Exhibit No. ___ (KSM-1T)
Docket UG-11_______
WITNESS: KEVIN S. MCVAY

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of **NORTHWEST NATURAL GAS COMPANY, dba NW Natural,** **Revision to Schedule P to include acknowledging the recovery of the cost of gas acquired through Gas Reserves.**	**Docket UG-11______**

NORTHWEST NATURAL GAS COMPANY

DIRECT TESTIMONY OF

KEVIN S. MCVAY

REDACTED

July 6, 2011

1 **Q. Please state your name, business address, and occupation.**

2 A. My name is Kevin S. McVay. My business address is 220 NW Second Avenue,
3 Portland, Oregon 97209. My current position is Manager – Integrated Resource
4 Planning of Northwest Natural Gas Company, d/b/a NW Natural ("NW Natural"
5 or the "Company").

6 **Q. Please summarize your educational background and business experience.**

7 A. I received a Bachelor of Science Degree in Accounting in 1981 from George
8 Mason University, Fairfax, Virginia. In 1986, I received a Master of Business
9 Administration degree from George Washington University, Washington, D.C.
10 From 1981 to 1987, I held positions in accounting, auditing, and forecasting for
11 Washington Gas Light Company in Washington, D.C. In 1987, I joined NW
12 Natural and have held positions in finance and regulatory affairs.

13 **Q. What is the purpose of your testimony?**

14 A. My testimony explains the Company's proposed ratemaking for its investment in
15 the acquisition of gas reserves through a joint venture with Encana Oil & Gas
16 (USA) Inc. (hereinafter, "Encana") (the "Transaction"). My testimony will also
17 describe the Company's proposed accounting treatment for the Transaction.

18 **Q. What is the Company's proposal for recovering the costs of the Transaction?**

19 A. While the nature of the Transaction is somewhat unique, the Company's proposed
20 ratemaking treatment is consistent with general principles of ratemaking. As
21 described in detail below, the Company proposes that the costs of the Transaction
22 should be recovered through the Company's annual Purchase Gas Adjustment
23 mechanism ("PGA"). The Company believes this treatment is appropriate

1 because even though the Transaction is fundamentally different from a traditional
2 hedge or long-term gas supply contract, it has characteristics similar to these types
3 of transactions. Because of this similarity, it is reasonable that recovery of the
4 costs of the Transaction take place within the same PGA mechanism as other gas
5 acquisition costs.

6 Thus, the Company proposes that each year it will re-forecast and update
7 costs associated with the Transaction, including depletion rate, volumes, and
8 operating costs, and include these costs in the Company's calculation of the
9 weighted average cost of gas ("WACOG"). To calculate the price of gas for
10 purposes of the WACOG, the Company will divide the projected annual cost of
11 service by the therms expected to be received under the Transaction. The cost of
12 service will consist of five components: (1) depletion, (2) operating expenses, (3)
13 midstream costs, (4) severance and ad valorem taxes, and (5) return on the
14 investment (carrying costs).

15 **Q. How will the gas received under the Transaction be classified in the annual**
16 **PGA WACOG calculation?**

17 A. NW Natural proposes that the cost of the gas be classified in the PGA as hedged
18 gas because the Company intends these volumes to replace a portion of its gas
19 buying portfolio that includes financial hedges. This classification includes the
20 cost of the methane as well as pass-throughs and carrying cost.

1 **RETURN ON INVESTMENT**

2 **Q. Please describe the capital costs.**

3 A. As outlined in detail in the testimony of Company witness Barbara J. Cronise, the
4 Transaction's capital costs are fixed at approximately $251 million, expended
5 over five years. This $251 million investment (plus transaction costs) will cover a
6 portion of the cost of drilling *[Confidential]* ******** *[Confidential]* new wells,
7 referred to as "Carry Wells." Encana will be responsible for the actual drilling
8 and is expected to drill approximately *[Confidential]* ****** *[Confidential]* wells
9 during each of the twelve month periods commencing May 1, 2011, through
10 December 31, 2015. At the conclusion of this investment period, the obligation to
11 fund well-drilling under the Transaction terminates.

12 **Q. How are the drilling costs determined?**

13 A. The Company is responsible for an estimated *[Confidential]* ***** *[Confidential]*
14 percent of the drilling costs for each Carry Well. These costs are estimated at
15 *[Confidential]* $****** *[Confidential]* million per well *[Confidential]* *********
16 ************ .*[Confidential]* Based on the cost per well and the estimated
17 number of wells drilled per year, NW Natural estimates that the annual amounts
18 paid by the Company for drilling each calendar year will be between
19 *[Confidential]* $*********** *[Confidential]* and *[Confidential]* $**********
20 *[Confidential]* million. NW Natural's obligation to fund drilling will terminate
21 once it has invested $250,920,000 toward the drilling of Carry Wells.

1 **Q. How does the Company propose to recover the fixed capital costs?**

2 A. The fixed $251 million investment will be recovered through the Company's
3 PGA rate-setting and deferral mechanisms. The depreciation, or rather the
4 depletion costs, associated with the Transaction will be included as an expense in
5 the PGA. The investment is proposed to be depleted on a monthly basis over 30
6 years, such that the balance in the asset account at the end of the 30-year term will
7 be zero. The Company will deplete the asset by recording an expense (debit) to
8 the cost of gas, with a corresponding reduction (credit) to the asset account.

9 **Q. How will the Company calculate the cost of capital that will be included**
10 **within the PGA and tracking mechanisms?**

11 A. The Company proposes to recover its costs of capital on the Transaction
12 investment as a component of gas costs within the PGA and deferral mechanisms.
13 The return on average monthly rate base includes the cost of debt, cost of equity,
14 and taxes. Rate base is derived using the cumulative investment, cumulative
15 depletion, and cumulative deferred taxes, consistent with utility plant. Although
16 rate base for the Transaction is considered a subset of total general rate base, the
17 Company proposes carving the program out of Company operations for purposes
18 of general rate cases because of the program's continuous ratemaking treatment
19 (*i.e.*, annual PGA adjustments, monthly debits and credits, amortization of
20 deferral balances, etc.). The authorized cost of capital, including the return on
21 equity ("ROE"), cost of debt, and capital structure, will be used to determine the
22 return on the investment.

1 **Q. In Oregon the Company agreed to apply the currently-authorized cost of**
2 **capital subject to a retrospective adjustment mechanism. Is the Company**
3 **proposing a similar adjustment mechanism here?**

4 A. No. In Oregon, parties expressed a concern that the Company's cost of capital for
5 the Oregon jurisdiction was last determined in a general rate case in 2003. For
6 this reason the parties believed that that cost of capital was quite stale. Moreover,
7 given that the parties knew that the Company intended to file a new rate case in
8 Oregon before the end of this year, they requested that the Company consider
9 applying a new cost of capital that will be adopted by the Public Utility
10 Commission of Oregon ("OPUC") in the upcoming rate case. Therefore, in
11 Oregon the parties agreed that once the new cost of capital is adopted by the
12 OPUC, that new cost of capital will be applied to Transaction investments, and
13 that the cost of capital already amortized into rates by that time will be "trued up"
14 to the amounts that would have been in place under the new cost of capital.

15 Thus, the Company agreed to the "true-up" mechanism specifically
16 because (1) the currently-authorized cost of capital was set 8 years ago and (2)
17 within the next 18 months or so the OPUC will be establishing a new, updated
18 cost of capital. In Washington, neither of these conditions exists. The
19 Company's current cost of capital was established in 2008 and the Company does
20 not intend to file another rate case in the near future. Therefore, there is no reason
21 in Washington to implement a similar adjustment mechanism.

1 **DEPLETION COST**

2 **Q. Please describe the depletion cost.**

3 A. Depletion is based on the total cost of the wells under the program, and is
4 calculated on a depletion basis tracking volume deliveries. As a result, if the
5 program includes $252.4 million of investment (including an assumed $1.5
6 million transaction cost), and is expected to provide approximately 1 billion
7 therms, the depletion rate per therm delivered will be about 25 cents per therm. In
8 years with high levels of deliveries, the amount of depletion will likewise be high.
9 For example, if in year 5 the deliveries are 100 million therms, using the above
10 numbers would mean that $25 million of depletion would be incurred.

11 **OPERATING COSTS**

12 **Q. Please describe the operating costs.**

13 A. The operating costs are variable costs that reflect the costs of actually operating
14 the wells so as to provide NW Natural with its share of the gas output. The cost
15 components for the day-to-day operation of the wells include daily site visits,
16 maintenance of pumps and equipment, and water disposal issues, among other
17 activities.

18 **TAXES**

19 **Q. Please describe the Severance and Ad Valorem taxes.**

20 A. Severance and Ad Valorem are levies made by the state of Wyoming. They are
21 calculated using volumes produced, the market price, and the tax rate. These
22 taxes, like operating expenses, are included as a reduction of the revenue check
23 from Encana within the settlement process. The tax rate modeled is 12.67

1 percent, *[Confidential]* **

2 ** *[Confidential]* To the

3 extent that actual taxes are higher as a function of the market value of gas, it

4 should be considered beneficial since the overall program cost of gas will be that

5 much more competitive to that market price, even if this one component

6 increases.

7 **MIDSTREAM COSTS**

8 **Q. Please describe the midstream costs.**

9 A. Midstream costs are the costs of gathering and processing between the wellhead

10 and the interstate pipeline. *[Confidential]* ****************************

11 **. *[Confidential]* There is a

12 shrinkage component modeled based on the market value of a percentage of gas

13 withdrawals, and, as described above with respect to taxes, the benefits associated

14 with the Transaction would actually increase in spite of increased midstream costs

15 resulting from increased market prices.

16 **RECOVERY OF COSTS OF SERVICE**

17 **Q. Please provide a step-by-step explanation as to how the Company proposes to**

18 **recover costs of service within the PGA mechanism.**

19 A. Recovery for these costs will occur in two steps, consistent with the PGA

20 methodology. First, the cost of gas for reserves and the associated volumes will

21 be included as a component of the total costs included in the PGA for setting

22 WACOG. The forecast costs and volumes for the Transaction for the PGA

23 tracking year will be included in the resource stack as a subcategory of hedged

1 gas, consistent with the inclusion of costs and volumes for other blocks of gas.
2 During the tracker period, monthly costs and volumes will be recorded on an
3 estimated basis and will be trued up upon subsequent settlement of the monthly
4 activity, consistent with other recording of costs and volumes of gas. The
5 Company is proposing no modification to the PGA and is requesting that the costs
6 associated with the Transaction receive consistent treatment will all other
7 purchased gas costs in the PGA.

8 **Q. Using current costs of capital and tax rates, what is the all-in cost of the gas**
9 **under the Transaction on a per-therm basis?**

10 A. The projected cost of gas under the Transaction is approximately *$0.5385* per
11 therm over the 30-year period of analysis. Using a single year as an example,
12 Exhibit No. (KSM-2T) to my testimony shows the derivation of an annual rate for
13 year two of the contract term, or November 1, 2011, to October 31, 2012. Line 31
14 of that exhibit calculates the rate using the overall costs of the gas on line 30 and
15 the overall therms delivered on line 6. Exhibit No. (KSM-3T) shows a table with
16 the annual rates per therm calculated under current assumptions. These rates are
17 on a calendar year basis rather than a PGA tracking year basis. Finally, the 3
18 pages of Exhibit No. (KSM-4T) show the annual components of volumes and
19 costs for each year of the modeled 30 years, along with the rates per therm for
20 each year.

21 **Q. What are the variable costs?**

22 A. As used here, "variable costs" refers to operating costs, severance and ad valorem
23 taxes, and midstream costs, which are discussed above. These costs will change

1 year-to-year as gas is pumped out of the ground and delivered to NW Natural.
2 The Company does not anticipate that these costs will change materially from
3 year to year, but they will vary.

4 **Q. What are replacement costs?**

5 A. The testimony of Randolph S. Friedman describes how the Company may choose
6 to have Encana market its gas acquired under the Transaction and in turn purchase
7 replacement gas on the market. Replacement costs are those costs that may be
8 incurred by NW Natural to purchase replacement gas in the event that the amount
9 of gas forecast to be delivered annually does not materialize. As part of the
10 WACOG calculation, the Company will estimate the amount of gas that it expects
11 to receive from the Transaction. If during the course of the year that amount
12 varies from the forecast the Company may need to purchase replacement gas at
13 market prices.

14 **Q. Will the variable and replacement costs be subject to ongoing prudence**
15 **reviews as they fluctuate from year-to-year?**

16 A. Yes, to the extent that these costs are impacted by subsequent decisions made by
17 NW Natural. As described in the testimony of Alex Miller, any subsequent
18 decision made by the Company in terms of exercising its discretion to manage the
19 contract is subject to an ongoing prudence review.

20 **Q. What are marketing variances?**

21 A. Under the terms of the Transaction, NW Natural can either take its gas in kind, or
22 it can opt to have Encana sell its gas at market prices allowing the Company to
23 purchase replacement gas on the market.

1 **Q. What happens if the Company incurs additional costs because it purchases**
2 **replacement gas at a higher price than the costs at which it could have**
3 **received the physical gas under the Transaction?**
4 A. In this event (which the Company believes would be relatively rare compared to
5 situations in which the marketing agreement would actually produce a benefit),
6 the Company agrees to provide notice to the Washington Utilities and
7 Transportation Commission and interested parties. This notice will be provided in
8 writing within 14 days of the transaction. These provisions are similar to those
9 agreed to by the Company and approved by the OPUC.
10 The Company recognizes that if it does purchase replacement gas at a
11 price higher than the price the Company receives for gas sold by Encana, the
12 purchase of replacement gas shall be subject to an ongoing prudence review as
13 provided above.
14 **Q. Does this conclude your testimony?**
15 A. Yes.

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Witness: Kevin S. McVay

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NORTHWEST NATURAL GAS	)	Docket No. UG-11____
COMPANY, dba NW Natural,	)	
	)	
Revision to Schedule P to include	)	
acknowledging the recovery of the cost	)	
of gas acquired through Gas Reserves.	)	

NORTHWEST NATURAL GAS COMPANY

EXHIBIT OF KEVIN S. MCVAY

Derivation of the Annual Rate

REDACTED

July 6, 2011

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Exhibit No. ___ (KSM-3T)
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NORTHWEST NATURAL GAS COMPANY

EXHIBIT OF KEVIN S. MCVAY

Annual Rate per Therm

REDACTED

July 6, 2011

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT OF KEVIN S. MCVAY

Annual Components of Volumes & Costs

REDACTED

July 6, 2011

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