009 WCSB unconventional production was already in excess of 14 Bcf per day.[250] PSG, noting that there are other projections for unconventional WCSB gas, cites sources indicating the WCSB contains as much as 623 Tcf, which would support 2009 production levels for over 115 years.[251] Trial Staff notes that a 2007 NEB study (as compared to the 2005 NEB study used by Portland for its conventional gas figure) projected recoverable unconventional gas of 221 Tcf, and that the Canadian Society for Unconventional Gas projected 356 Tcf.[252] Taking into account all the Western Canadian gas production resources, including unconventional gas resources, for all of the NEB's and the Canadian Society for Unconventional Gas' different scenarios, based on a high production level of 17 billion cubic feet per day, Trial Staff calculates that the remaining production time line ranges from 55 years to 176 years.[253]

162. Moreover, Portland's projections for WCSB unconventional production plateau and become a straight line by 2020 and do not change thereafter.[254] Such a straight line

[249] Ex. PNG-23 at Sch. 15 for the data. Ex. PNG-7, Figs. 17 and 18 for the graphic representation of the data.

[250] Ex. PSG-89 at 55-56:8-1 states that the Canadian Association of Petroleum Producers reported that 2009 actual production was 5.4 Tcf. 5,400 Bcf a year divided by 365 days equals 14.79 Bcf per day. Portland on rehearing claims that Ex. PSG-89's 2009 data were not actuals, and the result would be an error of 20 percent (citing Ex. PNG-59, at 33:16-34:7). However, after Ex. PNG-59 was introduced, Ex. PSG-251 was introduced into the record that supported the 2009 data. Portland's witness admitted he was unaware of that data source (Tr. 2296:8-10).

[251] Ex. PSG-89 at 55 (citing a study by J.M. Lawson in the record at Ex. PSG-113).

[252] Ex. S-21 at 72:12-13.

[253] *Id.* at 73:8-12.

[254] Ex. PNG-23 at Sch. 15.

projection is unexplained. Portland's own witness speculated that WCSB's unconventional gas should have its own Hubbert bell curve.[255] A straight line projection is inconsistent with the Hubbert model which assumes a bell-curve production profile over time.

163. Finally, Portland argues that the Commission ruled that "it is unreasonable to predict that supplies from the Utica Shale reserves will never flow on Portland's system."[256] This conclusion, Portland argues, ignores the standard the Commission applies in distinguishing resources to include in, from those to exclude from, a gas supply study. When examined under the appropriate standard, Portland claims that Utica Basin reserves were properly excluded by Portland as speculative.

164. Portland's position is contrary to the record evidence and ignores the fact that it was Portland, not the other parties to the proceeding, who introduced the issue of Utica Shale production.[257] It was Portland that projected that Utica Shale production would not be available to Portland, not because it will not be produced, but rather because what would be produced would be consumed in Quebec, Canada.[258] Further, the record contains evidence that TransCanada, Portland's parent, represented to its customers that the Marcellus and Utica Shale plays are "game changers," and that it anticipated flows on Portland from the Utica Shale on TQM.[259] The flow patterns projected by TransCanada are substantially similar to those posited by Trial Staff as possible paths for Utica Shale gas to reach Portland's system. Neither the ALJ nor Opinion No. 524 made any finding that identified the Utica shale as speculative nor that required speculative resources be included in a gas supply study. Based on that evidence, Opinion No. 524 affirmed the ALJ's determination that it was unreasonable to assume that Utica Shale production would never be available to Portland.

165. In summary, Portland's gas supply economic life analysis did not lead to a reasonable result. Granting rehearing on any of the individual items of the model that the ALJ and the Commission found to be suspect would not change the finding that the

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[255] Ex. PNG-59 at 33:8-13.

[256] Portland's Rehearing Request at 53, *citing* Opinion No. 524 at P 146.

[257] Ex. PNG-7 at 38-41.

[258] *Id.* at 39:12-16, 40:8-11.

[259] Ex. S-21 at 53-54.

results are not reasonable in light of record evidence, and that available gas supply is and will be significantly greater than projected by Portland.[260]

b. TQM's East Hereford Lateral Economic End Life

166. In support of its depreciation proposal, Portland also argued that its estimated truncation date (economic end life) of 2028 was supported by the truncation date of TQM's East Hereford Lateral. According to Portland, the NEB set a truncation date of 2023 for the East Hereford Lateral in a depreciation report submitted as part of a settlement application, noting that the lateral connects directly to Portland's northern terminus and is the only receipt point for WCSB or Dawn supplies to reach Portland. Portland claimed that the truncation date of the Hereford Lateral directly affects the economic end life of the Portland system. It thus concluded that based on a truncation date of 2023 for the lateral, it was reasonable to estimate a truncation date five years later, or 2028, for Portland.

167. The Commission rejected this argument in Opinion No. 524, finding that Portland's evidence in support of the truncation date of the East Hereford Lateral was lacking. The Commission found that contrary to Portland's claims, a reference by the NEB in settlement hearing to a truncation date of 2023 for the East Hereford Lateral did not constitute an endorsement of the study including that date or a ruling on TQM's economic end life. The Commission also noted that its previous order regarding Iroquois Gas Transmission System, LP[261] did not establish a general policy or rule requiring the use of an upstream pipeline's depreciation rate or remaining life for all downstream pipelines, as Portland had argued.

168. On rehearing, Portland argues that Opinion No. 524 was wrong to disregard evidence regarding the truncation date of the East Hereford Lateral. Portland contends it demonstrated that the truncation date of the lateral is 2023, or five years before the end of Portland's remaining economic life. Portland further argues that the Commission's dismissal of this evidence on the grounds that the Commission does not have a policy

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[260] The Commission notes that Trial Staff speculated, in light of the new era of abundant gas supply and changing market dynamics, the traditional presumption that the truncation date should be based on gas supply may need to be revisited. Ex. S-21 at 13-15:14-3. The ID and Opinion No. 524 did not address this speculation as the Commission found that no party supported changing Portland's currently effective depreciation rate.

[261] *Iroquois Gas Transmission System, LP*, 81 FERC ¶ 63,012 (1997), *aff'd*, 84 FERC ¶ 61,086 (1998).

requiring the use of an upstream pipeline's depreciation rate is misplaced. Portland claims that it was arguing only that the economic life of the upstream pipeline that is the major source of supply to Portland is relevant to Portland's economic life, and the Commission is not prohibited from considering such data.

169. Portland argues the economic life of the East Hereford Lateral is highly significant because it connects directly to Portland at Pittsburgh, New Hampshire, the primary receipt point on Portland's system. Portland claims that the NEB evidence it produced regarding the East Hereford Lateral's truncation date was recent and reliable, and it was error for the Commission to disregard the evidence because it was not a "ruling" on the economic life of the lateral. Portland further claims that the Commission erroneously failed to address evidence showing that after termination of service from the TQM's East Hereford Lateral, the only source of supplies available to Portland would be those delivered off Maritimes at Westbrook, Maine. Portland claims the foregoing demonstrates that the Commission erroneously failed to consider highly relevant evidence of Portland's economic end life.

170. Contrary to Portland's assertions, Opinion No. 524 did not ignore or disregard data regarding the truncation date of the East Hereford Lateral. Rather, the Commission determined that Portland had not produced sufficient evidence to demonstrate that the economic life of the lateral was 2023 as Portland contended.[262] The Commission reviewed and considered the data produced by Portland in support of its argument and agreed with the ALJ and the shippers' arguments that the NEB's statements, upon which Portland relies, did not constitute a ruling, or even an acknowledgement, of the economic end life of the East Hereford Lateral. Portland argues on rehearing that the fact the Commission found the NEB's statement was not a "ruling" on the 2023 economic end life is not dispositive and that the NEB did not reject or criticize the depreciation analysis underlying the end date determination but accepted it as part of the settlement. As we noted in Opinion No. 524, however, the NEB merely referred to the study and did not approve or endorse it. Accordingly, the NEB's reference to a report that was a part of a settlement remains unreliable as the basis for establishing the economic end life of Portland's system.

171. Further, as we stated in Opinion No. 524, Portland's depreciation argument also failed because Portland did not establish that TQM was the only source of natural gas supplies in the future.[263] First, Portland presented no evidence that TQM's East Hereford Lateral will be retired from service at the end of its truncation period. If the East

[262] Opinion No. 524, 142 FERC ¶ 61,197 at PP 145-146.

[263] *Id.* P 146.

Hereford Lateral is not retired from service, it will remain a path to sources of supply. Second, Portland failed to consider that potential reserves, such as from the Utica Shale, would ever flow on Portland's system. Contrary to Portland's arguments, the Commission did not base its evaluation of the pipeline's evidence in support of remaining economic life of its system on a perceived prohibition against tying the life of a downstream pipeline to the life of its primary upstream supply source. Instead the Commission did consider Portland's data regarding the economic end life of the East Hereford lateral and found it insufficient to support Portland's position. Moreover, the record data supports the claim that TransCanada's Canadian mainline system has an economic end life beyond the year 2037.[264]

c. Competitive Disadvantage

172. Portland also argues that it presented substantial evidence of its competitive market disadvantages going forward, and thus the Commission was wrong to affirm the ALJ's finding that "Portland's assertion that it will be unable to compete in Boston in the future is speculative." According to Portland, it identified eight potential projects by Texas Eastern and Tennessee that were designed to flow Marcellus supplies to Boston markets, and the Commission has certificated three of those projects, contrary to the Commission's position in Opinion No. 524 that such projects were speculative.[265] Portland further claims the evidence shows that Marcellus supplies cannot be economically transported to Portland's system today and that there is no record evidence showing it would be economical in the future. Portland also claims that its evidence shows the lowest delivered cost of WCSB supplies to Boston over Portland is higher than the highest delivered cost of Marcellus natural gas to Boston over a competitor pipeline.[266]

173. Portland's competitive disadvantage arguments fail to rescue its depreciation claims. As stated earlier, pursuant to longstanding policy 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.[267] There is no issue that multiple pipelines serve the Boston market, and that

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[264] *See* Ex. S-21 at 20-21:18-14.

[265] Portland Rehearing Request at 57-62.

[266] *Id.* at 62 n.206.

[267] Opinion No. 524, 142 FERC ¶ 61,197 at P 143 n.200 (citing *Memphis Light Gas and Water Division v. FPC*, 504 F.2d 225, 231 (D.C. Cir. 1974).

Portland's share of that market is comparatively small. Portland's general evidence of expansion projects in various stages of planning that will bring shale gas to the northeast and Boston markets are well documented but still speculative as to what will actually be constructed. If and when these projects do go into service, Portland's evidence does not establish the competitive effect of those facilities on Portland would be such that no shale gas would ever flow on Portland during the life of the shale gas reserves. As Portland itself acknowledges, "the evidence is undisputed concerning the abundance, and projected production of, Marcellus gas and how those supplies are changing the gas market."[268] Nowhere, however, does Portland claim that these competitive hurdles will result in forcing Portland out of service. The competitive business concerns and market risk facing the company and its investors are appropriately addressed through the return on equity, not depreciation rates.[269] In the next section we grant Portland an ROE at the top of the range of reasonable returns based in part on their very market risks.

d. NGA Section 9

174. Finally, Portland argues that the Commission failed its obligation to set a "proper and adequate" depreciation rate.[270] According to Portland, even if a pipeline fails to meet it burden to support its depreciation rate as just and reasonable, NGA section 9 requires the Commission to set a proper and adequate depreciation rate. Portland asserts the Commission failed to satisfy this obligation by merely defaulting to Portland's pre-existing 2 percent depreciation rate.

175. As we noted in Opinion No. 524, Portland's arguments regarding NGA section 9 are meritless. As discussed at length above, Portland has not met it burden to show that its proposed depreciation rate is just and reasonable. Further, Portland is wrong that that even if the Commission finds that a pipeline has not met its burden to demonstrate that its depreciation rate is just and reasonable, "NGA section 9 requires the Commission to still set a 'proper and adequate' depreciation rate."[271] NGA section 9(a) provides as follows:

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[268] Portland Rehearing Request at 57.

[269] *See e.g.*, *Texas Gas Transmission Corp.*, 51 FPC 447, 449 (1974) ("no weight should be accorded the financial side effects of a depreciation proposal in determining its reasonableness").

[270] Portland Rehearing Request at 63-68.

[271] *Id.*at 63.

> The Commission *may*, after hearing, require natural-gas companies to carry proper and adequate depreciation and amortization accounts in accordance with such rules, regulations, and forms of account as the Commission may prescribe. The Commission *may* from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas. (Emphasis added.)[272]

176. The permissive language of NGA section 9 provides the Commission the authority to examine and set a pipeline's depreciation rate but does not impose an affirmative obligation on the Commission to do so as Portland suggests.[273] Under NGA section 4 the Commission can review and alter a pipeline's new filed rates, including the underlying depreciation rates, to ensure that they are just and reasonable throughout the effective period of the rates.[274] NGA section 9 does not does not alter that NGA section 4 general authority but merely grants the Commission the specific authority, in addition to that granted under NGA section 4, to examine depreciation rates on its own motion and, after a hearing, to set proper and adequate depreciation rates.[275] It does not impose on the

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[272] 15 U.S.C. § 717h(a) (1998).

[273] According to Portland, in *Southwest Dakota Public Utilities Commission v. FERC*, 668 F.2d 333 (8th Cir. 1981), the court applied the NGA section 9 standard to require FERC to set a proper and adequate rate. Portland's reading of the decision is untenable. The court there reversed the Commission's approval of an increased depreciation rate on the basis that the Commission's determination was not supported by the record. It did not establish standards for NGA section 9.

[274] Portland's pre-existing depreciation rate of 2 percent was approved by the Commission as part of a settlement of Portland's first rate case. 2002 Settlement Order, 102 FERC ¶ 61,026. No party to this proceeding has made a showing that the 2.0 percent pre-existing is unjust and unreasonable, and thus the Commission was justified in retaining that depreciation rate for Portland in the absence of sufficient support for Portland's proposed increase.

[275] *See, e.g., Caprock Pipeline Co.,* 50 FERC ¶ 61,246 (1990) (exercising the Commission's NGA section 9 authority to require Caprock to set and include a depreciation rate in its rate settlement); *see also Tennessee Gas Pipeline Co*., 26 FERC

(continued…)

Commission the responsibility to derive a just and reasonable depreciation rate for the pipeline in the event the pipeline fails to support its own proposal.

E. Return On Equity and Portland's Placement in the Proxy Group

1. Opinion No. 524

177. Opinion No. 524 affirmed the ALJ's findings regarding the composition of the appropriate proxy group. As noted there, 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.[276] Those five companies also comprised part of the proxy group approved in Opinion No. 510,[277] and the Commission agreed 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 in this proceeding. The only dispute among the parties was whether to include El Paso Pipeline Partners, L.P. (El Paso Partners) in the proxy group because it had received a non-investment grade credit rating of BB from Standard and Poors (S&P).

178. Opinion No. 524 found that El Paso Partners was an appropriate proxy group member despite its non-investment grade rating from S&P. The Commission noted that El Paso Partners also had two investment grade ratings from Moody's and Fitch Ratings, and thus could be considered to be primarily investment grade. Further, recognizing that the crucial determination for proxy group purposes is whether a proxy group company is "risk-appropriate,"[278] the Commission found that El Paso Partners' business activities, which consist of owning and operating several natural gas pipeline companies, were substantially similar to Portland's. The Commission concluded that the advantage of including a proxy group company whose business activities are so similar to Portland's outweighed other factors, such as a non-investment rating from one of the three ratings

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¶ 61,109, at 61,264 (1984); *Tennessee Gas Pipeline Co.*, 58 FPC 1999, 2018-2019 (1977).

[276] Opinion No. 524,142 FERC ¶ 61,197 at P 291.

[277] *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, 142 FERC ¶ 61,198 at P 184.

[278] Opinion No. 510-A, 142 FERC ¶ 61,198 at P 211.

agencies.[279] The Commission thus found El Paso Partners an appropriate proxy group member.

179. Having found that El Paso Partners was an appropriate proxy group member, the Commission adopted Trial Staff's DCF analysis for El Paso Partners, which represented the top of the range of reasonable returns at 11.59 percent.[280] Accordingly the Commission modified the range approved in the ID from 8.69 percent to 11.53 percent to 8.69 percent to 11.59 percent.[281] Again, no party sought rehearing of these findings.

180. With respect to the placement of Portland's ROE within the zone of reasonable returns, the Commission found that Portland had made a persuasive case to overcome the presumption that its ROE should be set at the median of the proxy group and instead should be placed at the top of the range of reasonable returns.[282] The Commission's determination was based on two major factors – Portland's non-investment grade credit rating and its at-risk condition.

181. Opinion No. 524 held that S&P's downgrade of Portland's credit rating to below investment grade constituted a significant change in circumstances since its prior rate proceeding. The Commission found that Portland had the lowest credit rating of all the proxy group members with the possible exception of El Paso Partners. The Commission also noted that a non-investment grade rating would likely cause an investor to perceive Portland as a risky company because the non-investment grade rating would make it more difficult and costly for Portland to find financing. Thus a reasonable investor would likely require a premium to invest in Portland.

182. The Commission also took into account the fact that Portland's at-risk condition prevents it from designing rates based on less than its design capacity, despite the fact its projected billing determinants are about 20 percent less than its design capacity. The Commission stated that none of the pipelines owned by the members of the proxy group are subject to such an at-risk condition. The Commission also pointed out that Portland's shippers benefitted from that position because otherwise the pipeline would not have been built. The Commission found that Portland's agreeing to the at-risk condition did not foreclose the Commission from taking it into account in determining Portland's risk

[279] Opinion No. 524, 142 FERC ¶ 61,197 at PP 302-305.

[280] *Id.* P 321.

[281] *Id.* P 322.

[282] *Id.* P 395.

relative to the proxy group. The Commission concluded that Portland's non-investment grade rating, coupled with its at-risk condition, rendered Portland's circumstances highly unusual and warranted an upward adjustment to Portland's ROE.

2. Requests for Rehearing

183. No party sought rehearing of Opinion No. 524's holdings concerning the composition of the proxy group or the DCF analysis of each member of the proxy group. However, both Indicated Shippers and CAPP seek rehearing of the decision to place Portland at the top of the range of reasonable returns.[283]

184. Indicated Shippers argue that Portland's non-investment grade rating together with its at-risk condition do not constitute highly unusual circumstances warranting an upward adjustment to its ROE. According to Indicated Shippers, relying on the at-risk condition as a reason for escalating Portland's ROE would shift the costs of unsubscribed capacity to Portland's shippers, contrary to the Commission's findings in Opinion Nos. 510 and 510-A. They also assert that Portland voluntarily accepted the at-risk condition as it did the other business risks the Commission previously refused to consider in its ROE analysis.

185. Indicated Shippers also challenge the Commission's finding that Portland was unusually risky compared to the proxy group companies because of its at-risk condition. Indicated Shippers claim that some pipelines owned by members of the proxy group are also subject to at-risk conditions.[284] They assert that Spectra Corporation, a proxy group member, is part owner of the company that operates Maritimes and that Maritimes is subject to the same at-risk condition as Portland with respect to the joint facilities. They also note that Spectra owns an interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream), which Indicated Shippers assert was placed at-risk for unsubscribed capacity on its newly built system. Indicated Shippers also claim that although the Commission discontinued the use of at-risk conditions in 1999, the Commission continues to hold numerous pipelines at-risk for unsubscribed capacity through the 1999 Certificate Policy's requirement that pipelines financially support construction projects without subsidization from existing customers. Indicated Shippers conclude that because many proxy group member pipelines are responsible for the costs of underutilized and unsubscribed capacity on their systems, the Commission should not consider Portland's

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[283] *See* Indicated Shippers' Rehearing Request at 18-35; CAPP's Rehearing Request at 6-21.

[284] Indicated Shippers' Rehearing Request at 25-26.

at-risk condition a factor in determining where Portland's ROE should be placed in the zone because it does not make Portland anomalously risky.

186. CAPP also challenges the Commission's decision to place Portland's ROE at the top of the range of reasonable returns. According to CAPP, the two findings upon which the Commission relied for that determination, the below-investment grade rating and the "unusual circumstances related to the at-risk condition", are unsupported by the record. CAPP claims first that the only other time the Commission had awarded an ROE at the top of the zone of reasonable returns (in *Transco I*[285]) it considered both the financial and business risks facing the company and found the pipeline's parent company was in financial distress. CAPP asserts there is no record analysis of Portland's business risk in this proceeding. Second, CAPP claims that the S&P report specifically states that Portland's risk will "dampen" by 2018, and that this moderation in risk is a critical factor in the ROE analysis. CAPP claims the determination to place Portland's ROE at the top of the range is thus contrary to the record evidence. Third, CAPP argues the Commission's reliance on Portland's at-risk condition to justify awarding an ROE at the top of the range is contrary to the Commission's policy underlying the at-risk condition – preventing pipelines from shifting costs of unsubscribed capacity to its shippers. According to CAPP, the presence or absence of an at-risk condition does not support awarding the pipeline the highest ROE.

3. Commission Decision

187. The Commission denies rehearing and upholds the determination to place Portland at the high end of reasonable returns. As discussed below, the combination of Portland's credit rating downgrade and the fact that its at-risk condition requires it to design its rates based on its design capacity despite the bankruptcy of two major customers and the inability to obtain replacement firm contracts render it anomalously risky as compared to the companies in the proxy group. As we found in Opinion No. 524, the downgrade of Portland's credit rating to below investment grade during the test period was a significant changed circumstance relating to Portland's ROE as compared with its last rate case. Moreover, while Portland did accept the at-risk condition, the regulatory at-risk condition is not the same as the contracting and other business risks that the Commission found to be the consequence of Portland's own business decisions, and thus not appropriate as the basis for adjusting Portland's ROE upward. Based on the unusual circumstances of Portland's below investment grade credit rating and the fact the at-risk condition prevents it from reflecting unsubscribed capacity resulting from the bankruptcy of two of its initial shippers in designing rates, we find that Portland is above average risk when compared to

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[285] *Transcontinental Pipeline Corp.*, 60 FERC ¶ 61,246 (1992), *reh'g denied*, 64 FERC ¶ 61,039 (1993) (*Transco I*).

the proxy group members, and thus find it appropriate to place Portland's ROE at the top of zone of reasonable returns.

188. The purpose in deriving an ROE for a public utility is to enable the company to attract capital investment in the marketplace. As the United States Supreme Court has held, "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."[286] In order to attract capital, "a utility must offer a risk-adjusted expected rate of return sufficient to attract investors."[287]

189. Further, as we have stated numerous times, 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.[288] However, the Commission permits parties to present evidence to support any ROE 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 median of the zone of reasonableness established by the proxy group.[289]

190. In setting a reasonable rate of return, the Commission must balance the customer's rights to pay a just and reasonable rate with the pipeline's ability to attract investment by offering a return commensurate with its business and financial risks as compared with similar pipelines. Investors will require a higher return for investing in a more risky company, and an inability to raise capital increases a company's business risk. Thus, in Opinion No. 524, the Commission determined that based on specific risk factors relevant

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

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

[288] *Transcontinental Gas Pipe Line*, 90 FERC ¶ 61,279 (*Transco II*); *Kern River Gas Transmission Co.*, Opinion No. 486-B, 126 FERC ¶ 61,034, at P 140 (2009); *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at P 7 (2008).

[289] *Transcontinental Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,427 (1998).

to Portland, namely its below investment grade credit rating and its regulatory at-risk condition, Portland's risk compared to the other proxy group members was extremely high and thus warranted placing Portland's ROE at the top of the range of reasonable returns.

a. Portland's At-Risk Condition

191. Opinion No. 524 placed Portland's ROE at the top of the range based in part on the fact its at-risk condition prevents it from increasing its rates to recover the costs of capacity left unsubscribed when the contracts of two of its initial shippers were terminated in bankruptcy. Indicated Shippers and CAPP contest the Commission's reliance on Portland's at-risk condition as a factor in determining its level of risk as compared to the other proxy group members. They assert that such reliance is inconsistent with the at risk condition's objective of preventing cost shifts, that Portland is not unique in having an at-risk condition, and that Portland's at risk situation is solely the result of a voluntarily assumed business risk. We reject these contentions.

192. The at-risk condition Portland agreed to when it accepted its certificate requires Portland to be at risk for the recovery of the costs of its unsubscribed capacity. As described in detail above, the certificate orders stated that this would be accomplished by requiring Portland to design its rates based on the design capacity of its system once all construction authorized by the certificate orders was completed. In Opinion No. 524 and this order the Commission is enforcing this at-risk condition by requiring Portland to design its rates based on billing determinants of 210,840 Dth per day reflecting the full design capacity of its system as completed. Consistent with the at-risk condition, this requirement allocates to Portland the portion of its cost-of-service represented by the unsubscribed capacity, thereby requiring Portland to be at risk for the recovery of that portion of its cost-of-service.[290] It also prevents Portland from shifting to its customers the proportionate share of its cost-of-service represented by the unsubscribed capacity, thus carrying out the purpose of the at-risk condition.

193. However, in determining the ROE to be included in the overall cost-of-service that is allocated among the shippers and Portland based upon the at-risk condition billing determinants, we find it reasonable, in the circumstances of this case, to take into account how the at-risk condition affects investors' evaluation of the relative risk of Portland versus the proxy group members. As set forth in Portland's certificate orders, the at-risk

[290] This proportionate share of the overall cost-of-service allocated to Portland includes a proportionate share of the ROE we are setting at the top of the range of reasonable returns to reflect Portland's relatively high risk as compared to the proxy group.

condition simply requires Portland to design its rates based upon its design capacity. The certificate orders do not address the determination of Portland's ROE in subsequent rate cases. Moreover, as we noted in Opinion No. 524, while the shippers negotiated levelized rates during the certificate proceedings, Portland's contracts with its shippers contain no restriction on its flexibility to propose a revised ROE in section 4 rate cases. In considering any such proposal, we must balance the interests of shareholders with consumers and determine an ROE that is sufficient to ensure confidence in the financial integrity of the pipeline, so as to maintain its credit and to attract capital.

194. In this case, the interaction of Portland's at-risk condition with adverse market developments which may reasonably be considered outside Portland's control for purposes of the ROE risk analysis supports a finding that Portland faces greater risks than the proxy group members. As already described, in June 2005, Portland's firm contract with Androscoggin was rejected and terminated through bankruptcy. In April 2006, Portland's firm contract with Rumford was rejected and terminated through bankruptcy. Together, these two contracts accounted for 62,000 Dth per year, or almost 30 percent, of Portland's winter firm contracted capacity of 212,000 Dth. Androscoggin and Rumford were initial shippers on Portland. Both purchased firm capacity on Portland in order to serve their gas-fired generators. Their bankruptcies related to business problems faced by those electric generators outside Portland's control. As the United States Court of Appeals for the District of Columbia Circuit has stated, a pipeline's risks arising from the loss of contracts because of its shippers' lack of creditworthiness is a factor the Commission takes into account in setting a pipeline's ROE.[291]

195. In Opinion Nos. 510 and 510-A, we found that, in all the circumstances of Portland's 2008 rate case, Portland's loss of those two customers did not justify raising Portland's ROE from the 12.99 percent median of the range of reasonableness determined based on the record in that case to the 14.89 percent top of the range in that case. However, in denying Portland's request for rehearing of Opinion No. 510, the Commission stated that Portland's contentions ignored the fact that our use of the most updated financial data in the record of that case, reflecting the impact of the financial crisis,[292] helped recognize the business risks faced by Portland. Opinion No. 510-A explained, "As noted by the other participants in this proceeding, the DCF results for that time period were arguably at the high end of possible outcomes, because the increased dividend yields resulting from decreased stock prices were not fully offset by later

[291] *Gas Transmission Northwest Corp. v. FERC*, 504 F.3d 1318 (D.C. Cir. 2007).

[292] The DCF analysis in the 2008 rate case was based on financial data for the six months November 2008 through April 2009.

downward adjustments to other inputs to the DCF analysis."[293] In this case, by contrast, the DCF analysis is based on the six month period ending March 31, 2011, and the median ROE is 10.28 percent with the top of the range at 11.59 percent. Thus, the top of the range in this rate case is 140 basis points less than the *median* of the range in the 2008 rate case. Accordingly, the median of the range in this case does not reflect the business risks faced by Portland in the same manner as the median of the range in the 2008 rate case did.

196. The record in this case shows that in the four years following the termination of the Androscoggin and Rumford contracts, Portland has been unable to market any of the resulting unsubscribed capacity on a long-term firm basis.[294] Indeed, unlike the pipelines owned by the proxy group members, Portland has not entered into a single new long-term firm contract in those four years.[295] Since 2007, Portland has seen a 55.32 percent reduction in its total shipper firm contract demands. By contrast, the proxy group members have seen an average 18.15 percent increase in their total shipper firm contract demands.[296] While Portland did receive bankruptcy proceeds from the termination of the Androscoggin and Rumford contracts during the period 2006 through February 2008, an investor during the post December 1, 2010 period the rates in this rate case are in effect would likely nevertheless consider Portland more risky than the proxy group members in light of (1) its inability to remarket the subject capacity on a long-term basis and (2) Portland's substantial loss of firm contract demands compared to the proxy group members' average in increase in firm contract demands. Moreover, as the Commission has found above, even taking into account the bankruptcy proceeds, Portland is unable to satisfy its at-risk condition.[297]

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[293] Opinion No. 510-A, 142 FERC ¶ 61,198 at P 242.

[294] Ex. PNG-100 at 24. ("To date, despite heavy discounting and aggressive marketing, Portland has not been able to successfully re-market on a long-term firm basis the 62,000 Dth of firm capacity that was turned back as part of the Androscoggin and Rumford bankruptcies."). Portland has been able to contract with the new owners of the Androscoggin and Rumford generators for only four months during the six years after the termination of the first contract and those short-term contracts included discounts of approximately 70 percent of the maximum rate. Ex. PNG-100 at 34.

[295] Ex. PNG-100 at 26-27.

[296] Ex. PNG-194 at 3.

[297] In Opinion No 524, 142 FERC ¶ 61,197 at PP 242-247, the Commission required Portland to include the 62,000 Dth contract demand associated with the rejected

(continued…)

197. Furthermore, since the 2008 rate case, Portland's inability to market its unsubscribed capacity has been exacerbated by Maritimes' Phase IV expansion. Because of changes to Portland's system as a result of the Phase IV expansion, Portland is only able to flow 168,000 Dth per day from end to end on its system. Apart from backhaul transactions, Portland has little realistic ability to sell the unsubscribed capacity on its Joint Facilities without adding compression on its system or arranging for TQM to add compression on its system in order to return the capacity of its Northern Facilities to 210,000 Mcf per day. Currently, the only method of accessing Portland's capacity on the Joint Facilities in excess of 168,000 Mcf per day would be through Maritimes, but shippers on Maritimes have little incentive to contract with Portland for capacity on Portland's share of the Joint Facilities because the postage stamp rates they pay Maritimes include service on the Joint Facilities and are lower than Portland's rates. [298]

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contracts in its billing determinants subject to a discount adjustment. The Commission also required Portland to reduce its rate base by the amount of the bankruptcy proceeds in the same manner as the Commission required in Opinion No. 510-A, 142 FERC ¶ 61,198 at PP 129-142. Indicated Shippers point out that, in requiring this rate base reduction, Opinion No. 510-A stated that "the existence of the at-risk condition does not justify including in rate base amounts which we would not otherwise include in rate base so as to increase the return included in rates. . . . To the extent that Portland's at-risk condition results in Portland under-recovering its costs, Portland accepted that risk when it accepted its certificate subject to the at-risk condition and we will not mitigate that risk by artificially inflating the return included in its rates." *Id*. P 135. This statement addressed the proper determination of the rate base to which Portland's ROE is applied. It did not address the determination of Portland's ROE. For the reasons discussed above, we find that the at-risk condition may reasonably be considered in determining Portland's relative risk to the proxy group for purposes of setting its ROE, and that such consideration does not "artificially" inflate its ROE, as failing to reduce its rate base by the amount of the bankruptcy proceeds would.

[298] The rehearing applicants contend that Portland could have insisted that the Maritimes Phase IV expansion be constructed in a manner that would not have reduced its capacity on the Northern Facilities. They contend that this could have been accomplished by placing both Westbrook compressor units on the Joint Facilities, rather than placing one of those units on Maritimes' upstream facilities. However, that would have made Portland responsible for a share of the operation and maintenance costs of both compressor units, instead of only one unit. Ex. PNG-100 at 9. As the Commission found on rehearing of the Declaratory Order, Portland reasonably chose not to incur additional costs to preserve capacity on the Northern Facilities for which there was then no firm market. Declaratory Order Rehearing, 125 FERC ¶ 61,198 at P 19.

198. The record in this case indicates that near-term prospects for Portland to market any increase in its existing 168,000 Mcf per day capacity on the Northern Facilities are limited. Even if Portland's rates were lowered to the level advocated by the PSG at the hearing in this case, the cost of transportation from Dawn Ontario to Boston over a transportation path including Portland[299] would be 25 percent higher than the next most expensive alternative not using Portland[300] and more than twice as expensive as the cheapest alternative.[301] While substantial new gas supplies are being developed in the Marcellus Shale in West Virginia, Pennsylvania, and Ohio, Portland is not well placed to take significant advantage of those new gas supplies in the near-term. In order for Marcellus Shale gas to be transported over Portland to the Boston area market, that gas would first have to be shipped north to TransCanada and then along TransCanada to Portland and then from Portland to Tennessee or Algonquin, as opposed to more direct and less expensive routes within the United States.[302] While the Utica Shale natural gas reserves extend into Quebec, those reserves are not currently being developed on a significant scale due in part to environmental concerns. [303] Accordingly the requirement that Portland design its rates on billing determinants that are nearly twenty percent higher than the amount it can transport increases Portland's business risk with respect to its ability to attract capital as compared with the proxy group members, whose pipelines generally are not subject to such at-risk conditions and in any event do not face the same difficulty in marketing unsubscribed capacity.

199. By considering Portland's at-risk condition as a factor in placing Portland at the top of the return range, the Commission has balanced customers' rights against cost shifting with investors' need for a rate of return commensurate with the underlying risk of the company. The rate of return approved in Opinion No. 524, placing Portland's ROE at

[299] That path includes TransCanada to Portland to Tennessee.

[300] TransCanada to Iroquois to Algonquin.

[301] TransCanada to Tennessee. Ex. PNG-38 at 15. Ex. PNG-100 at 26-28.

[302] Ex. PNG-38 at 32.

[303] Ex. PNG-100 ("The provincial government of Quebec recently put all shale gas exploration on hold until a full environmental study can be done. The government of Quebec announced its decision in response to the findings of an environmental review board which called for a full evaluation of potential risks involved in the drilling and extraction of natural gas from shale formations in Quebec along the Saint-Lawrence River.").

the top of the range of reasonable returns, is 11.59 percent,[304] while the approved rate of return for Portland's prior rate proceeding, placing Portland's ROE at the median, is 12.99 percent. Thus, the actual ROE approved in Opinion No. 524, is less than that approved in Opinion Nos. 510 and 510-A, and does protect shippers and benefit consumers overall. Thus, contrary to Indicated Shippers' claims, placing Portland's ROE at the top of the range did not reduce the economic protections afforded shippers by the imposition of the at-risk condition.

200. We also reject the argument that Portland's acceptance of the at-risk condition with its certificate was a voluntary business risk akin to the contracting and other business risks that we previously stated did not support Portland's claims of anomalously high risk. The at-risk condition is a regulatory requirement that was imposed on Portland as part of the regulatory policy in effect at the time the pipeline was built. That regulatory requirement is fundamentally different than contracting and other conditions imposed on Portland by the marketplace. While Portland did accept the at-risk condition when it accepted its certificate, as we noted in Opinion No. 524, that decision directly benefitted all Portland's customers because if Portland had not accepted the condition that pipeline would not have been built.

201. Indicated Shippers claim that the contract concessions Portland negotiated with its initial shippers, including Androscoggin and Rumford, were likewise prerequisite conditions to the pipeline being constructed. Indicated Shippers note that the certificate required Portland to "execute firm contracts equal to the capacity to which its customers have committed themselves in the four precedent agreements prior to commencing construction."[305] Indicated Shippers argue that based on Portland's statements that it would not have been able execute the referenced agreements without making the concessions, those voluntarily assumed business risks are the same as the at-risk condition because without the agreements that pipeline would not have been built.

202. Indicated Shippers' argument lacks merit. In order to determine whether the pipeline project was even viable, Portland had to evaluate whether there was a market for the capacity that Portland wanted to construct, and to demonstrate that market in its certificate filing by showing a commitment by shippers to sign up for firm capacity. The

[304] The determination to place Portland at the top of the range is buttressed by the fact that the 11.59 percent is the rate of return calculated for El Paso Partners, the only other proxy group member that had a below investment grade credit rating. Ex. S-67 at 12.

[305] Indicated Shippers' Rehearing Request at 21-22 n.60 (citing July 1997 Preliminary Determination Order, 80 FERC at 61,448).

market conditions at the time apparently allowed such prospective customers to negotiate certain concessions from Portland, which were memorialized in the precedent agreements that were filed as part of Portland's certificate application. To the extent that Portland had not been able to reach agreement for conditions under which prospective customers would commit to the pipeline, it is true the pipeline would not have been constructed because there would have been no market for the capacity. Thus, the precedent agreements were the necessary showing of market need, without which Portland would not have filed the certificate application. The concessions, to which Portland agreed, were wholly driven by market forces. The Commission preliminarily approved the rates and conditions in the precedent agreements, and the requirement to execute binding firm transportation agreements based on the precedent agreements held the shippers and the pipeline to their demonstration of market need.

203. Even by providing the contractual market benefits to the initial shippers including Androscoggin and Rumford, Portland still did not have commitments sufficient to fill the total amount of capacity that it proposed to construct. The regulatory policy at the time, however, allowed pipelines to pursue projects for which they had some market showing, requiring them to accept the financial risk of sizing the pipeline to account for projected future markets through the at-risk condition. Absent an initial showing of market interest, the at-risk condition would never have arisen because Portland would not have filed the application and the Commission would not have issued the certificate. Thus, there is a fundamental difference between the business risks that the pipeline had to accept from the market as a prerequisite to filing its application, and the regulatory certificate requirement imposed by Commission, which works to protect the customers against Portland's assumption of the business risks.

204. Further, as we noted in Opinion No. 524, Portland, unlike the proxy group members, accepted an at-risk condition applicable to its entire system. Indicated Shippers' claim this statement is inaccurate because "many companies owned by proxy group members must cope with at-risk responsibilities of their own."[306] A review of the purported at-risk conditions of those companies, however, supports the Commission's position that no proxy group member has an at-risk condition that affects the company's risk to the extent of Portland's.

205. First, Indicated Shippers claim that Spectra Corporation, a proxy group member, has a partial ownership interest in the operating company of Maritimes, a system they assert has the same at-risk condition with respect to the Joint Facilities as Portland. Indicated Shippers also remark that Spectra owns a portion of Gulfstream which also has an at-risk condition. Indicated Shippers are correct that Maritimes and Gulfstream were

[306] *Id.* at 25-26.

both initially at-risk for a portion of unsubscribed capacity on their systems. The circumstances of those pipelines' at-risk conditions, however, are not comparable to Portland's. With respect to Maritimes, as discussed at length above, Maritimes has since been able to expand its system and has more than doubled its mainline capacity, [307] while Portland has not. Moreover, the Phase IV expansion gave Maritimes a competitive edge over Portland because it resulted in a rate decrease on Maritimes' system. Accordingly, Maritimes' situation is not as risky as Portland's with regard to the unsubscribed portion of the Joint Facilities, and it is not unreasonable that an investor would view Maritimes as less risky.

206. As with Maritimes, Gulfstream also had a later expansion, for which the Commission found the threshold cost requirement had been met, thus essentially mooting the at-risk condition.[308] Thus, contrary to Indicated Shippers' claims, the circumstances of those pipelines are not similar to Portland's. As discussed at length above, Portland is still unable to secure firm commitments for its total design capacity.

207. Additionally, the impact of the at-risk condition on Portland is much more severe than that imposed on Spectra by Gulfstream's at-risk condition. Gulfstream is only a small percentage of Spectra's natural gas pipeline assets, which also included at the time period relevant to this proceeding, Texas Eastern, Algonquin, East Tennessee, Ozark Gas Transmission, L.L.C., and Maritimes. It is not reasonable to expect that an investor would regard the effect of Gulfstream's at-risk condition on Spectra's risk profile as equivalent to the risk to Portland from its at-risk condition applicable to its entire system. Moreover, Portland is the only proxy group company with both an at-risk condition and a below investment grade credit rating. As we emphasized in Opinion No. 524, it is the combination of the at-risk condition and the credit rating that makes Portland unusually risky and thus warranting placement at the top of the range of returns.

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[307] Phase IV Certificate Order, 118 FERC ¶ 61,137, at P 26 (Maritimes' proposal "satisfies the threshold requirement that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. …[R]eview of Maritimes' proposal demonstrates that projected revenues will exceed projected costs; thus there will be no subsidization by existing customers").

[308] *Gulfstream Natural Gas System, LLC*, 130 FERC ¶ 61,195, at P 12 (2010).

208. Indicated Shippers' attempts to analogize Portland's at risk condition to pipelines purportedly at risk for unsubscribed expansion capacity under the Commission's 1999 Certificate Policy are likewise non-compelling.[309] Indicated Shippers assert that the Commission placed Midcontinent Express Pipeline LLC (Midcontinent), which is "owned in part" by proxy group member Energy Transfer Partners, at risk for capacity the pipeline leased as part of an expansion project by preventing a cost shift to customers that did not use that capacity. Again, however, Midcontinent's situation is not similar to Portland's. Midcontinent represented a small percentage of Energy Transfer Partners' total natural gas assets, which included Transwestern Pipeline Company, LLC. Thus, the risk to Energy Transfer Partners due to Midcontinent's being at risk for leased capacity is simply not comparable to that faced by Portland due to its at-risk condition. The same reasoning applies to Indicated Shippers' arguments regarding Gulf South Pipeline Company, LP (Gulf South), a subsidiary pipeline owned by Boardwalk Pipeline Partners, who also owned Texas Gas Transmission, LLC, and Gulf Crossing Pipeline Company LLC. Accordingly, for the reasons discussed, we deny the request for rehearing and affirm our determination that Portland is above average risk when compared to the other proxy group members, and thus its ROE should be set at the top of the range of reasonable returns as determined in this proceeding.

b. <u>Portland's Credit Rating</u>

209. As noted above, a critical factor in the determination to place Portland at the top of the zone of reasonable returns for the period covered by this proceeding was the fact that in the time between this and Portland's previous rate case, S&P downgraded its corporate credit rating on Portland's $275 million senior secured notes from BBB- to BB+,[310] a rating considered below investment grade. We determined this downgrade constituted changed circumstances that warranted an upward adjustment to Portland's ROE. As noted above, Indicated Shippers and CAPP challenge the downgrade as a basis for placing Portland at the top of the range.

210. Credit ratings are an appropriate consideration in determining a pipeline's relative risk within the range of ROEs established by the proxy group.[311] The Commission has

[309] *See* Indicated Shippers' Rehearing Request at 26 n.78, referencing Midcontinent and Gulf South as pipelines that are at risk for unsubscribed capacity.

[310] Opinion No. 524, 142 FERC ¶ 61,197 at P 387.

[311] 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 II*, 90 FERC at 61,937; Opinion No. 414-A, 84 FERC at 61,427-4 – 61,427-5.

previously taken into account below investment grade credit ratings when determining a pipeline's return on equity, and has set a pipeline's ROE at the top of the range because of its below investment grade credit rating.[312]

211. CAPP challenges our reliance on the S&P credit report. It notes that that the credit rating is applicable only to a series of bonds issued by Portland in 2003, which are due to mature in 2018. It thus asserts that the credit rating only affects the risks of the bondholders themselves, rather than investors in Portland's equity. Moreover, CAPP asserts that the S&P credit rating described the risks to bondholders as declining over the remaining term of the bonds, as Portland pays off the bonds, and that the Commission failed to take this into account in setting Portland's rates for an indefinite future period.[313] CAPP also asserts that the S&P's below investment grade instrument rating of Portland's long-term debt is not comparable to the investment grade corporate credit ratings of the proxy members as issuers of debt. CAPP further states that, because the S&P credit rating of Portland is labeled "confidential," it is not relevant to an analysis of investor expectations generally.

212. CAPP also claims that the Commission erred in placing Portland at the top end of the range of returns because there is no showing or record evidence the Portland faces unusual financial risk as opposed to business risk. CAPP points out that Portland's capital structure is similar to the capital structures of the proxy members. CAPP further argues that the Commission failed to examine various factual considerations embodied in the S&P report which undercut reliance on that report to find Portland is more risky than the proxy members.

213. Indicated Shippers also challenge the Commission's reliance on Portland's downgrade, claiming that the report is outdated and includes predictions that turned out not to be accurate.[314] According to Indicated Shippers, the downgrade should not be afforded significant weight because it is based on the outcome of Portland's Docket No. RP08-306-000 rate proceeding, and the factors on which it was based have purportedly subsequently been proven inaccurate or irrelevant to Portland's ROE. Indicated Shippers claim that the downgrade was essentially based on enforcement of Portland's at-risk condition, and as such, should not serve as the basis for an upward adjustment. Indicated Shippers also claim that it was error to rely on the S&P report as indicative of Portland's

[312] *Transco I*, 60 FERC at 61,826, *reh'g denied*, 64 FERC at 61,348.

[313] CAPP Rehearing Request at 4-5.

[314] Indicated Shippers' Rehearing Request at 27-35.

risk because the Commission had rejected several of the factors the report cites as reasons for downgrading Portland's credit rating.[315]

214. They also argue that because the report downgraded Portland based on the rates it would be able to collect during the locked in-period in that case, it is an unreliable predictor of the risk Portland would face during the period the rates established in this proceeding go into effect (December 1, 2010). In particular, Indicated Shippers claim that the S&P report indicated that one factor for the downgrade was the concern that the rates would affect Portland's debt service coverage ratio to the extent that Portland would be precluded from making distributions to its investors. Indicated Shippers refer to Portland's 2011 and 2012 FERC Form 2 filings, made on March 30, 2012 and April 16, 2013 respectively, to illustrate that Portland was in fact able to make distributions those years. Indicated Shippers claim the downgrade report has proven consistently to be wrong, a fact that would be known to investors based on Portland's publicly available filings. Indicated Shippers also claim that it was error to rely on the S&P report as indicative of Portland's risk because the Commission, in rejecting Portland's proposed increase in its depreciation rate, had rejected several of the factors the report cites as reasons for downgrading Portland's credit rating.[316]

215. The Commission rejects these contentions, and continues to find that S&P's July 2010 downgrade of Portland's senior secured debt credit rating to below investment level is both timely and pertinent to the establishment of Portland's ROE for the period covered by this proceeding. First, we disagree with CAPP's suggestion that the fact the credit rating downgrade was labeled "confidential" and applied to Portland's senior secured debt undercuts its usefulness in determining how an investor would evaluate the risks of investing in Portland's equity. Investment advisory services typically limit the availability of their services to subscribers, and require their subscribers to treat the advice as confidential. However, major investment advisory services such as S&P have many subscribers, and thus their opinions are highly relevant to a determination of how investors evaluate the risks of any particular investment.

216. In addition, the fact S&P's credit rating downgrade applied to Portland's senior secured debt does not render it any less relevant to an investor's evaluation of the risks of an equity investment in Portland. As the credit report itself makes clear, Portland's senior secured debt includes covenants limiting its ability to make distributions to equity owners if its revenues fall below a debt service coverage ratio (DSCR) of 1.3 times its debt service payments (1.3x). More generally, given that senior secured debt is, by

[315] *Id.* at 30-32.

[316] *Id.*

definition, less risky than an unsecured equity investment, an investor can reasonably be expected to view the below investment grade rating of Portland's secured debt as an indication of high risk in an investment in Portland's equity.

217. The S&P credit report stated that the credit rating downgrade was "based on a low debt service coverage ratio, declining utilization, and two outstanding rate cases."[317] The S&P report was issued after the ALJ's December 2009 initial decision in Portland's 2008 rate case and Portland's May 2010 filing of the instant rate case, but before issuance of Opinion No. 510 or the initial decision in this rate case. The S&P report stated that the ALJ's decision in the 2008 rate case would reduce Portland's rates below 85 cents per Dth and this would reduce the DSCR below 1.3x. The report forecast that, as a result, the covenants in Portland's senior secured debt would prevent it from making distributions to its equity investors. S&P stated that, if Portland's ultimately approved rates are below the level Portland proposed in the 2008 rate case, S&P "expect[ed] financial performance to remain below our expectations for an investment-grade rating. In particular, we expect debt service coverage ratios between 1.0x and 1.1x if the rate is set at 85 cents per dekatherm, 1.3x-1.35x if 91 cents per dekatherm, and 1.8x-2.0x if $1.32 per dekatherm."[318]

218. Indicated Shippers contend that the S&P report should not be accorded significant weight in the ROE analysis in this rate case, because S&P's concerns about Portland's low debt service coverage ratio were based on the ALJ's decision in the 2008 rate case; as a result, Indicated Shippers argue, those concerns are not relevant to an investor's evaluation of Portland's risks after the rates in this rate case went into effect. It also asserts that the concern that Portland would be unable to make distributions to its equity investors did not come true, as shown by its Form 2 annual reports for 2011 and 2012, the first two years in which the rates proposed in this rate case were in effect.

219. We disagree with these contentions. The downgrade of Portland's credit rating, which occurred in July 2010 during the test period in this proceeding, is directly relevant to an analysis of investors' perceived risks of investing in Portland during the period the rates in this rate case are in effect.[319] While the credit report mentions the ALJ's initial

[317] Ex. PNG-113 at 1.

[318] *Id*. at 2.

[319] As we noted in Opinion No. 510, the effect of the downgrade is best addressed in the instant proceeding because the downgrade occurred during the test period for this case. Opinion No. 510, 134 FERC ¶ 61,129 at P 271. *See also* Opinion No. 510-A, 142 FERC ¶ 61,198 at PP 210-212.

decision in the 2008 rate case and the estimated effect of that decision on Portland's rates, the credit report also mentions Portland's filing of the instant rate case. The credit report then goes on to discuss the impact of various different outcomes of both pending rate cases. As described above, the credit report projects a debt coverage ratio of between 1.0x to 1.1x if an 85 cents per Dth rate is approved, but 1.8x to 2.0x if a $1.32 per Dth is approved. The rate we are approving in this rate case is about 85 cents per Dth, the very rate S&P stated would produce revenues below the 1.3x debt coverage ratio required by the secured debt covenants and thus prevent Portland from making distributions to equity investors. While we agree with the rehearing applicants that the mere pendency of a pipeline's rate cases before the Commission is not a factor justifying a finding of increased risk,[320] it is certainly appropriate to consider the risks entailed in the Commission's ultimate rulings on the issues in the rate case.

220. In arguing that the S&P report's projection that Portland's debt coverage ratio would be too low to permit it to make distributions turned out to be inaccurate, Indicated Shippers rely on Portland's Form 2 reports for 2011 and 2012. However, those reports were not filed until March 2012 and April 2013, well after the hearing in this rate case was completed in May 2011. As we have stated before, while the Commission's longstanding policy for calculating ROE is to use the most recent record data,[321] including post-test period data, we do not consider updated information concerning events occurring after the close of the record, because that would violate the other parties' due process rights.[322]

221. Whether or not certain of the factors on which the downgrade was based may have been shown to be inaccurate after the test period and the hearing did not impact investor's view of Portland at the time report was issued, and during the period relevant to setting Portland's rates in this case. In nearly every rate case the rates established therein will be

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[320] *See Southern California Edison Co.*, 133 FERC ¶ 61,269, at P 22 (2010).

[321] *Trunkline Gas Co.*, 90 FERC ¶ 61,017, at 61,117 (2000) (citing *Panhandle Eastern Pipe Line Co.*, 74 FERC ¶ 61,109, at 61,362-63 (1996) and *Boston Edison Co. v. FERC*, 885 F.2d 962, 966 (1st Cir. 1989)); *Williston Basin Interstate Pipeline Co.*, 72 FERC ¶ 61,074, at 61,373 and 61,375 (1995).

[322] *See Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at PP 379-86 (2002), *reh'g denied*, 102 FERC ¶ 61,310 (2003) (denying the pipeline's motion to reopen the record after the hearing had concluded to consider the effects of Enron's bankruptcy on pipeline capital costs). *See also Office of Consumers' Counsel v. FERC*, 783 F.2d 206, 232 (D.C. Cir. 1986) ("In relying on ex parte submissions appearing in a post-hearing brief, the Commission violated fundamental canons of due process.").

effective for a period in the future. That does not change the fact that the Commission's determination of those rates must be based on a definitive record with a deadline as to the facts that may be considered. In any event, as Indicated Shippers recognize in their rehearing request, the Form 2 filings relate to the period when Portland's proposed rates in this rate case were in effect subject to refund. Those rates approximated $1.32 per Dth, a rate which the S&P report indicated would result in a debt coverage ratio well above 1.3x, unlike the 85 cent per Dth rate we are approving here.

222. Indicated Shippers also argue that the S&P report is not a valid indicator of Portland's risk because Opinion No. 524 addressed and rejected several of the risk factors upon which the report relies. Indicated Shippers claim that in Opinion No. 524 the Commission rejected Portland's claims of heightened competition in the Northeast and the purported decline in WCSB supplies as sufficient evidence to support its proposed increased depreciation rate. Indicated Shippers state that these items are two of the risk factors cited in the S&P report in support of Portland's downgrade.[323] It is therefore inconsistent, Indicated Shippers conclude, for the Commission to rely on the S&P downgrade report as a reason for placing Portland at the top of the zone.

223. We reject this argument. In determining whether a pipeline's economic life will be truncated by lack of access to natural gas supplies, the Commission estimates the life of the potentially recoverable natural gas reserves accessible to shippers on the pipeline during the pipeline's physical life. The pipeline's business risks of competing with other pipelines for the transportation of those reserves are taken into account in establishing its ROE, not in determining the pipeline's economic life. In the depreciation section of Opinion No. 524 and affirmed above, we found that Portland's assertion that it would be unable to compete in the Boston market in the future was speculative and Portland's higher prices might still be competitive if shippers face constraints trying to ship Marcellus gas into the Boston area on other pipelines.[324] We also found that Portland's estimate of potentially recoverable WCSB natural gas reserves significantly underestimated reserves of shale gas and other unconventional gas.[325] Thus, in rejecting

[323] The S&P report stated that the risks reflected in the BB+ rating included the fact "competition from other interstate pipelines in the Northeast and in the Boston area is strong," "Portland has a higher cost structure than regional competitors, which weakens its ability to attract new shippers," and "capacity use may decline significantly through the term of the debt due to the reduced availability of natural gas from Canada." Ex. PNG-113 at 2.

[324] Opinion No. 524, 142 FERC ¶ 61,197 at P 147.

[325] *Id.* P 144.

Portland's depreciation proposal, we recognized Portland's business risks in competing to transport those reserves but found that Portland had not demonstrated that those risks are so great as to justify excluding those reserves from the determination of its economic life as required to support its depreciation rate increase.

224. These findings in Opinion No. 524 concerning Portland's depreciation proposal are therefore not inconsistent with our reliance on the S&P report to award an ROE at the top of the range of reasonable returns. In determining where in the range to set Portland's ROE, we must determine how an investor would evaluate Portland's risk versus the proxy group. For that purpose, all information available to investors, including a report by a national credit rating firm such as S&P, are highly relevant, regardless of whether such a report may contain inaccuracies.[326] In any event, Opinion No. 524's findings concerning Portland's economic life are not inconsistent with the statements in the S&P report concerning Portland's risks cited by Indicated Shippers. Opinion No. 524 expressly recognized that Portland's rates were higher than those of other pipelines serving the Boston area and Portland's ability to compete with those pipelines to transport Marcellus Shale gas was limited to certain scenarios in which those pipelines were constrained. Also, Opinion No. 524's findings concerning the life of WCSB natural gas reserves, including unconventional reserves, are not inconsistent with a finding of increased business risk to Portland in terms of its ability to compete for access to such supplies and uncertainties about whether such supplies might actually be produced.

225. CAPP points to various statements in the S&P credit report as indicating that Portland does not, in fact, face substantial risks. Therefore, it argues, the Commission erred in relying on that report to find that an investor would view Portland as more risky than the proxy group members. CAPP focuses on the S&P report's description of various "strengths" which S&P states offset such risks as competition from other interstate pipelines and Portland's higher cost structure. These strengths include (1) that "the pipeline's capacity is about 80% contracted on an annual basis, with reservation charges constituting about 95% of revenues," (2) "contracts for 89% of capacity extend beyond the bonds' maturity, with a weighted average remaining life of the contracts of 8.5 years and weighted average shipper rating of 'BBB,'" and (3) "credit metrics should improve over time as the bonds fully amortize over their term." The S&P report also stated that Portland's "satisfactory business profile reflects long-term contracts with investment grade shippers."

[326] As the Commission held in *Transco II*, 90 FERC at 61,932, "the cost of common equity to a regulated enterprise depends upon what the market expects not upon precisely what is going to happen."

226. In considering how the S&P report would affect investors' evaluation of Portland's risk versus the risks of the proxy groups members, we find that the S&P report must be considered as whole, rather than simply focusing on particular statements in the report. The bottom line of the report is that, if the Commission approves rates approximating those we are approving in this rate case, S&P "expect[s Portland's] financial performance to remain below our expectations for an investment-grade rating." S&P's projection that Portland's revenues from the rates we are approving here would be below those necessary to satisfy the 1.3x debt service coverage ratio required in the covenants on Portland's senior secured debt, thereby preventing Portland from making distributions to equity investors, would inevitably lead an investor to consider an investment in Portland to entail significant risk. S&P's expectation that existing long-term firm contracts extending beyond the bonds' maturity will produce sufficient revenues for Portland to pay off those bonds would not offset an equity investor's concern that revenues from those existing contracts may be unlikely to satisfy the 1.3x debt service coverage ratio. This is particularly true in light of the report's statement that strong competition from other interstate pipelines and Portland's higher cost structure weaken its ability to attract new shippers.

227. CAPP also states that the S&P report recognizes that Portland's credit metrics will improve over time as Portland pays off the bonds and that its current long-term firm contracts will not expire until after the bonds have matured. Similarly, the Indicated Shippers state that Portland has no plans to incur further major debt and its debt is scheduled to be retired in 2018, at which point Portland will have a 100 percent equity capital structure and little financial risk. However, as discussed above, our risk analysis for purposes of setting Portland's ROE in this rate case must be based upon the expectations of investors during the 2009 to 2010 test period in this rate case, as well as the period through the May 2011 close of the record in this rate case. At that time, the maturity of Portland's $275 million of senior secured debt was still approximately seven years into the future. The potential for reduced risk seven years in the future is unlikely to counterbalance the more immediate risks reflected in S&P downgrade of Portland's senior secured debt to below investment grade.

228. Further, despite Indicated Shippers and CAPP's claims to the contrary, there is little dispute that investors will consider a pipeline with a non-investment grade credit rating to be more risky on its face than an investment grade pipeline. As a result, it will be more difficult and costly for such a pipeline to attract and obtain capital. [327] As

[327] Indicated Shippers state that in *Old Dominion Electric Cooperative and New Dominion Energy Cooperative*, 119 FERC ¶ 61,253, at P 18 (2007), the Commission rejected a contention that a lower credit rating could reasonably be expected to increase the company's financing costs. However, that case is distinguishable from the instant

(continued…)

discussed in Opinion No. 524, this was the case with Portland as it related to the other companies in the proxy group. Portland was the only pipeline with only a non-investment grade rating, and thus, when compared to the six proxy group members, Portland's non-investment grade credit rating placed it below all of the other proxy group members with the possible exception of El Paso Partners whose ROE establishes the top of the range of reasonable returns in this case.[328]

229. Finally, CAPP contends that Portland has average financial risk, because equity makes up 52.84 percent of its capital structure, and this is comparable to the capital structures of the proxy group members. CAPP contends that the Commission must find that both Portland's business and financial risks are higher than the proxy group members' corresponding risks in order to place its ROE at the top of the range of reasonable returns.[329] Therefore, CAPP asserts that the Commission's failure to find that Portland has higher than average financial risk forecloses placing its ROE at the top of the zone of reasonable returns.

230. As CAPP states, the Commission considers how investors would view both a pipeline's business and financial risks in deciding where to place its ROE in the zone of reasonable returns. However, the Commission disagrees that it must find a pipeline to have both higher business and financial risk in order place a pipeline's ROE at the top of the range of reasonable returns. While lower than average financial risk may offset higher than average business risk, average financial risk does not necessarily offset higher than average business risk so as to require a finding that a pipeline is of average overall risk. In any event, the Commission finds that, despite Portland's 52.84 percent equity capital structure, S&P's downgrade of Portland's senior secured debt to below investment grade could reasonably lead investors to consider Portland to have above average financial risk as well as above average business risk. As discussed above, the S&P report stated an 85 cents per Dth rate similar to the rate we are approving in this rate case would reduce Portland's debt service coverage ratios to between 1.0x and 1.1x, which is below the 1.3x ration required by the covenants in Portland's senior secured debt for making distributions to its equity investors. Such a finding by a major credit

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case, because it involved a credit rating downgrade from A+ to A, not a downgrade to below investment grade, as here.

[328] As we noted in Opinion No. 524, El Paso Partners had a non-investment grade rating from S&P, though it also had investment grade ratings from the other two ratings agencies.

[329] CAPP cites *Transco I*, 60 FERC ¶ 61,246, as making both findings to support placing that pipeline's ROE at the top of the zone of reasonable returns.

rating firm such as S&P, leading to a below investment grade credit rating, would reasonably cause investors to view Portland's financial risk as above average, despite its 52.84 percent capital structure.

231. 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.[330] For the reasons discussed above, the Commission has reasonably concluded that when compared to the other proxy group members, a potential investor could reasonably reach the conclusion that Portland is the most risky of the comparable companies, thus warranting a higher rate of return.

III. <u>Compliance Filing</u>

232. Opinion No. 524 required Portland to file *pro forma* recalculated rates, reflecting each of the rate adjustments required by that order and to compare the revised rates to those required by Opinion No. 510-A.[331] The Commission also required Portland, if it sought rehearing, to provide recalculated rates identifying the rate impact of each item at issue, with supporting work papers in electronic format, including formulas. The Commission permitted parties to file comments on Portland's compliance filing.

233. On April 22, 2013, Portland made its compliance filing. In that filing Portland enumerated each of the adjustments it made to its cost-of-service and billing determinants consistent with Opinion No. 524's findings (Opinion No. 524 Compliance Filing). Portland submitted an electronic spreadsheet with formulas that contained these revisions. Further, as required by Opinion No. 524, Portland states that it used the levelization model as required by Opinion No. 510-A. Opinion No. 510-A referred to that model as Scenario No. 2.[332] Portland's workpapers show that, using the adjustments required by Opinion No. 524 and the Scenario No. 2 levelization model required by Opinion No. 510-A, Portland's *pro forma* recalculated firm monthly reservation charge is $26.4173 per Dth, and the 100 percent load factor charge is $0.8704 per Dth.[333] This

[330] *Transco I,* 60 FERC at 61,826.

[331] Opinion No. 524, 142 FERC ¶ 61,197 at P 396.

[332] The Commission accepted the rates that were derived from the Scenario 2 model in Portland's Opinion No. 510-A compliance filing for the locked-in period of September 1, 2008 to November 30, 2010. Unpublished delegated letter order dated May 30, 2013, *Portland Natural Gas Transmission System,* Docket Nos. RP13-806-000 and -001.

[333] Opinion No. 524 Compliance Filing, Appendix 1, Part 4.1.

compares to the rates currently in effect, subject to refund, of $40.2456 per Dth and $1.3231 per Dth, respectively.[334]

234. Indicated Shippers, the sole party to protest Portland's compliance filing, objected to only one item in that filing: the beginning balance for the Deferred Regulatory Asset account in the compliance levelization model as of the December 1, 2010 effective date of the rate in this rate case. In their comments the Indicated Shippers note that the Commission required Portland to use the Scenario No. 2 model approved in Opinion No. 510-A.[335] Indicated Shippers observe that the annual periods for Scenario No. 2 in the Opinion No. 510-A compliance filing are October 1 through September 30 for each year (except for the last period ending March 31, 2020, which is referred to as the stub year). However, Indicated Shippers continue, the rates in this rate case took effect December 1, 2010, and thus the first annual period for levelized rates in this proceeding is December 1, 2010 through November 30, 2011. Thus, Indicated Shippers observe, there is a two month difference between the Opinion No. 510-A Scenario No. 2 annual periods and the initial annual period in the instant proceeding. Indicated Shippers argue that the Opinion No. 524 compliance levelization model's December 1, 2010 Deferred Regulatory Asset account beginning balance should be equal to the ending Deferred Regulatory Asset account balance for November 30, 2010 from the Opinion No. 510-A compliance filing. However, the Indicated Shippers note, Portland's Opinion No. 524 Compliance Filing's levelization model used $104.808 million as the beginning Deferred Regulatory Asset account balance, and Portland does not explain the origin of this figure. Indicated Shippers claim that the beginning balance should be between the $98.130 million balance reflected for October 1, 2010 (i.e., Year 12) and the $95.974 million balance reflected for October 1, 2011 (i.e., Year 13) as reflected in the Scenario No. 2 model from the Opinion No. 510-A compliance filing.

A. Commission Decision

235. Indicated Shippers' protest is focused on what the prior year accumulated regulatory asset account balance should be for starting the levelized cost-of-service calculations for the Docket No. RP10-729-000 proceeding. Their protest has two parts. First, Indicted Shippers claim that Portland did not use the appropriate levelization model to derive the end of period Deferred Regulatory Asset balance that will become the

[334] *See* Opinion No. 524 Compliance Filing, Appendix 2, Part 4.1.

[335] In Opinion No. 510-A, the Commission found that Scenario 2 from its compliance filing in that proceeding best reflected the necessary compliance with Opinion No. 510, including a levelization model that ends on March 31, 2020. Opinion No. 510-A, 142 FERC ¶ 61,198 at P 252.

beginning Deferred Regulatory Asset balance for the Docket No. RP10-729-000 proceeding. Second, the Indicated Shippers claim that Portland failed to modify the beginning Deferred Regulatory Asset balance to reflect the two month difference between the annual periods used in Docket No. RP08-306-000 (October to September) and Docket No. RP10-729-000 (December to November).

236. As discussed below, the Commission finds that Portland's *pro forma* rates comport with Opinion No. 524's findings, with the exception of the beginning Deferred Regulatory Asset account balance that Portland used in its Opinion No. 524 Compliance filing levelization model. We therefore require Portland to make a new compliance filing, within 30 days of this order, consistent with the discussion below.

237. As we found in Opinion Nos. 510 and 510-A, Portland committed in its 2002 Settlement to design its rates using a levelized cost-of service. A levelized cost-of-service is "generally employed to reduce traditional cost-of-service rates in the early years of a project by deferring a portion of the annual cost-of-service to later years of the project's life when annual costs would generally be lower (due to the reduction of plant and rate base by depreciation accumulated in prior years)."[336] A levelized cost-of-service is meant to ensure constant transportation rates over the life of a project and lower initial rates than could be achieved under a conventional cost-of-service methodology. The rate stability and predictability inherent in this approach provide planning benefits to both the pipeline and potential shippers.

238. In the levelized cost-of-service method, the projected annual cost-of-service is not equal to the annual levelized cost-of-service that is recovered through rates. Levelized rates are generally derived by projecting the traditional cost-of-service for some number of annual periods into the future. Based upon this projection, the pipeline determines a single "levelized" cost-of-service that will be fully compensatory to investors throughout all of the annual periods projected for the "levelization period."[337] The differences between the projected actual annual cost-of-service and the annual levelized cost-of-service recovered through the rates are reflected in a regulatory asset account. For the early periods of a levelized cost-of-service, projected actual costs are in excess of costs recovered through rates. During these periods when projected actual costs are not recovered in the rates, the difference accumulates in the regulatory asset account. However, after a certain point, the projected actual annual cost-of-service will be below

[336] *Id.*

[337] Opinion No. 510, 134 FERC ¶ 61,129 at P 13.

the annual levelized cost-of-service. When this point occurs, the accumulated regulatory asset account balance will decrease with each subsequent period. Upon reaching the final period of the levelization model the regulatory asset account should have a balance of zero.[338]

239. Because levelization models span multiple years, the results for certain cost-of-service items of a prior year are carried over into the next year. In a traditional cost-of-service calculation, a comparable feature would be taking the previous year's accumulated depreciation as the starting point for calculating the next year's accumulated depreciation for the purpose of determining rate base. In a levelization model, the line item is the accumulated regulatory asset account.

240. In Portland's case, the Commission found that Portland was required to use an iterative method to derive its levelized rates,[339] and that the appropriate levelization period for Portland's 2008 rate case was 21 years ending March 31, 2020.[340] In Opinion No. 510-A, we required Portland to file revised rates reflecting an iterative levelization model that ends on March 31, 2020.[341] Portland filed its Opinion Nos. 510 and 510-A compliance filing in Docket No. RP13-806-000 (Opinion No. 510-A Compliance Filing).

1. Levelization Model

241. Portland's Opinion No. 524 Compliance Filing's proposed beginning accumulated Deferred Regulatory Asset for the December 2010-November 2011 annual period of the levelization model in this rate case is $104.808 million.[342] Portland, in its Opinion No. 524 Compliance Filing, does not state where this figure originated. However, the

[338] Levelization models are complex and require spread sheet software to perform the iterative calculations to achieve a final result. The ALJ in the Docket No. RP08-306-000 proceeding provided a technical description of the iterative levelization model applicable to this proceeding at 2008 Rate Filing ID, 129 FERC ¶ 63,027 at P 23.

[339] *See, e.g.*, Opinion No. 510, 134 FERC ¶ 61,129 at P 27.

[340] Opinion No. 510, 134 FERC ¶ 61,129 at P 47.

[341] Opinion No. 510-A, 142 FERC ¶ 61,198 at P 252.

[342] Portland's Compliance Filing, Appendix 3, page 4 of 19, Line No. 50.

Commission notes that this is the same beginning accumulated Deferred Regulatory Asset balance used by Portland in its Ex. PNG-24 filed on May 5, 2011.[343] Portland, in its initial rate filing in this proceeding, claimed that the levelization model it used was the same that was proposed by the PNGTS Shipper Group[344] and Trial Staff in Portland's preceding NGA section 4 rate case in Docket No. RP08-306-000.[345] Portland states that it modified that model for some items not at issue here, and the end result was a beginning Deferred Regulatory Asset of $104.808 million.[346]

242. Portland's Opinion No. 524 Compliance Filing's proposal to use $104.808 million for the beginning Deferred Regulatory Asset for the December 2010-November 2011 period is incorrect. Neither Trial Staff's Ex. S-16 nor Portland's Ex. PNG-20 used the Scenario No. 2 levelization model required by Opinion No. 510-A. The accumulated Deferred Regulatory Asset balances are not the same for Trial Staff's and Portland's models as compared to the Opinion No. 510-A compliance filing's Scenario 2 model.

243. The Commission, in Opinion No. 510, affirmed the Presiding Judge's selection of the appropriate levelization model for Portland. That model was sponsored by the PNGTS Shippers' Group.[347] Opinion No. 510-A reviewed variations of this model proffered by Portland, and Opinion No. 510-A conditionally selected the model referred to as Scenario No. 2 as the model that came closest to complying with the findings of Opinion Nos. 510 and 510-A.[348] On April 22, 2013 in Docket No. RP13-806-000,

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[343] Ex. PNG-24, page 2 of 2, Line No. 50.

[344] The PNGTS Shippers' Group in the Docket No. RP08-306-000 proceeding consisted of Bay State Gas Company, Northern Utilities, Inc., DTE Energy Trading, Inc., H.Q. Energy Services (U.S.) Inc., New Page Corporation, and Wausau Paper Mills, LLC.

[345] Ex. PNG-19 at 7:1-2; Ex. PNG-22 at 22:3-4.

[346] Ex. PNG-20, page 2 of 2, Deferred Regulatory Asset (BOP), Year 12. Portland did not remove Commission Trial Staff's Docket No. RP08-306-000 Ex. S-16 reference from Portland's exhibit. Examination of the two exhibits' Year 12 Deferred Regulatory Asset (BOP) line items show that Ex. PNG-20's calculations are not Trial Staff's calculations. As an example, Trial Staff's certified Ex. S-16 shows a beginning Deferred Regulatory Asset balance for Year 12 as $106.451 million, not $104.808 million as shown on Ex. PNG-20.

[347] Opinion No. 510, 134 FERC ¶ 61,129 at P 27.

[348] Opinion No. 510-A, 142 FERC ¶ 61,198 at P 252.

Portland filed its final version of the Scenario No. 2 model.[349] Portland's Opinion No. 510 compliance filing was not protested, and the rates that resulted from that model were accepted as in compliance with Opinion Nos. 510 and 510-A.[350]

244. Portland's Ex. PNG-24 was filed May 5, 2011, which was before the date Opinion No. 510-A was issued: March 21, 2013. The largest single difference between Portland's model shown on Ex. PNG-24 in Docket No. RP10-729-000 and the Scenario No. 2 levelization model the Commission accepted as in compliance with Opinion No. 510-A is the treatment of the bankruptcy proceeds. Opinion No. 510 did not accept Trial Staff's or Portland's proposals to not reflect the bankruptcy proceeds as a reduction to rate base. Opinion No. 510 found that Portland's receipt of the bankruptcy award should be accounted for: (1) in Portland's rate design volumes; and (2) a reduction to rate base.[351] Opinion No. 510-A found that Scenario No. 2 was consistent with Opinion No. 510's findings as to how to treat the bankruptcy proceeds.[352] Portland's Ex. PNG-20 reflects zero in the bankruptcy proceeds line item adjustment to rate base.[353] However, Portland's Opinion No. 510-A Compliance Filing, which was found to be in compliance with Opinion Nos. 510 and 510-A, does include a bankruptcy proceeds' downward adjustment to rate base for Year 11 of approximately $53.360 million.[354]

245. The Commission finds that Portland's Opinion No. 524 Compliance Filing's levelization model Year 12 beginning accumulated Deferred Regulatory Asset figure was derived from its initial position not to reflect the bankruptcy proceeds as an adjustment to

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[349] Portland's Order No. 510-A compliance filing's Scenario 2 model filed in Docket No. RP13-806-000, *PNGTS_RP08-306 Compliance Filing Workpapers.XLS* is located at http://elibrary/idmws/common/OpenNat.asp?fileID=13239953.

[350] Unpublished delegated letter order in *Portland Natural Gas Transmission System*, Docket Nos. RP13-806-000 and -001, dated May 30, 2013.

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

[352] Opinion No. 510-A, 142 FERC ¶ 61,198 at P 252.

[353] Ex. PNG-20, page 2 of 2, Average Bankruptcy Proceeds.

[354] Opinion No. 510-A Compliance Filing, Appendix 5, page 7 of 9, Line No. 33. The Commission cites Year 11's figure, as that figure is used to derive the end of the year accumulated regulatory asset balance that becomes Year 12's beginning of the year accumulated regulatory asset balance, as may be seen at Line Nos. 50 and 51 for Years 11 and 12. *Id.* at page 8 of 9.

rate base, and is thus incorrect. Portland should have used as the beginning Deferred Regulatory Asset balance for its Opinion No. 524 Compliance Filing the end of period Deferred Regulatory Asset balance from the Scenario No. 2 model that the Commission found in compliance with Opinion Nos. 510 and 510-A as the starting point for calculating the Opinion No. 524 Compliance filing. The end of period Deferred Regulatory Asset for Year 11 from the Opinion Nos. 510 and 510-A compliance filing is \$98.130 million.[355]

2. Intra Period Adjustment to the Beginning Deferred Regulatory Asset Balance

246. Indicated Shippers note that there is a two month difference between the annual periods used to calculate the levelization models in Docket Nos. RP08-306-000 and RP10-729-000. They note that the accumulated Deferred Regulatory Asset balance in the compliance Scenario No. 2's Year 12 declines from \$98.130 million at the start of the year to \$95.974 million at the end of the year. Indicated Shippers argue that the beginning Deferred Regulatory Asset balance for the Opinion No. 524 Compliance Filing should reflect the two month difference, and that figure should be between \$98.130 million to \$95.974 million. Indicated Shippers do not propose a specific beginning Deferred Regulatory Asset balance.

247. The Commission agrees with the Indicated Shippers. As explained above, the accumulated Deferred Regulatory Asset account keeps track of the differences between the projected annual cost-of-service and the levelized cost-of-service that is to be recovered through rates. Costs projected to be recovered through the rates of past periods (in this case, the costs to be recovered by the rates established in Docket No. RP08-306-000) should not be included in the costs to be recovered from future periods (in this case, the costs to be recovered through the rates to be established in Docket No. RP10-729-000). Portland is required to calculate an end of November 2010 Accumulated Deferred Balance for the purpose of establishing the beginning Deferred Regulatory Asset balance for calculating Docket No. RP10-729-000's levelized cost-of-service. Portland's method of calculating the November 2010 balance should be consistent with the Scenario No. 2 model.[356]

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[355] *Id.*

[356] Using the model Portland provided in its Opinion No. 524 Compliance Filing, the Commission estimates that the final compliance rate should be approximately \$0.8545 per Dth. To arrive at this rate, the Commission used the beginning and end of Year 12 Deferred Regulatory Asset balances from the Opinion No. 510-A Compliance Filing to adjust for the two month difference in the test periods. However, Portland's

(continued…)

B. Compliance Filing and Refund Report

248. Above we find that Portland used the wrong Deferred Regulatory Asset balance in its compliance filing, and that Portland must use the end of period balance as derived from the Scenario No. 2 levelization model found to be in compliance with Opinion Nos. 510 and 510-A, as adjusted to reflect the difference in the test periods. Accordingly, within 30 days of the issuance of this order, Portland must file revised tariff records and rates, including proposed accounting and workpapers, reflecting the Commission's rulings in this order. The tariff records are to be effective December 1, 2010. Portland is required to provide work papers in electronic spreadsheet format, including formulas and following the Scenario 2 model, supporting the recalculated rates. Within sixty days, Portland is required to provide refunds and provide a report to the Commission consistent with section 154.501 of the Commission's regulations.[357]

The Commission orders:

(A) The requests for rehearing of Opinion No. 524 are denied as discussed above.

(B) Within 30 days of the issuance of this order, Portland must file revised tariff records and rates, effective December 1, 2010, including proposed accounting and workpapers, reflecting the Commission's rulings in this order.

Opinion No. 510-A Compliance Filing's model has a circular reference with regard to AFUDC items (lines 46, 53-56) which prevents the calculation of the exact beginning accumulated Deferred Regulatory Asset balance for December 1, 2010. Portland, in its next compliance filing, is required to explain the derivation of the AFUDC related line items in the calculation of the December 1, 2010 Deferred Regulatory Asset balance.

[357] 18 C.F.R. § 154.501 (2014). Docket No. RP10-729-000 predates the change in the Commission's electronic tariff filing procedures. As a result, Portland created a new docket number in this proceeding when it motioned into effect its suspended tariff records, effective December 1, 2010: Docket No. RP11-1541-000. To prevent the proliferation of docket numbers, Portland is required to use Type of Filing Code (TOFC) 580 for its compliance tariff filing and TOFC 670 for its refund report, and both of these filings should be associated with Docket No. RP11-1541-000. The compliance tariff filing's Filing Title should include "Docket No. RP10-729 Compliance Filing,"

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

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.