ORDER NO. 11 176

ENTERED MAY 25 2011

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1520/UG 204

In the Matters of NORTHWEST NATURAL GAS COMPANY, dba NW Natural Applications for Deferred Accounting Order Regarding Purchase of Natural Gas Reserves (UM 1520) and Proposed Purchase of Natural Gas Reserves (UG 204)	ORDER

DISPOSITION: APPROVAL OF STIPULATION AFFIRMED

I. INTRODUCTION

This order completes our review of Northwest Natural Gas Company's, dba NW Natural (NW Natural or Company) proposed joint venture with Encana Oil & Gas (USA), Inc. (Encana) to develop natural gas reserves in Wyoming. We previously approved the venture in an expedited order to permit NW Natural to meet timing requirements imposed by the transaction. *See* Order No. 11-140. In that order, we found that NW Natural's development of the natural gas reserves, under the negotiated terms of the transaction and the associated ratemaking treatment agreed to by the parties in this docket, was prudent and reasonable.[1] We reserved for a later order our analysis supporting that decision.

We now provide that analysis. As explained below, we find that the proposed transaction is prudent and in ratepayers' interest because: (1) the average expected cost of natural gas falls at the low end of a reasonable range of forecasts of future gas prices and indicative prices for other long-term supply arrangements; (2) the cost of gas acquired through the transaction is expected to be stable and offers a hedge against sharp price increases in the future; (3) many of the risks associated with developing gas reserves have been mitigated; and (4) the remaining risks and rewards are fairly shared in the annual purchased gas adjustment (PGA) mechanism.

[1] On May 2, 2011, we issued Order No. 11-144, an errata order that amended Order No. 11-140.

II. PROCEDURAL HISTORY

On January 31, 2011 and on February 18, 2011, respectively, NW Natural filed applications docketed as UM 1520 and UG 204 relating to its proposed purchase of natural gas reserves and the ratemaking treatment to be associated with that purchase (Proposed Transaction). In docket UG 204, NW Natural requests that the Public Utility Commission of Oregon (Commission) find the Proposed Transaction to be prudent. In docket UM 1520, NW Natural requests that it be allowed to implement deferred accounting to track related expenses from the date of the Proposed Transaction through October 31, 2011, when the Company proposes to begin to recover its expenses through its PGA filings.

A prehearing conference was held in both matters on February 25, 2011. The following participated as parties in this proceeding: NW Natural, the Citizens' Utility Board of Oregon (CUB), the Northwest Industrial Gas Users (NWIGU), Cascade Natural Gas Corporation (Cascade), and the Staff of the Commission (Staff).

On February 25, 2011, NW Natural filed the testimony of witnesses Alex Miller, Barbara Cronise, Kevin McVay, and Randy Friedman, in support of the applications. On March 23, 2011, NW Natural filed supplemental testimony for one of its witnesses.

On March 30, 2011, the intervenors and Staff filed testimony. CUB filed testimony of Bob Jenks. NWIGU filed testimony of Paula Pyron and William Harper. Staff filed testimony of Moshrek Sobhy, Ken Zimmerman, Carla Bird, and Jorge Ordonez. Much of this testimony raised concerns about whether the Proposed Transaction was prudent and in ratepayers' interests.

By letter dated April 5, 2011, NW Natural reported that parties in these dockets had reached a settlement in principle of all issues. The parties subsequently filed a stipulation on April 19, 2011, signed by NW Natural, CUB, and NWIGU, and Staff.

On that date, the Parties also filed joint testimony in support of their stipulation, as well as individual testimony of CUB, NWIGU, and Staff.

We held two public workshops in these proceedings. On March 10, 2011, we met with representatives from NW Natural, intervenors, and Staff to learn more about the Proposed Transaction. On April 22, 2011, we held a second Commission workshop with all parties to address the merits of the stipulation.

III. NW NATURAL's APPLICATIONS

In these proceedings, NW Natural seeks authorization to enter into a joint venture with Encana, whereby NW Natural would partially fund the drilling of natural gas wells in the Jonah Field in Wyoming, owned by Encana. In return, NW Natural would earn a working interest in both future and currently producing wells. NW Natural plans that the gas acquired under the Proposed Transaction would partially replace hedged gas that currently makes up a portion of NW Natural's gas supply portfolio.

Under the Proposed Transaction, NW Natural will invest about $251 million over 5 years and expects to receive approximately 93 billion cubic feet (BCF) of gas over a 30-year term. NW Natural expects to receive about 26 percent of the gas in the first 5 years, 63 percent in the first 10 years, 83 percent in the first 15 years, and 94 percent by year 20. The remaining volume would be received until the wells are capped at the end of their useful life. NW Natural either can take its gas in kind, or it can have Encana sell the gas at market prices, allowing the Company to purchase replacement gas at market prices.

NW Natural proposes to finance its investment with a mix of debt and equity. The Company proposes to include the drilling costs in rate base, while the operational costs will be recovered as ordinary gas cost expenses.

IV. THE STIPULATION

Following initial rounds of testimony and settlement workshops, all active parties to this docket entered into a stipulation intended to resolve all issues. A copy of the stipulation is attached as Appendix A and incorporated by reference.[2] The stipulating parties, NW Natural, CUB, NWIGU, and Staff, (collectively Parties) ask the Commission to find that the Proposed Transaction is prudent and to approve the Parties' agreed-upon ratemaking treatment. Because Cascade did not file testimony, we consider the settlement to be among all parties. We briefly summarize the terms of the stipulation as follows:

A. Prudence

The Parties agree that it is likely that the Proposed Transaction will provide benefits to NW Natural's ratepayers, and that the Company's decision to enter into the Proposed Transaction is prudent. They propose, however, that such a finding be conditional, so that if new information arises that demonstrates that NW Natural knew, or should have known, something of consequence to the Proposed Transaction, parties can use that information to challenge the prudency of the Proposed Transaction in a future Commission proceeding. The Parties also clarify that the prudence finding applies only to NW Natural's decisions to enter into the Proposed Transaction, and not any subsequent decisions the Company might make in terms of exercising its discretion to manage the underlying contracts.

B. Ratemaking Treatment

The Parties agree that the costs of the Proposed Transaction should be recovered on an ongoing basis through NW Natural's annual PGA, including the deferral process for the commodity cost of gas. Each year the Company will re-forecast and update costs

[2] We attach this stipulation, identical to the one attached as Appendix A to Order No. 11-140, again here in the interest of completeness.

associated with the Proposed Transaction. These costs will be included in NW Natural's PGA filing. To calculate the cost of gas for inclusion in the WACOG (weighted average gas cost) for the PGA, NW Natural will divide the projected annual cost of service by the therms expected to be received under the Proposed Transaction.

As an interim matter, the initial rates to cover NW Natural's carrying costs will be calculated at the Company's authorized cost of capital, approved in docket UG 152.[3] Once the Commission authorizes a new cost of capital in NW Natural's next general rate case, the Company will calculate the difference between the earlier cost of capital and the newly authorized cost of capital, and refund (or surcharge) 100 percent of that difference to ratepayers through the PGA mechanism.

All variances from forecast amounts associated with the costs and volumes will be subject to the PGA sharing mechanism, up to the first $10 million of the variance in any annual period. All variance in excess of $10 million, whether positive or negative, will be passed through to ratepayers through the PGA at 100 percent. In addition, NW Natural's investment will be amortized over 30 years to match the expected volumes, with the opportunity for the Parties to revisit the schedule in five years and recommend adjustments.

The Parties agree that any savings (or additional costs) related to NW Natural's decision to either take or sell gas will be subject to the PGA sharing mechanism. Where the Company incurs additional costs because it purchases replacement gas at a higher price, the Stipulation provides for NW Natural to provide notice to the other parties and later explain the transaction.

Finally, the Parties agree that NW Natural will file a general rate case not later than December 31, 2011, and will provide various reports associated with the Proposed Transaction.

V. EVIDENCE IN SUPPORT OF THE STIPULATION

Evidence to support the Stipulation is found in NW Natural's applications and testimony, opening testimony filed by CUB, NWIGU, and Staff, as well as joint and individual testimony offered by the Parties in support of the Stipulation. This testimony included the parties' own internal investigations, as well as analyses performed by independent consultants retained to assist in evaluating the terms of the Proposed Transaction. These advisors included Netherland Sewell & Associates, Inc. (NSAI), ENVIRON International Corporation (ENVIRON), the accounting firm of KPMG, and independent legal counsel.

We summarize the evidence from all these sources, and focus on four key issues: (1) the reasonableness of cost; (2) price stability; (3) risk mitigation; and (4) the allocation of remaining risks.

[3] *See* Order No. 03-507.

A. The Reasonableness of the Cost of Gas

Under the Proposed Transaction, NW Natural estimates that it will pay an average price of approximately $5.15 per dekatherm.[4] To determine the reasonableness of this figure, NW Natural, CUB, and Staff each conducted research into future gas cost trends and forecasts. While recognizing the inherent uncertainty in any such exercise, each party determined that cost of gas from the Proposed Transaction is reasonable.

NW Natural estimates that the Proposed Transaction will produce savings of at least $52 million on a net-present-value basis over the life of the investment. NW Natural derived this figure by evaluating the terms of the Proposed Transaction against two different comparators. First, NW Natural obtained an indicative quote for a comparable 10-year hedge, and then tested that price quote by conferring with other natural gas producers. NW Natural found that the cost under this potential comparison greatly exceeded the costs of the Proposed Transaction. Second, NW Natural compared the Proposed Transaction with the terms of a recently announced transaction between Public Service Company of Colorado (PSCo) and Anadarko. NW Natural found the gas cost under the Proposed Transaction was also significantly lower than the gas cost in the PSCo/Anadarko transaction. Moreover, NW Natural adds that, using the same forward price forecast assumed by PSCo, the gas cost savings under the Proposed Transaction would be about $110 million.[5]

KPMG also reviewed alternative gas supply transactions to assess the reasonableness of Proposed Transaction. KMPG found that these indicative prices were all higher than the expected cost of gas under the Proposed Transaction.[6]

NW Natural emphasizes that the estimated $52 million in savings is a conservative figure, and that the figure is likely to increase because there is a high probability that the actual volumes will exceed the forecast volume. NW Natural explains that the greater volumes would reduce the average gas cost.

To examine whether the expected cost of gas is reasonable, CUB examined forecasts from the Northwest Power and Conservation Council (NPCC) and other forecasts used by other utilities in their respective integrated resource plans. CUB found that forecasts of gas costs vary significantly. Beginning with the NPCC's 20-year gas price forecast, CUB notes that the Medium Low forecast remains below the cost of the Proposed Transaction until 2018 to 2020, but the Medium Forecast – which approach $6.00 per dekatherm by 2017 – show a benefit to ratepayers. CUB also reports that the Medium High and High forecasts show a significant benefit to ratepayers.

[4] NW Natural had designated the average price of gas under the Proposed Transaction as confidential and subject to Protective Order No. 11-045. NW Natural has since declassified this $5.15 per dekatherm figure and authorized its use in this order.
[5] NWN/200, Cronise/23.
[6] Joint/102 (KPMG Report at 30).

CUB found the gas forecasts used by utilities in the IRP process were consistent with those of the NPCC. CUB explains:

> Under a low gas cost future, the proposed transaction provides little or no benefit. Under a high gas cost future, it provides a great deal of benefits. Under a medium gas cost future, there is likely some benefit depending on how fast gas prices increase.[7]

CUB concludes that the cost of gas from the Proposed Transaction is priced reasonably when compared to market forecasts from the NPCC and others. For that reason, CUB believes the costs associated with the investment are reasonable.

To assess the potential savings for ratepayers, Staff analyzed the risks and benefits of the Proposed Transaction on a net present value (NPV) basis in comparison to selected alternatives. Staff compared the NPV of the Proposed Transaction to the NPV of alternative thirty-year scenarios.

Staff presents seven alternative cases. These alternative gas acquisition cases included those using price forecasts from the Energy Information Administration and Wood Mackenzie, as well as scenarios using rolling hedge strategies. Staff found that the NPV of the Proposed Transaction falls in the middle of the range of alternatives. Staff concludes that the Proposed Transaction presents to the ratepayers the potential benefit of price savings.

B. Price Stability

NW Natural believes that it would benefit both the Company and its ratepayers to obtain a portion of gas supplies at stable prices. NW Natural states that the stable gas cost will reduce overall price volatility and supply risk. NW Natural explains that, in addition to the estimated savings for ratepayers, "the Proposed Transaction helps the Company lessen the competitive harms it would experience if gas prices spiked or rose and stayed high for an extended period."[8]

CUB also believes that the Proposed Transaction provides significant benefits by locking in a steady price and avoiding the volatility of the gas markets. CUB notes that:

> * * * gas cost excursions are hard to predict. Hurricane season in the Gulf of Mexico can affect gas prices, as can overall economic conditions and many other external factors. A single year where events caused gas prices to be above $7.50MMBtu (as they were in 2005 and 2009) could create a benefit of more than $3 million from the proposed transaction.[9]

[7] *Id.* at 52-53.
[8] NWN/100, Miller/5.
[9] CUB/100, Jenks/53.

CUB adds that ratepayers currently bear risk that gas prices would increase significantly in any given year, and that there are many reasons, including issues surrounding "fracking"[10] with gas exploration, that could push gas prices higher than current forecasts. Thus, CUB concludes that the stability offered by the Proposed Transaction provides additional ratepayer benefits.

Staff also found that the Proposed Transaction presents to ratepayers the potential benefits of price stability and price savings. Staff concludes that, "[f]rom a price stability standpoint, the Transaction's objective to mitigate the effect of [the] price fluctuation is reasonable."[11]

C. Risk Mitigation

The Parties acknowledge that the Proposed Transaction involves certain risks associated with the development of the gas reserves. The Parties conclude, however, that the risks borne by NW Natural and its ratepayers have been reasonably mitigated or limited.

NW Natural identifies three primary risks: (1) price risk; (2) reserve risk; and (3) operating cost risk.[12] Regarding price risk, NW Natural notes that it is possible that the cost of gas received under the transaction will be more than the market price of gas over time. NW Natural explains, however, that such risk arises under any hedging strategy and is not unique to the Proposed Transaction. Regarding reserve risk, NW Natural acknowledges that its ratepayers bear the risk that reserves will be less than estimated. Based on its due diligence, the Company believes this risk is extremely small.[13] With respect to operating costs, NW Natural is responsible for its proportionate share of the operating costs. While the Company has confidence in its estimates of the costs, it does note that certain costs could be higher than expected.

CUB, NWIGU, and Staff identify numerous risks associated with the Proposed Transaction. To evaluate these risks, these parties performed their own analysis and evaluated NW Natural's due diligence. They also relied on the work conducted by KPMG, NSIA, ENVIRON, and independent legal experts.

KPMG evaluated the Proposed Transaction's economics to assess the value versus risk. KMPG found that the transaction provides the Company with a reliable long-term supply of gas at a reasonable price, and that NW Natural had negotiated several unique provisions to mitigate key risks and protect the Company and its ratepayers. These include NW Natural receiving a working interest in existing production, receipt of actual land title, a cancellation clause, and others.[14] KPMG also concluded that NW Natural's due diligence was comprehensive, and was not able to identify any risks that had not

[10] Hydraulic fracturing, commonly referred to as "fracking," is used to stimulate the production of natural gas from reservoirs with low permeability, such as shale rock reservoirs.
[11] Staff/100, Sobhy-Zimmerman/14.
[12] NWN/200, Cronise/13.
[13] *Id.* at 14.
[14] Joint/102 (KPMG Report at 4).

already been accounted for by NW Natural.[15] Although the Parties do not agree with all assumptions used by KPMG in its analysis, they "largely" agree with KPMG's conclusions.[16]

NSAI investigated and prepared a report as to the existing reserves in the producing region, examined the history of the field, and performed a petrophysical analysis of selected wells. NSAI estimated with a high degree of certainty that NW Natural would acquire net reserves of approximately 93.1 BCF under the Proposed Transaction, and that there is a 90 percent probability that the actual volumes will equal or exceed that amount.[17]

ENVIRON studied the environmental risks associated with the Proposed Transaction. ENVIRON's review consisted of two parts: (1) an environmental site assessment; and (2) a limited review of regulatory compliance and other environmental matters. ENVIRON found no present or historic recognized environmental conditions in connection with Encana's operations in the field, and found no material regulatory compliance violations.[18]

Independent legal counsel reviewed transactional documents and other matters. Their work included an assessment of the environmental issues that might interrupt production, and a review of the transaction to ensure that NW Natural's property interest would not be impacted negatively by an Encana bankruptcy. Counsel also concluded that NW Natural will have good title to the oil and gas leases subject to the transaction.[19]

NWIGU also hired an expert to examine the risk of royalty interest and overriding royalty interest litigation and severance and ad valorem tax variances. This witness identified risks and determined which had been limited or mitigated.[20]

CUB, NWIGU, and Staff believe that potential risks have been extensively examined and are satisfied with NW Natural's efforts to limit and mitigate risks through its due diligence efforts and the negotiated provisions that protect the Company and its ratepayers. Although these parties still have concerns about certain risks, they are relatively comfortable with the Proposed Transaction.

D. Allocation of Risks

Earlier in the proceedings, CUB, NWIGU, and Staff raised concerns about NW Natural's proposed ratemaking treatment to allocate the risks and benefits of the Proposed Transaction. Although there were some differences among these parties, all were

[15] Joint/100, Zimmerman-Miller-Jenks-Pyron/12-13.
[16] *Id.* at 13.
[17] *Id.* at 8.
[18] *Id.* at 10.
[19] *Id.* at 11.
[20] NWIGU/200.

primarily concerned with NW Natural's proposal to recover its costs of the Transaction through the PGA, but not to share the result of any variances from forecasted costs.

Through settlement discussions, CUB, NWIGU, and Staff were able to reach a compromise with NW Natural on this and other issues. As noted above, all costs of the Proposed Transaction will be tracked through the PGA mechanism. Variances from forecast amounts associated with the costs and volumes are subject to the PGA sharing mechanism, up to the first $10 million of the variance in any annual period. Any variance exceeding that amount, whether positive or negative, will be passed through to ratepayers through the PGA mechanism at 100 percent.

The Parties contend that the cost sharing provisions and other terms of the stipulation properly allocates risks between the Company and its ratepayers. While it wasn't possible to mitigate every risk associated with the Proposed Transaction, NWIGU believes that the Parties have fairly balanced the risks through the Stipulation, and it is prudent for NW Natural to enter into the Proposed Transaction.

VI. RESOLUTION

We find that the Proposed Transaction is prudent and in ratepayers' interest because: (1) the average expected cost of natural gas of $5.15 per dekatherm falls at the low end of a reasonable range of forecasts of future gas prices and indicative prices for other long-term supply arrangements; (2) the cost of gas acquired through the transaction is expected to be stable and offers a hedge against sharp price increases in the future; (3) many of the risks associated with developing gas reserves have been mitigated; and (4) the remaining risks and rewards are fairly shared in the annual PGA mechanism.

A. Expected Cost of Gas is Low Compared to Forecasts and Indicative Prices

Natural gas price forecasts from recent integrated resource plans and NPCC show an upward price trend over the next 20 years. The Proposed Transaction's $5.15 average per dekatherm cost of gas is at the low end of the range of these price forecasts.[21] NW Natural and KPMG also obtained indicative prices for 10- and 20-year fixed-price supply arrangements, all of which were higher than the expected cost of gas under the Proposed Transaction.[22] The long-run cost savings from entering into the Proposed Transaction are significant. As discussed above, using the indicative price for a 10-year fixed-price transaction, NW Natural conservatively estimates the cost savings from the Proposed Transaction to be $52 million in present value dollars.[23]

[21] We note that the NPCC forecasts discussed at CUB/100, Jenks/52 and most of the forecasts in CUB/102 are presented in real terms, *e.g.*, 2006 dollars per MMBtu. Increasing the forecast prices in future years to account for projected inflation would strengthen CUB's conclusion that the flat nominal expected cost of gas under the Proposed Transaction is at the low end of the gas price forecasts.
[22] NW Natural/200, Cronise/21; Joint/102 (KPMG Report at 30).
[23] NW Natural's comparison of the cost of the Proposed Transaction to indicative quotes for other supply alternatives was informative in this case. However, in future cases where long-term transactions are being considered we expect utilities to go beyond transaction level analysis and to provide analysis of entire resource portfolios; including a portfolio that contains the proposed transaction. The resource portfolios

We recognize that near-term gas prices are lower than the expected cost per dekatherm of the Proposed Transaction. However, gas prices are likely to be significantly higher in the future than under the proposal here, enough so that, even discounting those future savings, there is a net benefit for ratepayers. The estimated savings appear to be robust and we conclude that ratepayers are likely to benefit from the transaction's low long-term cost of gas.

B. Stable, Low Cost Gas is a Good Hedge against Future Price Spikes

The per dekatherm cost of gas is also expected to be stable over the 30-year life of the transaction. The stability in the cost of gas is largely due to NW Natural's overall investment being capped at $251 million and the 30-year amortization schedule being matched to expected volumes. Any remaining variation in the cost of gas will likely be confined to changes in operating and midstream costs and variation in production volumes. Indeed, it is likely that the actual per dekatherm cost will be slightly lower than $5.15, as that estimate is based on a conservative estimate of the production volume available to NW Natural from the Jonah Field.

The volume of gas supplied over the first 10 to 15 years of the Proposed Transaction is expected to make a significant contribution towards meeting NW Natural's annual requirements. The Proposed Transaction will, on-average over the next 10 years, provide 10 percent of NW Natural's annual gas supply.

The combination of these two factors – stable, low cost gas and significant volumes of gas – makes the transaction a good hedge against price spikes in the wholesale natural gas market. We agree with the Parties that this transaction will partially protect ratepayers against price excursions in the natural gas market caused by such things as hurricanes in the Gulf of Mexico or uncertainty regarding future regulation of fracking.

C. Risks of Developing Gas Reserves are Mitigated

The Proposed Transaction contains a number of provisions that mitigate or limit the risks of developing natural gas reserves for NW Natural and its ratepayers.[24] Risks that are mitigated or limited in the transactions include: financial or legal liability related to the environmental impacts of drilling; lower working interest due to poor drilling outcomes; inflation in capital cost associated with well drilling; loss of working interest due to Encana bankruptcy; and elimination of all of the tax benefits contemplated in the

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should be designed to explore the cost and risk tradeoff that exists when selecting between portfolios with different levels of hedging. Each of the portfolios should be analyzed under a wide range of future scenarios. Portfolio analysis is a foundation of Integrated Resource Planning and provides the basis for selecting a portfolio of resources that provides the best combination of cost and risk for customers.

[24] *See* Joint/102 (KPMG Report at 16).

transaction. These risks are significant; the measures that limit their consequences provide key protections for NW Natural's ratepayers.[25]

D. Remaining Risks and Benefits are Shared Fairly

The costs of the Proposed Transaction will be tracked and recovered on an annual basis through NW Natural's PGA mechanism. The symmetric sharing of the transaction's remaining risks was an important consideration in our prudence determination. If NW Natural's ratepayers are to bear the risk of increased operating and midstream costs, then it is important that they also share in the cost savings associated with higher than expected production or associated with Encana marketing NW Natural's share of the gas. This ratemaking treatment is particularly important due to the fact that there is a 90 percent chance that actual volumes of the Proposed Transaction will equal or exceed the estimates used to evaluate the transaction.[26] Furthermore, because NW Natural will share in any variance in the net cost of gas under the Proposed Transaction, it will have an incentive to minimize those net costs where it can.

VII. CONCLUSION

For the four reasons stated above we find that the Proposed Transaction is prudent and in the interest of NW Natural's ratepayers.

VIII. ORDER

IT IS ORDERED that Order No. 11-140, as corrected by Order No. 11-144, is affirmed. For the reasons set forth in those decisions and this supplemental order, the Public Utility Commission of Oregon concludes that:

1. The approval of the stipulation among Northwest Natural Gas Company, dba NW Natural, the Citizens' Utility Board of Oregon, the Northwest Industrial Gas Users, and the Staff of the Public Utility Commission of Oregon is affirmed.

2. The finding that the Proposed Transaction between Northwest Natural Gas Company, dba NW Natural, and Encana Oil & Gas (USA) Inc., is prudent as described in the stipulation attached as Appendix A, is affirmed.

3. The approval of the application of Northwest Natural Gas Company, dba NW Natural, for deferred accounting regarding the purchase of natural gas reserves is affirmed.

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[25] Most of the risk mitigation measures relate to specific provisions in the contract that are protected from disclosure under the terms of the protective order in this case. For that reason, we cannot publicly discuss these measures, but clarify that they were closely reviewed by parties and the Commission, and we find the risk protection measures to be prudent.
[26] NW Natural/200, Cronise/15.

4. The authorization to Northwest Natural Gas Company, dba NW Natural, to develop amortization rates assuming the entire investment, net of any cumulative amortization, and the entire remaining volume delivery forecast, is affirmed.

Made, entered, and effective MAY 25 2011.

John Savage	**Susan K. Ackerman**
Commissioner	Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1520, UG 204

In the Matters of NORTHWEST NATURAL GAS COMPANY, dba NW Natural, Application for Deferred Accounting Order Regarding Purchase of Gas Reserves (UM 1520), and Application for Proposed Purchase of Natural Gas Reserves (UG 204).	**STIPULATION**

This Stipulation resolves all known issues among the parties to this Stipulation related to Northwest Natural Gas Company's ("NW Natural" or "Company") request in these dockets for approval by the Public Utility Commission of Oregon ("Commission") of its acquisition of natural gas reserves.

I. PARTIES

1. The parties to this Stipulation are Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Northwest Industrial Gas Users ("NWIGU"), and NW Natural (together, the "Parties").

II. BACKGROUND

2. For several years, NW Natural has been investigating opportunities to obtain a long-term fixed-price gas supply for approximately 10 percent of its portfolio. The Company believes that such an arrangement would provide substantial benefits to its customers. The Company has now entered into an agreement intended to provide long-term price stability through a joint venture with Encana Oil & Gas (USA) Inc ("Encana") to

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develop gas reserves (the "Proposed Transaction"). In these consolidated dockets, NW Natural requests Commission approval for the Proposed Transaction.

A. Terms of the Proposed Transaction

3. The Proposed Transaction calls for NW Natural and Encana to enter into a joint venture to develop gas reserves for service to NW Natural's customers. Encana will contribute its interest in certain natural gas leases and wells in the Jonah Field, which is located in the Green River Basin in Sublette County, Wyoming. NW Natural will participate with Encana by paying to Encana a portion of the costs of drilling a specified number of new wells referred to in the agreements as "Carry Wells." For each Carry Well drilled, the Company will receive either a working interest in a section of the field (including existing wells and the Carry Wells) or a working interest in the reserves in the field plus a certain percentage of the output of the drilled well, depending upon the section in which the well is drilled. The details of the Proposed Transaction are described in paragraphs 4 through 6 below.

4. Over five years, NW Natural will invest approximately $251 million in the Proposed Transaction through its commitment to pay a portion of the costs of drilling its Carry Wells. In addition to this initial capital investment, over the life of the agreement the Company will pay a portion of the costs to operate and maintain its wells, and to gather and process the gas from those wells. NW Natural expects to receive 63 percent of the total gas from the Proposed Transaction in the first 10 years, 83 percent in the first 15 years, and 94 percent by the end of year 20. The remaining volumes would be received until the wells are finally capped at the end of their useful life—estimated to be approximately 30 years from the date NW Natural and Encana enter into the agreement as described in Paragraph 2 above. These gas volume amounts are expected to represent

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approximately 10 percent of NW Natural's total annual gas requirements during the first ten years of the agreement, and will taper off over the remaining expected life of the wells.

5. The ownership interest earned by NW Natural in the Jonah Field gas reserves differs depending on where in the Jonah Field the wells are drilled. For each well drilled by NW Natural in the part of the Jonah Field referred to as the Updip Area, NW Natural will earn a percentage interest in the oil and gas lease and all of the wells (and all of the gas produced) in one of three sections in that area, up to a specified maximum interest in each section. For each well drilled by NW Natural in the part of the Jonah Field referred to as the Downdip Area, NW Natural will earn a percentage interest in the individual wellbore, (and the gas produced by that well) in addition to the specified interest in the leases, wells and gas produced in one of the sections in the Updip Area as described above. Under the terms of the agreement, Encana will act as the operator of the wells, subject to the terms of the Joint Operating Agreement (NWN/502). Under the Joint Operating Agreement, NW Natural can elect to take its share of production in kind, to sell the production, or to transport it to NW Natural's distribution system. Alternatively, NW Natural may elect to have Encana sell NW Natural's share of production at market prices, and to receive the proceeds of such sale, minus the appropriate royalty and other costs specified in the Proposed Transaction. Then NW Natural could use the proceeds to purchase quantities of gas (or offset portions of the cost of gas) at Opal or from other locations. Initially, NW Natural has elected to have Encana sell NW Natural's share of production.

6. The Proposed Transaction is specifically conditioned upon NW Natural receiving Commission approval, including a finding of prudence.

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B. Dockets UM 1520 and UG 204.

7. Docket UM 1520 was opened on January 31, 2011, when NW Natural filed an Application for Deferred Accounting that sought the deferral of expenses related to the Proposed Transaction from the date of its closing (following Commission approval) through the date that the costs are included in rates through the Company's Purchased Gas Adjustment Mechanism ("PGA") on October 31, 2011.

8. Thereafter, on February 18, 2011, the Company filed Advice No. OPUC 11-2, along with its direct testimony, opening Docket UG 204. This filing requests a Commission order finding the Proposed Transaction is prudent and requests approval of revisions to Schedule P of NW Natural's tariff (see Exhibit A) including provisions that will allow NW Natural to assign to its Oregon customers the benefits and costs associated with the Proposed Transaction.

9. On February 22, 2011, Administrative Law Judge ("ALJ") Patrick Power consolidated these two dockets. On February 25, 2011, ALJ Power granted NWIGU's petition to intervene and took notice of CUB's February 3, 2011, notice of intervention.[1]

10. On March 11, 2011, the Commission held a workshop where the Company presented the Proposed Transaction's details and its analysis outlining its proposed ratemaking treatment and estimated customer benefits. At that workshop, presentations were also made by Encana, and certain consultants that had reviewed the Proposed Transaction for NW Natural and the Parties. Also at that workshop the intervening parties and Staff made comments and explained portions of their positions relative to the Proposed Transaction.

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[1] Cascade Natural Gas Corporation also intervened in this docket, although it has not been an active participant and is not a party to this Stipulation.

11. At the time that the Company filed its direct testimony, the final transactional documents had not yet been fully executed. Therefore, on March 23, 2011, the Company filed supplemental direct testimony that included final and fully executed copies of all of the primary transactional documents, including the Carry & Earning Agreement (NWN/501) and the Joint Operating Agreement (NWN/502).

12. Pursuant to the procedural schedule, Staff, CUB, and NWIGU filed testimony on March 30, 2011.

13. A settlement conference was held on March 31, 2011, and was followed up with conference calls on April 1 and April 4. All the Parties participated in the conference and the subsequent calls.

14. The timeline for Commission review of the Proposed Transaction is very short – this is an expedited docket. Nonetheless, the Parties did, in short order, conduct an analysis of the terms of the Proposed Transaction and its attendant risks and benefits. Staff and the intervening parties served, and the Company provided responses to (both up to the date of the filing of testimony and thereafter), more than 150 data requests seeking detailed information about the Proposed Transaction. The Company also made available to Staff and the intervening parties and the Commission drafts and final copies of all transactional documents (final documents being made available just before testimony was due and filed), and reports prepared by Netherland and Sewell (regarding volumes of gas reserves in the Jonah Field), draft reports by KPMG (regarding the pricing assumptions and benefits of the Proposed Transaction – final report received after testimony was filed), and Environ (regarding environmental review of Encana's operations at the Jonah Field) as part of the Company's evidence of its due diligence.

15. In addition, the Company agreed to fund the retention of an independent legal counsel to act as special legal counsel to CUB and NWIGU for the purpose of reviewing

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the transactional documents under Wyoming oil and gas law and to independently advise CUB and NWIGU.

III. AGREEMENT

16. The Parties agree that it is likely that the Proposed Transaction, over its life, will provide benefits to NW Natural's customers and that therefore, subject to the terms and conditions set forth in this Stipulation and exhibits hereto, including but not limited to the accompanying supporting testimony, the Company's decision to enter into the Proposed Transaction is prudent. Moreover, the Parties agree that given the unique nature of the Proposed Transaction, the Commission should make a finding of prudence at this time based upon the information the Parties have reviewed. However, the Parties recognize that the review in this case has been expedited and that, if in the future, new information, not made available to Staff and the intervening parties, arises which demonstrates that NW Natural knew, or should have known, something of consequence to the Proposed Transaction at the time of the Proposed Transaction, Staff and the intervening parties can then use that information to challenge the prudence of the Transaction. On this point, the Parties agree that a prudence finding by the Commission at this time should apply only to the Company's decision to enter into the Proposed Transaction, and not to any subsequent decisions the Company might make in terms of exercising its discretion to manage the contract. The Parties specifically agree that a prudence finding by the Commission at this time should not, for example, extend to a future decision by the Company to participate in drilling Elective Wells, as that term is defined in the Carry and Earning Agreement (NWN/501). If the Company does choose to participate in drilling Elective Wells, the Parties agree that such decisions would be subject to separate determinations of prudence in future proceedings. Other decisions in addition to that of the drilling of Elective Wells may also require separate prudence findings.

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17. For ratemaking purposes, the Parties agree that the costs of the Proposed Transaction should be recovered on an ongoing basis only through the Company's annual Purchased Gas Adjustment ("PGA"), including the deferral process for the commodity cost of gas. Each year the Company will re-forecast and will update costs associated with the Proposed Transaction, including depletion rate, volumes, operating costs (including midstream costs and ad valorem and severance taxes), and return (carrying costs). These costs will be included in the Company's PGA filing. To calculate the Proposed Transaction's cost of gas for inclusion in the WACOG for the PGA, the Company will divide the projected annual cost of service by the therms expected to be received under the Proposed Transaction. The cost of service will consist of five components: (1) depletion, (2) operating expenses, (3) midstream costs, (4) severance and ad valorem taxes, and (5) return on the investment (carrying costs). The Parties agree that the operating expense and midstream costs are subject to ongoing prudence reviews in the annual PGA filing as provided in Paragraph 16. For purposes of PGA rate calculations and cost of gas deferrals, items 1 through 5 above will be computed and included as part of the Company's commodity costs. Exhibit B attached hereto provides an example of the development of the rate components for gas related to the transaction. For purposes of recording expenses on its books, and for the earnings test, only items 1 through 4 above will be, and the carrying costs will not be, included as part of the Company's cost of gas. For purposes of any general rate proceeding, NW Natural agrees to remove the amounts associated with carrying costs and rate base, including accumulated depletion and deferred (and accumulated deferred) taxes from its books to avoid the potential for double recovery related to the continual ratemaking for the Proposed Transaction. Also, each year at the same time as the earnings test is filed, the Company will provide a separate

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reporting of the earnings test year with the transaction results removed as they would be for a rate case. Exhibit C attached hereto illustrates this proposed ratemaking treatment.

18. **Cost of Capital:** To address the dispute that has arisen with respect to the appropriate return on the investment included in rates through the PGA, the Parties have agreed to a retrospective adjustment of the cost of capital portion of rates, i.e. the portion of the rates designed to recover the Company's return on equity ("ROE") and cost of debt. As an interim matter, the initial rates to recover the Company's carrying costs in the Proposed Transaction will be calculated at the Company's authorized cost of capital, as determined by the Commission in Docket UG 152. However, the Parties agree that once the Commission authorizes a new cost of capital in the Company's next general rate case, the Company will calculate the difference between the current cost of capital as it relates to the Proposed Transaction as authorized by the Commission in docket UG 152 and the newly authorized cost of capital. The Company will then refund to (or surcharge) customers 100 percent of that difference through the PGA mechanism. This adjustment will occur whether the newly authorized cost of capital is higher or lower than the UG 152 cost of capital. This adjustment is a onetime event and thereafter the return on this investment will be calculated at the new Commission-authorized cost of capital that applies generally to the Company. The applicable cost of capital would be adjusted each time the Commission authorizes a new cost of capital in the context of a general rate proceeding.

19. **Incremental Cost of Capital:** The Parties also agree that in future rate cases, no Party will use the Proposed Transaction to argue for a higher or lower cost of capital. This provision prohibits parties from seeking incremental adjustments (higher or lower) to their cost of capital calculated using traditional or prevailing methods based on the effects of the Proposed Transaction.

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20. Cost Sharing: The Parties agree that variances from forecast amounts associated with the costs and volumes related to the Proposed Transaction will be subject to the PGA's normal sharing mechanism, up to the first $10 million of the variance in any annual period, whether that variance is positive or negative. All variance in excess of $10 million (whether positive or negative) will be passed through to customers through the PGA at 100 percent. For instance, in the event that NW Natural has elected 90%/10% sharing in a particular PGA year and in the event variances from forecast amounts associated with the Proposed Transaction in that PGA year come to $11 million, NW Natural will bear $1 million of the variance and customers will bear $10 million ($10 M = (90% x $10 M) + (100% x $1 M)) of the variance. Likewise, if variances result in a benefit of $11 million, then NW Natural will retain $1 million of the savings and customers will realize $10 million in savings (as in the equation above).

21. Amortization: The Parties agree to amortize this investment over 30 years in a manner designed to match the expected volumes. However, the Parties agree to revisit this amortization schedule in five years to determine whether the amortization schedule should be modified for any reason, notwithstanding the annual revisions as specified in paragraph 17 above. Further, for purposes of facilitating the periodic development of amortization rates to be used in recording amortization expense, the Parties specifically request that the Commission, as part of its Order in this proceeding, authorize the company to develop amortization rates assuming the entire investment, net of any cumulative amortization, and the entire remaining volume delivery forecast.

22. Marketing Variances: Under the terms of the Proposed Transaction, the Company has the ability to either take its share of gas production in kind or it can elect to have Encana sell the Company's share of the gas at market prices. If the Company elects to have Encana sell its share, the Company can then purchase replacement gas at Opal

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or another location. The Parties agree that any savings resulting from Encana marketing NW Natural's share of the gas will be subject to the PGA sharing mechanism unless the savings become predictable and are included in the forecasted WACOG. In the event that the Company purchases replacement gas as described under this paragraph at a price higher than the price at which Encana sells the gas under the marketing agreement, the Company agrees to provide written notice to the other Parties within 14 days of the transaction. The Parties also agree that if this occurs, the transaction will be placed on the agenda of the next quarterly meeting of the Gas Portfolio Review meeting, where the Company will explain the facts and provide documentation surrounding the purchase. Notwithstanding anything else in this paragraph, the Parties specifically agree that if the Company does purchase replacement gas at a price higher than the price the Company receives for gas sold by Encana, the purchase of replacement gas will be subject to ongoing prudence reviews as provided in Paragraph 16.

23. **<u>Capital Costs:</u>** The Parties agree that the capital costs authorized in rates are capped at $251 million related to the overall investment per well under the agreement. In addition, transactional costs (the incremental amount needed to produce the transaction, including all due diligence-- of up to $1.5 million) will also be capitalized and will be amortized volumetrically with the investment capital costs.

24. **<u>Additional Reporting:</u>** The Parties agree that NW Natural will provide the following:

a. A report that identifies the Company's contract management duties and responsibilities with respect to the Joint Operating Agreement and the Carry and Earning Agreement. This report must be filed within 30 days of the Commission's order approving this Stipulation.

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b. Prior to the Company's 2016 PGA filing, the Company agrees to file a detailed report that describes the results of the Proposed Transaction. This report will include a comparison of actual results to forecast results and an assessment of the Company's actions with respect to its ongoing duties and responsibilities managing the Joint Operating Agreement and the Carry and Earning Agreement.

c. Each quarter, as part of the regular quarterly portfolio review process, the Company agrees to report on the decisions it has made to manage the Proposed Transaction's investment.

d. The Company agrees to report to the Commission, within 10 days, of (1) any ratings downgrade of Encana; (2) any environmental liability or cleanup by Encana exceeding $20,000; or (3) any event that materially impacts the operations and drilling in the Jonah Field.

25. The Company agrees to file a general rate proceeding no later than December 31, 2011.

26. The Parties agree that the Commission should approve NW Natural's Application for Deferred Accounting, filed in UM 1520, and the revised Schedule P attached hereto as Exhibit A subject to the agreement and conditions set forth in this Stipulation and exhibits attached hereto. The Parties agree that approval of Schedule P will result in just and reasonable rates.

27. The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the adjustments and the rates resulting from this Stipulation are fair, just, and reasonable.

28. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation

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at any hearing (if necessary), and recommend that the Commission issue an order adopting the settlements contained herein.

29. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties reserve the right to cross–examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented including the right to raise issues that are incorporated in the settlements embodied in this Stipulation.

30. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

31. By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

32. In the event that the Proposed Transaction does not close because NW Natural determines that it has not received an order from the Commission that is satisfactory, no Party shall be bound by any of the terms of this Stipulation.

33. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

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This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF	CITIZENS' UTILITY BOARD
By: Michael T	By:
Date: 4/19/11	Date:
NW NATURAL	NWIGU
By:	By:
Date:	Date:

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This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF

By: ______________________________

Date: ______________________________

CITIZENS' UTILITY BOARD

By: ______________________________

Date: 4-19-2011

NW NATURAL

By: ______________________________

Date: ______________________________

NWIGU

By: ______________________________

Date: ______________________________

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This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF	CITIZENS' UTILITY BOARD
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________
NW NATURAL	NWIGU
By: ______________________	By: ______________________
Date: 4/19/11	Date: ______________________

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This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

NW NATURAL

By: ______________________

Date: ______________________

NWIGU

By: Paula E. Pyron

Date: 4/19/2011

Exhibit A

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 24 ________ Revision of Sheet P-1
Cancels ________ Revision of Sheet P-1

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS

APPLICABILITY:
This schedule applies to all schedules for natural gas Sales Service within the entire territory served by the Company in the State of Oregon. The definitions and provisions described herein shall establish the natural gas costs for Purchased Gas Adjustment (PGA) deferral purposes on a monthly basis.

PURPOSE:
The purpose of this schedule is to allow the Company, on established Adjustment Dates, to adjust rate schedules for changes in the cost of gas purchased in accordance with the rate adjustment provisions described herein.

This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to the customer notification requirements as described in OAR 860-022-0017.

DEFINITIONS:
1. Actual Commodity Cost: The natural gas supply costs for commodity actually paid for the month, including Financial Transactions, fuel use, and distribution system lost and unaccounted for natural gas (LUFG) plus Gas Storage Facilities withdrawals, plus or minus the cost of natural gas associated with pipeline imbalances, plus propane costs, plus odorization charges, if applicable, less Net Commodity Off-System Sales Revenues for the month, plus actual Variable Transportation Costs, plus commodity-related reservation charges, plus the costs of Gas Reserves,[1] less all transportation demand charges embedded in commodity costs.

2. Net Commodity Off-System Sales Revenues: Revenues from the sale of natural gas to a party other than the Company's Oregon Sales Service customers less costs associated with the sales transactions.

3. Variable Transportation Costs: Variable transportation costs, including Pipeline volumetric charges, and other variable costs related to volumes of commodity delivered to Sales Service customers.

4. Actual Non-Commodity Cost: Actual Non-Commodity gas costs shall be equal to actual Demand Costs, less actual Capacity Release Benefits, plus or minus actual Pipeline refunds or surcharges.

5. Demand Costs: Fixed monthly Pipeline costs and other demand-related natural gas costs such as capacity reservation charges, plus any transportation demand charges embedded in commodity costs.

6. Capacity Release Benefits: This component includes revenues associated with pipeline capacity releases. The benefits to customers, through the monthly PGA deferrals, shall be 100% of the capacity release revenues up to the full Pipeline rate, and 80% of the capacity release revenues exceeding amounts reflecting full Pipeline rates. Capacity release revenues shall be quantified on a transaction-by-transaction basis.

[1] Per the terms of the Stipulation in Docket UM 1520.

Issued October 17, 2006
NWN Advice No. OPUC 06-13B

Effective with service on
and after November 1, 2006

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

19. Embedded Non-Commodity Cost – MDDV Based Sales Service: The Estimated Non-Commodity Cost per Therm – MDDV Based Firm Sales Service multiplied by the Actual Monthly MDDV Sales Service Volumes.

20. Financial Transactions: Cost of Financial Transactions related to gas supply, including but not limited to, hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.

21. Gas Storage Facilities: The cost of natural gas for injections shall be the actual cost of purchasing gas for storage and the cost of injection of the gas into the storage facility. Withdrawals of natural gas shall be valued at the weighted average cost of gas in the facility plus any variable withdrawal costs. For purposes of annual rate filings, the cost of inventory in storage shall be an overall average cost including existing inventory volumes and costs and refill inventory volumes and costs. Refill volumes will be priced at the expected pricing used in each filing. Only the cost of natural gas withdrawn from Gas Storage Facilities will be included in the Actual Commodity Cost, as defined herein.

22. Seasonalized Fixed Charges: The projected monthly non-Commodity costs of gas recovery, calculated by multiplying the Embedded Non-Commodity Costs by Oregon forecasted sales.

23. Gas Reserves: The volumes of natural gas actually received by the Company through its acquisition of gas reserves through joint venture agreements as authorized by the Commission.[1] For purposes of annual rate filings, the cost of Gas Reserves includes all carrying costs on the rate base investment, amortization, operating expenses, gathering and processing costs, and ad Valorem and severance taxes. The cost of Gas Reserves will be included in Actual Commodity Costs. (N)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES:
The Company shall maintain sub-accounts of Account 191. Monthly entries into these sub-accounts shall be made to reflect: 1) the difference between the monthly Actual Commodity Cost and the monthly Embedded Commodity Cost, 2) the difference between Actual Non-Commodity Cost and the monthly portion of Estimated Non-Commodity Cost and, 3) the difference between Embedded Non-Commodity Cost and monthly Seasonalized Fixed Charges. The entries shall be calculated each month as follows:

1. A debit or credit entry shall be made equal to 100% of the difference between the monthly Actual Non-Commodity Cost and the Monthly Embedded Non-Commodity Cost, net of revenue sensitive effects.

(continue to Sheet P-5)

| [1] See Commission order in UM 1520

Effective with service on
and after May 1, 2011

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24

_______ Revision of Sheet P-5
Cancels _____ Revision of Sheet P-5

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued):

2. A debit or credit entry shall be made equal to 100% of any monthly difference between Embedded Non-Commodity Costs and Monthly Seasonalized Fixed Charges. The monthly Seasonalized Fixed Charges for the period November 1, 2010 through November 30, 2011 are:

November 2010	$8,508,808
December 2010	$12,783,584
January 2011	$12,472,968
February	$10,224,130
March	$8,795,971
April	$6,322,866
May	$4,126,576
June	$2,703,901
July	$2,166,691
August	$2,157,069
September	$2,417,892
October	$5,432,235
November	$9,197,282
ANNUAL TOTAL	$78,801,165

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. For any given tracker year, if the total activity subject to debit or credit (N) entries that is related to the Gas Reserves transaction exceeds $10 million, amounts beyond $10 (N) million will be recorded at 100%. (N)

4. Monthly differentials shall be deemed to be positive if actual costs exceed embedded costs and to be negative if actual costs fall below embedded costs.

6. The cost differential entries shall be debited to the sub-accounts of Account 191 if positive, and credited to the sub-accounts of Account 191 if negative.

7. Interest – Beginning November 1, 2007, the Company shall compute interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission.

(continue to Sheet P-6)

Effective with service on
and after May 1, 2011

Exhibit B

Reserves Acquisition Project
Sample PGA Backup Document

Volume and Rate Per Therm would be included in the PGA to develop WACOG (Lines 21 and 22)

			Projected November 20XX	Projected December 20XX	Projected January 20XX	Projected February 20XX	Projected March 20XX	Projected April 20XX	Projected May 20XX	Projected June 20XX	Projected July 20XX	Projected August 20XX	Projected September 20XX	Projected October 20XX
1	Therms Delivered (000s)													
2	Total Therms		1,132.0	1,310.8	1,475.7	1,631.5	1,780.3	1,987.6	2,087.5	2,302.5	2,358.1	2,547.4	2,846.6	3,061.7
3	Rate per Therm (Depletion Rate)		0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416
4	Delivery Value		274	317	357	394	430	480	504	556	570	616	688	740
5														
6	Opex / Severance / Ad Valorem													
7	Operating Cost		87.2	100.1	113.0	124.9	137.2	154.1	164.0	176.5	182.7	200.5	218.5	230.2
8	Severance and Ad Valorem Taxes		59.95	69.42	86.76	95.91	104.66	116.85	122.72	135.36	138.63	149.76	167.35	180.00
9	Total		147.17	169.48	199.79	220.80	241.86	270.99	286.74	311.87	321.34	350.24	385.89	410.18
10														
11	Average Rate Base		23,154.78	26,198.00	29,226.67	32,262.08	35,270.76	39,078.57	42,857.27	44,945.75	46,179.50	49,051.58	52,706.30	54,648.55
12														
13	Carrying Cost													
14	Equity	10.1588%	98.36	111.29	124.16	137.05	149.83	166.01	182.06	190.93	196.17	208.37	223.90	232.15
15	Equity % of Cap Struct	50.1800%												
16	Equity Pretax	39.9400%	116.58	130.65	138.42	152.68	167.07	184.41	206.71	224.60	230.21	250.53	279.49	290.11
17	Debt	7.0660%	67.93	76.85	85.74	94.64	103.47	114.64	125.72	131.85	135.47	143.90	154.62	160.32
18	Total Carrying Cost		184.50	207.50	224.16	247.32	270.54	299.05	332.44	356.45	365.68	394.42	434.10	450.43
19														
20	Total Cost		605.21	693.72	780.55	862.37	942.60	1,050.33	1,123.62	1,224.72	1,256.84	1,360.24	1,507.88	1,600.47
21	Total Volume		1,132.0	1,310.8	1,475.7	1,631.5	1,780.3	1,987.6	2,087.5	2,302.5	2,358.1	2,547.4	2,846.6	3,061.7
22	Total Rate Per Therm		0.535	0.529	0.529	0.529	0.529	0.528	0.538	0.532	0.533	0.534	0.530	0.523

ORDER NO. 11176

APPENDIX A
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Exhibit C

NW Natural
20XX Oregon Earnings Review
12 Months Ended December 31, 20XX Forecast
($000's)

Line No.		Test Year Results (a)	TYPE I Adjustments (b)	Test Year Adjusted (c)	OREGON EARNINGS TEST Gas Reserves (d)	Test Year Results (e)	TYPE II Adjustments (f)	Test Year Adjusted Results (g)
	Operating Revenues							
1	Sale of Gas			$0		$0		$0
2	WARM Revenues			0		0		
3	Revenue & Technical Adjustments			0		0		
4	Transportation			0		0		
5	Miscellaneous Revenues			0		0		
6	SB408 Deferrals			0		0		
7	Total Operating Revenues	0	0	0		0	0	0
	Operating Revenue Deductions							
8	Gas Purchased			0	1/	0		0
9	Uncollectible Accrual for Gas Sales			0		0		0
10	Other Operating & Maintenance Expenses			0		0		0
11	Total Operating & Maintenance Exp.	0	0	0		0	0	0
12	Federal Income Tax			0	1/	0		0
13	State Excise			0	1/	0		0
14	Property Taxes			0		0		0
15	Other Taxes			0		0		0
16	Depreciation & Amortization			0		0		0
17	Total Operating Revenue Deductions	0	0	0		0	0	0
18	Net Operating Revenues	$0	$0	$0	$0	$0		$0
	Average Rate Base							
19	Utility Plant in Service			$0	2/	$0		$0
20	Accumulated Depreciation			0	3/	0		0
21	Net Utility Plant	0	0	0	0	0	0	0
22	Aid in Advance of Construction			0		0		0
23	Materials & Supplies			0		0		0
24	Water Heater Program			0		0		0
25	Leasehold Improvements			0		0		0
26	Accumulated Deferred Income Taxes			0	4/	0		0
27	Total Rate Base	$0	$0	$0	$0	$0	$0	$0
28	Rate of Return							
29	Return on Common Equity							

Adjustments for rate cases and annual reporting of results assuming removal of effects of the gas reserves transaction

1/ The Carrying Cost (return and taxes) will be added back to gas purchased to produce a cost of gas commensurate with revenues
The federal and state income taxes will be adjusted to reflect the add back of carrying costs in addition to the removal of the depletion allowance tax benefit.

2/ The cumulative investment amount will be removed as an item of Utility Plant in Service

3/ The cumulative amortization will be removed as an item of Utility Accumulatied Depreciation

4/ The cumulative deferred income taxes will be removed as an item of Utility Accumulated Deferred Income Taxes

ORDER NO. 11 176

APPENDIX A
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