Rates and Regulatory Affairs
Facsimile: 503.721.2516

NW Natural
220 NW 2ND AVENUE
PORTLAND, OR 97209
TEL 503.226.4211
www.nwnatural.com

September 2, 2010 NWN Advice No. OPUC 10-13

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
550 Capitol Street, NE, Suite 215
Post Office Box 2148
Salem, Oregon 97308-2148

Attn: Filing Center

Re: UG ____
Annual Purchased Gas Cost and Technical Rate Adjustments
Request for Amortization of Certain Deferred Accounts

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith revisions to its Tariff, P.U.C. Or. 24, stated to become effective with service on and after November 1, 2010, as follows:

Eleventh Revision of Sheet 162-1,
Schedule 162,
"Temporary (Technical) Adjustments to Rates";

Ninth Revision of Sheet 162-2,
Schedule 162,
"Temporary (Technical) Adjustments to Rates (continued)";

Ninth Revision of Sheet 164-1,
Schedule 164,
"Purchased Gas Cost Adjustment to Rates";

Seventh Revision of Sheet P-2,
Schedule P,
"Purchased Gas Cost Adjustments (continued)";

Eighth Revision of Sheet P-3,
Schedule P,
"Purchased Gas Cost Adjustments (continued)";

Tenth Revision of Sheet P-5,
Schedule P,
"Purchased Gas Cost Adjustments (continued)"; and

First Revision of Sheet P-6,
Schedule P,
"Purchased Gas Cost Adjustments (continued)".

Introduction and Summary

The first purpose of this filing is to: (a) remove the effect of all temporary rate adjustments incorporated into rates effective November 1, 2009; and (b) to apply the effect of the amortization of gas cost adjustments deferred under Docket UM 1445.

The second purpose of this filing is to revise rates for the effects of changes in purchased gas costs.

If the effects of the changes to temporary rate increments were permanent, the result of all components of the rate changes in this filing would be a decrease in the Company's revenues from its Oregon operations of about $18,385,951 or about 2.10%.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2009.

In addition to the supporting materials submitted as part of this filing, the Company will separately submit work papers in electronic format, all of which are incorporated herein by reference.

Removal of Temporary Rate Adjustments Currently in Effect, and Amortization of Gas Cost Deferrals (UM 1445)

The effect of the temporary technical adjustments to rates for the amortization of credit or debit balances in its gas cost balancing Federal Energy Regulatory Commission (FERC) deferred accounts, Account 191, is a net decrease to customer rates of $0.02190 cents per therm for firm sales service customers, and a net decrease to customer rates of $0.02832 per therm for interruptible sales service customers.

The rate increments associated with the amortization of the applicable deferral accounts have been calculated in accordance with the PGA Filing Guidelines as prescribed by the OPUC Order.

This portion of the filing is in compliance with ORS 757.259 (2003), which authorizes deferred utility expenses or revenues to be allowed (amortized) in rates to the extent authorized by the Commission in a proceeding to change rates. All of the deferrals included in this filing occurred with appropriate application by Commission authorization, as rate orders or under approved tariffs.

This filing does not require a review of earnings due to the elimination of the fall earnings review pursuant to OPUC Order No. 08-504 in Docket UM 1286. For the purpose of recovering "other" deferred balances as outlined in ORS 757.259, the required earnings review covering the period(s) during which the deferrals in this filing occurred was performed with Staff's review of the 2010 Spring Earnings Review, currently scheduled to go before the Commission at its September 7, 2010 public meeting.

The effect of this portion of the filing is to increase the Company's annual revenues by $5,860,490. The effect of removing the temporary adjustments placed into rates November 1, 2009, is an increase of $21,338,810. The effect of applying the new temporary rate adjustments for the amortization of gas cost deferral is a reduction of $15,478,320.

Purchased Gas Cost Adjustment (PGA)

This portion of the filing will pass through (1) changes in the cost of gas purchased by the Company from its natural gas suppliers, including the costs of purchasing financial derivative products to limit customers' exposure to gas cost volatility, and (2) changes in the cost of pipeline and storage capacity under contract with the Company's pipeline transporters.

This filing applies the method for calculating the proposed Annual Sales Weighted Average Cost of Gas ("WACOG") that is set forth in a joint party stipulation approved by the Commission in OPUC Order No. 08-504, Docket UM 1286, and as further prescribed by the PGA Filing Guidelines, Section III (1)(d) of the OPUC Order. In addition, this filing revises the Winter Sales WACOG option that is available to the Company's Rate Schedule 31 and 32 sales service customers.

The total effect of the PGA portion of this filing is to decrease the Company's annual revenues by about $24,246,441. The effect of the change in gas costs is a decrease of $29,627,803, which results in a proposed Annual Sales WACOG (with revenue sensitive effects) of $0.54299 per therm, and a proposed Winter Sales WACOG of $0.55388.

The effect of the change in demand charges is an increase in total demand charges of about $5,381,362, which results in a proposed firm service pipeline capacity charge of $0.12986 per therm, or $1.93 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01544 per therm.

If there are changes in the Company's gas supply costs or costs associated with pipeline services and charges from the levels used to develop the purchased gas adjustments included in this filing, then the Company will reflect such changes to Oregon gas customers in a manner approved by the Commission.

Effect on Customer Bills

The average residential Schedule 2 bill will decrease by 3.5%; the average Commercial Schedule 3 bill will decrease by 1.2%; the Commercial Schedule 31 Firm Sales Service bill will decrease by 2.2%; and the bill for the average Schedule 32 Industrial Firm Sales Service customer will decrease by 2.1%.

The monthly bill of the average residential customer served under Schedule 2 using 55 therms per month will decrease by $2.36. The monthly decrease for the average Schedule 3 customer using 224 therms is $2.81.

UM 1286 Natural Gas Portfolio Development Guidelines

In support of this filing, the Company provides Exhibit C which contains the data required by the Natural Gas Portfolio Development Guidelines Sections IV and V as adopted by the Commission in OPUC Order No. 10-197 in Docket UM 1286 ("the OPUC Order"). Some of the information contained in the PGA Filing Guidelines, Section V is confidential and highly confidential and is subject to the Modified Protective Order in Docket UM 1286, Order No. 10-337.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after November 1, 2010.

Copies of this letter and the filing made herewith are available in the Company's main office in Oregon and on its website at www.nwnatural.com.

Please address correspondence on this matter to me at eFiling@nwnatural.com, with copies to the following:

Kelley C. Miller, Staff Assistant
Rates & Regulatory Affairs
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220 NW Second Avenue
Portland, Oregon 97209
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Natasha Siores, Sr. Rate Analyst
Rates & Regulatory Affairs
NW Natural
220 NW Second Avenue
Portland, Oregon 29709
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ncs@nwnatural.com

Sincerely,

NW NATURAL

/s/ Onita R. King

Onita R. King
Regulatory Affairs

Attachments: Exhibit A – PGA Filing Guidelines Index
Exhibit B – Purchased Gas Costs
Exhibit C – Portfolio Development Guidelines

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in all of the Company's conventional deferred revenue and gas cost accounts, Accounts 186 and 191, respectively.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1	Schedule 3	Schedule 31	Schedule 33
Schedule 2	Schedule 19	Schedule 32	

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2010 (T)

The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments [1]	Total Temporary Adjustment	
1R		$(0.02919)	$0.00729		**$(0.02190)**	(C)
1C		$(0.02919)	$0.00729		**$(0.02190)**	
2		$(0.02919)	$0.00729		**$(0.02190)**	
3 (CSF)		$(0.02919)	$0.00729		**$(0.02190)**	
3 (ISF)		$(0.02919)	$0.00729		**$(0.02190)**	
19		$(0.56)	$0.14		**$(0.42)**	
31 (CSF)	Block 1	$(0.02919)	$0.00729		**$(0.02190)**	
	Block 2	$(0.02919)	$0.00729		**$(0.02190)**	
31(CTF)	Block 1	N/A	N/A			
	Block 2	N/A	N/A			
31 (CSI)	Block 1	$(0.02919)	$0.00087		**$(0.02832)**	
	Block 2	$(0.02919)	$0.00087		**$(0.02832)**	
31 (ISF)	Block 1	$(0.02919)	$0.00729		**$(0.02190)**	
	Block 2	$(0.02919)	$0.00729		**$(0.02190)**	
31 (ITF)	Block 1	N/A	N/A			
	Block 2	N/A	N/A			
31 (ISI)	Block 1	$(0.02919)	$0.00087		**$(0.02832)**	
	Block 2	$(0.02919)	$0.00087		**$(0.02832)**	

[1] The sum of the adjustments identified in Schedules 161, 169, 170, 172, 178, 179, 190 and 305. (C)

(continue to Sheet 162-2)

SCHEDULE 162
TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES
(continued)

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2010 (T)

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments [1]	Total Temporary Adjustment
32 (CSF)	Block 1	$(0.02919)	$0.00729		**$(0.02190)** (C)
	Block 2	$(0.02919)	$0.00729		**$(0.02190)**
	Block 3	$(0.02919)	$0.00729		**$(0.02190)**
	Block 4	$(0.02919)	$0.00729		**$(0.02190)**
	Block 5	$(0.02919)	$0.00729		**$(0.02190)**
	Block 6	$(0.02919)	$0.00729		**$(0.02190)**
32 (ISF)	Block 1	$(0.02919)	$0.00729		**$(0.02190)**
	Block 2	$(0.02919)	$0.00729		**$(0.02190)**
	Block 3	$(0.02919)	$0.00729		**$(0.02190)**
	Block 4	$(0.02919)	$0.00729		**$(0.02190)**
	Block 5	$(0.02919)	$0.00729		**$(0.02190)**
	Block 6	$(0.02919)	$0.00729		**$(0.02190)**
32 (TF)	Block 1	N/A	N/A		
	Block 2	N/A	N/A		
	Block 3	N/A	N/A		
	Block 4	N/A	N/A		
	Block 5	N/A	N/A		
	Block 6	N/A	N/A		
32 (CSI)	Block 1	$(0.02919)	$0.00087		**$(0.02832)**
	Block 2	$(0.02919)	$0.00087		**$(0.02832)**
	Block 3	$(0.02919)	$0.00087		**$(0.02832)**
	Block 4	$(0.02919)	$0.00087		**$(0.02832)**
	Block 5	$(0.02919)	$0.00087		**$(0.02832)**
	Block 6	$(0.02919)	$0.00087		**$(0.02832)**
32 (ISI)	Block 1	$(0.02919)	$0.00087		**$(0.02832)**
	Block 2	$(0.02919)	$0.00087		**$(0.02832)**
	Block 3	$(0.02919)	$0.00087		**$(0.02832)**
	Block 4	$(0.02919)	$0.00087		**$(0.02832)**
	Block 5	$(0.02919)	$0.00087		**$(0.02832)**
	Block 6	$(0.02919)	$0.00087		**$(0.02832)**
32 (TI)	Block 1	N/A	N/A		
	Block 2	N/A	N/A		
	Block 3	N/A	N/A		
	Block 4	N/A	N/A		
	Block 5	N/A	N/A		
	Block 6	N/A	N/A		
33 (TI)		N/A	N/A		
33 (TF)		N/A	N/A		

(C)

[1] The sum of the adjustments identified in Schedules 161, 169, 170, 172, 178, 179, 190 and 305.

GENERAL TERMS: This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued September 2, 2010 Effective with service on
NWN Advice No. OPUC 10-13 and after November 1, 2010

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

PURPOSE:
To (a) identify the Commodity and Pipeline Capacity Components applicable to the Rate Schedules listed below; and (b) to identify any changes to such components due to changes in the cost of Pipeline capacity and the cost of gas purchased from the Company's suppliers that apply the Rate Schedules listed below.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1	Schedule 3	Schedule 31
Schedule 2	Schedule 19	Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2010 (T)

Annual Sales WACOG [1]	$0.54299	(R)
Winter Sales WACOG [2]	$0.55388	(R)
Firm Sales Service Pipeline Capacity Component [3]	$0.12986	(I)
Firm Sales Service Pipeline Capacity Component [4]	$1.93	(I)
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01544	(I)

[1] Applies to all Sales Service Rate Schedules (per therm) except where Winter Sales WACOG or Monthly Incremental Cost of Gas applies.
[2[Applies to Sales Customers that request Winter Sales WACOG at the September 15 Annual Service Election.
[3] Applies to Rate Schedules 1, 2, 3, and Schedule 31 and Schedule 32 Firm Sales Service Volumetric Pipeline Capacity option (per therm).
[4] Applies to Schedules 31 and 32 Firm Sales Service Peak Demand Pipeline Capacity option (per therm of MDDV per month).
[5] Applies to Schedule 31 and Schedule 32 Interruptible Sales Service (per therm).

ADJUSTMENTS TO RATE COMPONENTS: Effective: November 1, 2010 (T)

The above listed components shall be adjusted as follows:

Commodity Component	**Firm Pipeline Capacity Component**
$(0.00000)	**$(0.00000)**

GENERAL TERMS:
This schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued September 2, 2010
NWN Advice No. OPUC 10-13

Effective with service on
and after November 1, 2010

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

7. Estimated Annual Sales Weighted Average Cost of Gas (Annual Sales WACOG): The estimated Annual Sales WACOG is the default Commodity Component for billing purposes, and is used for purposes of calculating the monthly gas cost deferral costs for entry into the Account 191 sub-accounts calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by forecasted sales volumes.
   a. "Forecasted Purchases" means November 1 – October 31 forecasted sales volumes, "weather-normalized", plus a percentage for distribution system LUFG.
   b. "Distribution system embedded LUFG" means the 5-year average of actual distribution system LUFG, not to exceed 2%.
   c. "Adjusted contract prices" means actual and projected contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel use and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

   Effective November 1, 2010: (R)
   Estimated Annual Sales WACOG per therm (w/ revenue sensitive): **$0.54299** (R)
   Estimated Annual Sales WACOG per therm (w/o revenue sensitive): **$0.52779**

8. Estimated Winter Sales WACOG: The Company's weighted average Commodity Cost of Gas for the five-month period November through March.
   Effective November 1, 2010: (R)
   Estimated Winter Sales WACOG per therm (w/ revenue sensitive): **$0.55388** (R)
   Estimated Winter Sales WACOG per therm (w/o revenue sensitive): **$0.53838**

9. Estimated Non-Commodity Cost: Estimated annual Non-Commodity gas costs shall be equal to estimated annual Demand Costs, less estimated annual Capacity Release Benefits, plus or minus estimated annual pipeline refunds or surcharges.

10. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by November 1 – October 31 forecasted Firm Sales Service volumes.
    Effective November 1, 2010: (I)
    Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): **$0.12986** (I)
    Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive: **$0.12623**

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

11. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by November 1 – October 31 forecasted Interruptible Sales Service volumes.
Effective November 1, 2010:
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):
$0.01544 (I)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):
$0.01501 (I)

12. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.
Effective November 1, 2010:
Estimated Non-Commodity Cost per therm - MDDV Based Sales (w/revenue sensitive):
$1.93 (I)
Estimated Non-Commodity Cost per therm- MDDV Based Sales (w/o revenue sensitive):
$1.88 (I)

13. Actual Monthly Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service therms, excluding MDDV based volumes, adjusted for estimated unbilled Firm Sales Service therms.

14. Actual Monthly Interruptible Sales Service Volumes: The total actual monthly billed Interruptible Sales Service therms, adjusted for estimated unbilled Interruptible Sales Service therms.

15. Actual Monthly MDDV Based Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service Volumes for Rate Schedule 31 and Rate Schedule 32 customers billed under the Firm Pipeline Capacity Charge - Peak Demand option, adjusted for estimated unbilled MDDV Firm Sales Service Volumes.

16. Embedded Commodity Cost: The Estimated Annual Sales WACOG, updated for October 31 storage inventory prices, multiplied by the Total of the Actual Monthly Firm and Interruptible Sales Service Volumes.

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

18. Embedded Non-Commodity Cost per Therm – Interruptible Sales Service: The Estimated Non-Commodity Cost per Therm – Interruptible Sales Service multiplied by the Actual Monthly Interruptible Sales Service Volumes.

(continue to Sheet P-4)

Issued by: NORTHWEST NATURAL GAS COMPANY
d.b.a. NW Natural
220 N.W. Second Avenue
Portland, Oregon 97209-3991

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	(C)
December 2010	$9,176,491	
January 2011	$12,737,411	
February	$12,436,749	
March	$10,198,886	
April	$8,785,493	
May	$6,327,557	
June	$4,145,505	
July	$2,728,382	
August	$2,193,496	
September	$2,183,893	
October	$2,443,388	
November	$5,443,914	
ANNUAL TOTAL	$78,801,165	(C)

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.

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.

5. 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.

6. 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)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

AMORTIZATION OF PGA ACCOUNT DEFERRALS:
The balances in the sub-accounts of Account 191 shall be amortized over the twelve (12) month period commencing with the November 1 adjustment date or such other time period acceptable to the Company and the Commission. The amount of amortization for the PGA Accounts shall consist of an amount necessary to recover or return the amount accumulated in the sub-accounts and other deferral accounts.

ADJUSTMENT DATES:
The Adjustment Date shall be November 1 of each year for changes in annual gas costs. The Company may file out-of-cycle PGA adjustments to be effective at times other than November 1 of each year, if the sum of the Company's annual Actual Commodity Cost and Actual Non-Commodity Costs differs from the sum of the annual Embedded Commodity Cost and Embedded Non-Commodity Costs, by ten percent (10%) or more, or for such other reasons and on such terms as the Commission may approve.

TIME AND MANNER OF FILING:
Applications will be made to the Commission not less than sixty (60) days in advance of the requested effective date, or upon such other date as the Commission may authorize. (C)

AMOUNT OF ADJUSTMENT:
The amount of adjustment to be made to customers' rates effective on each November 1 adjustment date shall consist of the sum of the changes in the Embedded Commodity Cost and Non-Commodity Cost and the change in amortization rates of the PGA Accounts, as well as other deferral accounts as the Commission may approve.

GENERAL TERMS:
Service under this Rate Schedule is governed by the terms of this Rate Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Rate Schedule apply to service under this Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Exhibit: A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW Natural

SUPPORTING MATERIALS

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 10-13

Exhibit A
Supporting Materials
Purchased Gas Costs Deferral Amortizations
NWN Advice No. OPUC 10-13

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PGA Filing Guidelines Index	1
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191411 Amortization Demand	6
191400 Deferral WACOG	7
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191417 Deferral Coos Bay Demand	10

Gas Cost Deferrals:

PGA LDC Template (see Workpapers submitted separately)

NW Natural

Exhibit A
PGA Filing Guidelines Index
NWN Advice No. OPUC 10-13
INDEX

Guideline Reference	Data Requirement	Location	Link
III	Assumptions		
1	General Rate Development		
a)	Deferrals and amortizations: LDCs should use forecasted therms to develop rate increments associated with deferrals and amortizations	See work papers of Natasha Siores (submitted separately)	
b)	Calculation and application of revenue sensitive costs: When revenue sensitive costs are updated, the LDC should send in work papers to support revision. The LDCs should first determine the entire revenue requirement associated with the annual PGA and then apply the revenue sensitive calculation to the total. Allocation of revenue requirement totals into rate increments should be made after that point. Alternatively, the revenue requirement could be allocated to customer classes and then the total for each customer class could be grossed up. The rate increment would be calculated from the grossed up total.	See work papers of Natasha Siores (submitted separately)	
c)	Deferral accounts: The revenue totals in the PGA Summary Sheet should tie directly to deferral account totals. Utility will provide 2 columns consisting of pre- and post-grossed up totals	See work papers of Natasha Siores (submitted separately)	
d)	Annual Sales WACOG: The forward price curve used by the utility in its PGA filing for its Annual Sales WACOG should be based on the formula described in Order 08-504, at page 16-17.	See work papers of Natasha Siores (submitted separately)	
2	PGA Amortizations unrelated to gas distribution: With its Spring Earnings filing, the company should provide Staff with a notice of “intent to request amortization effective November 1” for any deferral it intends to amortize in the PGA that requires a separate earnings test.	See NW Natural Advice Nos. OPUC 10-14 and OPUC 10-15	
	The notice should include a completed (hard copy and electronic) Deferral Summary Worksheet. The LDC would be expected to submit an updated summary sheet and other necessary information when filing for amortization.	See NW Natural Advice Nos. OPUC 10-14 and OPUC 10-15 and work papers of Natasha Siores (submitted separately)	
3	Calculation of 3% Test. The calculation for the 3% Test should conform to ORS 757.259(6), (i.e. total proposed amortization times the LDC’s gross revenues from the preceding year should not exceed 3%). Gross revenues is defined as all Oregon revenues including Other Revenues that are booked above the line. (First column of the ROO from the preceding year.) Preceding year is defined as preceding calendar year as submitted in the ROO provided for the spring earnings review.) The 3% consists of the total of all amortizations. If the total exceeds 3%, it will be dealt with on a case by case basis as provided by related statutes and regulation. See ORS 757.259(7).	See Exhibit B to this filing NW Natural Advice No. OPUC 10-13.	
4	Deferral Application	See separately filed: (1) Application for Reauthorization, Docket UM 1027 dated August 30, 2010; and (2) Application for Reauthorization of purchased gas costs dated August 30, 2010 (not yet docketed)	

NW Natural
Rates & Regulatory Affairs
2010-2011 PGA Filing - Oregon: August Filing
PGA Effects on Revenue - Staff's Format: Detail for Memo Attachment
Tariff Advice 10-13: PGA Gas Costs

		Excluding Revenue Sensitve Amount	Including Revenue Sensitve Amount
1			
2	**Purchased Gas Cost Adjustment (PGA)**		
3			
4	Commodity Cost Change	($28,798,520)	($29,627,803)
5			
6	Demand Capacity Cost Change	5,230,738	5,381,362
7			
8	**Total Gas Cost Change**	(23,567,782)	(24,246,441)
9			
10	**Temporary Increments**		
11			
12	Amortization of 191.xxx Account Gas Costs	(15,045,082)	(15,478,320)
13	(Demand, Coos Bay Demand & Commodity)		
14			
15	Removal of All Current Temporary Increments	(20,700,353)	(21,338,810)
16			
17			
18	**TOTAL OF ALL COMPONENTS OF RATE CHANGES**	**($17,912,511)**	**($18,385,951)**
19			
20			
21			
22	2009 Oregon Earnings Test Normalized Total Revenues	$874,581,000	$874,581,000
23			
24	Effect of this filing, as a percentage change (line 18 ÷ line 22)	-2.05%	-2.10%

NW Natural
Rates & Regulatory Affairs
2010-2011 PGA Filing - Oregon: August Filing
Summary of TEMPORARY Increments

Schedule	Block	Current Temporaries	ADD WACOG Deferral	ADD Demand Deferral FIRM	ADD Demand Deferral INTERR	ADD Residential Decoupling	ADD Commercial Decoupling	ADD Smart Energy	ADD Intervenor Funding - CUB	RETAIN Current SB408 Fed & State	ADD PUC Fee Refund	ADD Industrial DSM	ADD AMR Deferral	Total Proposed Temps	Net Effect of Temps
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
1R		(0.01849)	(0.02919)	0.00729	0.00000	0.04120	0.00000	0.00005	0.00018	0.00095	(0.00274)	0.00000	0.00753	0.02527	0.04376
1C		(0.04879)	(0.02919)	0.00729	0.00000	0.00000	0.01253	0.00005	0.00000	0.00064	(0.00190)	0.00000	0.00522	(0.00536)	0.04343
2R		(0.01856)	(0.02919)	0.00729	0.00000	0.04120	0.00000	0.00005	0.00018	0.00064	(0.00185)	0.00000	0.00510	0.02342	0.04198
3C Sales Firm		(0.04883)	(0.02919)	0.00729	0.00000	0.00000	0.01253	0.00005	0.00000	0.00046	(0.00132)	0.00000	0.00363	(0.00655)	0.04228
Intentionally blank															
3I Sales Firm		(0.05242)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00039	(0.00111)	0.00835	0.00306	(0.01121)	0.04121
Intentionally blank															
19	1st mantle	(0.99)	(0.56)	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.42)	0.57
19	add'l mtls	(0.99)	(0.56)	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.42)	0.57
31C Sales Firm	Block 1	(0.04887)	(0.02919)	0.00729	0.00000	0.00000	0.01253	0.00005	0.00000	0.00032	(0.00093)	0.00000	0.00255	(0.00738)	0.04149
	Block 2	(0.04888)	(0.02919)	0.00729	0.00000	0.00000	0.01253	0.00005	0.00000	0.00029	(0.00084)	0.00000	0.00233	(0.00754)	0.04134
31C Trans Firm	Block 1	0.00254	0.00000	0.00000	0.00000	0.00000	0.01253	0.00000	0.00000	0.00027	(0.00072)	0.00000	0.00000	0.01208	0.00954
	Block 2	0.00254	0.00000	0.00000	0.00000	0.00000	0.01253	0.00000	0.00000	0.00025	(0.00066)	0.00000	0.00000	0.01212	0.00958
31C Sales Interr	Block 1	(0.04308)	(0.02919)	0.00000	0.00087	0.00000	0.01253	0.00005	0.00000	0.00032	(0.00076)	0.00000	0.00210	(0.01408)	0.02900
	Block 2	(0.04309)	(0.02919)	0.00000	0.00087	0.00000	0.01253	0.00005	0.00000	0.00029	(0.00070)	0.00000	0.00192	(0.01423)	0.02886
31I Sales Firm	Block 1	(0.05244)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00031	(0.00075)	0.00835	0.00207	(0.01192)	0.04052
	Block 2	(0.05244)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00028	(0.00068)	0.00835	0.00187	(0.01208)	0.04036
31I Trans Firm	Block 1	0.00010	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00027	(0.00068)	0.00000	0.00000	(0.00041)	(0.00051)
	Block 2	0.00010	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00025	(0.00061)	0.00000	0.00000	(0.00036)	(0.00046)
31I Sales Interr	Block 1	(0.04656)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00058	(0.00093)	0.00835	0.00256	(0.01776)	0.02880
	Block 2	(0.04658)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00052	(0.00084)	0.00835	0.00231	(0.01798)	0.02860
32C Sales Firm	Block 1	(0.05138)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00005	0.00000	0.00017	(0.00049)	0.00835	0.00000	(0.01382)	0.03756
	Block 2	(0.05139)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00005	0.00000	0.00014	(0.00042)	0.00835	0.00000	(0.01378)	0.03761
	Block 3	(0.05140)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00005	0.00000	0.00010	(0.00029)	0.00835	0.00000	(0.01369)	0.03771
	Block 4	(0.05140)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00005	0.00000	0.00006	(0.00017)	0.00835	0.00000	(0.01361)	0.03779
	Block 5	(0.05142)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00005	0.00000	0.00003	(0.00010)	0.00835	0.00000	(0.01357)	0.03785
	Block 6	(0.05141)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00005	0.00000	0.00002	(0.00005)	0.00835	0.00000	(0.01353)	0.03788
32I Sales Firm	Block 1	(0.05247)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00018	(0.00045)	0.00835	0.00000	(0.01382)	0.03865
	Block 2	(0.05247)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00016	(0.00038)	0.00835	0.00000	(0.01377)	0.03870
	Block 3	(0.05248)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00011	(0.00027)	0.00835	0.00000	(0.01371)	0.03877
	Block 4	(0.05250)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00016)	0.00835	0.00000	(0.01365)	0.03885
	Block 5	(0.05250)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00004	(0.00009)	0.00835	0.00000	(0.01360)	0.03890
	Block 6	(0.05250)	(0.02919)	0.00729	0.00000	0.00000	0.00000	0.00000	0.00000	0.00002	(0.00005)	0.00835	0.00000	(0.01358)	0.03892
32 Trans Firm	Block 1	0.00007	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00014	(0.00041)	0.00000	0.00000	(0.00027)	(0.00034)
	Block 2	0.00006	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00012	(0.00035)	0.00000	0.00000	(0.00023)	(0.00029)
	Block 3	0.00005	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00008	(0.00024)	0.00000	0.00000	(0.00016)	(0.00021)
	Block 4	0.00004	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00005	(0.00014)	0.00000	0.00000	(0.00009)	(0.00013)
	Block 5	0.00004	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00003	(0.00008)	0.00000	0.00000	(0.00005)	(0.00009)
	Block 6	0.00003	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	(0.00004)	0.00000	0.00000	(0.00003)	(0.00006)
32C Sales Interr	Block 1	(0.04669)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00005	0.00000	0.00016	(0.00042)	0.00835	0.00000	(0.02018)	0.02651
	Block 2	(0.04669)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00005	0.00000	0.00014	(0.00035)	0.00835	0.00000	(0.02013)	0.02656
	Block 3	(0.04670)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00005	0.00000	0.00010	(0.00025)	0.00835	0.00000	(0.02007)	0.02663
	Block 4	(0.04671)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00005	0.00000	0.00006	(0.00015)	0.00835	0.00000	(0.02001)	0.02670
	Block 5	(0.04672)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00005	0.00000	0.00003	(0.00008)	0.00835	0.00000	(0.01997)	0.02675
	Block 6	(0.04672)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00005	0.00000	0.00002	(0.00004)	0.00835	0.00000	(0.01994)	0.02678
32I Sales Interr	Block 1	(0.04669)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00016	(0.00042)	0.00835	0.00000	(0.02023)	0.02646
	Block 2	(0.04669)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00014	(0.00035)	0.00835	0.00000	(0.02018)	0.02651
	Block 3	(0.04670)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00010	(0.00025)	0.00835	0.00000	(0.02012)	0.02658
	Block 4	(0.04671)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00015)	0.00835	0.00000	(0.02006)	0.02665
	Block 5	(0.04672)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00003	(0.00008)	0.00835	0.00000	(0.02002)	0.02670
	Block 6	(0.04672)	(0.02919)	0.00000	0.00087	0.00000	0.00000	0.00000	0.00000	0.00002	(0.00004)	0.00835	0.00000	(0.01999)	0.02673
32 Trans Interr	Block 1	0.00006	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00013	(0.00039)	0.00000	0.00000	(0.00026)	(0.00032)
	Block 2	0.00005	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00011	(0.00033)	0.00000	0.00000	(0.00022)	(0.00027)
	Block 3	0.00005	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00008	(0.00023)	0.00000	0.00000	(0.00015)	(0.00020)
	Block 4	0.00004	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00005	(0.00014)	0.00000	0.00000	(0.00009)	(0.00013)
	Block 5	0.00004	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00003	(0.00008)	0.00000	0.00000	(0.00005)	(0.00009)
	Block 6	0.00003	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	(0.00004)	0.00000	0.00000	(0.00003)	(0.00006)
Intentionally blank															
33		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	(0.00002)	0.00000	0.00000	(0.00001)	(0.00001)

Sources:

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
Direct Inputs	Jun 10 Filing								Jun 10 Filing					
Equal ¢ per therm		Column D	Column G	Column J	Column M	Column P	Column S	Column V			Column Y			
Equal % of margin										Column O		Column L		

Filing:

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
Tafiff Advice Notice #	10-13	10-13	10-13	10-13	10-14	10-14	10-15	10-14		10-15	10-14	10-15		

NW Natural
Rates & Regulatory Affairs
2010-2011 PGA Filing - Oregon: August Filing
Summary of Deferred Accounts Included in the PGA

Account	Balance 06/30/10	Adjustment	Jul Actual + Aug-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2010	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection	Amounts Excluded from PGA Filing	Amounts Included in PGA Filing
A	B	C	D	E	F	G1	G2	H	I	J
					F = sum B thru E		2.24%	H = F + G2		Excl. Rev Sens
Decoupling Deferrals and Amortizations										
186277 RESIDENTIAL DECOUPLING AMORTIZATION	2,505,737		(1,593,139)	12,792	925,390					
186275 RESIDENTIAL DECOUPLING DEFERRAL	13,757,751		(479,547)	387,327	13,665,530					
Subtotal	16,263,488	0	(2,072,686)	400,119	14,590,921	2.24%	177,642	14,768,563		**14,768,563**
186271 COMMERCIAL DECOUPLING AMORTIZATION	207,268		(90,000)	1,178	118,445					
186270 COMMERCIAL DECOUPLING DEFERRAL	2,333,701		98,040	70,252	2,501,993					
Subtotal	2,540,969	0	8,039	71,430	2,620,438	2.24%	31,903	2,652,341		**2,652,341**
Intervenor Funding Deferrals and Amortizations										
186276 INTERVENER FUNDING	57,500		0	0	57,500					
186284 INTERVENOR ISSUE FUND - CUB Grants	0		0	0	0					
186286 AMORT - CUB INTERVENER MATCHING FUND	15,013		(11,123)	72	3,962					
Subtotal	72,513	0	(11,123)	72	61,462	2.24%	748	62,210		**62,210**
186278 NWIGU INTERVENOR MATCHING FUND	1,670		0	0	1,670					
186284 INTERVENOR ISSUE FUND - NWIGU Grants	0		0	0	0					
186288 AMORT - NWIGU INTERVENER MATCHING FUND	2,067		(3,195)	4	(1,124)					
Subtotal	3,737	0	(3,195)	4	545	2.24%	7	552	552	**0**
Miscellaneous Amortizations										
186306 OREGON SMART ENERGY AMORT	127,331		(98,740)	591	29,182	2.24%	355	29,537		**29,537**
186370 PENSION EXPENSE CREDIT	(49,280)		42,030	(216)	(7,465)	2.24%	(91)	(7,556)	to PUC Fee account	**0**
186232 INDUSTRIAL DSM (Mar 09 - Feb 10 activity only)	938,043		0	0	938,043	2.24%	11,421	949,464		**949,464**
186308 AMR Deferral (2009 deferrals only)	2,541,396		0	0	2,541,396	2.24%	30,941	2,572,337		**2,572,337**
186236 OPUC FEE REFUND	(922,167)		0	(26,778)	(948,945)	2.24%	(11,553)	(960,498)		**(968,054)**
Gas Cost Deferrals and Amortizations										
191401 AMORTIZE OREGON WACOG	(10,191,626)		5,546,184	(53,316)	(4,698,758)					
191400 WACOG - ACCRUE OREGON	(13,921,206)		(203,433)	(409,399)	(14,534,038)					
Subtotal	(24,112,832)	0	5,342,751	(462,715)	(19,232,796)	2.24%	(234,156)	(19,466,952)		**(19,466,952)**
191411 AMORTIZE DEMAND OREGON	(512,278)		668,087	(1,700)	154,109					
191410 DEMAND - ACCRUE OREGON	2,026,733		364,593	68,101	2,459,427					
191417 DEMAND - ACCRUE COOS BAY	126,747		18,819	0	145,567					
191450 OREGON DEMAND ACCRUE VOLUME	1,800,896		(237,583)	46,267	1,609,579					
Subtotal	3,442,098	0	813,917	112,667	4,368,682	2.24%	53,188	4,421,870		**4,421,870**
GRAND TOTAL								**5,021,868**	**552**	**5,021,316**

Notes

Please refer to NWN workpapers or electronic file "NWN 2010-11 Oregon PGA rate development file.xls" for application of revenue sensitive effect and calculation of rate increments.

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon WACOG Deferral
Account Number: 191401
Current docket is UM 1445
Current Amortization was granted in Order No. 09-450

Debit (Credit)

Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
(a)	(b)	(c)	(d)	(e)	(e2)	(f)	(g)
Beginning Balance							
Sep-06							222,338.25
Oct-06	A/	152,902.48	(13,952,286.98)	(98,054.87)		(13,897,439.37)	(13,675,101.12)
Nov-06		681,874.43		(95,761.52)		586,112.91	(13,088,988.21)
Dec-06		1,664,674.32		(88,023.18)		1,576,651.14	(11,512,337.07)
Jan-07		2,061,166.83		(75,276.46)		1,985,890.37	(9,526,446.70)
Feb-07		1,895,402.78		(61,609.69)		1,833,793.09	(7,692,653.61)
Mar-07		1,407,487.90		(50,192.02)		1,357,295.88	(6,335,357.73)
Apr-07		1,056,910.60		(41,703.24)		1,015,207.36	(5,320,150.37)
May-07		835,784.10		(35,206.39)		800,577.71	(4,519,572.66)
Jun-07		572,166.88		(30,403.51)		541,763.37	(3,977,809.29)
Jul-07		456,533.76		(26,927.96)		429,605.80	(3,548,203.49)
Aug-07		431,504.55		(23,932.55)		407,572.00	(3,140,631.49)
Sep-07		452,146.07		(20,931.39)		431,214.68	(2,709,416.81)
Oct-07		692,956.86		(16,969.84)		675,987.02	(2,033,429.79)
Nov-07	old rates 1	512,027.94	(38,490,957.42)	(289,194.03)		(38,268,123.51)	(40,301,553.30)
	new rates	1,627,466.87		5,843.96		1,633,310.83	(38,668,242.47)
Dec-07		4,605,415.21		(261,165.15)		4,344,250.06	(34,323,992.41)
Jan-08		5,565,138.14		(226,519.99)		5,338,618.15	(28,985,374.26)
Feb-08		5,395,299.91		(188,789.67)		5,206,510.24	(23,778,864.02)
Mar-08		4,102,663.80		(156,039.89)		3,946,623.91	(19,832,240.11)
Apr-08		4,064,480.37		(127,833.67)		3,936,646.70	(15,895,593.41)
May-08		2,763,341.55		(104,234.15)		2,659,107.40	(13,236,486.01)
Jun-08		1,878,334.14		(88,315.25)		1,790,018.89	(11,446,467.12)
Jul-08		1,358,730.49		(63,525.90)		1,295,204.59	(10,151,262.53)
Aug-08		1,193,538.54		(33,998.07)		1,159,540.47	(8,991,722.06)
Sep-08		1,285,117.79		(29,709.11)		1,255,408.68	(7,736,313.38)
Oct-08		1,678,629.42		(24,541.82)		1,654,087.60	(6,082,225.78)
Nov-08	old rates	1,227,584.49		(19,458.51)		1,208,125.98	(4,874,099.80)
	new rates 1	(267,301.42)	12,409,909.45	43,683.02		12,186,291.05	7,312,191.25
Dec-08		(876,612.87)		24,459.57		(852,153.30)	6,460,037.95
Jan-09		(1,224,466.27)		20,808.44		(1,203,657.83)	5,256,380.12
Feb-09		(1,065,471.61)		16,808.30		(1,048,663.31)	4,207,716.81
Mar-09		(963,469.63)		13,258.29		(950,211.34)	3,257,505.47
Apr-09		(740,382.64)		10,274.03		(730,108.61)	2,527,396.86
May-09		(478,611.92)		8,141.79		(470,470.13)	2,056,926.73
Jun-09	1	29,762,815.05	(30,872,131.00)	(49,581.09)		(1,158,897.04)	898,029.69
Jul-09		237,111.52		3,617.35		240,728.87	1,138,758.56
Aug-09		(225,695.08)		3,650.53		(222,044.55)	916,714.01
Sep-09		(247,012.14)		2,822.50		(244,189.64)	672,524.37
Oct-09		(331,706.40)		1,802.90		(329,903.50)	342,620.87
Nov-09	old rates	(287,928.43)		706.89		(287,221.54)	55,399.33
	new rates 1	1,399,170.11	(34,046,133.91)	(56,967.02)	2.05%	(32,703,930.82)	(32,648,531.49)
Dec-09		4,202,356.33		(52,185.06)	2.05%	4,150,171.27	(28,498,360.22)
Jan-10		4,686,910.99		(44,681.30)	2.05%	4,642,229.69	(23,856,130.53)
Feb-10		3,496,884.62		(37,767.30)	2.05%	3,459,117.32	(20,397,013.21)
Mar-10		3,098,842.84		(32,197.97)	2.05%	3,066,644.87	(17,330,368.34)
Apr-10		3,024,257.29		(27,022.83)	2.05%	2,997,234.46	(14,333,133.88)
May-10		2,349,961.32		(22,478.51)	2.05%	2,327,482.81	(12,005,651.07)
Jun-10		1,832,968.70		(18,943.99)	2.05%	1,814,024.71	(10,191,626.36)
Jul-10		1,221,957.01		(16,366.94)	2.05%	1,205,590.07	(8,986,036.29)
Aug-10	forecast	1,034,212.72		(14,467.76)	2.05%	1,019,744.96	(7,966,291.33)
Sep-10	forecast	1,140,669.71		(12,634.76)	2.05%	1,128,034.95	(6,838,256.38)
Oct-10	forecast	2,149,344.32		(9,846.12)	2.05%	2,139,498.20	(4,698,758.18)

NOTES:
1 - Transfer in from deferral account 191400

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon Demand Deferral
Account Number: 191411
Current docket is UM 1445
Current Amortization was granted in Order No. 09-450

Debit (Credit)

Month/Year	Note	Amortization	Transfers	Interest	Interest Rate	Activity	Balance	
(a)	(b)	(c)	(d)	(e)		(f)	(g)	
Beginning Balance								
Sep-06							(378,656.89)	
Oct-06		(291,861.54)	222,250.90	(2,171.28)		(71,781.92)	(450,438.81)	
Nov-06		(257,895.34)		(4,160.96)		(262,056.30)	(712,495.11)	
Dec-06		94,876.40		(4,776.22)		90,100.18	(622,394.93)	
Jan-07		118,262.11		(4,045.17)		114,216.94	(508,177.99)	
Feb-07		108,861.66		(3,258.66)		105,603.00	(402,574.99)	
Mar-07		78,907.86		(2,607.81)		76,300.05	(326,274.94)	
Apr-07		58,175.23		(2,134.30)		56,040.93	(270,234.01)	
May-07		45,130.10		(1,778.68)		43,351.42	(226,882.59)	
Jun-07		29,502.17		(1,523.46)		27,978.71	(198,903.88)	
Jul-07		22,629.78		(1,347.20)		21,282.58	(177,621.30)	
Aug-07		20,873.27		(1,200.66)		19,672.61	(157,948.69)	
Sep-07		22,093.40		(1,055.00)		21,038.40	(136,910.29)	
Oct-07		35,774.94		(854.78)		34,920.16	(101,990.13)	
Nov-07	old rates 1	31,401.27	(6,001,472.08)	(43,720.27)		(6,013,791.08)	(6,115,781.21)	
	new rates	60,069.29		215.70		60,284.99	(6,055,496.22)	
Dec-07		194,326.89		(42,790.76)		151,536.13	(5,903,960.09)	
Jan-08		236,057.57		(41,552.63)		194,504.94	(5,709,455.15)	
Feb-08		230,550.71		(40,175.53)		190,375.18	(5,519,079.97)	
Mar-08		170,429.85		(39,024.21)		131,405.64	(5,387,674.33)	
Apr-08		169,366.36		(38,084.31)		131,282.05	(5,256,392.28)	
May-08		112,452.54		(37,345.86)		75,106.68	(5,181,285.60)	
Jun-08		73,388.89		(36,946.74)		36,442.15	(5,144,843.45)	
Jul-08		50,811.13		(30,204.68)		20,606.45	(5,124,237.00)	
Aug-08		42,791.51		(18,157.61)		24,633.90	(5,099,603.10)	
Sep-08		46,120.92		(18,064.03)		28,056.89	(5,071,546.21)	
Oct-08		62,869.76		(17,934.40)		44,935.36	(5,026,610.85)	
Nov-08	old rates 1	55,707.49		(17,787.24)		37,920.25	(4,988,690.60)	
	new rates	456,903.23	(9,244,720.70)	(32,082.89)		(8,819,900.36)	(13,808,590.96)	
Dec-08		1,790,295.46		(45,950.34)		1,744,345.12	(12,064,245.84)	
Jan-09		2,520,785.25		(38,443.71)		2,482,341.54	(9,581,904.30)	
Feb-09		2,197,581.53		(30,185.75)		2,167,395.78	(7,414,508.52)	
Mar-09		1,968,272.17		(22,881.41)		1,945,390.76	(5,469,117.76)	
Apr-09		1,495,651.24		(16,799.93)		1,478,851.31	(3,990,266.45)	
May-09		936,183.17		(12,533.07)		923,650.10	(3,066,616.35)	
Jun-09		556,425.02		(9,922.07)		546,502.95	(2,520,113.40)	
Jul-09		444,954.39		(8,175.76)		436,778.63	(2,083,334.77)	
Aug-09		393,829.40		(6,712.51)		387,116.89	(1,696,217.88)	
Sep-09		440,378.19		(5,252.20)		435,125.99	(1,261,091.89)	
Oct-09		605,395.85		(3,410.29)		601,985.56	(659,106.33)	
Nov-09	old rates 1	629,531.75		(1,225.28)		628,306.47	(30,799.86)	
	new rates	167,367.09	(3,599,290.33)	(6,562.47)	2.24%	(3,438,485.71)	(3,469,285.57)	
Dec-09		592,567.97		(5,922.94)	2.24%	586,645.03	(2,882,640.54)	
Jan-10		633,413.70		(4,789.74)	2.24%	628,623.96	(2,254,016.58)	
Feb-10		460,439.86		(3,777.75)	2.24%	456,662.11	(1,797,354.47)	
Mar-10		402,882.40		(2,979.04)	2.24%	399,903.36	(1,397,451.11)	
Apr-10		382,446.87		(2,251.62)	2.24%	380,195.25	(1,017,255.86)	
May-10		288,265.92		(1,629.83)	2.24%	286,636.09	(730,619.77)	
Jun-10		219,500.42		(1,158.96)	2.24%	218,341.46	(512,278.31)	
Jul-10		146,991.66		(819.06)	2.24%	146,172.60	(366,105.71)	
Aug-10	forecast	117,667.60		(573.57)	2.24%	117,094.03	(249,011.68)	1
Sep-10	forecast	131,863.11		(341.75)	2.24%	131,521.36	(117,490.32)	11
Oct-10	forecast	271,564.96		34.15	2.24%	271,599.11	154,108.79	21

NOTES:
1 - Transfer from deferral accounts 191410, 191450, 191417

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Commodity gas cost deferral
Account Number: 191.400
Current docket is UM 1445
Current Reauthorization was granted in Order No. 09-45(

Narrative: Deferral of customer's share of the difference between actual core commodity cost incurred and the Annual Sales WACOC embedded as defined in the related annual PGA. Prior to Nov 08 deferral was 67%; Nov 08 - Oct 08 deferral was 80% From Nov 09 forward deferral is 90%

Debit (Credit)

Month/Year (a)	(b)	(c)	Commodity Deferral (d)	8.618% Interest (e)	Adjustment (f)	Storage Adjustment 2/ (g)	Hedge Adjustment 3/ (h)	Transfer (i)	Activity (j)	Deferral Plus Int. GL Balance (k)
Sep-06										(13,952,287)
Oct-06			(3,727,373)	-	6,937			13,952,287	10,231,851	(3,720,436)
Nov-06			(3,484,746)	-					(3,484,746)	(7,205,182)
Dec-06			(5,108,000)	-					(5,108,000)	(12,313,182)
Jan-07			(7,731,759)	-					(7,731,759)	(20,044,941)
Feb-07			(3,491,835)	-					(3,491,835)	(23,536,776)
Mar-07			(2,626,360)	-					(2,626,360)	(26,163,136)
Apr-07			(2,985,080)	-					(2,985,080)	(29,148,216)
May-07			(691,726)	-					(691,726)	(29,839,942)
Jun-07			(1,003,088)	-					(1,003,088)	(30,843,030)
Jul-07			(232,754)	-					(232,754)	(31,075,784)
Aug-07			(779,271)	-					(779,271)	(31,855,055)
Sep-07			(709,131)	-					(709,131)	(32,564,186)
Oct-07			(6,100,622)	-					(6,100,622)	(38,664,808)
Nov-07	1/		(1,647,495)	(8,428)		(17,769)	(334,049)	38,490,957	36,483,217	(2,181,592)
Dec-07			(563,263)	(18,458)		(22,380)	(191,574)		(795,675)	(2,977,267)
Jan-08			(2,629,191)	(31,699)		(26,519)	(217,488)		(2,904,897)	(5,882,164)
Feb-08			(1,130,874)	(46,508)		(18,745)	(37,994)		(1,234,121)	(7,116,285)
Mar-08			(209,151)	(52,047)		(18,917)	(33,698)		(313,813)	(7,430,098)
Apr-08			4,256,494	(38,547)		(15,511)	(115,688)		4,086,748	(3,343,350)
May-08			4,017,700	(9,593)		(8,631)	6,134		4,005,610	662,260
Jun-08			4,032,874	19,201		(7,130)	(2,900)		4,042,045	4,704,305
Jul-08			3,852,841	47,602		(5,028)	0		3,895,415	8,599,720
Aug-08			2,241,181	69,789		(5,172)	0		2,305,798	10,905,518
Sep-08			1,424,486	83,415		(5,633)	0		1,502,268	12,407,786
Oct-08			(55,616)	88,797		(10,372)	(20,686)		2,123	12,409,909
Nov-08	1/		1,595,366	5,484		(68,129)	0	(12,409,909)	(10,877,188)	1,532,721
Dec-08			(2,687,328)	920		(121,914)	0		(2,808,322)	(1,275,601)
Jan-09			(9,397,006)	(43,325)		(117,349)	0		(9,557,680)	(10,833,281)
Feb-09			(10,437,568)	(115,621)		(94,853)	0		(10,648,042)	(21,481,324)
Mar-09			(9,207,614)	(187,659)		(90,389)	0		(9,485,662)	(30,966,986)
Apr-09			(7,501,026)	(249,541)		(58,824)	0		(7,809,391)	(38,776,377)
May-09			(3,643,034)	(291,692)		(36,548)	0		(3,971,274)	(42,747,650)
Jun-09	1/		(3,656,716)	(98,509)		(25,599)	0	30,872,131	27,091,307	(15,656,343)
Jul-09			(4,218,185)	(127,667)		(22,708)	0		(4,368,560)	(20,024,903)
Aug-09			(4,271,989)	(159,236)		(23,213)	0		(4,454,438)	(24,479,340)
Sep-09			(3,952,471)	(190,086)		(25,390)	0		(4,167,947)	(28,647,288)
Oct-09			(5,125,496)	(224,316)		(49,034)	0		(5,398,846)	(34,046,134)
Nov-09	1/		(4,923,013)	(17,710)		(8,863)	0	34,046,134	29,096,548	(4,949,586)
Dec-09			(522,205)	(37,476)		(15,316)	0		(574,997)	(5,524,583)
Jan-10			186,499	(39,044)		(10,452)	0		137,003	(5,387,580)
Feb-10			(614,891)	(40,930)		(8,505)	0		(664,326)	(6,051,906)
Mar-10			(1,765,863)	(49,835)		(8,806)	0		(1,824,504)	(7,876,410)
Apr-10			(2,112,002)	(64,176)		(7,263)	0		(2,183,441)	(10,059,851)
May-10			(2,434,277)	(81,007)		(5,277)	0		(2,520,561)	(12,580,411)
Jun-10			(1,242,188)	(94,822)		(3,784)	0		(1,340,794)	(13,921,206)
Jul-10			(200,690)	(100,708)		(2,743)	0		(304,141)	(14,225,347)
Aug-10				(102,162)					(102,162)	(14,327,508)
Sep-10				(102,895)					(102,895)	(14,430,404)
Oct-10				(103,634)					(103,634)	(14,534,038)

NOTES:

* No sharing was recorded in the October activity. Actual results reflect the cost of gas experienced for October compared to the then embedded OR 05 - 06 Annual Sales WACOG.

1/ - Transfer to amortization account 191401

2/ - Adjustment for storage true up

3/ - Adjustment for unembedded hedges

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Demand cost deferral
Account Number:	191.410
	Current docket is UM 1445
	Current Reauthorization was granted in Order No. 09-450
Narrative:	Deferral of 100% of the Difference between actual demand cost incurred and the demand cost embedded as defined in the related state's annual PGA.

Debit (Credit)

Month/Year		Refer to pg #	Demand Deferral	8.618% Interest*	Adjustment	Transfer	Activity	Deferral GL Balance
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Sep-06								(2,522,172)
Oct-06	A/		(62,173)		82,132	2,522,172	2,542,130	19,958
Nov-06			66,115				66,115	86,073
Dec-06			(308,132)				(308,132)	(222,059)
Jan-07			(216,880)				(216,880)	(438,939)
Feb-07			(194,834)				(194,834)	(633,773)
Mar-07			(235,107)				(235,107)	(868,880)
Apr-07	A/		(700,334)			(1,545,359)	(2,245,693)	(3,114,572)
May-07			(670,018)				(670,018)	(3,784,590)
Jun-07			(741,726)				(741,726)	(4,526,316)
Jul-07			(709,908)				(709,908)	(5,236,224)
Aug-07			(749,039)				(749,039)	(5,985,263)
Sep-07			(673,579)				(673,579)	(6,658,842)
Oct-07			4,505				4,505	(6,654,337)
Nov-07	A/		(351,714)	(1,263)		6,654,337	6,301,360	(352,977)
Dec-07			(147,008)	(3,063)			(150,070)	(503,047)
Jan-08			228,338	(2,793)			225,545	(277,502)
Feb-08			318,372	(850)			317,522	40,020
Mar-08			(1,301,433)	(4,386)			(1,305,819)	(1,265,799)
Apr-08			11,986	(9,048)			2,938	(1,262,860)
May-08			264	(9,068)			(8,804)	(1,271,665)
Jun-08			(88,925)	(9,452)			(98,377)	(1,370,042)
Jul-08			(60,627)	(10,057)			(70,684)	(1,440,726)
Aug-08			(158,016)	(10,914)			(168,930)	(1,609,656)
Sep-08			(58,940)	(11,772)			(70,712)	(1,680,368)
Oct-08			(92,937)	(12,402)			(105,339)	(1,785,706)
Nov-08	A/		(273,301)	(13,806)		1,785,706	1,498,600	(287,107)
Dec-08			(373,360)	(3,403)			(376,763)	(663,869)
Jan-09			(638,863)	(7,062)			(645,925)	(1,309,794)
Feb-09			(241,426)	(10,273)			(251,699)	(1,561,493)
Mar-09			(391,661)	(12,621)			(404,282)	(1,965,775)
Apr-09			(246,572)	(15,003)			(261,575)	(2,227,350)
May-09			(251,352)	(16,899)			(268,251)	(2,495,600)
Jun-09			39,071	(17,782)			21,289	(2,474,312)
Jul-09			(239,806)	(18,631)			(258,437)	(2,732,748)
Aug-09			(219,051)	(20,412)			(239,463)	(2,972,212)
Sep-09			(250,905)	(22,246)			(273,151)	(3,245,363)
Oct-09			(222,693)	(24,107)			(246,800)	(3,492,163)
Nov-09	A/		(286,059)	(1,027)		3,492,163	3,205,077	(287,086)
Dec-09			71,045	(1,807)			69,238	(217,848)
Jan-10			226,245	(752)			225,493	7,645
Feb-10			119,566	484			120,050	127,695
Mar-10			594,213	3,051			597,264	724,959
Apr-10			509,075	7,034			516,109	1,241,068
May-10			321,943	10,069			332,012	1,573,080
Jun-10			440,773	12,880			453,653	2,026,733
Jul-10			364,593	15,865			380,458	2,407,191
Aug-10				17,288			17,288	2,424,479
Sep-10				17,412			17,412	2,441,890
Oct-10				17,537			17,537	2,459,427

* No interest is applied to this activity until the 2007-2008 Tracker period

NOTES

A/Transfer to amortization account 191411

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Demand Collection Deferral
Account Number:	191.450
	Current docket is UM 1445
	Current Reauthorization was granted in Order No. 09-450
Narrative:	Deferral of 100% of the difference between actual demand costs collected and the seasonalized imbedded demand costs as defined in the state's annual PGA.

Debit (Credit)

Month/Year	Note	Refer to pg #	Demand Deferral	8.618% Interest*		Transfer		Activity	Deferral Plus Int. GL Balance
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Sep-06									3,060,327
Oct-06			(141,222)			(3,060,327)		(3,201,549)	(141,222)
Nov-06			(2,359,013)					(2,359,013)	(2,500,235)
Dec-06			(19,563)					(19,563)	(2,519,798)
Jan-07			(2,018,375)					(2,018,375)	(4,538,173)
Feb-07			1,398,546					1,398,546	(3,139,627)
Mar-07			3,775,526					3,775,526	635,899
Apr-07			1,451,760					1,451,760	2,087,658
May-07			560,128					560,128	2,647,786
Jun-07			471,203					471,203	3,118,989
Jul-07			311,188					311,188	3,430,177
Aug-07			(209,897)					(209,897)	3,220,280
Sep-07			(340,578)					(340,578)	2,879,702
Oct-07			(2,587,877)					(2,587,877)	291,824
Nov-07	1		(2,669,208)	(9,585)		(291,824)		(2,970,617)	(2,678,793)
Dec-07			527,745	(17,343)				510,402	(2,168,391)
Jan-08			(1,854,248)	(22,231)				(1,876,479)	(4,044,870)
Feb-08			265,686	(28,095)				237,592	(3,807,278)
Mar-08			(1,036,394)	(31,064)				(1,067,458)	(4,874,736)
Apr-08			(1,788,323)	(41,430)				(1,829,754)	(6,704,490)
May-08			17,069	(48,088)				(31,019)	(6,735,508)
Jun-08			(630,252)	(50,635)				(680,887)	(7,416,395)
Jul-08			39,907	(53,119)				(13,212)	(7,429,608)
Aug-08			(45,926)	(53,522)				(99,448)	(7,529,056)
Sep-08			(1,303)	(54,076)				(55,379)	(7,584,434)
Oct-08			(140,888)	(54,975)				(195,863)	(7,780,297)
Nov-08	1		1,160,024	4,165		7,780,297		8,944,487	1,164,190
Dec-08			(1,120,690)	4,337				(1,116,353)	47,837
Jan-09			(699,148)	(2,167)				(701,315)	(653,478)
Feb-09			(99,344)	(5,050)				(104,393)	(757,872)
Mar-09			(995,501)	(9,017)				(1,004,519)	(1,762,391)
Apr-09			(31,210)	(12,769)				(43,979)	(1,806,369)
May-09			822,486	(10,019)				812,466	(993,903)
Jun-09			297,582	(6,069)				291,512	(702,391)
Jul-09			164,535	(4,454)				160,082	(542,309)
Aug-09			111,739	(3,493)				108,246	(434,063)
Sep-09			162,690	(2,533)				160,157	(273,907)
Oct-09			76,681	(1,692)				74,989	(198,917)
Nov-09	1		575,104	2,065		198,917		776,087	577,169
Dec-09			(2,010,508)	(3,074)				(2,013,582)	(1,436,413)
Jan-10			2,426,982	(1,601)				2,425,381	988,968
Feb-10			2,018,891	14,352				2,033,243	3,022,212
Mar-10			427,365	23,239				450,604	3,472,816
Apr-10			(527,889)	23,045				(504,844)	2,967,972
May-10			(634,421)	19,037				(615,384)	2,352,587
Jun-10			(566,552)	14,861				(551,691)	1,800,896
Jul-10			(237,583)	12,080				(225,503)	1,575,393
Aug-10				11,314				11,314	1,586,707
Sep-10				11,395				11,395	1,598,102
Oct-10				11,477				11,477	1,609,579

* No interest is applied to this activity until the 2007-2008 Tracker period

NOTES

1 - transfer to Amorization account 191411

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Coos County Demand
Account Number:	Account 191417
Class of Customers:	Core

Narrative: Deferral of transportation charge payable by NW Natural for use of the natural gas transmission pipeline owned by Coos County.

Date	Deferral	Adjustment (b)	Transfer (c)	Reference	Interest (a)	Activity	Balance
9/30/2006	24,809.17	(17,533.12)				7,276.05	290,846.66
10/31/2006	24,809.13		(290,846.66)			(266,037.53)	24,809.13
11/30/2006	24,809.13	(2,813.18)				21,995.95	46,805.08
12/31/2006	24,809.13	(2,144.42)				22,664.71	69,469.79
1/31/2007	24,809.13	(2,836.10)				21,973.03	91,442.82
2/28/2007	24,809.13	(2,425.31)				22,383.82	113,826.64
3/31/2007	24,809.13	(2,718.54)				22,090.59	135,917.23
4/30/2007	24,809.13	(2,104.68)				22,704.45	158,621.68
5/31/2007	77,152.87	(1,685.00)				75,467.87	234,089.55
6/30/2007	26,542.00	(1,023.27)				25,518.73	259,608.28
7/31/2007	26,542.00	(1,307.00)				25,235.00	284,843.28
8/31/2007	26,542.00	(947.02)				25,594.98	310,438.26
9/30/2007	26,542.00	(945.17)				25,596.83	336,035.09
10/31/2007	26,542.00	(1,536.05)				25,005.95	361,041.04
11/30/2007	26,542.00	(1,940.08)	(361,041.04)			(336,439.12)	24,601.92
12/31/2007	32,469.30	(2,958.44)				29,510.86	54,112.78
1/31/2008	29,594.00	(4,025.23)				25,568.77	79,681.55
2/29/2008	29,594.00	(4,077.53)				25,516.47	105,198.02
3/31/2008	29,594.00	(2,879.08)				26,714.92	131,912.94
4/30/2008	29,594.00	(4,119.14)				25,474.86	157,387.80
5/31/2008	29,795.69	(2,755.75)				27,039.94	184,427.74
6/30/2008	30,272.28	(2,063.32)				28,208.96	212,636.70
7/31/2008	29,727.62	(2,336.23)				27,391.39	240,028.09
8/31/2008	29,727.62	(2,465.30)				27,262.32	267,290.41
9/30/2008	29,831.58	(2,582.15)				27,249.43	294,539.84
10/31/2008	29,797.68	(3,055.12)				26,742.56	321,282.40
11/30/2008	29,790.74	(3,493.06)	(321,282.40)			(294,984.72)	26,297.68
12/31/2008	(77,100.00)	(3,189.48)				(80,289.48)	(53,991.80)
1/31/2009	18,503.85	(6,024.05)				12,479.80	(41,512.00)
2/28/2009	18,503.85	(6,234.04)				12,269.81	(29,242.19)
3/31/2009	18,435.50	(5,234.98)				13,200.52	(16,041.67)
4/30/2009	18,435.50	(4,846.50)				13,589.00	(2,452.67)
5/31/2009	18,435.50	(3,632.95)				14,802.55	12,349.88
6/30/2009	18,435.50	(2,831.26)				15,604.24	27,954.12
7/31/2009	18,664.77	(2,593.94)				16,070.83	44,024.95
8/31/2009	18,434.50	(2,250.62)				16,183.88	60,208.83
9/30/2009	18,434.50	(2,263.58)				16,170.92	76,379.75
10/31/2009	18,434.50	(3,024.27)				15,410.23	91,789.98
11/30/2009	18,434.50	(3,995.40)	(91,789.98)			(77,350.88)	14,439.10
12/31/2009	18,434.50	(4,742.99)				13,691.51	28,130.61
1/31/2010	21,725.00	(6,646.34)				15,078.66	43,209.27
2/28/2010	21,308.03	(5,565.85)				15,742.18	58,951.45
3/31/2010	21,674.75	(5,382.49)				16,292.26	75,243.71
4/30/2010	21,689.82	(5,393.22)				16,296.60	91,540.31
5/31/2010	21,678.19	(4,259.59)				17,418.60	108,958.91
6/30/2010	21,674.75	(3,886.21)				17,788.54	126,747.45
7/31/2010	21,674.75	(2,855.42)				18,819.33	145,566.78
8/31/2010						0.00	145,566.78
9/30/2010						0.00	145,566.78
10/31/2010						0.00	145,566.78

Notes:

a. No interest is applied to this activity

b. Per Order 03-236 in docket UG-152; the amount collected via the Coos County 2¢ surcharge should be applied toward this deferral with the balance recoverable statewide as part of the PGA.

c. Balance transferred to account 191411.

Exhibit: B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW Natural

SUPPORTING MATERIALS

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 10-13

September 2, 2010

NW Natural

Exhibit B
Supporting Materials
Purchased Gas Costs
NWN Advice No. OPUC 10-13

<u>Commodity and Non-Commodity Costs</u>:

Effects of Average Bill by Rate Schedule By Filing	1
3 Percent Test (combined effects of NWN Advice Nos. 10-13, 10-14 and 10-15	2
Summary of Total Commodity Cost	3
Summary of Total Demand Charges	4
Derivation of Demand Increments	5
Calculation of Winter Sales WACOG – Oregon	6
Derivation of Seasonalized Fixed Charges	7
Northwest Pipeline GP; Substitute Original Sheet No. 5; Fifth Revised Volume No. 1	8
Northwest Pipeline GP; Substitute Original Sheet No. 7; Fifth Revised Volume No. 1	9
Northwest Pipeline GP; Substitute Original Sheet No. 8; Fifth Revised Volume No. 1	10

NW Natural
Rates & Regulatory Affairs
2010-2011 PGA Filing - Oregon: August Filing
Effects on Average Bill by Rate Schedule

Calculation of Effect on Customer Average Bill by Rate Schedule [1]

			Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	6/1/2010 Billing Rates	6/1/2010 Current Average Bill	Proposed 11/1/2010 PGA [2] Rates	Proposed 11/1/2010 PGA [2] Average Bill	Advice 10-13 Proposed 11/1/2010 **PGA [2] % Bill Change**	Proposed 11/1/2010 Temp I [3] Rates	Proposed 11/1/2010 Temp I [3] Average Bill	Advice 10-14 Proposed 11/1/2010 **Temp I [3] % Bill Change**	Proposed 11/1/2010 Temp II [4] Rates	Proposed 11/1/2010 Temp II [4] Average Bill	Advice 10-15 Proposed 11/1/2010 **Temp II [4] % Bill Change**	Proposed 11/1/2010 Permanent [5] Rates	Proposed 11/1/2010 Permanent [5] Average Bill	Advice 10-16 Proposed 11/1/2010 **Permanent [5] % Bill Change**	Proposed 11/1/2010 Total **Rates**	Proposed 11/1/2010 Total Average Bill	Proposed 11/1/2010 **Total % Bill Change**
5								**F=D+(C * E)**		**H=D+(C * G)**	**I =(H - F)/F**		**K=D+(C * J)**	**L =(K - F)/F**		**N=D+(C * M)**	**O =(N - F)/F**		**Q=D+(C * P)**	**R =(Q - F)/F**		**T=D+(C * S)**	**U =(T - F)/F**
6	Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**	**Q**	**R**	**S**	**T**	**U**
7	1R		732,166	N/A	17.0	5.00	1.18957	25.22	1.14665	24.49	-2.9%	1.23095	25.93	2.8%	1.19441	25.30	0.3%	1.19218	25.27	0.2%	1.19643	25.34	0.5%
8	1C		146,693	N/A	66.0	5.00	1.13791	80.10	1.12529	79.27	-1.0%	1.15044	80.93	1.0%	1.14128	80.32	0.3%	1.13978	80.23	0.2%	1.14370	80.48	0.5%
9	2R		357,769,124	N/A	55.0	6.00	1.12251	67.74	1.07966	65.38	-3.5%	1.16389	70.01	3.4%	1.12581	67.92	0.3%	1.12448	67.85	0.2%	1.12695	67.98	0.4%
10	3C Firm Sales		149,064,075	N/A	224.0	8.00	1.01033	234.31	0.99775	231.50	-1.2%	1.02286	237.12	1.2%	1.01269	234.84	0.2%	1.01158	234.59	0.1%	1.01435	235.21	0.4%
11	Intentionally blank																						
12	3I Firm Sales		4,532,614	N/A	1,359.0	8.00	0.97691	1,335.62	0.96792	1,323.40	-0.9%	0.98526	1,346.97	0.8%	0.97886	1,338.27	0.2%	0.97800	1,337.10	0.1%	0.97970	1,339.41	0.3%
13	Intentionally blank																						
14	19	1st mantle	16,797	N/A	100.0	22.04	17.39	17.39	17.20	17.20	-1.1%	17.39	17.39	0.0%	17.39	17.39	0.0%	17.40	17.40	0.1%	17.21	17.21	-1.0%
15	19	add'l mtls	0	N/A	0.0	21.43	16.78	16.78	16.59	16.59	-1.1%	16.78	16.78	0.0%	16.78	16.78	0.0%	16.79	16.79	0.1%	16.60	16.60	-1.1%
16	31C Firm Sales	Block 1	25,462,215	2,000	4,128.0	325.00	0.72390	1,772.80	0.70652	1,738.04		0.73643	1,797.86		0.72557	1,776.14		0.72483	1,774.66		0.72197	1,768.94	
17		Block 2	34,174,988	all additional			0.70778	1,506.16	0.69041	1,469.19		0.72031	1,532.82		0.70932	1,509.43		0.70864	1,507.99		0.70563	1,501.58	
18		**Total**						**3,278.96**		**3,207.23**	-2.2%		**3,330.68**	1.6%		**3,285.57**	0.2%		**3,282.65**	0.1%		**3,270.52**	-0.3%
19	31C Firm Trans	Block 1	108,676	2,000	1,294.0	325.00	0.18782	568.04	0.18528	564.75		0.20035	584.25		0.18710	567.11		0.18825	568.60		0.19779	580.94	
20		Block 2	1,097,399	all additional			0.17173		0.16919			0.18426			0.17107			0.17212			0.18170		
21		**Total**						**568.04**		**564.75**	-0.6%		**584.25**	2.9%		**567.11**	-0.2%		**568.60**	0.1%		**580.94**	2.3%
22	31C Interr Sales	Block 1	275,097	2,000	10,584.0	325.00	0.73238	1,789.76	0.70279	1,730.58		0.74491	1,814.82		0.73377	1,792.54		0.73235	1,789.70		0.71700	1,759.00	
23		Block 2	1,376,053	all additional			0.71603	6,146.40	0.68645	5,892.49		0.72856	6,253.96		0.71730	6,157.30		0.71601	6,146.23		0.70052	6,013.26	
24		**Total**						**7,936.16**		**7,623.07**	-3.9%		**8,068.78**	1.7%		**7,949.84**	0.2%		**7,935.93**	0.0%		**7,772.26**	-2.1%
25	31I Firm Sales	Block 1	5,501,309	2,000	7,070.0	325.00	0.70361	1,732.22	0.68980	1,704.60		0.71196	1,748.92		0.70493	1,734.86		0.70333	1,731.66		0.69950	1,724.00	
26		Block 2	14,436,132	all additional			0.68733	3,484.76	0.67352	3,414.75		0.69568	3,527.10		0.68852	3,490.80		0.68709	3,483.55		0.68310	3,463.32	
27		**Total**						**5,216.98**		**5,119.35**	-1.9%		**5,276.02**	1.1%		**5,225.66**	0.2%		**5,215.21**	0.0%		**5,187.32**	-0.6%
28	31I Firm Trans	Block 1	65,384	2,000	12,275.0	325.00	0.16773	660.46	0.16763	660.26		0.16773	660.46		0.16705	659.10		0.16764	660.28		0.16713	659.26	
29		Block 2	523,835	all additional			0.15157	1,557.38	0.15147	1,556.35		0.15157	1,557.38		0.15096	1,551.11		0.15149	1,556.56		0.15103	1,551.83	
30		**Total**						**2,217.84**		**2,216.61**	-0.1%		**2,217.84**	0.0%		**2,210.21**	-0.3%		**2,216.84**	0.0%		**2,211.09**	-0.3%
31	31I Interr Sales	Block 1	187,284	2,000	3,539.0	325.00	0.71516	1,755.32	0.68905	1,703.10		0.72351	1,772.02		0.71679	1,758.58		0.71153	1,748.06		0.69598	1,716.96	
32		Block 2	109,997	all additional			0.69834	1,074.75	0.67225	1,034.59		0.70669	1,087.60		0.69981	1,077.01		0.69506	1,069.70		0.67931	1,045.46	
33		**Total**						**2,830.07**		**2,737.69**	-3.3%		**2,859.62**	1.0%		**2,835.59**	0.2%		**2,817.76**	-0.4%		**2,762.42**	-2.4%
34	32C Firm Sales	Block 1	4,831,912	10,000	18,164.0	675.00	0.63582	7,033.20	0.62095	6,884.50		0.64417	7,116.70		0.63538	7,028.80		0.63622	7,037.20		0.62943	6,969.30	
35		Block 2	4,710,642	20,000			0.62082	5,068.37	0.60596	4,947.06		0.62917	5,136.54		0.62045	5,065.35		0.62115	5,071.07		0.61441	5,016.04	
36		Block 3	1,194,904	20,000			0.59585		0.58100			0.60420			0.59561			0.59610			0.58946		
37		Block 4	160,994	100,000			0.57089		0.55604			0.57924			0.57077			0.57104			0.56448		
38		Block 5	0	600,000			0.55590		0.54107			0.56425			0.55585			0.55598			0.54948		
39		Block 6	0	all additional			0.54593		0.53109			0.55428			0.54593			0.54597			0.53950		
40		**Total**						**12,101.57**		**11,831.56**	-2.2%		**12,253.24**	1.3%		**12,094.15**	-0.1%		**12,108.27**	0.1%		**11,985.34**	-1.0%
41	32I Firm Sales	Block 1	4,539,045	10,000	26,204.0	675.00	0.63559	7,030.90	0.62181	6,893.10		0.64394	7,114.40		0.63514	7,026.40		0.63554	7,030.40		0.62984	6,973.40	
42		Block 2	6,172,653	20,000			0.62048	10,054.26	0.60670	9,830.97		0.62883	10,189.56		0.62010	10,048.10		0.62043	10,053.45		0.61478	9,961.90	
43		Block 3	2,034,570	20,000			0.59530		0.58153			0.60365			0.59503			0.59528			0.58970		
44		Block 4	460,720	100,000			0.57010		0.55635			0.57845			0.56994			0.57007			0.56457		
45		Block 5	0	600,000			0.55499		0.54124			0.56334			0.55490			0.55498			0.54953		
46		Block 6	0	all additional			0.54494		0.53119			0.55329			0.54489			0.54493			0.53950		
47		**Total**						**17,085.16**		**16,724.07**	-2.1%		**17,303.96**	1.3%		**17,074.50**	-0.1%		**17,083.85**	0.0%		**16,935.30**	-0.9%
48	32 Firm Trans	Block 1	6,268,582	10,000	68,242.0	675.00	0.09939	1,668.90	0.09932	1,668.20		0.09939	1,668.90		0.09898	1,664.80		0.09978	1,672.80		0.09944	1,669.40	
49		Block 2	9,159,926	20,000			0.08446	1,689.20	0.08440	1,688.00		0.08446	1,689.20		0.08411	1,682.20		0.08480	1,696.00		0.08451	1,690.20	
50		Block 3	5,840,925	20,000			0.05964	1,192.80	0.05959	1,191.80		0.05964	1,192.80		0.05940	1,188.00		0.05989	1,197.80		0.05968	1,193.60	
51		Block 4	12,559,498	100,000			0.03481	635.00	0.03477	634.27		0.03481	635.00		0.03467	632.45		0.03495	637.56		0.03482	635.19	
52		Block 5	12,780,991	600,000			0.01991		0.01987			0.01991			0.01983			0.01999			0.01990		
53		Block 6	67,429	all additional			0.00999		0.00996			0.00999			0.00995			0.01002			0.00996		
54		**Total**						**5,185.90**		**5,182.27**	-0.1%		**5,185.90**	0.0%		**5,167.45**	-0.4%		**5,204.16**	0.4%		**5,188.39**	0.0%
55	32C Interr Sales	Block 1	6,411,102	10,000	48,518.0	675.00	0.64080	7,083.00	0.61482	6,823.20		0.64915	7,166.50		0.64043	7,079.30		0.64087	7,083.70		0.62303	6,905.30	
56		Block 2	8,490,539	20,000			0.62577	12,515.40	0.59979	11,995.80		0.63412	12,682.40		0.62547	12,509.40		0.62584	12,516.80		0.60805	12,161.00	
57		Block 3	4,549,037	20,000			0.60074	11,124.50	0.57477	10,643.59		0.60909	11,279.13		0.60054	11,120.80		0.60077	11,125.06		0.58305	10,796.92	
58		Block 4	7,184,691	100,000			0.57570		0.54974			0.58405			0.57560			0.57570			0.55805		
59		Block 5	1,814,920	600,000			0.56065		0.53470			0.56900			0.56062			0.56067			0.54307		
60		Block 6	660,521	all additional			0.55065		0.52470			0.55900			0.55066			0.55066			0.53309		
61		**Total**						**30,722.90**		**29,462.59**	-4.1%		**31,128.03**	1.3%		**30,709.50**	0.0%		**30,725.56**	0.0%		**29,863.22**	-2.8%
62	32I Interr Sales	Block 1	8,590,095	10,000	50,006.0	675.00	0.64080	7,083.00	0.61482	6,823.20		0.64915	7,166.50		0.64038	7,078.80		0.64085	7,083.50		0.62296	6,904.60	
63		Block 2	11,376,286	20,000			0.62577	12,515.40	0.59979	11,995.80		0.63412	12,682.40		0.62542	12,508.40		0.62582	12,516.40		0.60798	12,159.60	
64		Block 3	6,095,155	20,000			0.60074	12,014.80	0.57477	11,495.40		0.60909	12,181.80		0.60049	12,009.80		0.60077	12,015.40		0.58300	11,660.00	
65		Block 4	9,626,607	100,000			0.57570	3.45	0.54974	3.30		0.58405	3.50		0.57555	3.45		0.57570	3.45		0.55800	3.35	
66		Block 5	2,431,772	600,000			0.56065		0.53470			0.56900			0.56057			0.56067			0.54302		
67		Block 6	885,018	all additional			0.55065		0.52470			0.55900			0.55061			0.55066			0.53304		
68		**Total**						**31,616.65**		**30,317.70**	-4.1%		**32,034.20**	1.3%		**31,600.45**	-0.1%		**31,618.75**	0.0%		**30,727.55**	-2.8%
69	32 Interr Trans	Block 1	8,508,398	10,000	187,286.0	675.00	0.09970	1,672.00	0.09964	1,671.40		0.09970	1,672.00		0.09931	1,668.10		0.10000	1,675.00		0.09968	1,671.80	
70		Block 2	14,648,794	20,000			0.08474	1,694.80	0.08469	1,693.80		0.08474	1,694.80		0.08441	1,688.20		0.08499	1,699.80		0.08472	1,694.40	
71		Block 3	10,129,137	20,000			0.05984	1,196.80	0.05979	1,195.80		0.05984	1,196.80		0.05961	1,192.20		0.06001	1,200.20		0.05981	1,196.20	
72		Block 4	27,987,359	100,000			0.03492	3,492.00	0.03488	3,488.00		0.03492	3,492.00		0.03478	3,478.00		0.03502	3,502.00		0.03489	3,489.00	
73		Block 5	54,915,266	600,000			0.01998	744.97	0.01994	743.48		0.01998	744.97		0.01990	741.99		0.02004	747.21		0.01995	743.86	
74		Block 6	81,585,080	all additional			0.01002		0.00999			0.01002			0.00998			0.01006			0.01000		
75		**Total**						**8,800.57**		**8,792.48**	-0.1%		**8,800.57**	0.0%		**8,768.49**	-0.4%		**8,824.21**	0.3%		**8,795.26**	-0.1%
76	Intentionally blank																						
77	33		0	N/A	0.0	38,000.00	0.00539	38,000.00	0.00539	38,000.00	0.0%	0.00539	38,000.00	0.0%	0.00537	38,000.00	0.0%	0.00540	38,000.00	0.0%	0.00539	38,000.00	0.0%
78																							
79	**Totals**		932,252,405																				
80			0																				

82 **Sources:**

83	Direct Inputs	per Tariff	per Tariff					
85	Rates in summary	Column A	Column D +	Column A +	Column A +	Cols D+E+G	Column H
86	Temporaries		Cols -A+B+C+D	Cols E+F+H+K	Cols G+J+L		

88 [1] For convenience of presentation, the cent per therm demand charge is used, rather than the available MDDV demand option for Rate Schedules 31 and 3
89 [2] Tariff Advice Notice 10-13: PGA Gas Costs, Gas Cost Amortizations and the removal of all current temporary adjustments
90 [3] Tariff Advice Notice 10-14: Non-Gas Cost Amortizations not subject to earnings test
91 [4] Tariff Advice Notice 10-15: Non-Gas Cost Amortizations subject to earnings test
92 [5] Tariff Advice Notice 10-16: Combined Effects of Permanent rate changes for Safety Programs and Price Elasticity

NW Natural
Rates and Regulatory Affairs
2010-2011 PGA Filing - Oregon
Estimated Revenue Effects for the 12 Months Beginning November 1, 2010

Line No.	Item	AMR Deferral Increment Amount	Residual Balance Smart Energy Increment Amount	PUC Refund Increment Amount	Total Increment Amounts	Limit For Increment Amounts
1	Commodity and Demand Deferrals				($15,478,320)	
2	Temporary Increments	2,572,337	30,388	(995,930)	1,606,795	
3	Total	$2,572,337	$30,388	($995,930)	($13,871,525)	
4	2009 Oregon Utility Revenues					$893,472,000
5	@ 3% threshold					3.0%
6	Threshold for Annual Effect of Proposed Change in Amortization					$26,804,160

ORS 757.259 (6)

NW Natural
2010-2011 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost

SYSTEM COSTS

1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)		
2			November	December	January	February	March	April	May	June	July	August	September	October	TOTAL		
3			1	2	3	4	5	6	7	8	9	10	11	12			
4	**COSTS**																
5	**Commodity Cost from Supply**		$42,590,010	$48,830,809	$44,204,010	$33,096,288	$33,739,295	$30,285,276	$20,760,139	$14,755,309	$12,636,223	$12,671,680	$13,814,314	$27,407,316	$334,790,669		
6	tab commodity cost from supply, column ci, lines 93-105																
7	**Volumetric Pipeline Chgs**		$276,298	$304,871	$284,365	$219,396	$201,319	$192,947	$130,392	$89,472	$73,813	$73,541	$81,530	$168,235	$2,096,179		
8	tab commodity cost from vol pipe, column e, line 78-90																
9	**Commodity Cost from Storage**		$746,640	$14,519,674	$18,171,471	$18,097,294	$11,512,652	$147,905	$152,835	$147,905	$152,835	$152,835	$147,905	$152,835	$64,102,786		
10	tab Commodity Cost from Storage, column h, line 61-73																
11	**Total Commodity Cost**		$43,612,948	$63,655,354	$62,659,846	$51,412,978	$45,453,266	$30,626,128	$21,043,366	$14,992,686	$12,862,871	$12,898,056	$14,043,749	$27,728,386	$400,989,634		
12																	
13	**VOLUMES**																
14	Pipeline Commodity at Receipt Points		87,965,423	95,779,116	86,115,299	63,710,039	64,740,076	63,071,660	43,136,300	29,840,985	24,881,882	24,797,862	27,279,638	55,268,478	666,586,758		
15	Pipeline Fuel Use		2,746,465	3,037,309	2,756,993	2,009,545	2,069,495	1,984,114	1,461,717	1,019,868	877,655	874,049	948,407	1,730,920	21,516,537		
16	Pipeline Gas Arriving at City Gate		85,218,958	92,741,807	83,358,306	61,700,494	62,670,581	61,087,546	41,674,583	28,821,117	24,004,227	23,923,813	26,331,231	53,537,558	645,070,221		
17	Storage Gas Deliveries		1,611,515	26,016,730	32,762,884	33,927,571	20,742,195	240,000	248,000	240,000	248,000	248,000	240,000	248,000	116,772,895		
18	Total Gas At Citygate (Storage and Pipeline)		86,830,473	118,758,537	116,121,190	95,628,065	83,412,776	61,327,546	41,922,583	29,061,117	24,252,227	24,171,813	26,571,231	53,785,558	761,843,116		
19																	
20	Unaccounted for Gas		275,769	300,111	269,747	199,664	202,801	197,676	134,858	93,267	77,675	77,420	85,208	173,248	2,087,444	0.274%	0.000%
21																	
22	Load Served		86,554,704	118,458,426	115,851,443	95,428,401	83,209,975	61,129,870	41,787,725	28,967,850	24,174,552	24,094,393	26,486,023	53,612,310	759,755,672		
23															0		
24	**Annual Sales WACOG**		$0.50388	$0.53736	$0.54086	$0.53876	$0.54625	$0.50100	$0.50358	$0.51756	$0.53208	$0.53531	$0.53023	$0.51720	$0.52779		
25																	
OR	**OREGON Sales WACOG with Revenue Sensitive**		$0.51839	$0.55283	$0.55643	$0.55427	$0.56198	$0.51543	$0.51808	$0.53246	$0.54740	$0.55072	$0.54550	$0.53209	$0.54299		

NW Natural
2010-2011 PGA - SYSTEM: August Filing
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
		30	31	31	28	31	30	31	30	31	31	30	31	365
Transport charges by transporter:														
Northwest Pipeline		$3,994,861	$4,150,096	$4,128,021	$3,728,537	$4,128,021	$3,994,861	$4,128,021	$3,994,861	$4,128,021	$4,128,021	$3,994,861	$4,128,021	$48,626,203
GTN		517,197	534,437	534,437	482,717	534,437	435,253	449,761	435,253	449,761	449,761	435,253	534,437	5,792,704
TCPL BC		390,258	390,258	390,258	390,258	390,258	347,889	347,889	347,889	347,889	347,889	347,889	390,258	4,428,884
NOVA		935,369	935,369	935,369	935,369	935,369	935,369	935,369	935,369	935,369	935,369	935,369	935,369	11,224,424
Terasen (Southern Crossing)		629,109	792,771	650,079	587,167	650,079	629,109	650,079	629,109	650,079	650,079	629,109	650,079	7,796,848
Spectra (Westcoast)		770,299	773,523	773,523	763,850	773,523	770,299	773,523	770,299	773,523	773,523	770,299	773,523	9,259,707
KB Pipeline		18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	224,256
Total System Demand		$7,255,781	$7,595,142	$7,430,375	$6,906,586	$7,430,375	$7,131,468	$7,303,330	$7,131,468	$7,303,330	$7,303,330	$7,131,468	$7,430,375	$87,353,026

Detail in file "NOVA ANG Monthly Summary for Tracker 2010-11 Updated.xls"

NW Natural
2010-2011 PGA - OREGON: August Filing
Derivation of Oregon per therm Non-Commodity Charges

Oregon Derivation of Demand Increments

Line			Without Revenue Sensitive	WITH Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$87,353,026	
5	Oregon Allocation Factor 1/		90.21%	
6	Oregon Demand		$78,801,165	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		615,941,553	
9	Oregon Interruptible Sales Forecasted Normal Volumes		70,064,174	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.12623	$0.12986
13	Proposed Interruptible Demand 2/		$0.01501	$0.01544
14	Proposed MDDV Demand Charge		$1.88	$1.93
15				
16	Current Firm Demand Per Therm		$0.12128	$0.12502
17	Current Interruptible Demand		$0.01442	$0.01486
18	Current MDDV Demand Charge		$1.81	$1.87
19				
20	Percent Change in Firm Demand		4.08%	
21				
22				
23	1/Allocation Factor: Actual 12 months ended 06/30/10 firm sales volumes:			
24		Washington	Oregon	System
25	Residential	42,176,285	339,025,054	381,201,339
26	Commercial	18,975,597	214,251,712	233,227,309
27	Industrial	2,701,443	35,014,509	37,715,952
28	Total	63,853,325	588,291,275	652,144,600
29		9.79%	90.21%	100.00%
30				
31	2/Calculation of Proposed Demand Rates:			
32				
33	Demand change factor		1.041	
34				
35	Firm Demand (line 8 * line 35)		$0.12623	$77,749,613
36	Interruptible Demand (line 9 * line 36)		$0.01501	$1,051,552
37				$78,801,165
38				$0

NW Natural
2010-2011 PGA - SYSTEM: August Filing
Calculation of Winter WACOG

		AECO/NIT	Without Rev Sensitive	WITH Rev Sensitive
1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.43070		
6	December	$0.46040		
7	January	$0.46850		
8	February	$0.46660		
9	March	$0.46180		
10	April	$0.43755		
11	May	$0.43415		
12	June	$0.43465		
13	July	$0.43845		
14	August	$0.44420		
15	September	$0.44830		
16	October	$0.45790		
17				
18				
19	Average price, November-March		$0.45760	average lines 5-9
20				
21	Annual average price, November-October		$0.44860	average lines 5-16
22				
23	Ratio of winter to annual		1.02006	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.52779	$0.54299
OR	Oregon Winter WACOG		$0.53838	$0.55388
			line 23 * $0.52779	

NW Natural
2010-2011 PGA - OREGON: August Filing
Derivation of Oregon Seasonalized Fixed Charges

		Normalized Residential Volumes	Normalized Commercial Volumes	Firm Industrial Volumes	Interruptible Volumes	Total	Firm Deman Increment Eff. 11/01/1	terr. Demand Increment ff. 11/01/10	Seasonalized Fixed Charges
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
November	2010								$8,508,808
December	2010	43,308,204	25,142,576	3,493,785	6,330,586	78,275,151	$0.12623	$0.01501	$9,176,491
January	2011	61,875,580	34,258,466	3,940,745	7,001,947	107,076,738	$0.12623	$0.01501	$12,737,411
February	2011	60,319,315	33,412,246	3,966,164	6,961,454	104,659,180	$0.12623	$0.01501	$12,436,749
March	2011	49,007,580	27,585,404	3,473,537	6,142,041	86,208,563	$0.12623	$0.01501	$10,198,886
April	2011	41,108,746	24,162,755	3,564,526	6,423,101	75,259,127	$0.12623	$0.01501	$8,785,493
May	2011	28,430,463	17,821,652	3,179,415	5,854,738	55,286,268	$0.12623	$0.01501	$6,327,557
June	2011	17,065,036	12,184,275	2,928,864	5,576,012	37,754,187	$0.12623	$0.01501	$4,145,505
July	2011	10,088,432	8,346,691	2,578,098	5,057,361	26,070,582	$0.12623	$0.01501	$2,728,382
August	2011	7,440,859	6,886,805	2,460,402	4,954,060	21,742,127	$0.12623	$0.01501	$2,193,496
September	2011	7,404,992	6,851,824	2,455,682	4,949,834	21,662,332	$0.12623	$0.01501	$2,183,893
October	2011	8,716,368	7,549,434	2,501,130	4,960,874	23,727,805	$0.12623	$0.01501	$2,443,388
November	2011	23,752,512	15,544,295	3,134,695	5,852,165	48,283,667	$0.12623	$0.01501	$5,443,914
		358,518,087	219,746,422	37,677,043	70,064,174	686,005,727			$78,801,165

STATEMENT OF RATES
Effective Rates Applicable to
Rate Schedules TF-1, TF-2, TI-1, TFL-1 and TIL-1
(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate Minimum	Base Tariff Rate Maximum	ACA(2)	Currently Effective Tariff Rate(3) Minimum	Currently Effective Tariff Rate(3) Maximum
Rate Schedule TF-1 (4)(5)					
Reservation					
(Large Customer)					
System-Wide	.00000	.37984	-	.00000	.37984
15 Year Evergreen Exp.	.00000	.38101	-	.00000	.38101
25 Year Evergreen Exp.	.00000	.36445	-	.00000	.36445
Volumetric					
(Large Customer)					
System-Wide	.00756	.03000	.00190	.00946	.03190
15 Year Evergreen Exp.	.00369	.00369	.00190	.00559	.00559
25 Year Evergreen Exp.	.00369	.00369	.00190	.00559	.00559
(Small Customer) (6)	.00756	.67209	.00190	.00946	.67399
Scheduled Overrun	.00756	.40984	.00190	.00946	.41174
Rate Schedule TF-2 (4)(5)					
Reservation	.00000	.37984	-	.00000	.37984
Volumetric	.00756	.03000	-	.00756	.03000
Scheduled Daily Overrun	.00756	.40984	-	.00756	.40984
Annual Overrun	.00756	.40984	-	.00756	.40984
Rate Schedule TI-1					
Volumetric (7)	.00756	.40984	.00190	.00946	.41174
Rate Schedule TFL-1 (4)(5)					
Reservation	-	-	-	-	-
Volumetric	-	-	-	-	-
Scheduled Overrun	-	-	-	-	-
Rate Schedule TIL-1					
Volumetric	-	-	-	-	-

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedules SGS-2F and SGS-2I

(Dollars per Dth)

Rate Schedule and Type of Rate	Currently Effective Tariff Rate (1)	
	Minimum	Maximum
Rate Schedule SGS-2F (2) (3) (4) (5)		
Demand Charge		
Pre-Expansion Shipper	0.00000	0.01551
Expansion Shipper	0.00000	0.08476
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2010 Phase	0.00000	0.00233
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.01551
Expansion Shipper	0.00000	0.08476
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2010 Phase	0.00000	0.00233
Rate Schedule SGS-2I		
Volumetric	0.00000	0.00113

Footnotes

(1) Shippers receiving service under these rate schedules are required to furnish fuel reimbursement in-kind at the rates specified on Sheet No. 14.

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedule LS-1

(Dollars per Dth)

Type of Rate	Currently Effective Tariff Rate (1)
Demand Charge (2)	0.03062
Capacity Charge (2)	0.00391
Liquefaction	0.64110
Vaporization	0.04184

Footnotes

(1) Shippers receiving service under this rate schedule are required to furnish fuel reimbursement in-kind at the rate specified on Sheet No. 14.

(2) Rates are daily rates computed on the basis of 365 days per year, except that rates for leap years are computed on the basis of 366 days.

Exhibit: C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW Natural

SUPPORTING MATERIALS

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 10-13

September 2, 2010

NW NATURAL **EXHIBIT C**

OPUC ORDER No. 10-197

DOCKET UM 1286

SECTION IV and V. PGA PORTFOLIO GUIDELINES

DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
IV	General Information and Forecasting		
1	General Information		
a)	Definitions of all major terms and acronyms in the data and information provided.	Definitions!A1	
b)	Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.	IV.1b!A1	
c)	All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.	IV.1c!A1	
2	Workpapers		
a)	PGA Summary Sheet	IV.2a!A1	
b)	Gas Supply Portfolio and Related Transportation		
1	Summary of portfolio planning	IV.2b 1-6'!A1	
2	LDC sales system demand forecasting	IV.2b 1-6'!A1	
3	Natural gas price forecasts	IV.2b 1-6'!A1	
4	Physical resources for the portfolio	IV.2b 1-6'!A1	
		IV.2b.4 Tables 1 - 5	
5	Financial resources for the portfolio (derivatives and other financial arrangements).	IV.2b 1-6'!A1	
6	Storage resources.	IV.2b 1-6'!A1	
7	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation.	IV.2b.7!A1	
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.	IV.2b.8!A1	
9	Summary of portfolio documentation provided	IV.2b.9!A1	
V.1	**Physical Gas Supply**	V.1.a pg 1'!A1	**HIGHLY CONFIDENTIAL**
		V.1.a pg 2'!A1	**HIGHLY CONFIDENTIAL**
		V.1.a pg3'!A1	**HIGHLY CONFIDENTIAL**
a)	For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:		
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.		
2	For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process.		

OPUC ORDER No. 10-197
DOCKET UM 1286
SECTION IV and V. PGA PORTFOLIO GUIDELINES
DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
3	Brief explanation of each contract's role within the portfolio.		
b)	For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:	V.1.b!A1	
1	An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.	V.1.b!A1	
2	Any contract provisions that materially deviate from the standard NAESB contract.	V.1.b!A1	
V.2	**Hedging**		
	The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.	V.2!A1	**HIGHLY CONFIDENTIAL**
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	V.3.a!A1	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	V.3.b!A1	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	V.3.c!A1	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,		
1	Annual for each customer class	V.3.d.1!A1	
2	Annual and monthly baseload.	V.3.d.2!A1	
3	Annual and monthly non-baseload.	V.3.d.3!A1	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	V.3.d.4!A1	
V.4	**Market Information**		
	General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.	V.4!A1	
V.5	**Data Interpretation**		
	If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.	V.5!A1	
V.6	**Credit Worthiness Standards**		

OPUC ORDER No. 10-197
DOCKET UM 1286
SECTION IV and V. PGA PORTFOLIO GUIDELINES
DATA AND ANALYSIS

Guideline Reference	Data Requirement	Location/Link	Status
	A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.	V.6!A1	
	Attachment 1 to V.6	V.6 attachment'!A1	CONFIDENTIAL/HIGHLY CONFIDENTIAL
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.		
a)	Type of storage (e.g., depleted field, salt dome).	V.7.a-c'!A1	
b)	Location of each storage facility.	V.7.a-c'!A1	
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	V.7.a-c'!A1	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	V.7.d-e'!A1	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	V.7.d-e'!A1	
f)	An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.	V.7.f!A1	
g)	Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.	V.7.g!A1	
h)	For LDCs that own and operate storage:	V.7.h!A1	CONFIDENTIAL
a.	The date and results of the last engineering study for that storage.		
b.	A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.		

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Section IV. a)	**1 General Information** Definitions and Acronyms
AECO	The industry acronym used for Alberta sourced natural gas supply. It originally
Base Load gas (contract)	Purchase agreements in which NW Natural has to take a set amount of gas each day from a supplier for the term of the agreement. Usually involves paying for any gas not taken unless excused by reason of Force Majeure.
Base Rate	The portion of rates that does not change outside of a general rate case, except as allowed through a Commission approved base rate adjustment.
Base Rate Adjustment	A permanent adjustment to rates approved by the Commission outside of a general rate case process.
Btu	British thermal unit. 100,000 Btus is equivalent to one therm.
CGPR	Canadian Gas Price Reporter. This is the industry publication in Canada that is put out by Canadian Enerdata Ltd and is the exclusive source of Canadian natural gas storage and price forecasts and publishes first of month Canadian indices used in baseload purchase pricing
Collar	Financial hedges that set ceiling and floor values on the price of gas purchases.
Commodity Component	The Tariff term used to refer to the cost of gas component of a customer's billing rate, and which will equal either (a) the Annual Sales WACOG, (b) the Winter Sales WACOG, or (c) the Monthly Incremental Cost of Gas.
Dth	Dekatherm. A unit of measure equal to 10 therms or one million Btu.
Demand [Charge]	The term used to refer to Pipeline Capacity related costs.
Derivative products	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.
EIA	U.S. Energy Information Administration
FERC	Federal Energy Regulatory Commission
Financial swaps	Transactions that involve an exchange of cash flows with a counterparty.
Financially hedged	Purchases that have associated financial swaps such that the price of the gas is fixed for a pre-determined period of time.
FOM	First of Month
Fuel-in-Kind (KIG)	The published fuel rate calculated based on the amount of fuel used on each pipeline to run the compressors and other equipment to move gas across their pipes. Fuel is taken in kind from all receipt shippers by reducing each shippers daily volumes in accordance to the pipelines estimated fuel requirements.
GMR-NWP Rockies	Inside FERC's Gas Market Report, a publication put out by Platts (a McGraw-Hill subsidiary) that is the source used for price forecasts and indices that used to set US baseload and some daily purchase prices.

IRP	Integrated Resource Plan
MDDV	Maximum Daily Delivery Volume
NWP	Northwest Pipeline
Off-system storage	Storage facilities located outside NW Natural’s service territory.
On-system storage	Storage facilities located inside NW Natural’s service territory.
PGA	Purchased Gas Adjustment
Peak day	The day in which volumes distributed or sold by NW Natural are at a maximum. May be theoretical (the “design day”) or actual.
Pipeline Capacity	The quantity (volume) of natural gas available on the interstate pipeline for the transportation of gas supplies to the Company's distribution system. Pipeline Capacity related costs are often referred to as "Demand".
Recallable gas supply/capacity	Refers to arrangements that allow NW Natural to use the upstream pipeline capacity and gas supplies held by third parties.
Revenue Sensitive	The amount by which rates are adjusted to reflect the effects of revenue related costs, such as uncollectible expense, regulatory fees, and city license and franchise fees
Swing gas (contract)	Purchase agreements in which NW Natural has the right, but not the obligation, to take gas from a supplier on any given day.
Technical Rate Adjustments	Also referred to as Temporary Rate Adjustments.
Therm	A unit of heating value equivalent to 100,000 Btus. The amount of heat energy in approximately 100 cubic feet of Natural Gas.
Total Commodity Cost	The combined costs for all purchased gas supplies, excluding transportation costs.
Total Gas Cost	The combined costs of all purchased gas supplies and associated transportation costs.
Transportation Cost	The combined costs for all pipeline related demand, capacity or reservation charges
Transportation Resources	The various upstream pipeline capacity agreements held by the company.
Upstream pipeline	Those pipelines that collect natural gas from the areas where it is produced in the British Columbia, Alberta and the U.S. Rocky Mountain supply regions and transport that gas to NW Natural’s service territory.
Upstream pipeline capacity	Refers to the rights that NW Natural has obtained to transport gas on upstream pipelines.
WACOG	The Company’s weighted average commodity cost of gas (excluding transportation cost), also referred to as Annual Sales WACOG.
Winter Sales WACOG	The Company’s winter period weighted average commodity cost of gas (excluding transportation cost).

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IV General Information and Forecasting

1 General Information

b) Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (known as the Dodd-Frank bill) was signed into law in July 2010 but does not take effect until July 2011. Whether NW Natural's financial hedging activities will be affected depends on the rules that are written during the interim period to clarify this piece of legislation that totals more than 2,300 pages. For example, there are provisions in the Dodd-Frank bill that would require the daily posting of collateral, which would increase the cost of financial hedging activities, but NW Natural could end up in the group of consumers that is exempted from this provision. So while nothing has changed at the moment, we will be following this process closely.

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IV General Information and Forecasting
1 General Information
c) All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is

In accordance with the PGA Filing Guidelines at Section IV(1)(c), the Company acknowledges that all forecasts of demand, weather, etc. upon which the gas supply portfolio for this PGA filing is based on the methodology and data sources that are consistent with the Company's most recently acknowledged IRP.

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IV. General Information and Forecasting
2 Workpapers - a. PGA Summary Sheet

NW Natural
PGA Summary Sheet

	Amount	Location in Company Filing (cite)
1) Change in Annual Revenues		
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To .1 million)*	$2,800,000	Exhibit B, Page 3
B) Percent *(To .1 percent)*	0.32%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	(24,246,441)	Exhibit B, Page 3
B) Remove Last Year's Temporary Increment Total	(21,338,810)	"
C) Add New Temporary Increment	4,590,185	"
D) Other Additions or Subtractions (*Break out & List each below -- Attach additional sheet if necessary*)		
1) Net Safety Programs	963,000	Exhibit B, Page 3
2) Storage Recall	0	"
3) Elasticity	166,462	"
4)	0	"
5)	-	"
6)	-	
E) Total Proposed Change	2,812,016	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$1.12251	Exhibit B, Page 2
2) Proposed Billing Rate per Therm	$1.12695	"
3) Rate Change Per Therm	$0.00444	
4) Percent Change per Therm *(to .1%)*	0.4%	
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	55.0	Exhibit B, Page 2
2) Customer Charge	$6.00	"
3) Current Average Monthly Bill	$67.74	"
4) Proposed Average Monthly Bill	$67.98	"
5) Change in Average Monthly Bill	$0.24	"
6) Percent change in Average Monthly Bill *(to .1%)*	0.4%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	110.0	N/A
2) Customer Charge	$6.00	N/A
3) Current Average January Bill	$129.48	N/A
4) Proposed Average January Bill	$129.96	N/A
5) Change in Average January Bill	$0.48	N/A
6) Percent change in Average January Bill (*to .1%*)	0.4%	N/A

	Amount	Location in Company Filing (cite)
4) Breakdown of Costs		
A) Embedded in Rates		
1) Total Commodity Cost	0	
a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Volumetric Cost (assoc. w/ supply)	$341,967,325	N/A
e) Total Storage Cost (assoc. w/ supply)	0	
f) Other	$2,004,863	N/A
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	32,881,145	N/A
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	48,673,480	N/A
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$67,276,229	N/A
4) Capacity Release Credits	0	
5) Total Gas Costs	$492,803,042	N/A
B) Projected For New Rates		
1) Total Commodity Cost	0	
a) Total Demand Cost (assoc. w/ supply)	0	
b) Total Peaking Cost (assoc. w/ supply)	0	
c) Total Reservation Cost (assoc. w/ supply)	0	
d) Total Vaporization Cost (assoc. w/ supply)	0	
e) Total Volumetric Cost (assoc. w/ supply)	$334,790,669	Exhibit B, Page 5
f) Total Storage Cost (assoc. w/ supply)	0	
g) Other (A&G Benchmark Savings)	$2,096,179	Exhibit B, Page 5
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	38,502,567	Exhibit B, Page 6
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	48,850,459	Exhibit B, Page 6
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$64,102,786	Exhibit B, Page 5
4) Capacity Release Credits	0	
5) Total Gas Costs	$488,342,660	Exhibit B, Page 5

	Amount	Location in Company Filing (cite)
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*	0	
a. With revenue sensitive	$0.58734	N/A
b. Without revenue sensitive	$0.56977	N/A
2) WACOG (Non-Commodity)	$0.00000	
a. With revenue sensitive	$0.12502	N/A
b. Without revenue sensitive	$0.12128	N/A

B) Proposed for New Rates		
1) WACOG *(Commodity Only)*	$0.00000	
a. With revenue sensitive	$0.54299	Exhibit B, Page 5 and Page 8
b. Without revenue sensitive	$0.52779	"
2) WACOG (Non-Commodity)	$0.00000	
a. With revenue sensitive	$0.12986	Exhibit B, Page 7
b. Without revenue sensitive	$0.12623	"
6) Therms Sold	759,755,672	Exhibit B, Page 5
7) Purchasing/ Hedging Strategies *Prepare 1-2 page summary of gas cost situation to include resources, purchasing strategy, hedging, and pipeline issues. Within the summary include:*		
A) Resources embedded in current rates and an explanation of proposed resources.		
1) Firm Pipeline Capacity		
a) Year-round supply contracts	N/A	Exhibit A, IV.2.b 1-7
b) Winter-only contracts	N/A	"
c) Reliance on Spot Gas/Other Short Term Contracts	N/A	"
d) Other - e.g. Supply area storage	N/A	"
2) Market Area Storage		
a) Underground-owned	N/A	"
b) Underground- contracted	N/A	"
c) LNG-owned	N/A	"
d) LNG-contracted	N/A	"
3) Other Resources		
a) Recallable Supply	N/A	"
b) City gate Deliveries	N/A	"
c) Owned-Production	N/A	"
d) Propane/Air	N/A	"

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IV	General Information and Forecasting
2	Workpapers
b)	Gas Supply Portfolio and Related Transportation
1	Summary of portfolio planning process
2	LDC sales system demand forecasting
3	Natural gas price forecasts
4	Physical resources for the portfolio
5	Financial resources for the portfolio (derivatives and other financial arrangements)
6	Storage Resources

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1 Summary of Portfolio Planning Process

NWN's goal is to assemble resources sufficient to meet expected firm customer requirements under "design" year conditions at the lowest reasonable cost. [1]

To ensure adequate reliability, NWN contracts for firm upstream pipeline capacity, firm off-system storage service and firm recallable gas supply/capacity arrangements with certain on-system customers, in addition to its development of on-system underground and LNG storage. [2]

Upstream pipeline capacity has been contracted with the following objectives in mind: (1) Diversify capacity sources so that disruptions in any one supply region, such as from a pipeline rupture, well freeze-offs, etc., have a minimal impact on NWN; (2) Obtain upstream capacity along the path from NWN's service territory to points generally recognized for their liquidity, such as AECO, to maximize trading opportunities and minimize price volatility; and (3) Find ways to minimize the cost of upstream capacity such as through optimization activities or committing to capacity only on a winter season basis if possible

[1] "Design" year is based on the 85% probability of the coldest heating season in the last 20 years. The design year is augmented by the coldest historical coincident system-weighted average day observed during the last 20 years. This coincident system-weighted coldest average day occurred on February 3, 1989. In addition, the days prior to and following the peak day are also included in the design year to model a consecutive three-day cold snap. For the non-heating season (April through October), daily heating degree day values are assumed equal to the 20-year average.

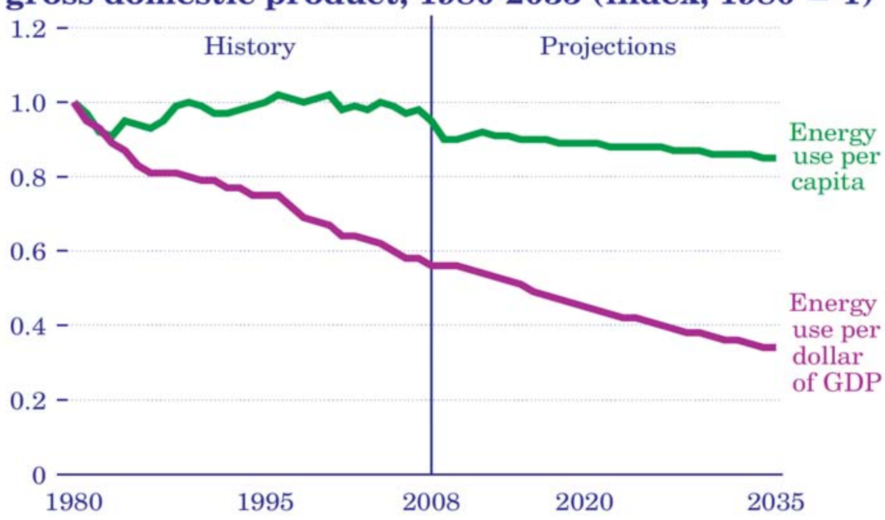
[2] Customer requirements increase dramatically during the heating season, so past and present storage developed in or adjacent to NWN's service territory has offered a significant cost advantage because it avoids the need to subscribe to upstream pipeline capacity that would be under-utilized much of the year. Future storage developments will depend of course on the cost to develop new reservoirs and associated infrastructure.

Upstream gas supply contracts have been negotiated with the following objectives in mind: (1) Use a diverse group of reliable suppliers as established by their asset positions, past performance and other factors; (2) Try to match our year-round customer requirements to baseload (take-or-pay) annual or multi-year supply contracts to obtain the most favorable pricing; (3) Use winter only (Nov-Mar) term contracts to match our rise in requirements during the heating season; (4) Leave very little to be purchased on the spot market during the winter due to the likely correlation of high requirements with high spot prices; (5) Use a variety of multi-year contract durations to avoid having to re-contract all supplies every year; (6) Use index-related pricing formulas in term contracts to enable easy evaluation of competitive offers and avoid the need for further price negotiation over the term of the contract; (7) Structure the portfolio to provide some opportunity to take advantage when spot prices are favorable; and (8) Avoid over-contracting gas on a take-or-pay basis, which could result in excess gas supplies that must be sold at a loss if requirements fail to materialize such as during a warm winter.

2. LDC sales system demand forecasting.

Customer growth has not equated to load growth in recent years. Conservation and price elasticity among existing residential and commercial customers have offset customer gains. Due in part to its 5-day curtailment of interruptible sales customers in December 2008 and then 3-day curtailment in December 2009, many industrial sales customers have switched to transportation service, further suppressing sales demand. While interruptible customers do not affect peak day planning and requirements, their annual sales volumes are accounted for in the company's purchasing plans. As a result, the company's annual sales outlook has declined from prior years on a weather-adjusted basis. This mirrors national trends as shown below.

Figure 39. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980 = 1)



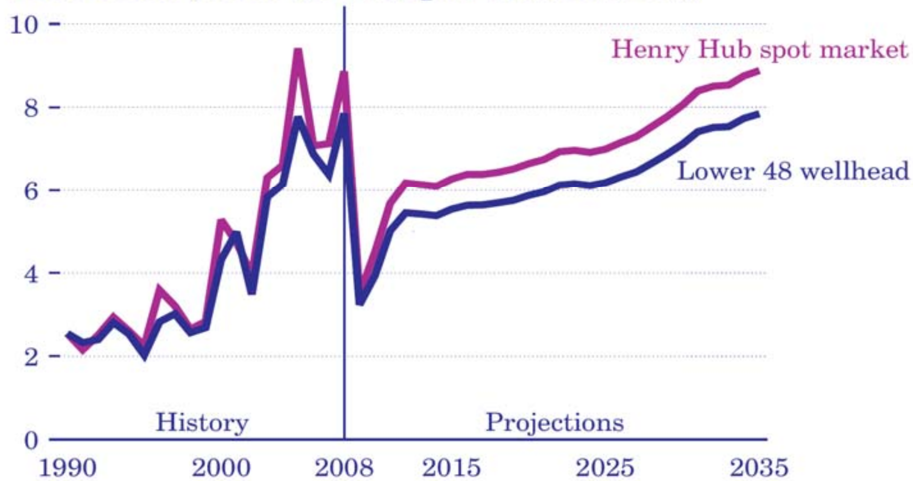
Source: EIA 2010 Annual Energy Outlook

The company's methodology for forecasting annual sales and firm peak day requirements follow the methodology established in its last IRP.

3. Natural gas price forecasts.

NWN relies on forecasts prepared by the U.S. Energy Information Administration (EIA), the CERA consulting firm as well as NYMEX futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NWN by way of trade publications, consultant visits, oil/gas company presentations and other governmental sources. These provide opportunities to test assumptions and explore alternate viewpoints. As an example, below is the latest long-range natural gas forecast from EIA's 2010 Annual Energy Outlook (AEO) as released in May 2010.

Figure 69. Annual average lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2035 (2008 dollars per million Btu)



In this case, the recent sharp drop in natural gas prices, coupled with forecasts for rising prices, leads NWN to formulate hedging strategies around locking in prices on a longer term basis (2 to 3 years out or even longer) for a portion of its expected purchase volumes.

4. Physical resources for the portfolio.

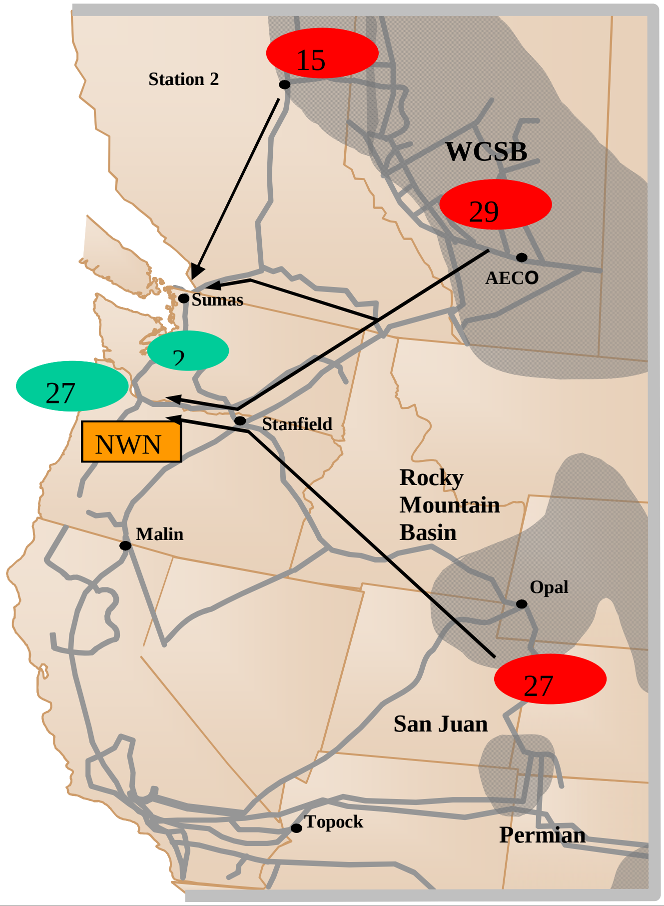
As mentioned above, NWN's physical portfolio on any given day includes gas supplies purchased and transported over the upstream pipeline grid as well as supplies either placed into or withdrawn from five different gas storage facilities. The company also has arrangements with three large on-system customers that allow it to call on their gas supplies on short notice for use by the company ("recall arrangements"). Finally, a very small portion of the company's gas supply (less than 1%) is native gas produced from the Mist Field. This is the company's only gas supply that does not require transportation at one time or another over the interstate pipeline system.

One change has occurred in the company's physical supply resources over the past year. We acquired an additional 4,147 Dth/day of Northwest Pipeline (NWP) capacity from an industrial customer on a permanent basis effective December 1, 2009. This small addition to our portfolio meets a targeted need in a section of our service territory that is not interconnected to our storage resources.

Using its mix of transportation and storage resources, the company achieves the following profile on a typical winter day.

Alberta

NW Natural
Average Winter Day

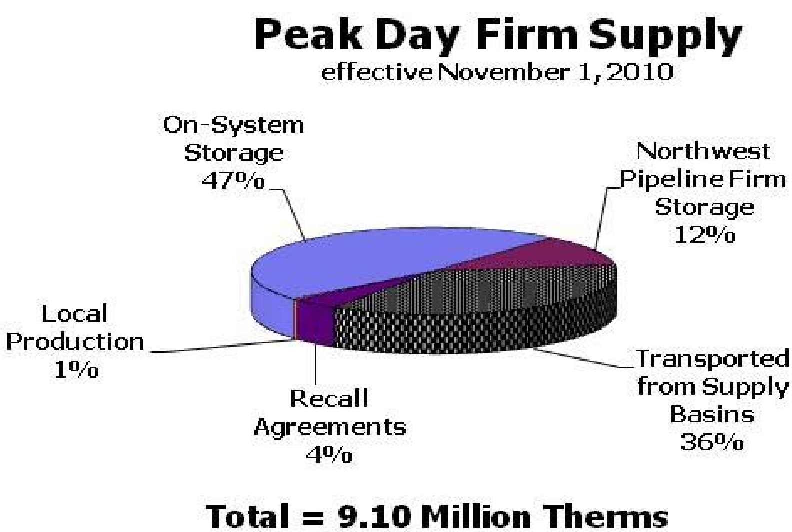


Flowing Supplies

Storage

Average Day Winter Supply Volumes (Dth)	
British Columbia (Station 2)	58,000
Alberta	115,000
Rockies	110,000
Jackson Prairie	10,000
Mist Storage	107,000
Portland LNG	0
Newport LNG	0
Plymouth LNG	0
Total	400,000

Should its “design” peak day occur, all physical resources would be used in the following proportions:



A summary of the company's physical supply resources is provided in Tables 1 through 5.

Regarding physical supply purchasing, NWN has contracted with suppliers for approximately 600,000 therms per day of firm deliveries on a daily basis over the upcoming November 2010 through October 2011 period. This reflects the relatively stable daily component of NWN's demand, including some portion of storage injection requirements in the summer months. This figure has been reduced from prior periods to allow more purchase flexibility during the summer months. It also reflects the lack of load growth associated with new customer additions and the migration of certain interruptible industrial customers from sales to transportation service as mentioned above.

For the November 2010 through March 2011 heating season, NWN will have contracts for an additional 1.6 million therms/day of supply under baseload and peaking (swing) agreements. This reflects the higher consumption of customers during those months and is more than the volumes contracted for the prior three winter periods in consideration of the decrease in year-round term contracts mentioned above. Buying under term supply contracts lessens the need to rely extensively on the spot market during periods of high demand when competition with mid-continent markets for Rockies and Alberta supplies may be intense. Most of the winter contracted volume (1,200,000 therms/day) is purchased on a take-or-pay basis. The remaining 400,000 therms/day are made available to NWN on a daily basis in exchange either for payment of a fixed "reservation" charge or for equivalent value in the form of put options during the summer months. These swing contracts have no minimum daily, monthly or seasonal purchase requirement, but they provide additional daily supply flexibility, which is especially valuable since winter weather can fluctuate rapidly between mild and cool temperatures, resulting in rapidly changing customer requirements.

This means between 1.1 and 1.5 million therms/day of upstream capacity could be available during the heating season for spot (one month and shorter duration) purchases as and when needed. Accordingly, on days when all upstream capacity is in use, purchases will be split among three categories – year-round contracts, winter term contracts and spot purchases.

5. *Financial resources for the portfolio (derivatives instruments and other financial arrangements).*

NWN "swaps" monthly index prices for fixed prices and other price structures through the use of financial instruments in order to increase price stability across the year. Volumes in storage provide another form of hedging. Overall, NWN's target this year is to hedge the prices of approximately 75% of its expected annual purchase volumes for the upcoming 12-month period commencing in November, the traditional start month for its supply contracts. As storage currently accounts for about 17% of annual purchase quantities, this leaves approximately 58% to be financially hedged. Actual financial hedging targets are set by an executive level oversight committee within the company (the Gas Acquisition Strategy & Policies Committee or GASP) and could change from time-to-time in reaction to market conditions or other factors as the year progresses.

In addition to financial swaps, the company's derivative policies allow the use of financial options (puts and calls) to limit exposure to gas price fluctuations. For example, these instruments can be used in combination in order to "collar" the price of gas for specific purchases.

The company's Gas Supply department performs the actual derivative transactions, while separate individuals, reporting to different executives, oversee the risk management of the hedging program such as approving counterparties and determining credit limits.

6. *Storage resources.*

NWN relies on five storage facilities to balance its supply portfolio and meet customer requirements. Mist, Portland LNG (also known as Gasco) and Newport LNG are owned and operated by the company. NWN contracts with Northwest Pipeline for service at Jackson Prairie and the Plymouth LNG plant. Storage provides the following benefits to customers:

a. Avoids the need to subscribe to year-round interstate pipeline capacity to meet winter season loads.
b. Allows more gas purchasing during the non-heating season, when prices are typically lower, instead of heating season periods when prices typically peak.
c. Provides diversity of supply and gas movement to and through NWN's service territory, improving overall reliability.
d. Helps balance daily demand with supplies, reducing the potential of imbalance penalties with upstream pipelines.
e. Provides flexibility to take advantage of daily, monthly and seasonal variations in gas pricing, either directly by NWN or through its optimization arrangements.

Additional benefits attributable to Mist have been created through the development of an interstate storage service starting back in 2001. For example, rather than large "lumpy" resource additions requiring years of preparation, the "pre-build" of interstate storage service provides the ability to time and size incremental Mist capacity to a degree not achievable through typical resource development.

More information on the company's storage resources is provided in Table 3 and the workpapers.

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2010/2011 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
BP Canada Energy Company	Nov-Oct	5,000		10/31/2012
Shell Energy North America (Canada)	Nov-Oct	5,000		10/31/2011
IGI Resources	Nov-Oct	5,000		10/31/2011
AltaGas Energy	Nov-Oct	5,000		10/31/2011
Husky Energy Marketing	Nov-Oct	5,000		10/31/2011
Macquarie Energy Canada	Nov-Oct	5,000		10/31/2011
ConocoPhillips Canada	Nov-Oct	10,000		10/31/2011
Suncor Energy Marketing	Nov-Mar	5,000		3/31/2011
EDF Trading North America	Nov-Mar	5,000		3/31/2011
Alberta:				
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
Suncor Energy Marketing	Nov-Mar	5,000		3/31/2011
Husky Energy Marketing	Nov-Mar	5,000		3/31/2011
Sequent Energy Canada	Nov-Mar	10,000		3/31/2011
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2011
ConocoPhillips Canada	Nov-Mar	5,000		3/31/2011
Tenaska Marketing Canada	Nov-Mar	5,000		3/31/2011
IGI Resources	Nov-Mar	5,000		3/31/2011
Iberdrola Canada Energy Services	Nov-Mar	5,000		3/31/2011
Powerex	Nov-Mar	5,000		3/31/2011
TD Energy Trading	Nov-Mar	5,000		3/31/2011
Sequent Energy Canada	Nov-Mar		10,000	3/31/2011
Sequent Energy Canada	Apr-Oct		10,000	10/31/2011
pending	Nov-Mar	5,000		3/31/2011
Rockies:				
BP Energy Company	Nov-Oct	10,000		10/31/2011
IGI Resources	Nov-Mar	5,000		3/31/2011
Iberdrola	Nov-Mar	5,000		3/31/2011
Macquarie Energy	Nov-Mar	5,000		3/31/2011
Anadarko Energy Services	Nov-Mar	5,000		3/31/2011
National Fuel Marketing	Nov-Mar	5,000		3/31/2011
ONEOK Energy Services	Nov-Mar	5,000		3/31/2011
Ultra Resources	Nov-Mar	10,000		3/31/2011
Occidental Energy Marketing	Nov-Mar	5,000		3/31/2011
ONEOK Energy Services	Nov-Mar		5,000	3/31/2011
Kansas Energy	Nov-Mar		10,000	3/31/2011
Kansas Energy	Nov-Mar		5,000	3/31/2011
Shell Energy North America (US)	Nov-Mar	5,000		3/31/2011
Sequent Energy Management	Nov-Mar		5,000	3/31/2011
ConocoPhillips Company	Nov-Mar		5,000	3/31/2011
Kansas Energy	Apr-Oct		5,000	10/31/2011
Sequent Energy Management	Apr-Oct		5,000	10/31/2011
Total Off-System Firm Contract Supply		180,000	60,000	

Notes:
1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.
2. Nov-Mar "Swing" contracts represent physical call options at NWN's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion.

Table 2

NW Natural
Firm Transportation Capacity
for the 2010/2011 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion	214,889	9/30/2013
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2012
Occidental (formerly Duke) Cap. Acq.	5,000	10/31/2012
International Paper Cap. Acq.	4,147	11/30/2011
Total NWP Capacity	361,191	
less recallable release to -		
Portland General Electric	(30,000)	11/1/2011
Net NWP Capacity	331,191	
TransCanada's GTN System:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2012
Total GTN Capacity	57,822	
TransCanada's BC System:	47,747	
1993 Expansion	47,727	10/31/2012
1995 Rationalization	57,417	10/31/2012
Engage Capacity Acquisition	3,708	10/31/2012
2004 Capacity Acquisition	48,187	10/31/2016
Total TCPL-BC Capacity	157,039	
TransCanada's Alberta System:		
1993 Expansion	48,135	10/31/2012
1995 Rationalization	57,909	10/31/2012
Engage Capacity Acquisition	3,739	Upon 1-year notice
2004 Capacity Acquisition	49,138	10/31/2016
Total TCPL-ALberta Capacity	158,921	
WEI T-South Capacity	57,822	10/31/2014
Southern Crossing Pipeline	47,747	10/31/2020

Notes:
1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE which requires a mutual agreement to continue.
2. The WEI and Southern Crossing contracts are denominated in volumetric units. Accordingly, the above energy units are an approximation.
3. The numbers shown for the 1993 Expansion contracts on GTN and TCPL-BC are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
4. Regarding the 1993 Expansion contract on Northwest Pipeline, a small portion (1,155 Dth/day) continues after October 1, 2013 on a year-to-year basis at NWN's option.

Table 3

NW Natural
Firm Storage Resources
for the 2010/2011 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	Upon 1-year notice
TF-2 (redelivery service)	32,624	839,046	Upon 1-year notice
TF-2 (redelivery service)	13,406	281,242	Upon 1-year notice
Plymouth LNG:			
LS-1	60,100	478,900	Upon 1-year notice
TF-2 (redelivery service)	60,100	478,900	Upon 1-year notice
Total Firm Off-system Storage:			
Withdrawal/Vaporization	106,130	1,599,188	
TF-2 Redelivery	106,130	1,599,188	
Firm On-System Storage Plants:			
Mist (reserved for core)	250,000	9,420,270	n/a
Portland LNG Plant	120,000	600,000	n/a
Newport LNG Plant	60,000	1,000,000	n/a
Total On-System Storage	430,000	11,020,270	
Total Firm Storage Resource	536,130	12,619,458	

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option.
2. The second Jackson Prairie TF-2 service, for 13,406 Dth/day, is a subordinated firm service. However, on cold weather days, when flows are maximized on NWP's system, service on this agreement should be highly reliable.
3. On-system storage peak deliverability based on design criteria.
4. Mist numbers shown are the portions reserved for service to utility core customers per the company's Integrated Resource Plan. Additional capacity and deliverability has been contracted under varying terms to off-system customers. The number is approximate as it depends on the heat content of the stored gas, which in turn is dependent on the blended heat content of upstream pipeline gas together with Mist production gas.

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2010/2011 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	11/1/2011
International Paper	8,000	40	pending
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	39,000		
Citygate Deliveries:			
none			
Mist Production:			
Enerfin Resources	≈4,000	n/a	12/31/2010

Notes:

1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements. All of the recall arrangements include delivery to NW Natural's system.
2. Mist production is currently flowing at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation to take gas from existing wells continues for the life of those wells.

Table 5

NW Natural
Firm Resource Summary
for the 2010/2011 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	331,191
Off-System Storage (Jackson Prairie and Plymouth)	106,130
On-System Storage (Mist, Portland LNG and Newport LNG)	430,000
Recallable Capacity and Supply Agreements	39,000
Citygate Deliveries	-
Nominal Mist Production Gas	4,000
Total Firm Resource	910,321

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IV	General Information and Forecasting
2	Workpapers
b)	Gas Supply Portfolio and Related Transportation
7	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation

NW Natural includes *realized* demand response savings in forecasted annual and peak demand by updating use per customer coefficients prior to the annual PGA filing. The updated use per customer coefficient reflects demand measures actually taken in the previous year. Because our ability to accurately forecast annual demand savings is relatively uncertain, we do not include projected demand measures in our forecasted annual and peak demand.

	2010/2011
Forecast Annual Demand (therms)	762,008,617
Forecast Peak Demand (therms) - Normal	4,150,031
Forecast Peak Demand (therms) - Design	9,483,872
Forecast DSM Annual (therms)	2,252,945
Forecast DSM Peak (therms) - Design Peak	25,067
Forecast Annual Demand with Forecast DSM	759,755,672
Forecast Peak Demand with Forecast DSM - Normal	4,150,031
Forecast Peak Demand with Forecast DSM - Design	9,458,805

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 10-197, Docket UM 1286

IV	General Information and Forecasting
2	Workpapers
b)	Gas Supply Portfolio and Related Transportation
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.

Our forecasted annual and peak demand is not impacted by gas supply incentive mechanisms.

NW Natural
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OPUC Order No. 10-197, Docket UM 1286

IV	General Information and Forecasting
2	Workpapers
b)	Gas Supply Portfolio and Related Transportation
9	Summary of portfolio documentation provided

See Index to this Worksheet.

Northwest Natural Gas Company

PGA Filing Guidelines

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November 1, 2010 - October 31, 2011

Physical Natural Gas term contracts

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies

Approved Counterparties all have executed NAESB contracts with NW Natural

Rocky Mountain Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location
BP Energy Company	11/1/2008	10/31/2011	[redacted]	IFGMR-NWP Rockies FOM	10,000		[redacted]		Opal / Shute Creek
IGI Resources, Inc. (1)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Opal/Wyoming Pool
Ultra Resources, Inc. (2)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	10,000		[redacted]		Opal
Oneok Energy Services Company, LP (2)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Opal
Iberdrola Renewables, Inc.(3)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Wyoming Pool / Green G
Occidental Energy Marketing, Inc.(4)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Wyoming Pool
Shell Energy North America (US), LP (4)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Wyoming Pool
Anadarko Energy Services Company (5)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Clay Basin / Silverdome
National Fuel Marketing Company, LLC (6)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Rocky Mountain Pool / Gre
Macquarie Energy, LLC (6)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Rocky Mountain Pool
Kansas Energy, LLC (7)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM		10,000	[redacted]	NWN Winter Call	Opal
ConocoPhillips Company (7)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Opal
Oneok Energy Services Company, LP (7)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Shute Creek
Kansas Energy, LLC (8)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Opal
Sequent Energy Management, LP (8)	11/1/2010	3/31/2011	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Opal
Kansas Energy, LLC (8)	4/1/2011	10/31/2011	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	Kansas Put Option	Opal
Sequent Energy Management, LP (8)	4/1/2011	10/31/2011	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	Sequent Put Option	Opal

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Opal	5	[redacted]	Price
(2) Opal	6	[redacted]	Price
(3) Wyoming Pool	5	[redacted]	Price
(4) Wyoming Pool	7	[redacted]	Price, Non-winning bidders had 2010-2011 term deals in place
(5) Rocky Mountain Pool	6	[redacted]	Price
(6) Rocky Mountain Pool	6	[redacted]	Price, Non-winning bidders had 2010-2011 term deals in place
(7) Winter Call - Reservation Fee	6	[redacted]	Price, Non-winning bidders had 2010-2011 term deals in place
(8) Winter Call - Summer Put	6	[redacted]	Price & volume

Northwest Natural Gas Company

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November 1, 2010 - October 31, 2011

Physical Natural Gas term contracts

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies

Approved Counterparties all have executed NAESB contracts with NW Natural

Station 2 Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's
BP Canada Energy	11/1/2009	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000
IGI Resources, Inc (1)	11/1/2010	10/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000
AltaGas Energy Limited Partnership (1)	11/1/2010	10/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000
Shell Energy North America (Canada) Inc (1)	11/1/2010	10/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000
Husky Energy Marketing Inc (1)	11/1/2010	10/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000
Macquarie Energy Canada Ltd (2)	11/1/2010	10/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000
ConocoPhillips Canada Marketing & Trading UL	11/1/2010	10/31/2011		CGPR AECO FOM (7A) $US/Dth	10,000
Suncor Energy Marketing Inc (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000
EDF Trading North America LLC (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	8	[redacted]	Price
(2)	6		Price
(3)	6		Price, Non-winning bidders had 2010-2011 term deals in place

Northwest Natural Gas Company

PGA Filing Guidelines

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November 1, 2010 - October 31, 2011
Physical Natural Gas term contracts

All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies
Approved Counterparties all have executed NAESB contracts with NW Natural

Aeco-NIT Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Contractual Conditions
Sempra Energy Trading	11/1/2004	10/31/2014	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000		
ConocoPhillips Canada Marketing & Trad	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
Husky Energy Marketing Inc (2)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
Shell Energy North America (Canada) Inc	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
Sequent Energy Canada Corp (2)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	10,000		
Suncor Energy Marketing Inc (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
Tenaska Marketing Canada (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
TD Energy Trading Inc (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
IGI Resources, Inc (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
Iberdrola Canada Energy Services Inc (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
Powerex Corp (3)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth	5,000		
Pending	*11/1/2010*	*3/31/2011*		*CGPR AECO FOM (7A) $US/Dth*	*5,000*		
Sequent Energy Canada Corp (4)	11/1/2010	3/31/2011		CGPR AECO FOM (7A) $US/Dth		5,000	NWN Winter Call
Sequent Energy Canada Corp (4)	4/1/2011	10/31/2011		CGPR AECO FOM (7A) $US/Dth		5,000	Sequent Put Option

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	4	[redacted]	Price negotiated through a World Energy Action (Note #1)
(2)	6		Price, (See Note #1)

NW Natural

PGA Portfolio Guidelines

2010-2011 Oregon PGA

V.1 b) Physical Gas Supply

For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:

---

1 An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.

1. The purchasing of baseload and spot supplies for the 2010-2011 PGA follows the Gas Acquisition Plan as prepared by the Gas Supply department and approved by the Gas Acquisition Strategy and Policies Committee (also known as GASP).

2. In our gas purchasing for 2010-2011, we target diversity of supply on a regional basis and among approved counterparties, as listed in the Gas Supply Risk Management Policies. The advantage of regional diversity is the opportunity to manage purchases to capture the lowest cost while maintaining a diversity of suppliers and avoiding over-reliance on any one trading point or counterparty.

3. Diversity of contracts in the portfolio is determined by the forecasted usage of NW Natural customers.

a. One year and greater baseload (take or pay) contract volumes are meant to meet low end requirements by NW Natural firm and interruptible sale customers during the PGA year while capturing the most favorable pricing. Contract volumes are set to avoid having excess supply that might have to be sold at a loss when sales volumes are low.

b. November – March winter contract volumes are aligned to meet the forecasted seasonal increase during the heating season and are divided between baseload and winter call option contracts. This helps minimize the exposure to purchasing large volumes of high priced spot gas during cold weather events.

c. April – October summer put option contracts are tied to winter call option contracts to capture a discounted monthly index price and avoid payment of a reservation fee. The volume of the put option contracts is kept to a minimum to avoid over supply during the summer months when added to term volumes.

d. Spot purchases are used to fill in requirements on a monthly or daily basis throughout the PGA year. One month spot purchases are negotiated to capture the best monthly index pricing, either *Inside FERC's Gas Market Report* for Rockies purchases or *Canadian Gas Price Reporter* for Canadian purchases. Daily spot purchasing utilizes either a daily index (in the case of Rocky Mountain or Sumas supply as published in *Gas Daily*) or a fixed price in US dollars as negotiated using the electronic trading platform Intercontinental Exchange (ICE) for Rocky Mountain, Sumas, Station 2 and Alberta (Aeco/NIT) supplies. NW Natural does not trade electronically but does use the active Bid/Offer pricing at the above liquid points on ICE to negotiate daily spot deals. In the new PGA filing there are no active spot purchases in the NW Natural portfolio.

2 Any contract provisions that materially deviate from the standard NAESB contract.

None.

GAS SUPPLY I 2010-2011 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT
29-May-09	2009-26	[redacted]	[redacted]	AECO	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
16-Jun-09	2009-28	[redacted]	[redacted]	AECO	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
30-Jun-09	2009-32	[redacted]	[redacted]	Stn 2	Nov10-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
15-Jul-09	2009-41	[redacted]	[redacted]	Stn 2	Nov10-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
1-Sep-09	2009-52	[redacted]	[redacted]	Rockies	Nov10-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
1-Sep-09	2009-56	[redacted]	[redacted]	Rockies	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
1-Sep-09	2009-57	[redacted]	[redacted]	Rockies	Nov10-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
1-Sep-09	2009-58	[redacted]	[redacted]	Rockies	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
30-Sep-09	2009-62	[redacted]	[redacted]	AECO	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
1-Oct-09	2009-63	[redacted]	[redacted]	AECO	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
1-Oct-09	2009-64	[redacted]	[redacted]	AECO	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
6-Oct-09	2009-65	[redacted]	[redacted]	AECO	Nov09-Oct12	1,096	2,500	2,740,000	[redacted]	[redacted]
17-Feb-10	2010-01	[redacted]	[redacted]	Stn 2	Oct11	31	5000	155,000	[redacted]	[redacted]
17-Feb-10	2010-02	[redacted]	[redacted]	Stn 2	Oct11	31	5,000	155,000	[redacted]	[redacted]
17-Feb-10	2010-03	[redacted]	[redacted]	Stn 2	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
18-Feb-10	2010-04	[redacted]	[redacted]	Stn 2	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
18-Feb-10	2010-05	[redacted]	[redacted]	Stn 2	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
18-Feb-10	2010-06	[redacted]	[redacted]	Stn 2	Oct11	31	5,000	155,000	[redacted]	[redacted]
18-Feb-10	2010-07	[redacted]	[redacted]	Stn 2	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
19-Feb-10	2010-08	[redacted]	[redacted]	Stn 2	Apr11	30	5,000	150,000	[redacted]	[redacted]
19-Feb-10	2010-09	[redacted]	[redacted]	Stn 2	Apr11	30	5,000	150,000	[redacted]	[redacted]
22-Feb-10	2010-10	[redacted]	[redacted]	Stn 2	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
23-Feb-10	2010-11	[redacted]	[redacted]	Rockies	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
24-Feb-10	2010-12	[redacted]	[redacted]	Rockies	Nov10-Mar11	151	2,500	377,500	[redacted]	[redacted]
24-Feb-10	2010-13	[redacted]	[redacted]	Rockies	Apr11	30	5,000	150,000	[redacted]	[redacted]
25-Feb-10	2010-14	[redacted]	[redacted]	Rockies	Nov10-Mar11	151	2,500	377,500	[redacted]	[redacted]
25-Feb-10	2010-15	[redacted]	[redacted]	Rockies	Apr 11	30	5,000	150,000	[redacted]	[redacted]
11-Mar-10	2010-17	[redacted]	[redacted]	Rockies	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
12-Mar-10	2010-18	[redacted]	[redacted]	AECO	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
16-Mar-10	2010-21	[redacted]	[redacted]	Stn 2	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
22-Mar-10	2010-22	[redacted]	[redacted]	Stn 2	Apr 11	30	5,000	150,000	[redacted]	[redacted]
22-Mar-10	2010-23	[redacted]	[redacted]	Stn 2	Apr 11	30	5,000	150,000	[redacted]	[redacted]
22-Mar-10	2010-24	[redacted]	[redacted]	AECO	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
25-Mar-10	2010-25	[redacted]	[redacted]	AECO	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
25-Mar-10	2010-26	[redacted]	[redacted]	Rockies	Apr 11	30	5,000	150,000	[redacted]	[redacted]
12-Apr-10	2010-27	[redacted]	[redacted]	Stn 2	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
12-Apr-10	2010-28	[redacted]	[redacted]	AECO	Nov10-Mar11	151	5,000	755,000	[redacted]	[redacted]
12-Apr-10	2010-29	[redacted]	[redacted]	Stn 2	May 11	31	5,000	155,000	[redacted]	[redacted]
12-Apr-10	2010-30	[redacted]	[redacted]	Stn 2	May 11	31	5,000	155,000	[redacted]	[redacted]
27-Apr-10	2010-31	[redacted]	[redacted]	Stn 2	May 11	31	5,000	155,000	[redacted]	[redacted]
29-Apr-10	2010-33	[redacted]	[redacted]	Stn 2	May 11	31	5,000	155,000	[redacted]	[redacted]
30-Apr-10	2010-34	[redacted]	[redacted]	Stn 2	Oct 11	31	5,000	155,000	[redacted]	[redacted]
30-Apr-10	2010-35	[redacted]	[redacted]	Stn 2	Apr 11	30	5,000	150,000	[redacted]	[redacted]
12-May-10	2010-36	[redacted]	[redacted]	AECO	Apr 11	30	5,000	150,000	[redacted]	[redacted]

GAS SUPPLY I 2010-2011 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT
13-May-10	2010-37	[redacted]	[redacted]	Rockies	Dec 10	31	5,000	155,000	[redacted]	[redacted]
13-May-10	2010-38	[redacted]	[redacted]	AECO	Apr 11	30	5,000	150,000	[redacted]	[redacted]
13-May-10	2010-39	[redacted]	[redacted]	Rockies	Dec 10	31	5,000	155,000	[redacted]	[redacted]
13-May-10	2010-40	[redacted]	[redacted]	Rockies	Dec 10	31	5,000	155,000	[redacted]	[redacted]
20-May-10	2010-41	[redacted]	[redacted]	Stn 2	Oct 11	31	5,000	155,000	[redacted]	[redacted]
20-May-10	2010-43	[redacted]	[redacted]	AECO	Dec 10	31	5,000	155,000	[redacted]	[redacted]
21-May-10	2010-44	[redacted]	[redacted]	Stn 2	Apr 11	30	5,000	150,000	[redacted]	[redacted]
21-May-10	2010-45	[redacted]	[redacted]	AECO	Nov10-Jan11	92	5,000	460,000	[redacted]	[redacted]
21-May-10	2010-46	[redacted]	[redacted]	Stn 2	May 11	31	5,000	155,000	[redacted]	[redacted]
25-May-10	2010-47	[redacted]	[redacted]	AECO	Nov10-Jan11	92	5,000	460,000	[redacted]	[redacted]
10-Jun-10	2010-48	[redacted]	[redacted]	Rockies	Nov 10	30	5,000	150,000	[redacted]	[redacted]
10-Jun-10	2010-49	[redacted]	[redacted]	Rockies	Oct 11	31	5,000	155,000	[redacted]	[redacted]
10-Jun-10	2010-50	[redacted]	[redacted]	Rockies	Oct 11	31	5,000	155,000	[redacted]	[redacted]
10-Jun-10	2010-51	[redacted]	[redacted]	Rockies	Nov 10	30	5,000	150,000	[redacted]	[redacted]
10-Jun-10	2010-52	[redacted]	[redacted]	Rockies	Jan 11	31	10,000	310,000	[redacted]	[redacted]
11-Jun-10	2010-53	[redacted]	[redacted]	Rockies	Dec 10	31	5,000	155,000	[redacted]	[redacted]
11-Jun-10	2010-54	[redacted]	[redacted]	Stn 2	Dec 10	31	5,000	155,000	[redacted]	[redacted]
11-Jun-10	2010-55	[redacted]	[redacted]	Rockies	Dec 10	31	5,000	155,000	[redacted]	[redacted]
11-Jun-10	2010-56	[redacted]	[redacted]	Stn 2	Dec 10	31	5,000	155,000	[redacted]	[redacted]
11-Jun-10	2010-57	[redacted]	[redacted]	AECO	Dec 10	31	5,000	155,000	[redacted]	[redacted]
21-Jun-10	2010-58	[redacted]	[redacted]	Rockies	Nov 10	30	5,000	150,000	[redacted]	[redacted]
21-Jun-10	2010-59	[redacted]	[redacted]	Rockies	Apr 11	30	5,000	150,000	[redacted]	[redacted]
22-Jun-10	2010-60	[redacted]	[redacted]	AECO	Jan 11	31	5,000	155,000	[redacted]	[redacted]
22-Jun-10	2010-61	[redacted]	[redacted]	AECO	Dec 10	31	5,000	155,000	[redacted]	[redacted]
24-Jun-10	2010-62	[redacted]	[redacted]	AECO	Mar 11	31	5,000	155,000	[redacted]	[redacted]
24-Jun-10	2010-63	[redacted]	[redacted]	AECO	Jan 11	31	5,000	155,000	[redacted]	[redacted]
24-Jun-10	2010-64	[redacted]	[redacted]	Stn 2	Dec 10	31	5,000	155,000	[redacted]	[redacted]
24-Jun-10	2010-65	[redacted]	[redacted]	AECO	Jan 11	31	5,000	155,000	[redacted]	[redacted]
25-Jun-10	2010-66	[redacted]	[redacted]	AECO	Dec 10	31	5,000	155,000	[redacted]	[redacted]
28-Jun-10	2010-67	[redacted]	[redacted]	Rockies	Jan 11	31	5,000	155,000	[redacted]	[redacted]
28-Jun-10	2010-68	[redacted]	[redacted]	Rockies	Jan 11	31	5,000	155,000	[redacted]	[redacted]
2-Jul-10	2010-69	[redacted]	[redacted]	Rockies	Apr 11	30	5,000	150,000	[redacted]	[redacted]
2-Jul-10	2010-70	[redacted]	[redacted]	AECO	Nov 10	30	5,000	150,000	[redacted]	[redacted]
2-Jul-10	2010-71	[redacted]	[redacted]	Stn 2	Oct 11	31	5,000	155,000	[redacted]	[redacted]
19-Jul-10	2010-72	[redacted]	[redacted]	AECO	Dec 10	31	5,000	155,000	[redacted]	[redacted]
19-Jul-10	2010-73	[redacted]	[redacted]	AECO	Nov 10	30	5,000	150,000	[redacted]	[redacted]
19-Jul-10	2010-74	[redacted]	[redacted]	Rockies	Dec 10	31	5,000	155,000	[redacted]	[redacted]
27-Jul-10	2010-75	[redacted]	[redacted]	Rockies	Nov10-Oct13	1,096	2,500	2,740,000	[redacted]	[redacted]
27-Jul-10	2010-76	[redacted]	[redacted]	AECO	Oct 11	31	5,000	155,000	[redacted]	[redacted]
27-Jul-10	2010-77	[redacted]	[redacted]	Rockies	Oct 11	31	5,000	155,000	[redacted]	[redacted]
27-Jul-10	2010-78	[redacted]	[redacted]	Stn 2	Nov10-Oct13	1,096	2,500	2,740,000	[redacted]	[redacted]
27-Jul-10	2010-79	[redacted]	[redacted]	AECO	Oct 11	31	5,000	155,000	[redacted]	[redacted]
9-Aug-10	2010-80	[redacted]	[redacted]	AECO	3 Winters 10-13	454	2,500	1,135,000	[redacted]	[redacted]
9-Aug-10	2010-81	[redacted]	[redacted]	Stn 2	Nov10-Oct13	1,096	2,500	2,740,000	[redacted]	[redacted]
10-Aug-10	2010-82	[redacted]	[redacted]	AECO	3 Winters 10-13	454	2,500	1,135,000	[redacted]	[redacted]
10-Aug-10	2010-83	[redacted]	[redacted]	AECO	Nov 10	30	5,000	150,000	[redacted]	[redacted]

GAS SUPPLY I 2010-2011 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT
10-Aug-10	2010-84	[redacted]		Rockies	Nov 10	30	5,000	150,000	[redacted]	
11-Aug-10	2010-85			AECO	Nov 10	30	5,000	150,000		
11-Aug-10	2010-86			Rockies	Nov 10	30	5,000	150,000		
13-Aug-10	2010-87			AECO	3 Winters 10-13	454	2,500	1,135,000		
16-Aug-10	2010-88			AECO	3 Winters 10-13	454	2,500	1,135,000		
16-Aug-10	2010-89			AECO	Apr 11 - May 11	61	5,000	305,000		
16-Aug-10	2010-90			AECO	3 Winters 10-13	454	2,500	1,135,000		
18-Aug-10	2010-91			Rockies	Oct 11	31	5,000	155,000		
18-Aug-10	2010-92			AECO	Jan 11	31	5,000	155,000		
18-Aug-10	2010-93			Rockies	Oct 11	31	5,000	155,000		
19-Aug-10	2010-94			AECO	Jan 11	31	5,000	155,000		
19-Aug-10	2010-95			AECO	Apr 11 - May 11	61	5,000	305,000		
Total Hard Hedges								**65,035,000**		

CONFIDENTIAI 2009-2010 FINANCIAL SOFT HEDGES (counterparty owns option)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Days	Daily Volume	Total Trade Volume	Amount OTM	NOTIONAL AMOUNT	CALL STRIKE PRICE
10-Mar-10	2010-16	[redacted]		Stn 2	Nov10-Mar11	151	5000	755,000	[redacted]		$11.150
12-Mar-10	2010-19			Rockies	Nov10-Mar11	151	5,000	755,000			$7.900
16-Mar-10	2010-20			Stn 2	Nov10-Mar11	151	5,000	755,000			$6.100
29-Apr-10	2010-32			Stn 2	Nov10-Mar11	151	5,000	755,000			$5.850
20-May-10	2010-42			Rockies	Nov10-Mar11	151	5,000	755,000			$5.850
Total Soft Hedges								**3,775,000**			
Total Hard and Soft Hedges								**68,810,000**			

2008 Hedges by Counterparty:

Counterparty	Volume
[redacted]	775,000
	3,060,000
	8,042,500
	3,825,000
	5,480,000
	18,165,000
	7,055,000
	16,875,000
	5,532,500
	68,810,000

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V.3.a Customer count and revenue by month and class

	Customer Cnt Aug-09	Revenue Aug-09	Customer Cnt Sep-09	Revenue Sep-09	Customer Cnt Oct-09	Revenue Oct-09
Total	**659,332**	$ 34,481,318.63	**659,292**	$ 37,061,153.82	**661,938**	$ 48,978,087.64
Oregon	591,904	30,855,019.10	591,821	33,217,169.84	594,295	43,828,894.36
Washington	67,428	3,626,299.53	67,471	3,843,983.98	67,643	5,149,193.28
Total Residential	596,905	15,177,826.81	596,917	16,313,800.06	599,491	24,002,872.66
Total Commercial	61,502	10,421,841.21	61,449	11,326,324.84	61,519	14,493,080.05
Total Industrial	605	3,005,013.89	605	3,490,760.83	607	3,510,810.46
Total Interruptible	172	4,749,453.01	173	4,784,697.23	173	5,783,423.70
Total Transportation - Commercial Firm	3	6,150.94	3	7,068	3	7,529.36
Total Transportation - Industrial Firm	67	457,731.34	67	463,098	67	479,875.65
Total Transportation - Interruptible	78	663,301.43	78	675,405	78	700,495.76
Unbilled Revenue		1,496,964.16		1,828,953		22,832,687.75
Agency Fees		-		-		
Net Balancing/Overrun		-		-		-
Total Gas Operating Revenue		**$ 35,978,282.79**		**$ 38,890,106.41**		**$ 71,810,775.39**

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UM1286 PGA Portfolio Guidelines
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V.3.a Customer count and revenue by month and class

	Customer Cnt Nov-09	Revenue Nov-09	Customer Cnt Dec-09	Revenue Dec-09	Customer Cnt Jan-10	Revenue Jan-10
Total	**664,382**	$ 79,194,978.02	**667,794**	$ 112,782,643.00	**669,594**	$ 126,190,128.24
Oregon	596,459	71,443,406.52	599,524	101,407,935.31	601,092	113,315,383.21
Washington	67,923	7,751,571.50	68,270	11,374,707.69	68,502	12,874,745.03
Total Residential	601,740	48,441,894.48	604,692	70,872,438.49	606,135	80,212,572.78
Total Commercial	61,719	22,991,399.74	62,169	33,680,640.23	62,519	37,841,883.09
Total Industrial	586	3,222,867.20	595	3,414,426.64	594	3,253,058.13
Total Interruptible	156	3,363,846.16	158	3,627,858.44	158	3,699,413.54
Total Transportation - Commercial Firm	10	34,182.31	-	42,375.71	12	34,745.60
Total Transportation - Industrial Firm	72	468,888.65	74	507,527.14	74	502,853.02
Total Transportation - Interruptible	99	671,899.48	96	637,376.35	102	645,602.08
Unbilled Revenue		8,077,197.94		23,289,909.69		(20,680,219.22)
Agency Fees						
Net Balancing/Overrun		701.00		1,373.00		-
Total Gas Operating Revenue		**$ 87,272,876.96**		**$ 136,073,925.69**		**$ 105,509,909.02**

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V.3.a Customer count and revenue by month and class

	Customer Cnt Feb-10	Revenue Feb-10	Customer Cnt Mar-10	Revenue Mar-10	Customer Cnt Apr-10	Revenue Apr-10
Total	**670,119**	$ 96,360,310.31	**670,329**	$ 82,539,535.59	**670,197**	$ 75,576,133.59
Oregon	601,525	87,360,753.69	601,653	74,835,736.81	601,559	68,177,807.12
Washington	68,594	8,999,556.62	68,676	7,703,798.78	68,638	7,398,326.47
Total Residential	606,804	61,081,837.39	606,935	50,767,273.23	606,841	45,581,518.69
Total Commercial	62,384	27,957,167.91	62,465	24,429,507.36	62,430	22,735,258.00
Total Industrial	595	2,875,417.46	595	2,834,414.04	593	2,757,800.82
Total Interruptible	154	3,338,207.14	152	3,343,642.10	151	3,346,980.30
Total Transportation - Commercial Firm	12	32,132.50	12	33,660.94	12	31,931.28
Total Transportation - Industrial Firm	71	458,101.94	72	475,110.70	72	463,803.68
Total Transportation - Interruptible	99	617,445.97	98	655,927.22	98	658,840.82
Unbilled Revenue		(12,575,682.97)		203,442.13		(7,614,394.46)
Agency Fees						
Net Balancing/Overrun		-		-		(25.00)
Total Gas Operating Revenue		**$ 83,784,627.34**		**$ 82,742,977.72**		**$ 67,961,714.13**

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V.3.a Customer count and revenue by month and class

	Customer Cnt May-10	Revenue May-10	Customer Cnt Jun-10	Revenue Jun-10	Customer Cnt Jul-10	Revenue Jul-10
Total	**670,037**	$ 58,828,945.03	**669,405**	$ 35,553,950.78	**668,402**	$ 32,548,235.10
Oregon	601,353	53,096,018.94	600,661	30,957,626.32	599,611	29,108,347.45
Washington	68,684	5,732,926.09	68,744	4,596,324.46	68,791	3,439,887.65
Total Residential	606,796	34,475,465.46	606,323	20,178,085.54	605,522	16,759,643.20
Total Commercial	62,315	17,714,229.42	62,159	10,591,102.33	61,957	10,056,840.24
Total Industrial	593	2,593,477.67	595	1,685,872.29	594	2,115,026.09
Total Interruptible	151	2,901,470.02	146	1,947,207.20	147	2,479,582.85
Total Transportation - Commercial Firm	12	29,643.41	12	26,834.29	12	23,924.31
Total Transportation - Industrial Firm	72	463,568.36	72	454,155.99	72	444,412.68
Total Transportation - Interruptible	98	651,090.69	98	670,693.14	98	668,805.73
Unbilled Revenue		(7,561,204.02)		(8,314,863.60)		(3,858,483.05)
Agency Fees						
Net Balancing/Overrun		-		-		-
Total Gas Operating Revenue		**$ 51,267,741.01**		**$ 27,239,087.18**		**$ 28,689,752.05**

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V.3.b Historical (five years) and forecasted (one year ahead) sales system physical peak demand

	2010/2011 Forecasted [1]	2009 [2]	2008 [2]	2007 [2]	2006 [2]
System peak demand (therms)	9,458,805	8,339,000	8,363,000	7,344,000	7,401,000

[1] Normalized peak as used for purposes of the Annual PGA Filing
[2] Source: NWN Annual Report - Total Peak Delivery

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V.3.c Historical (five years) and forecasted (one year ahead) sales system physical annual demand

Gas Year *	**Forecasted 2010/2011**	**2009/2010**	**2008/2009**	**2007/2008**	**2006/2007**
Annual Demand (therms)	759,755,671	735,406,042	769,120,519	840,420,224	787,127,130

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V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:

1. Annual for each customer class

Gas Year *	Forecasted 2010/2011	2009/2010 [1]	2008/2009 [1]	2007/2008	2006/2007
Residential (therms)	403,163,642	396,259,291	403,419,481	435,212,254	395,702,901
Commercial (therms)	240,379,891	240,251,834	249,432,740	267,646,613	248,760,365
Industrial Firm (therms)	40,579,358	37,528,316	40,798,724	47,873,776	53,828,063
Industrial Interruptible (therms)	75,632,780	61,366,601	75,469,574	89,687,581	88,835,801

[1] Updated for actuals

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V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:

2. Annual and monthly baseload

Gas Year	Forecasted 2010-2011	2009/2010[1]	2008/2009[1]	2007/2008	2006/2007
November	22,964,131	22,368,074	23,287,321	25,070,006	26,190,648
December	23,766,649	23,309,822	24,085,841	25,827,339	26,743,482
January	23,707,980	23,367,602	24,512,946	25,673,977	26,116,496
February	21,429,390	20,987,986	21,870,814	24,358,834	25,455,856
March	23,742,813	23,184,270	24,107,559	25,171,242	25,226,067
April	22,993,771	22,392,041	22,955,784	24,947,798	24,684,614
May	23,773,918	23,123,968	23,728,867	24,495,722	24,762,960
June	22,993,803	22,206,833	22,918,154	25,098,765	25,393,815
July	23,746,608	22,939,571	23,582,019	25,062,882	25,303,961
August	23,732,954	23,388,626	23,561,523	24,974,191	25,381,941
September	22,993,867	22,650,442	22,875,547	25,266,815	25,298,427
October	23,811,317	23,442,459	23,690,099	24,441,090	24,878,078
Annual	279,657,202	273,361,694	281,176,475	300,388,661	305,436,346

[1] Updated for actuals

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V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:

3. Annual and monthly non-baseload

Gas Year	Forecasted 2010/2011	2009/2010[1]	2008/2009 [1]	2007/2008	2006/2007
November	63,590,570	41,313,882	33,595,043	43,762,463	38,998,713
December	94,691,775	83,307,972	69,578,284	79,693,312	77,658,460
January	92,143,464	91,849,305	106,271,855	101,915,519	103,367,842
February	73,999,012	61,712,656	92,276,003	99,041,078	93,338,223
March	59,467,160	50,195,196	78,889,604	68,842,326	62,999,517
April	38,136,100	47,177,713	55,529,796	67,165,395	41,287,841
May	18,013,811	29,743,398	26,806,441	38,226,764	27,259,608
June	5,974,052	18,397,682	8,694,151	17,272,557	10,263,521
July	427,941	4,870,382	2,359,545	5,532,941	3,248,045
August	361,441	354,520	0	1,811,539	1,654,431
September	3,492,155	3,487,037	2,714,748	3,328,953	3,096,795
October	29,800,989	29,634,606	11,228,575	13,438,716	18,517,788
Annual	480,098,469	462,044,348	487,944,044	540,031,563	481,690,784

[1] Updated for actuals

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V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:

4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update

[1] Updated for actuals

Forecasted 2010/2011	**Albany**	**Astoria**	**The Dalles (OR**	**Eugene**	**Newport/LC**	**Portland**	**Salem**	**Vancouver**
November	4,959,916	1,181,910	976,471	6,093,291	841,898	52,191,698	12,029,968	8,279,550
December	6,706,640	1,567,324	1,317,575	8,030,677	1,078,658	72,295,375	16,080,489	11,381,686
January	6,428,931	1,542,329	1,294,840	7,742,596	1,080,067	71,116,974	15,453,443	11,192,263
February	5,331,359	1,348,074	1,054,854	6,476,387	938,079	58,127,468	12,932,342	9,219,840
March	4,712,359	1,295,297	877,393	5,756,191	961,515	50,088,596	11,567,776	7,950,846
April	3,634,153	1,033,779	638,917	4,512,144	799,486	35,713,111	8,954,678	5,843,604
May	2,586,793	760,689	462,558	3,460,136	630,656	23,453,547	6,399,808	4,033,541
June	1,828,365	540,505	357,151	2,583,575	472,178	15,642,111	4,646,697	2,897,273
July	1,471,837	416,796	326,228	2,202,455	364,844	12,957,543	4,002,423	2,432,422
August	1,468,589	407,830	326,903	2,202,435	354,563	12,897,945	4,004,067	2,432,062
September	1,614,442	479,232	357,891	2,349,459	434,560	14,182,409	4,309,814	2,758,217
October	3,134,091	813,560	645,310	4,125,991	634,510	30,973,111	7,957,094	5,328,640
Annual	43,877,476	11,387,325	8,636,090	55,535,337	8,591,014	449,639,887	108,338,598	73,749,944

2009/2010 [1]	**Albany**	**Astoria**	**The Dalles (OR)**	**Eugene**	**Newport/LC**	**Portland**	**Salem**	**Vancouver**
November	3,958,516	968,524	703,552	4,370,947	736,861	38,814,912	8,125,283	6,003,361
December	6,772,815	1,604,810	1,234,519	7,379,170	1,203,057	64,354,442	13,715,517	10,353,464
January	6,070,896	1,544,701	1,498,610	7,575,728	1,108,916	69,550,378	16,105,104	11,762,574
February	4,831,240	1,204,871	1,047,212	5,743,681	921,299	49,129,022	11,741,477	8,081,840
March	4,587,575	1,187,139	883,460	5,485,529	860,701	42,640,221	10,757,366	6,977,475
April	4,436,188	1,110,783	773,939	5,525,032	867,080	39,833,508	10,655,298	6,367,926
May	3,162,615	958,600	585,146	4,540,385	679,126	30,025,275	7,968,938	4,947,281
June	2,321,219	765,367	454,378	3,246,129	635,811	23,278,201	6,007,833	3,895,577
July	1,601,212	555,689	354,528	2,446,357	522,058	15,162,414	4,387,896	2,779,799
August	1,445,409	407,326	320,610	2,152,307	352,737	12,761,222	3,918,716	2,384,818
September	1,593,342	479,370	352,018	2,298,029	432,280	14,051,804	4,226,232	2,704,405
October	3,110,182	815,434	638,823	4,051,411	631,161	30,746,146	7,853,207	5,230,700
Annual	43,891,209	11,602,613	8,846,795	54,814,705	8,951,087	430,347,545	105,462,867	71,489,221

2008/2009 [1]	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	3,624,754	842,463	640,959	4,421,504	677,435	32,913,429	8,348,655	5,413,165
December	5,556,185	1,378,466	976,214	6,322,720	980,942	56,571,715	12,925,515	8,952,368
January	7,223,977	1,825,939	1,484,627	7,980,532	1,299,523	80,856,761	17,451,986	12,661,456
February	6,522,841	1,556,524	1,251,678	7,558,121	1,142,165	69,875,673	15,135,892	11,103,923
March	6,071,184	1,535,991	1,143,546	6,702,613	1,081,079	62,235,214	14,255,558	9,971,978
April	4,645,149	1,288,499	862,128	5,374,562	1,024,022	47,093,604	10,846,813	7,350,803
May	3,021,243	874,917	562,286	3,971,888	704,416	29,445,167	7,272,580	4,682,811
June	1,929,893	628,927	374,076	2,717,956	581,767	17,872,542	4,573,498	2,933,646
July	1,607,519	518,550	344,447	2,323,798	611,160	14,098,105	4,026,192	2,411,793
August	1,535,419	461,201	311,839	2,031,167	508,509	12,712,093	3,738,961	2,262,334
September	1,659,289	464,897	336,511	2,267,834	477,909	13,559,775	4,403,620	2,420,460
October	2,327,537	588,062	482,484	2,960,848	518,803	19,964,839	4,696,482	3,379,619
Annual	45,724,990	11,964,436	8,770,795	54,633,543	9,607,730	457,198,917	107,675,752	73,544,356

2007/2008	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	4,182,195	1,020,306	714,633	5,328,764	794,380	40,443,798	9,916,379	6,432,017
December	6,111,505	1,434,454	1,148,124	7,266,264	1,132,170	64,040,525	14,279,473	10,108,139
January	7,525,889	1,818,000	1,362,710	8,906,960	1,334,030	76,765,888	17,669,672	12,206,347
February	7,275,281	1,727,923	1,310,289	8,767,209	1,280,677	74,546,238	16,944,082	11,548,213
March	5,806,592	1,423,964	982,372	7,207,188	1,022,585	55,796,872	13,321,732	8,452,263
April	5,536,384	1,496,823	898,205	7,094,652	1,095,624	54,452,628	12,940,164	8,598,713
May	3,831,143	996,118	616,226	5,055,033	779,567	36,821,140	8,801,220	5,822,039
June	2,623,616	779,248	414,955	3,645,849	614,661	24,355,810	5,994,332	3,942,849
July	1,975,877	592,231	347,030	2,691,864	548,150	16,945,575	4,496,352	2,998,745
August	1,788,317	539,314	327,890	2,597,000	580,394	14,184,574	4,226,755	2,541,487
September	1,879,260	491,798	338,625	2,655,135	496,788	15,144,990	4,923,500	2,665,670
October	2,495,259	683,858	430,146	3,293,375	610,483	20,928,007	5,890,615	3,548,062
Annual	51,031,318	13,004,037	8,891,205	64,509,293	10,289,509	494,426,045	119,404,276	78,864,544

2006/2007	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver
November	4,034,228	933,260	652,611	4,892,941	762,841	38,509,913	9,234,927	6,168,643
December	6,135,144	1,419,027	1,139,427	6,858,605	1,068,942	63,676,035	14,232,857	9,871,907
January	7,407,237	1,704,833	1,506,828	8,557,052	1,255,834	79,077,437	17,536,028	12,439,091
February	6,782,072	1,624,244	1,299,240	8,697,719	1,145,151	71,981,839	16,101,922	11,161,895
March	5,270,516	1,331,447	1,019,044	6,573,081	951,132	52,537,651	12,242,601	8,300,115
April	4,030,552	1,069,544	671,423	5,196,638	902,369	38,661,593	9,485,498	5,954,841
May	3,282,925	904,218	503,315	4,340,822	711,752	30,095,182	7,622,525	4,561,830
June	2,324,876	658,575	402,560	3,266,164	631,874	20,099,683	5,107,270	3,166,337
July	1,862,146	535,992	353,273	2,666,890	524,643	15,625,445	4,356,279	2,627,340
August	1,809,024	468,414	250,531	2,581,508	454,717	14,788,546	4,150,622	2,533,010
September	1,882,860	472,501	413,488	2,592,907	459,875	15,130,819	4,723,060	2,719,714
October	2,738,939	669,244	471,650	3,732,974	590,570	24,661,298	6,485,520	4,045,675
Annual	47,560,519	11,791,299	8,683,390	59,957,301	9,459,700	464,845,441	111,279,109	73,550,398

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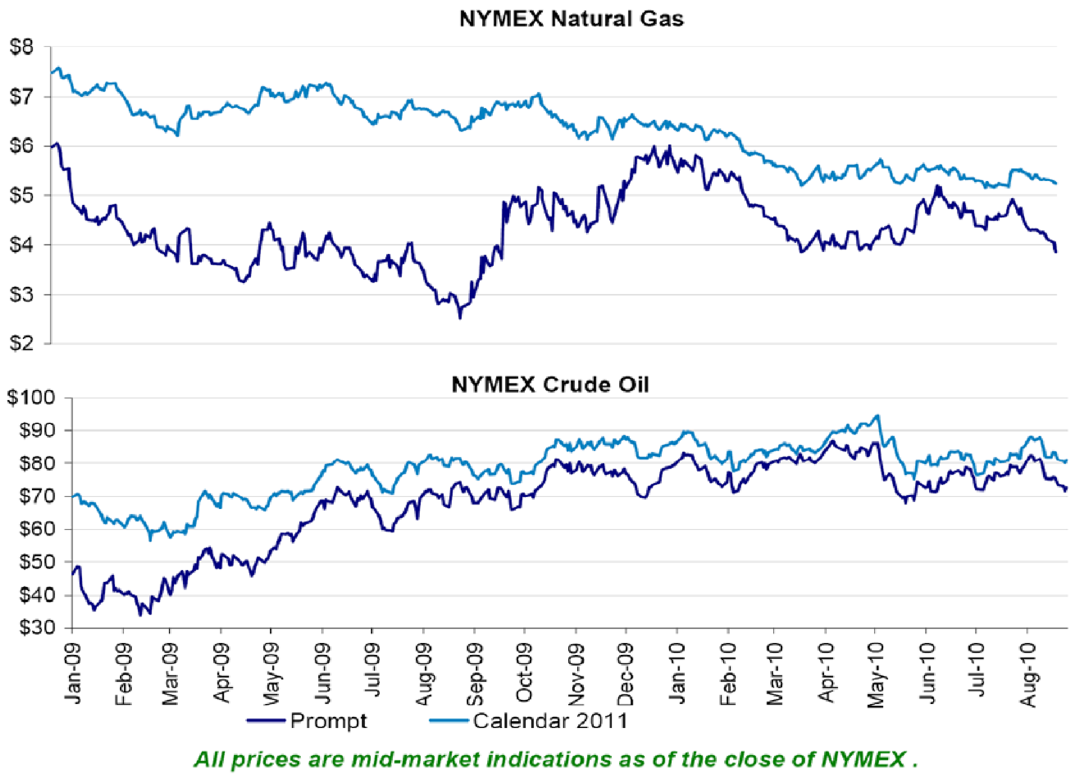
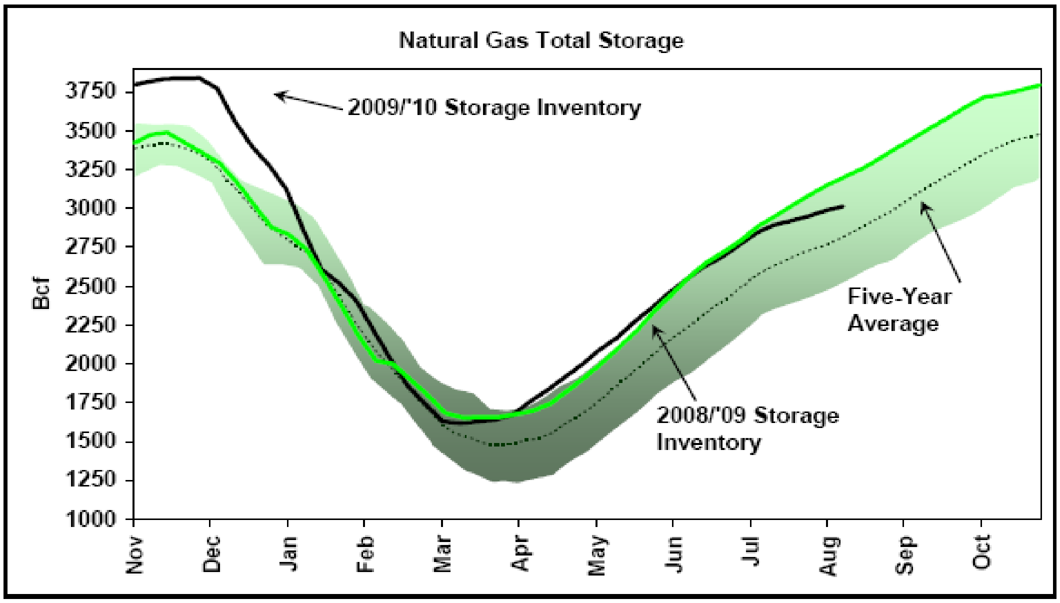
V.4 Market Information:
General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.

During 2009, oil prices ranged between $35 and $75/barrel, a less volatile range than the prior year when oil went as high as $133/barrel in June 2008 and then dropped to $41 in December. More recent oil prices have been relatively stable in a range between $75 and $82/barrel, reflecting amble supply and low demand caused by world-wide economic weakness. Because of these same factors (ample supply and weak demand), the correlation between natural gas and oil prices have tended to be very weak in recent times. In its August 2010 Short Term Energy Outlook, EIA expects the natural gas (Henry Hub) spot price to average $4.69/Mcf this year, a $0.74/Mcf increase over the 2009 average, though like oil, this average does not tell the story of the wild swings that gas prices experienced through 2008 and into 2009. A graphical depiction of the course of natural gas and oil prices since the beginning of 2009 is shown below.

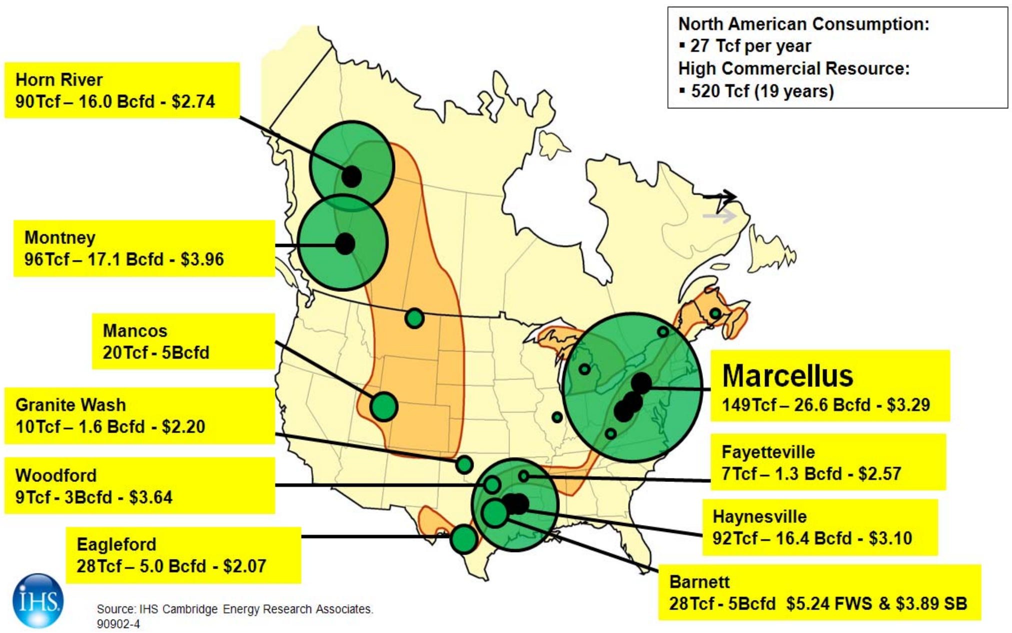


Source: BMO Capital Markets *Daily Market Summary Report*, August 25, 2010

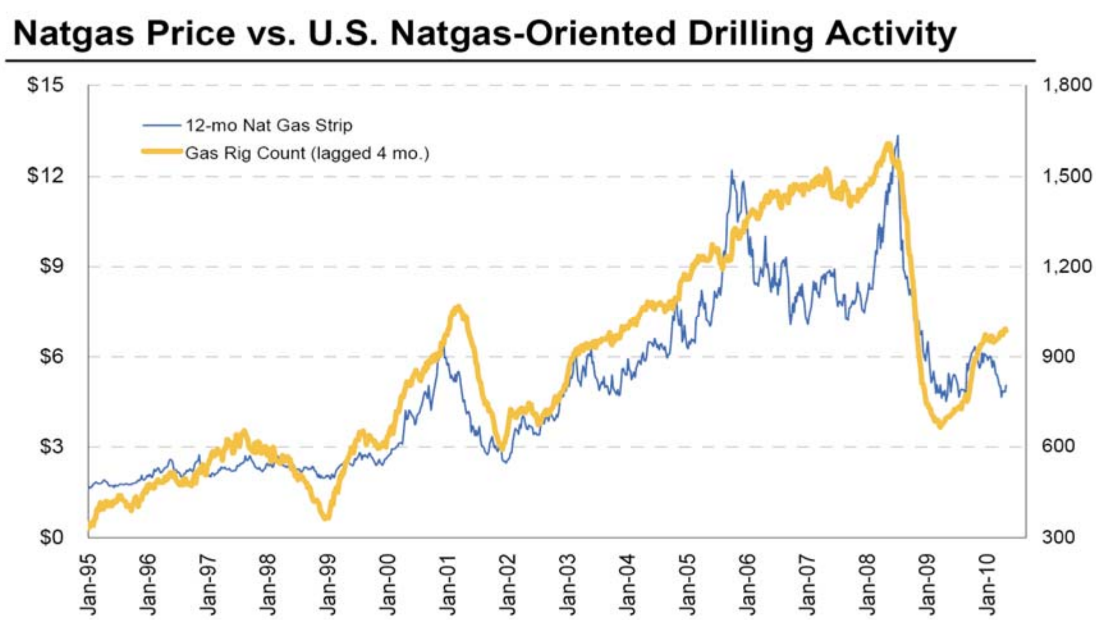
Nationwide, natural gas storage levels in 2009 exceeded EIA's 5-year average levels for each month of 2009. Storage levels were at an all-time high in November 2009. In July 2010, inventory levels were 9% above the 5-year average and 3% below last year's record high. The hurricane activity in the Gulf of Mexico has been mild with little impact on production. This, combined with increased production from shale reserves, has helped maintain a strong storage inventory level in spite of recent heat waves and their impact on gas-fired electric generation demand. It also reflects lower demand due to the recession gripping the country, which also led to a very high level of gas remaining in storage at the end of the past heating season. Weekly storage levels through early August 2010 are depicted in the following chart.



A topic of frequent discussion over the past year has been the resurgence of domestic natural gas production. Once thought to have peaked and be inexorably in decline, domestic gas production has increased and led some to say that the U.S. will be "awash" with gas supplies in the future. These predictions center on the rapid emergence of non-conventional gas production from tight sands and especially shale gas deposits. While more expensive than conventional gas production, the previous regime of higher prices spurred development of this resource, bringing more gas on line than previously thought technically and/or economically feasible. This was a primary factor in last year's dramatic gas cost decrease. Shale gas can be found throughout the U.S. and Canada as shown below.



However, the sharp drop in natural gas prices has also taken a toll on drilling activity, as shown in the next graph.



Source: Morgan Stanley *Weekly Explorer* dated August 23, 2010

As with the rest of the industry, NW Natural is monitoring these trends with great interest. While the potential for robust gas production now seems undeniable for the foreseeable future, there are of coursed no guarantees. For example, recent public concerns over shale gas developments, along with BP oil spill in the Gulf, is putting intense scrutiny on production companies to minimize the environmental impact of their operations. While these efforts are not likely to reduce supplies appreciably, they can only put upward pressure on pricing.

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V.5 Data Interpretation

If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.

See this Exhibit C , IV.2.b.

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V.6 Credit Worthiness Standards

A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.

IV. Credit Risk Management

The following steps are taken by the Front, Mid and Back Offices to provide credit risk management:

	Procedure	Responsible Office
1	Analyzes the counterparty's profile to determine credit risk tolerances.	Mid Office
2	Sets counterparty credit limits in accordance with company policy (see Exhibit "E" of the Gas Supply Risk Management Policies).	Mid Office
3	Monitors credit exposure and coordinates with the Front Office to mitigate risk.	Mid Office
4	If the credit exposure amount exceeds the counterparty credit limit, verifies the limit violation.	Mid Office
5	Notifies Front Office Executive of limit violations in physical transactions, and Mid Office Executive of limit violations in financial transactions.	Mid Office
6	Determines any appropriate action in response to physical transaction violations.	Front Office Executive
7	Communicates instructions for dealing with physical transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Front Office Executive
8	Determines any appropriate action in response to financial transaction violations.	Mid Office Executive
9	Communicates instructions for dealing with financial transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Mid Office Executive
10	Calculates and analyzes various credit risk metrics to better understand the current and potential risks in the portfolio.	Mid Office
11	Calculates and records appropriate credit reserves on a monthly basis.	Mid Office
12	Reviews credit limits at least twice a year, and additionally as needed, to assess whether changes should be made.	Mid Office
13	Monitors news articles, bankruptcy filings, legal actions, etc. on a daily basis for all established counterparties.	Front Office Mid Office Back Office

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures
Effective March 28, 2005; Last updated January 5, 2008

Northwest Natural Gas Company
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V.6 Credit Worthiness Standards

A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.

See Attachment 1 to V.6 to this Exhibit C -
HIGHLY CONFIDENTIAL and CONFIDENTIAL
Subject to Modified Protective Order 10-337

EXHIBIT C
Attachment 1 to V.6
Highly Confidential
and Confidential

NW NATURAL

Gas Supply Risk Management Policies

Index No. 110

January, 2007

Derivatives Policy: Updated September 2006

Physical Gas Commodity Transactions Policy: Updated January 2007

Original Date of Approval: March 29, 2005

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V.7	**Storage**
a)	Type of storage (e.g., depleted field, salt dome).
b)	Location of each storage facility.
c)	Total level of storage in terms of deliverability and capacity held during the gas year.

NW Natural storage withdrawals in the Purchased Gas Adjustment (PGA) filing for 2010-2011 are produced from stochastic modeling. As noted in the Integrated Resource Plan (IRP), the Company's Gas Supply Department utilizes a program Sendout to perform its dispatch modeling. Based on expected conditions, this modeling provides guidance to the department in how it anticipates dispatching from various pipeline supplies and storage facilities. The objective is to ensure reliable service during the heating season on an aggregate system-wide basis and, at the same time, achieve the maximum economic benefit from seasonal price differences and varying gas delivery terms. With the assistance of Sendout, resource portfolios are developed with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. The system is operated as an integrated whole and costs are apportioned accordingly.

NW Natural's heavy reliance on storage gas requires examination of the Company's ability to meet peaking loads. Sendout models an ideal operation profile for each storage facility to meet core customer demand based on historical heating season patterns.

Operational capabilities of each storage facility are factored into the analysis. Storage resources modeled for the 2010-2011 PGA included the following:

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	Upon 1-Year Notice
TF-2 (redelivery service)	32,624	839,046	Upon 1-Year Notice
TF-2 (redelivery service)	13,406	281,242	Upon 1-Year Notice
Plymouth LNG:			
LS-1	60,100	478,900	Upon 1-Year Notice
TF-2 (redelivery service)	60,100	478,900	Upon 1-Year Notice
Total Firm Off-system Storage:			
Withdrawal/Vaporization	106,130	1,599,188	
TF-2 Redelivery	106,130	1,599,188	
Firm On-System Storage Plants:			
Mist (reserved for core)	250,000	9,420,270	n/a
Portland LNG Plant	120,000	600,000	n/a
Newport LNG Plant	60,000	1,000,000	n/a
Total On-System Storage	430,000	11,020,270	
Total Firm Storage Resource	536,130	12,619,458	

Based on Mist core and interstate capacity allocations, Sendout recommended the following monthly core activity from that storage facility during 2010-2011 to meet the stated objectives in the IRP:

2010-2011	2010 Mist Storage Allocation		
Dth	**Core**	**Interstate**	**Total**
Working Gas	9,420,270	6,674,080	16,094,350
Withdrawal (Dth/day)	250,000	269,200	519,200

2010-2011	Mist PGA
Month	Withdrawal
November	0
December	2,007,509
January	2,682,981
February	2,616,456
March	2,007,294
April	0
May	-
June	-
July	-
August	-
September	-
October	-

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V.7.d Historical (five years) gas supply delivered to storage, both annual total and by month.

V.7.e Historical (five years) gas supply withdrawn from storage, both annual total and by month.

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary (Gasco, Newport, Jackson Prairie, Plymouth, Mist)
ACCOUNT NO. (164.21, 164.23, 164.22, 164.16, 164.12)

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Dec-04								-	122,270,766	$ 54,383,996.84	0.44478
Jan-05	122,270,766	$ 54,383,996.84	0.44478	41,203,077	$ 18,472,351.85	6,377,879	$ 2,797,036.71	0.43855	87,445,568	$ 38,708,681.70	0.44266
FEB	87,445,568	$ 38,708,681.70	0.44266	27,877,221	$ 12,308,754.89	1,117,160	$ 606,899.05	0.54325	60,685,507	$ 27,006,825.86	0.44503
MAR	60,685,507	$ 27,006,825.86	0.44503	13,402,702	$ 5,968,337.92	4,822,400	$ 2,781,280.71	0.57674	52,105,205	$ 23,819,768.65	0.45715
APR	52,105,205	$ 23,819,768.65	0.45715	24,411,118	$ 10,879,747.56	2,640,702	$ 1,807,310.58	0.68441	30,334,789	$ 14,747,331.67	0.48615
MAY	30,334,789	$ 14,747,331.67	0.48615	5,650,680	$ 2,695,555.44	12,296,816	$ 7,703,968.49	0.62650	36,980,925	$ 19,755,744.72	0.53421
JUN	36,980,925	$ 19,755,744.72	0.53421	3,863,370	$ 2,183,211.31	19,670,654	$ 12,192,118.81	0.61981	52,788,209	$ 29,764,652.22	0.56385
JUL	52,788,209	$ 29,764,652.22	0.56385	1,224,010	$ 724,858.72	38,439,609	$ 23,367,872.93	0.60791	90,003,808	$ 52,407,666.43	0.58228
AUG	90,003,808	$ 52,407,666.43	0.58228	482,112	$ 281,435.79	21,523,928	$ 14,766,749.57	0.68606	111,045,624	$ 66,892,980.21	0.60239
SEP	111,045,624	$ 66,892,980.21	0.60239	208,406	$ 118,393.47	20,997,893	$ 20,226,464.42	0.96326	131,835,111	$ 87,001,051.16	0.65992
OCT	131,835,111	$ 87,001,051.16	0.65992	4,373,083	$ 2,830,619.23	15,320,883	$ 17,255,139.72	1.12625	142,782,911	$ 101,425,571.65	0.71035
NOV	142,782,911	$ 101,425,571.65	0.71035	12,187,672	$ 8,652,795.12	6,795,869	$ 6,489,344.74	0.95490	137,391,108	$ 99,262,121.27	0.72248
DEC	137,391,108	$ 99,262,121.27	0.72248	41,587,528	$ 30,478,415.34	6,447,660	$ 8,189,402.06	1.27014	102,251,240	$ 76,973,107.99	0.75278
TOTAL 2005 ACTIVITY				176,470,979	95,594,476.64	156,451,453	118,183,587.79				
Jan-06	102,251,240	$ 76,973,107.99	0.75278	18,958,017	$ 14,644,496.32	1,712,020	$ 1,537,405.03	0.89801	85,005,243	$ 63,866,016.70	0.75132
Feb	85,005,243	$ 63,866,016.70	0.75132	25,301,163	$ 19,685,349.69	1,260,790	$ 912,186.10	0.72350	60,964,870	$ 45,092,853.11	0.73965
Mar	60,964,870	$ 45,092,853.11	0.73965	16,380,123	$ 12,714,357.74	5,744,820	$ 3,500,585.93	0.60935	50,329,567	$ 35,879,081.30	0.71288
Apr	50,329,567	$ 35,879,081.30	0.71288	8,029,038	$ 5,805,872.06	3,712,467	$ 2,413,036.77	0.64998	46,012,996	$ 32,486,246.01	0.70602
May	46,012,996	$ 32,486,246.01	0.70602	2,127,418	$ 1,433,491.41	31,242,513	$ 18,049,315.16	0.57772	75,128,091	$ 49,102,069.76	0.65358
Jun	75,128,091	$ 49,102,069.76	0.65358	1,536,935	$ 990,817.43	30,380,924	$ 17,478,793.68	0.57532	103,972,080	$ 65,590,046.01	0.63084
Jul	103,972,080	$ 65,590,046.01	0.63084	1,228,413	$ 780,336.37	19,668,264	$ 12,257,997.01	0.62324	122,411,931	$ 77,067,706.65	0.62958
Aug	122,411,931	$ 77,067,706.65	0.62958	336,093	$ 210,229.38	12,172,288	$ 7,881,693.44	0.64751	134,248,126	$ 84,739,170.71	0.63121
Sep	134,248,126	$ 84,739,170.71	0.63121	412,841	$ 248,185.88	14,724,165	$ 8,382,441.08	0.56930	148,559,450	$ 92,873,425.91	0.62516
Oct	148,559,450	$ 92,873,425.91	0.62516	8,524,419	$ 5,535,541.34	-	$ -	-	140,035,031	$ 87,337,884.57	0.62369
Nov	140,035,031	$ 87,337,884.57	0.62369	17,928,294	$ 11,288,271.47	5,991,010	$ 3,707,869.38	0.61891	128,097,747	$ 79,757,482.48	0.62263
Dec	128,097,747	$ 79,757,482.48	0.62263	24,118,160	$ 14,846,060.55	6,030,810	$ 3,664,130.91	0.60757	110,010,397	$ 68,575,552.84	0.62336
TOTAL 2006 ACTIVITY				124,880,914	88,183,009.64	132,640,071	79,785,454.49				

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V.7.d Historical (five years) gas supply delivered to storage, both annual total and by month.

V.7.e Historical (five years) gas supply withdrawn from storage, both annual total and by month.

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary (Gasco, Newport, Jackson Prairie, Plymouth, Mist)
ACCOUNT NO. (164.21, 164.23, 164.22, 164.16, 164.12)

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-07	110,010,397	$ 68,575,552.84	0.62336	32,747,989	$ 20,502,938.66	2,947,690	$ 1,721,085.84	0.58388	80,210,098	$ 49,793,700.02	0.62079
FEB	80,210,098	$ 49,793,700.02	0.62079	21,665,609	$ 13,340,971.41	1,868,810	$ 1,276,550.79	0.68308	60,413,299	$ 37,729,279.40	0.62452
MAR	60,413,299	$ 37,729,279.40	0.62452	5,716,652	$ 3,635,769.46	12,732,030	$ 7,734,741.02	0.60750	67,428,677	$ 41,828,250.96	0.62033
APR	67,428,677	$ 41,828,250.96	0.62033	17,999,410	$ 11,024,026.68	6,693,218	$ 3,500,379.10	0.52297	56,122,485	$ 34,304,603.38	0.61125
MAY	56,122,485	$ 34,304,603.38	0.61125	7,676,136	$ 4,607,187.63	27,758,648	$ 14,102,546.19	0.50804	76,204,997	$ 43,799,961.94	0.57476
JUN	76,204,997	$ 43,799,961.94	0.57476	2,290,199	$ 1,267,185.11	22,587,207	$ 10,082,107.84	0.44636	96,502,005	$ 52,614,884.67	0.54522
JUL	96,502,005	$ 52,614,884.67	0.54522	938,890	$ 518,930.35	27,986,126	$ 14,749,934.89	0.52704	123,549,241	$ 66,845,889.21	0.54105
AUG	123,549,241	$ 66,845,889.21	0.54105	934,511	$ 518,496.94	22,279,127	$ 11,416,040.83	0.51241	144,893,857	$ 77,743,433.10	0.53655
SEP	144,893,857	$ 77,743,433.10	0.53655	1,018,869	$ 561,305.39	11,414,527	$ 2,424,935.55	0.21244	155,289,515	$ 79,607,063.26	0.51264
OCT	155,289,515	$ 79,607,063.26	0.51264	14,791,065	$ 7,301,584.37	2,198,039	$ 724,296.55	0.32952	142,696,489	$ 73,029,775.44	0.51178
NOV	142,696,489	$ 73,029,775.44	0.51178	3,305,990	$ 1,423,564.17	4,497,822	$ 2,768,087.19	0.61543	143,888,321	$ 74,374,298.46	0.51689
DEC	143,888,321	$ 74,374,298.46	0.51689	14,553,312	$ 7,322,402.53	5,864,210	$ 4,026,896.20	0.68669	135,199,219	$ 71,078,792.13	0.52573
TOTAL 2007 ACTIVITY				123,638,632	72,024,362.70	148,827,454	74,527,601.99				
Jan-08	135,199,219	$ 71,078,792.13	0.52573	42,682,544	$ 22,727,144.60	3,402,230	$ 2,562,147.29	0.75308	95,918,905	$ 50,913,794.82	0.53080
Feb	95,918,905	$ 50,913,794.82	0.53080	29,833,245	$ 15,663,187.27	3,037,860	$ 2,358,605.97	0.77640	69,123,520	$ 37,609,213.52	0.54409
Mar	69,123,520	$ 37,609,213.52	0.54409	29,308,951	$ 16,697,534.41	783,760	$ 651,398.76	0.83112	40,598,329	$ 21,563,077.87	0.53113
Apr	40,598,329	$ 21,563,077.87	0.53113	14,741,559	$ 9,004,018.90	5,468,770	$ 5,261,381.50	0.96208	31,325,540	$ 17,820,440.47	0.56888
May	31,325,540	$ 17,820,440.47	0.56888	1,394,242	$ 1,259,289.68	7,377,193	$ 7,072,723.41	0.95873	37,308,491	$ 23,633,874.20	0.63347
Jun	37,308,491	$ 23,633,874.20	0.63347	2,575,879	$ 2,082,625.25	17,920,700	$ 16,021,216.64	0.89401	52,653,312	$ 37,572,465.59	0.71358
Jul	52,653,312	$ 37,572,465.59	0.71358	2,389,833	$ 2,600,403.22	29,495,668	$ 27,744,517.14	0.94063	79,759,147	$ 62,716,579.51	0.78632
Aug	79,759,147	$ 62,716,579.51	0.78632	867,160	$ 729,520.01	26,131,565	$ 18,238,203.36	0.69794	105,023,552	$ 80,225,262.86	0.76388
Sep	105,023,552	$ 80,225,262.86	0.76388	143,600	$ 102,744.03	28,405,529	$ 14,134,411.09	0.49759	133,285,481	$ 94,256,929.92	0.70718
Oct	133,285,481	$ 94,256,929.92	0.70718	4,536,969	$ 3,453,264.43	26,631,384	$ 13,808,487.81	0.51850	155,379,896	$ 104,612,153.30	0.67327
Nov	155,379,896	$ 104,612,153.30	0.67327	6,716,700	$ 4,480,626.85	7,646,172	$ 6,526,427.47	0.85355	156,309,368	$ 106,657,953.92	0.68235
Dec	156,309,368	$ 106,657,953.92	0.68235	34,572,504	$ 24,087,225.38	5,896,960	$ 3,563,069.48	0.60422	127,633,824	$ 86,133,798.02	0.67485
TOTAL 2008 ACTIVITY				169,763,186	102,887,584.03	162,197,791	117,901,140.31				

Northwest Natural Gas Company
PGA Portfolio Guidelines
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V.7.d Historical (five years) gas supply delivered to storage, both annual total and by month.

V.7.e Historical (five years) gas supply withdrawn from storage, both annual total and by month.

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary (Gasco, Newport, Jackson Prairie, Plymouth, Mist)
ACCOUNT NO. (164.21, 164.23, 164.22, 164.16, 164.12)

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)		ENDING BALANCE		
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-09	127,633,824	$ 86,133,798.02	0.67485	21,470,123	$ 14,421,841.03	1,969,140	$ 915,206.80	0.46477	108,132,841	$ 72,627,163.79	0.67165
Feb	108,132,841	$ 72,627,163.79	0.67165	8,052,347	$ 5,259,751.99	3,917,370	$ 1,541,494.90	0.39350	103,997,864	$ 68,908,906.70	0.66260
Mar	103,997,864	$ 68,908,906.70	0.66260	7,169,301	$ 3,809,030.51	15,685,782	$ 5,335,886.23	0.34017	112,514,345	$ 70,435,762.42	0.62602
Apr	112,514,345	$ 70,435,762.42	0.62602	12,549,307	$ 6,792,634.68	6,003,002	$ 1,863,485.18	0.31043	105,968,040	$ 65,506,612.92	0.61817
May	105,968,040	$ 65,506,612.92	0.61817	6,257,410	$ 3,304,746.27	5,698,237	$ 2,601,331.17	0.45652	105,408,867	$ 64,803,197.82	0.61478
Jun	105,408,867	$ 64,803,197.82	0.61478	1,920,050	$ 700,166.12	10,701,397	$ 5,542,374.50	0.51791	114,190,214	$ 69,645,406.20	0.60991
Jul	114,190,214	$ 69,645,406.20	0.60991	902,489	$ 333,164.85	14,375,074	$ 7,356,483.97	0.51175	127,662,799	$ 76,668,725.32	0.60056
Aug	127,662,799	$ 76,668,725.32	0.60056	850,513	$ 355,286.25	12,119,369	$ 6,151,720.64	0.50759	138,931,655	$ 82,465,159.71	0.59357
Sep	138,931,655	$ 82,465,159.71	0.59357	844,063	$ 357,760.71	10,236,492	$ 5,276,073.94	0.51542	148,324,084	$ 87,383,472.94	0.58914
Oct	148,324,084	$ 87,383,472.94	0.58914	4,176,560	$ 1,736,106.06	10,379,167	$ 4,536,149.64	0.43704	154,526,691	$ 90,183,516.52	0.58361
Nov	154,526,691	$ 90,183,516.52	0.58361	2,628,536	$ 1,135,797.56	4,189,298	$ 1,447,394.43	0.34550	156,087,453	$ 90,495,113.39	0.57977
Dec	156,087,453	$ 90,495,113.39	0.57977	38,007,275	$ 20,770,776.55	5,277,200	$ 2,921,280.66	0.55357	123,357,378	$ 72,645,617.50	0.58890
TOTAL 2009 ACTIVITY				104,827,974	58,977,062.58	100,551,528	45,488,882.06				
Jan-10	123,357,378	$ 72,645,617.50	0.58890	9,410,501	$ 5,373,535.47	4,395,990	$ 2,432,943.95	0.55345	118,342,867	$ 69,705,025.98	0.58901
Feb	118,342,867	$ 69,705,025.98	0.58901	4,879,344	$ 2,627,742.75	2,365,397	$ 1,217,833.57	0.51485	115,828,920	$ 68,295,116.80	0.58962
Mar	115,828,920	$ 68,295,116.80	0.58962	7,912,236	$ 4,425,625.23	2,309,560	$ 985,508.03	0.42671	110,226,244	$ 64,854,999.60	0.58838
Apr	110,226,244	$ 64,854,999.60	0.58838	15,503,891	$ 8,614,804.86	1,670,862	$ 646,032.16	0.38665	96,393,215	$ 56,886,226.90	0.59015
May	96,393,215	$ 56,886,226.90	0.59015	1,927,556	$ 793,228.54	9,406,506	$ 3,645,785.79	0.38758	103,872,165	$ 59,738,784.15	0.57512
Jun	103,872,165	$ 59,738,784.15	0.57512	652,061	$ 363,386.29	5,713,773	$ 2,465,796.73	0.43155	108,933,877	$ 61,841,194.59	0.56769
Jul	108,933,877	$ 61,841,194.59	0.56769	287,609	$ 183,359.98	12,279,896	$ 5,485,162.22	0.44668	120,926,164	$ 67,142,996.83	0.55524
TOTAL 2010 ACTIVITY				40,573,198	22,381,683.12	38,141,984	16,879,062.45				

Northwest Natural Gas Company
PGA Portfolio Guidelines
2010-2011 Oregon PGA

V.7.f An explanation of the methdology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.

The price of gas placed into storage, classed as working inventory, will be the average cost of gas defined as the average commodity cost of gas delivered to the city gate (utilizing discretionary sources first: i.e., spot gas first, then swing, and base load term supplies last) unless the site is outside the company service territory. This price would represent commodity cost, transmission cost, and fuel-in-kind (FIK) at either the NNG city gas (internal storage) or at the external storage site. This price will include all pipeline demand charges and supplier reservation charges.

This pricing policy will apply to all storage locations owned or under contract to the NNG, with exception as noted.

When the contract for a storage site includes a provision for the price of the gas placed into storage, the price shall be the price as defined by the agreement

Direct associated costs, such as liquefaction fees (LS-1), FIK (SGS) and actual material costs incurred (Newport) can be added to the base cost when determined significant.

Withdrawals at each facility (Mist, Gasco, etc.) are priced at the average inventory price as established at the beginning of each month. The beginning of the month cost at each facility is adjusted for any withdrawals and any injections to create the end of the month cost, which then becomes the beginning of the month cost for the next month.

NW Natural

PGA Portfolio Guidelines
2010-2011 Oregon PGA

V.7.g Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.

See Attachment to this Exhibit C.

FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT

Rate Schedule SGS-2F Service Agreement

Contract No. 100502

THIS SERVICE AGREEMENT (Agreement) by and between Northwest Pipeline GP (Transporter) and Northwest Natural Gas Company (Shipper) restates the Service Agreement made and entered into on January 01, 1998.

WHEREAS:

A Pursuant to Section 11.4 of the General Terms and Conditions of Transporter's FERC Gas Tariff, Transporter and Shipper desire to restate the Service Agreement dated January 01, 1998("Contract # 100502") in the format of Northwest's currently effective Form of Service Agreement and to make certain additional non-substantive changes, while preserving all pre-existing, substantive contractual rights.

B Shipper orginally acquired capacity by entering into a binding precedent agreement through the open season for incremental firm storage service at Jackson Prairie; as authorized by FERC in Docket No. CP06-416.

THEREFORE, in consideration of the premises and mutual covenants set forth herein, Transporter and Shipper agree as follows:

1. Tariff Incorporation. Rate Schedule SGS-2F and the General Terms and Conditions (GT&C) that apply to Rate Schedule SGS-2F, as such may be revised from time to time in Transporter's FERC Gas Tariff (Tariff), are incorporated by reference as part of this Agreement, except to the extent that any provisions thereof may be modified by non-conforming provisions herein.

2. Storage Service. Subject to the terms and conditions that apply to service under this Agreement, Transporter agrees to inject, store and withdraw natural gas for Shipper, on a firm basis. Shipper may request Transporter to withdraw volumes in excess of Shipper's Contract Demand on a best efforts basis as provided in Rate Schedule SGS-2F. The Contract Demand and Storage Capacity are set forth on Exhibit A.

3. Storage Rates. Shipper agrees to pay Transporter for all services rendered under this Agreement at the rates set forth or referenced herein. The maximum currently effective rates (Recourse Rates) set forth in the Statement of Rates in the Tariff, as revised from time to time, that apply to the Rate Schedule SGS-2F customer category identified on Exhibit A will apply to service hereunder unless and to the extent that discounted Recourse Rates or awarded capacity release rates apply as set forth on Exhibit A or negotiated rates apply as set forth on Exhibit D.

4. Service Term. This Agreement becomes effective on the date first set forth above. The primary term begin date for the storage service hereunder is set forth on Exhibit A. This Agreement will remain in full force and effect through the primary term end date set forth on Exhibit A and, if Exhibit A indicates that an evergreen provision applies, through the established evergreen rollover periods thereafter until terminated in accordance with the notice requirements under the applicable evergreen provision.

5. Non-Conforming Provisions. All aspects in which this Agreement deviates from the Tariff, if any, are set forth as non-conforming provisions on Exhibit B. If Exhibit B includes any material non-conforming provisions, Transporter will file the Agreement with the Federal Energy Regulatory Commission (Commission) and the effectiveness of such non-conforming provisions will be subject to the Commission acceptance of Transporter's filing of the non-conforming Agreement.

6. Capacity Release. If Shipper is a temporary capacity release Replacement Shipper, any capacity release conditions, including recall rights and the amount of the Releasing Shipper's Working Gas Quantity released to Shipper for the initial Storage Cycle, are set forth on Exhibit A.

7. Exhibit Incorporation. Exhibit A is attached hereto and incorporated as part of this Agreement. If Exhibits B and/or D apply, as noted on Exhibit A to this Agreement, then such Exhibits also are attached hereto and incorporated as part of this Agreement.

8. Regulatory Authorization. Storage service under this Agreement is authorized pursuant to the Commission regulations set forth on Exhibit A.

9. Superseded Agreements. When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s): Original Service Agreement dated January 1, 1998.

IN WITNESS WHEREOF, Transporter and Shipper have executed this Restated Agreement on January 21, 2008.

Northwest Natural Gas Company	Northwest Pipeline GP
By: /S/	By: /S/

Name: RANDOLPH S. FRIEDMAN

Title: DIRECTOR, GAS SUPPLY

Name: JANE F HARRISON

Title: MANAGER NWP MARKETING SERVICES

FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT
(Continued)

EXHIBIT A
(Dated January 21, 2008, Effective January 21, 2008)
to the
Rate Schedule SGS-2F Service Agreement
(Contract No. 100502)
between Northwest Pipeline GP
and Northwest Natural Gas Company

SERVICE DETAILS

1. Customer Category: Pre-Expansion Shipper

2. Contract Demand: 46,030 Dth per day

3. Storage Capacity: 1,120,288 Dth

4. Recourse or Discounted Recourse Storage Rates:

   (Show Not Applicable if Exhibit D is attached.)

   a. Demand Charge (per Dth of Contract Demand):

      Maximum Currently Effective Tariff Rate

   b. Capacity Demand Charge (per Dth of Storage Capacity):

      Maximum Currently Effective Tariff Rate

   c. Rate Discount Conditions Consistent with Section 3.2 of Rate Schedule SGS-2F:

      Not Applicable

5. Service Term:

   a. Primary Term Begin Date:

      November 01, 1998

   b. Primary Term End Date:

      October 31, 2004

   c. Evergreen Provision:

      Yes, grandfathered unilateral evergreen under Section 15.3 of Rate Schedule SGS-2F

6. Regulatory Authorization: 18 CFR 284.223

7. Additional Exhibits:

   Exhibit B No

   Exhibit D No

TF0350 000004P126Original Sheet No. 50
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm

1. AVAILABILITY

This Rate Schedule is available to any Shipper for the purchase c natural gas storage service from Transporter when Shipper and Transporter have executed a Service Agreement for the storage of gas under this Rate Schedule and have arranged for the related transportation of gas to and from the Jackson Prairie Storage Project under one of Transporter's transportation rate schedules.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Applicability. This Rate Schedule shall apply to firm storage ga service consisting of Transporter's injection, storage and withdrawal o Shipper's gas at the Jackson Prairie Storage Project. The executed Service Agreement for service under this Rate Schedule will specify the Shipper category, i.e., whether the Shipper is a Pre-Expansion Shipper or an Expansion Shipper. The Jackson Prairie Storage Project capacity available for this Rate Schedule will be Transporter's undivided interest as an owner in the Project, excluding any portion of such interest which may be authorized for use by Transporter for transportation balancing. Delivery of natural gas by Shipper to Transporter for injection and by Transporter to Shipper upon withdrawal shall be at the point of interconnection between the Jackson Prairie Storage Project and Transporter's main transmission line.

2.2 Character of Service. Storage gas service rendered to Shipper under this Rate Schedule, up to Shipper's Contract Demand and Storage Capacity and subject to the limitations of this Rate Schedule and the executed Service Agreement, shall be firm and shall not be subject to curtailment or interruption except as provided in Sections 9, 10, 12, and 14 of the General Terms and Conditions.

2.3 Capacity Release. Shippers releasing firm storage rights shall d so in accordance with the capacity release provisions outlined in Section 22 of the General Terms and Conditions. Any such release is subject to the terms and conditions of this Rate Schedule.

3. MONTHLY RATE

Each month, Shipper will pay Transporter for service rendered under this Rate Schedule the amounts specified in this Section 3, as applicable.

TF0351 0010004P126First Revised Sheet No. 51
TF04 Original Sheet No. 51
TF05Larèn M. Gertsch, Director
TF06092508 110108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

3.1 Storage Service. The sum of (a),(b) and (c) below:

(a) Demand Charge: The sum of the daily product of Shipper's Contract Demand and the Demand Charge stated on Sheet No. of this Tariff that applies to the customer category identified in the Service Agreement.

(b) Capacity Demand Charge: The sum of the daily product of Shipper's Storage Capacity and the Capacity Demand Charge stated on Sheet No. 7 of this Tariff that applies to the customer category identified in the Service Agreement.

The related transportation of gas to and from the Jackson Prairie storage facility shall be subject to separate transportation charges under applicable open-access Rate Schedules. The rates set forth in th sub-paragraphs above are exclusive of the aforementioned transportation charges.

3.2 Discounted Recourse Rates. Transporter reserves the right to discount at any time the Recourse Rates for any individual Shipper unde any service agreement without discounting any other Recourse Rates for that or another Shipper; provided, however, that such discounted Recourse Rates shall not be less than the Minimum Currently Effective Rates set forth on Sheet No. 7 of this Tariff, or any superseding tariff. Such discounted Recourse Rates may apply to specific volumes o gas such as volumes injected, withdrawn or stored above or below a certain level or all volumes if volumes exceed a certain level, and volumes of gas injected, withdrawn or stored during specific time periods. If Transporter discounts any Recourse Rates to any Shipper, Transporter will file with the Commission any required reports reflecting such discounts.

TF0352 0020004P126Second Revised Sheet No. 52
TF04 First Revised Sheet No. 52
TF05Laren M. Gertsch, Director
TF06012109 022009
TF07

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

3.3 Charges for Capacity Release Service: The rates for capacity release service are set forth in Sheet No. 7. See Section 22 of the General Terms and Conditions for information about rates for capacity release service, including information about acceptable bids. In the event of a base tariff maximum and/or minimum rate change, the Replacement Shipper will be obligated to pay:

(a) the lesser of the awarded bid rate and the new maximum base tariff rate, or the greater of the awarded bid rate and the new minimum base tariff rate, as applicable, for the remaining term of the release for capacity release transactions with a term of more than one year and where the awarded bid rate was not tied to the maximum rate as it may change from time to time;

(b) the greater of the minimum base tariff rate and the awarded bid rate for the remaining term of the release for capacity release transactions with a term of one year or less that take effect on or before one year from the date on which Transporter is notified of the release and where the award bid rate was not tied to the maximum tariff rate; or

(c) the new maximum rate or, if applicable, the percentage of the new maximum rate for capacity release transactions where the awarded bid rate was tied to the maximum rate as it may change from time to time.

For capacity release service subject to demand charges, the payments by the Replacement Shipper shall be equal to the sum of the daily product of the accepted Demand Charge bid rate and the Contract Demand, plus the sum of the daily product of the accepted Capacity Demand Charge bid rate and the Storage Capacity.

For capacity release service subject to volumetric bid rates, the payments by the Replacement Shipper shall be equal to the accepted volumetric bid rate for withdrawals multiplied by the actual volumes withdrawn each day plus the accepted volumetric bid rate for storage multiplied by the actual volumes in storage each day.

TF0352-A 0010004P156First Revised Sheet No. 52-A
TF04 Original Sheet No. 52-A
TF05Laren M. Gertsch, Director
TF06012109 022009
TF07

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

The SGS-2F Volumetric Bid Charge will be calculated as set forth in section 3.1 herein except that (a) and (b) change as specified below

(a) Withdrawal Charge: Per Dth of Withdrawals during the applicable month.

(b) Storage Charge: Per Dth of Shipper's Working Gas Inventory per day.

3.4 Negotiated Rates. Notwithstanding the general provisions of this Section 3, if Transporter and Shipper mutually agree to Negotiated Rates for service hereunder, such Negotiated Rates will apply in lieu of the otherwise applicable rates identified in this Section 3.

4. MINIMUM MONTHLY BILL

Unless Transporter and Shipper mutually agree otherwise, the Minimum Monthly Bill will consist of the sum of the Demand and Capacity Demand Charges specified in Section 3 of this Rate Schedule, as applicable.

5. FUEL GAS REIMBURSEMENT

Shipper shall reimburse Transporter for fuel use in-kind, as detailed in Section 14 of the General Terms and Conditions.

6. CONTRACT DEMAND

The Contract Demand shall be the largest number of Dth Transporte is obligated to withdraw and deliver to Shipper, and Shipper is entitle to receive from Transporter, at Jackson Prairie on any one day, to the limitations set forth in Section 9 below, and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter's service obligation is limited to Shipper's Contract Demand, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions

TF0352-B 0010004P156First Revised Sheet No. 52-B
TF04 Original Sheet No. 52-B
TF05Laren M. Gertsch, Director
TF06012109 022009
TF07

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

7. STORAGE CAPACITY

Shipper's Storage Capacity shall be the maximum quantity of gas in Dth which Transporter is obligated to store for Shipper's account and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter's service obligation is limited to Shipper's Storage Capacity, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions.

8. DEFINITIONS

8.1 A Storage Cycle is the twelve-month period beginning October 1 of any calendar year and ending September 30 of the following calendar year.

8.2 Shipper's Working Gas Inventory shall be the actual quantity of working gas in storage for Shipper's account at the beginning of any given day.

8.3 Shipper's Working Gas Quantity for a Storage Cycle shall be determined as of October 1 and shall be the lesser of:

(a) Shipper's Working Gas Inventory as of October 1, the beginning of the Storage Cycle; or

(b) The minimum quantity of Shipper's Working Gas Inventory at any time between August 31 and September 30 of the preceding Storage Cycle divided by 0.80; or

(c) The minimum quantity of Shipper's Working Gas Inventory at any time between June 30 and September 30 of the preceding Storage Cycle divided by 0.35.

TF0353 000004P126Original Sheet No. 53
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

8. DEFINITIONS (Continued)

In addition to the quantity calculated above, an Expansion Shipper's Working Gas Quantity will include any increases in its Storag Capacity during the current Storage Cycle.

The above method of determining Shipper's Working Gas Quantity ma be modified consistent with any comparable modification under the January 15, 1998 Gas Storage Project Agreement, or superseding agreement, permitted by the Jackson Prairie Storage Project Management Committee. A Shipper's Working Gas Quantity will be adjusted for any Working Gas Quantity released as indicated on Exhibit A to a Replacemen Shipper's Service Agreement.

8.4 Shipper's Available Working Gas on any day during the Storage Cycle shall be equal to Shippers' Working Gas Inventory less Shipper's Unavailable Working Gas.

8.5 Shipper's Unavailable Working Gas on any day during the Storage Cycle shall be equal to the highest level of Shipper's Working Gas Inventory during the preceding days of the current Storage Cycle less Shipper's Working Gas Quantity.

9. WITHDRAWALS OF STORAGE GAS

9.1 General Procedure. When Shipper desires the withdrawal of gas under this Rate Schedule on any day, it shall give notice to Transporter, specifying the volume of gas within Shipper's Available Working Gas which it desires withdrawn under this Rate Schedule during such day. Transporter shall thereupon withdraw the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject as necessary to confirmation of the nomination changes for the related transportation service agreement.

TF0354 000004P126Original Sheet No. 54
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

9. WITHDRAWALS OF STORAGE GAS (Continued)

9.2 Withdrawal Obligation. Transporter's daily withdrawal obligation shall be at 100 percent of the Shipper's Contract Demand as long as Shipper's Available Working Gas is greater than or equal to 60 percent of Shipper's Storage Capacity. On any day when Shipper's Available Working gas is less than 60 percent of Shipper's Storage Capacity, Transporter's daily withdrawal obligation shall be reduced by two percent of Shipper's Contract Demand for each one percent that Shipper' Available Working Gas is less than 60 percent of Shipper's Storage Capacity, until a minimum daily withdrawal rate equal to 10 percent of Shipper's Contract Demand is reached.

10. INJECTIONS OF WORKING GAS FOR SHIPPER'S ACCOUNT

Shipper shall provide written notice to Transporter prior to May of each year, of the volumes of gas to be injected for the account of Shipper during the period of May 1 through September 30 of such year. When Shipper desires the injection of gas under this Rate Schedule on any day, it shall give notice to Transporter, specifying the volume of gas it desires injected under this Rate Schedule during such day, including the applicable fuel reimbursement requirements. Transporter shall thereupon inject the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject to delivery of such volume, and shall retain any fuel use reimbursement furnished in-kind in accordance with Section 14 of the General Terms and Conditions in addition to any fuel reimbursement required from the part under whose Service Agreement the gas is to be transported to Jackson Prairie.

11. WITHDRAWALS AND INJECTIONS SUBSEQUENT TO THE INTRADAY 2 NOMINATION CYCL

To the extent Transporter's existing transportation and storage obligations are not compromised, Shipper may request up to two changes in scheduled daily withdrawal or injection quantities following the Intraday 2 Nomination Cycle for the remainder of the Gas Day. Transporter will thereupon withdraw or inject the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule including fuel gas reimbursement requirements and subject as necessary to confirmation of the nomination changes for the related transportatio service agreement.

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

12. LIMITATIONS ON INJECTIONS AND WITHDRAWALS FROM STORAGE

Shipper may request Transporter to cause gas to be injected into or withdrawn from storage for Shipper's account at any time during the year. Available injection capacity will be allocated to each Shipper proportionate to such Shipper's Storage Capacity. In no event shall th balance of gas stored in Shipper's account exceed Shipper's Storage Capacity as defined under Section 6 of this Rate Schedule.

After the commencement of an annual Storage Cycle, withdrawals from Shipper's Available Working Gas may be replaced both to maintain deliverability and to restore the quantity available for withdrawals. Additional working gas may also be injected during the Storage Cycle; provided, however, that Shipper's Unavailable Working Gas as defined in Section 8 above shall not be available for withdrawal during the curren Storage Cycle.

13. WITHDRAWALS IN EXCESS OF FIRM ENTITLEMENT (BEST-EFFORTS WITHDRAWALS)

Shipper may request Transporter to withdraw volumes in excess of Shipper's Contract Demand on a best-efforts basis; provided, however, that the total volume withdrawn may not exceed the level of Shipper's Available Working Gas. Transporter may make such excess withdrawal, consistent with the priority of service provisions contained in Section 12 of the General Terms and Conditions, if and to the extent that capacity is available to make such withdrawal after Transporter's needs for withdrawal capacity to satisfy its system balancing requirements have been met.

14. TRANSFER OF WORKING GAS INVENTORY

Shippers subject to either this Rate Schedule or to Rate Schedule SGS-2I may agree to transfer their respective Working Gas Inventories between themselves. Participating Shippers must notify Transporter's Marketing Services personnel of their intent to transfer such inventory in writing, prior to the beginning of the gas day in which such transfe will occur. Transfers of Working Gas Inventory may not result in any Shipper taking title to Working Gas Inventory volumes that exceed such Shipper's Rate Schedule SGS-2F Storage Capacity or Rate Schedule SGS-2I Interruptible Storage Capacity.

TF0356 000004P126Original Sheet No. 56
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

14. TRANSFER OF WORKING GAS INVENTORY (Continued)

Pursuant to the January 15, 1998 Gas Storage Project Agreement, owners of the Jackson Prairie Storage Project may transfer portions of their respective available working gas inventories, as defined in the Project Agreement, to each other. Upon agreement of the parties, and subject to the terms of the Project Agreement, Transporter may utilize its ownership account on behalf of a Rate Schedule SGS-2F Shipper to transfer such Shipper's Working Gas Inventory to an owner's available working gas inventory account. Conversely, an owner may transfer its available working gas inventory to a Rate Schedule SGS-2F Shipper's Working Gas Inventory account.

15. EVERGREEN PROVISION

15.1 Standard Unilateral Evergreen Provision. If Transporter and Shipper agree to include a standard unilateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

(a) The established rollover period will be one year.

(b) Shipper may terminate the Service Agreement in its entiret upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving written notice to Transporter so stating at least five years before the terminatio date.

(c) The termination notice required under Section 15.1(b) will be deemed given when posted on Transporter's Designated Site.

15.2 Standard Bi-Lateral Evergreen Provision. If Transporter and Shipper agree to include a standard bi-lateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(a) The established rollover period will be:

(i) one month for a Service Agreement with a primary ter of less than one year; or

(ii) one year for a Service Agreement with a primary term of one year or more.

(b) Either Transporter or Shipper may terminate the Service Agreement in its entirety upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving the other party termination notice at least:

(i) ten Business Days before the termination date if Section 15.2(a)(i) applies; or

(ii) one year before the termination date if Section 15.2(a)(ii) applies.

(c) The termination notice required under Section 15.2(b) will be deemed given when posted on Transporter's Designated Site. If Transporter gives termination notice, such termination notice als will be given via Internet E-mail or fax if specified by Shipper on the Business Associate Information form.

15.3 Grandfathered Unilateral Evergreen Provision. If a Shipper with Service Agreement containing a unilateral evergreen provision elects: (i) to restate such Service Agreement in the format of the Form of Service Agreement contained in this Tariff, or (ii) to permanently release all or a portion of its firm contract rights, including its unilateral evergreen rights, to a Replacement Shipper at the Maximum Base Tariff Rate pursuant to Section 22.5 of the General Terms and Conditions, then the Exhibit A of the applicable restated or replacemen Service Agreement will indicate that the following grandfathered unilateral evergreen conditions will apply:

(a) The established rollover period will be one year, at Shipper's sole option.

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TF04
TF05Laren M. Gertsch, Director
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(b) Shipper may terminate all or any portion of service under its Service Agreement either at the expiration of the primary term, or upon any anniversary thereafter, by giving written notice to Transporter so stating at least twelve months in advance.

(c) Shipper also will have the sole option to enter into a new Service Agreement for all or any portion of the service under it Service Agreement at or after the end of the primary term of its Service Agreement. It is Transporter's and Shipper's intent tha this provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurren pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR 284.221(d)(2)(i) as promulgated by Order No. 636 on May 8, 1992.

(d) The termination notice required under Section 15.3(b) will be deemed given when posted on Transporter's Designated Site.

16. INTERIM BEST-EFFORTS WITHDRAWAL CHARGE REVENUE CREDITING

One hundred percent (100%) of Interim Best-Efforts Withdrawal Charge revenues received by Transporter pursuant to Section 3.1 will be credited to Rate Schedule SGS-2F Pre-Expansion Shippers, excluding such Shippers receiving service under capacity release Service Agreements. For each month Transporter receives Interim Best-Efforts Withdrawal Charge revenues, credits for such revenues will be allocated to the eligible Rate Schedule SGS-2F Pre-Expansion Shippers pro rata in proportion to the Demand Charge revenues, net of credits from capacity releases as described in Section 23 of the General Terms and Conditions, received from each eligible Rate Schedule SGS-2F Pre-Expansion Shipper for that month. Such allocated monthly revenue credits will be accrued during a calendar year and reflected as credit billing adjustments on the eligible Shippers' March invoices following such calendar year.

17. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, except Sections 13, 16 and 21 and except as modified in the executed Service Agreement, are applicable to this Rate Schedule and are hereby made a part hereof.

SERVICE AGREEMENT
(Liquefaction - Storage Gas Service under Rate Schedule LS-1)

THIS AGREEMENT, made and entered into this 12th day of January 12, 1994, by and between NORTHWEST PIPELINE CORPORATION, a Delaware corporation, hereinafter called "Transporter", and NORTHWEST NATURAL GAS COMPANY, hereinafter called "Shipper".

In consideration of the mutual covenants and agreements as herein set forth, the parties hereto agree as follows:

ARTICLE I - GAS TO BE STORED AND DELIVERED

Subject to the terms, conditions, and limitations hereof and of the applicable Rate Schedule LS-1, Transporter agrees to liquefy, store in liquid phase, vaporize and deliver to Shipper for transportation, and Shipper agrees to receive from Transporter, up to the following quantities of natural gas:

A Storage Demand Volume of 60,100 MMBtus,
A Storage Capacity of 478,900 MMBtus.

ARTICLE II - DELIVERY OF GAS

Delivery of natural gas by Transporter to Shipper for transportation shall be at or near the point of vaporization at Transporter's LNG facilities. Shipper shall arrange for redelivery transportation to mainline delivery points under Transporter's transportation rate schedules.

ARTICLE III - APPLICABLE RATE SCHEDULE

Shipper agrees to pay Transporter for all natural gas service rendered under the terms of this Agreement in accordance with Transporter's Rate Schedule LS-1 as filed with the Federal Energy Regulatory Commission ("FERC"), and as such rate schedule may be amended or superseded from time to time. This Agreement shall be subject to the provisions of such rate schedule and the General Terms and Conditions applicable thereto on file with the FERC and effective from time to time, which by this reference are incorporated herein and made a part hereof.

ARTICLE IV - TERM OF AGREEMENT

This Agreement shall become effective on the date so designated by the FERC and shall continue in effect for a period continuing through October 31, 2004 and year to year thereafter at Shipper's sole option. Shipper may terminate all or any portion of service under this Agreement either at the expiration of the primary term, or upon any anniversary thereafter by giving at least twelve (12) months in advance. Shipper also shall have the sole option to enter into a new agreement for all or any portion of the service under this Agreement at or after the end of the primary term of this Agreement. It is Transporter's and Shipper's intent that this term provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurrent pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR § 284.221 (d)(2)(i) as promulgated by Order 636 on May 8, 1992.)

ARTICLE V - CANCELLATION OF PRIOR AGREEMENTS

When this Agreement takes effect, it supersedes, cancels and terminates the following agreements:

Service Agreement (Liquefaction-Storage Gas Service) dated October 1, 1992 between Northwest Pipeline Corporation, "Seller" and Northwest Natural Gas Company, "Buyer".

ARTICLE VI - SUCCESSORS AND ASSIGNS

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above set forth.

"TRANSPORTER"
NORTHWEST PIPELINE CORPORATION

By: ______________________
Joe H. Fields
Attorney-In-Fact

1/12/9
PES

ATTEST:

By: ______________________

"SHIPPER"
NORTHWEST NATURAL GAS COMPANY

LEGAL DEPARTME
Approved As To For
This Date 1/18/
By SEP

By: ______________________
Name: Dwayne L. Foley
Title: Sr. Vice President

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TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service

1. AVAILABILITY

This Rate Schedule is available only to those existing Shippers who (i) have contracted for Rate Schedule LS-1 liquefaction-storage service and have received authorization under Section 7(c) of the Natural Gas Act for the purchase of such service from Transporter when Shipper and Transporter have executed Service Agreements for service under this Rate Schedule, and (ii) have arranged for the related transportation of gas to and from the Plymouth LNG Facility under one o Transporter's transportation rate schedules.

2. APPLICABILITY AND CHARACTER OF SERVICE

This Rate Schedule shall apply to the liquefaction-storage gas service rendered by Transporter to Shipper under the executed Service Agreement for such service.

Service under this Rate Schedule shall consist of the liquefactic and storage by Transporter for Shipper's account of gas transported to the LNG facility under a separate executed Service Agreement pursuant t Rate Schedules TF-1 or TI-1, the vaporization of such stored gas, and delivery to Shipper for transportation under a separate executed Servic Agreement pursuant to Rate Schedules TF-1, TF-2 or TI-1. Delivery of natural gas by Shipper to Transporter for liquefaction and by Transporter to Shipper upon vaporization shall be at the point of interconnection between Transporter's Plymouth LNG Facility and Transporter's main transmission line.

Service rendered to Shipper under this Rate Schedule, within the limitations described in the Service Agreement and in Sections 7 and 8 of this Rate Schedule, shall be firm and shall not be subject to curtailment or interruption except as provided in Sections 9, 10, 12, and 14 of the General Terms and Conditions.

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TF04 Original Sheet No. 71
TF05Laren M. Gertsch, Director
TF06040708 050808
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RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

3. RATE

Shipper shall pay Transporter each month for service rendered hereunder, the sum of the following amounts:

(a) Demand Charge: The sum of the daily product of Shipper's Storage Demand and the Demand Charge.

(b) Capacity Charge: The sum of the daily product of Shipper's Storage Capacity and the Capacity Charge.

(c) Liquefaction Charge: Per Dth of gas liquefied and stored for Shipper's account during the month.

(d) Vaporization Charge: Per Dth of gas vaporized and schedule for delivery to Shipper during the month.

The unit rates shall be those as set forth from time to time in the currently effective Sheet No. 8 of this Tariff.

The related transportation of gas to and from the Plymouth LNG storage facility shall be subject to separate transportation charges under applicable Rate Schedules. The rates set forth above in subparagraphs (a) through (d) are exclusive of the aforementioned charges.

4. MINIMUM MONTHLY BILL

The Minimum Monthly Bill shall consist of the sum of the Demand Charge and the Capacity Charge specified in Section 3 of this Rate Schedule.

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TF04
TF05Laren M. Gertsch, Director
TF06121907021897RP97-180 013108
TF077861157

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

5. FUEL GAS REIMBURSEMENT

Upon liquefaction of Shipper's gas, Shipper shall reimburse Transporter for fuel use in-kind, as detailed in Section 14 of the General Terms and Conditions.

6. DEFINITIONS

6.1 Storage Demand Volume. The Storage Demand Volume shall be the largest number of Dth Transporter is obligated to vaporize for, and Shipper is entitled to receive from, Transporter's liquefied natural ga storage plant under this Rate Schedule on any one day, subject to the limitations described in Section 8 of this Rate Schedule, and shall be specified in the executed Service Agreement between Transporter and Shipper.

6.2 Storage Capacity Volume. The Storage Capacity Volume shall be th maximum quantity of gas in Dth which Transporter is obligated to liquef and store in liquid form for Shipper's account and shall be specified i the executed Service Agreement between Transporter and Shipper.

6.3 Liquefaction Period. The Liquefaction Period shall be the seven consecutive months beginning on April 1 of any year and extending through the next succeeding October 31.

6.4 Vaporization Period. The Vaporization Period shall be the five consecutive months beginning on November 1 of any year and extending through the next succeeding March 31.

6.5 Storage Capacity Balance. Shipper's Storage Capacity Balance at any particular time shall be the quantity of gas in storage in liquid form for Shipper at such time.

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TF04
TF05Laren M. Gertsch, Director
TF06121907021897RP97-180 013108
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RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

6. DEFINITIONS (Continued)

6.6 Nominated Storage Volume. Shipper's Nominated Storage Volume shall be the quantity of gas in Dth, up to Shipper's Storage Capacity Volume, which Shipper nominates to have liquefied and stored in liquid form by Transporter for Shipper's account and shall be provided to Transporter in writing on or before April 1 of each year. In the event that Shipper does not submit a storage volume nomination by April 1, Shipper's Nominated Storage Volume for the Liquefaction Period shall be Shipper's Storage Capacity Volume. Shipper upon ten (10) days written notice to Transporter may elect to change its Nominated Storage Volume during the liquefaction period. Such change shall not reduce the Nominated Storage Volume below Shipper's Storage Capacity Balance at th time of election.

7. LIQUEFACTION INTO STORAGE FOR SHIPPER'S ACCOUNT

During a liquefaction period, Shipper is entitled to tender to Transporter for liquefaction and storage sufficient quantities of gas t fill Shipper's Storage Capacity Volume. Such tenders shall commence on April 1 and shall consist of uniform daily quantities equal to 1/200th of Shipper's Nominated Storage Volume (except for the last day of liquefaction) until Shipper's Storage Capacity Balance is equal to Shipper's Nominated Storage Volume. In addition, Transporter may schedule the liquefaction period and rate of liquefaction to fit system operating conditions.

Transporter shall not be obligated to liquefy and store gas for Shipper in excess of Shipper's Storage Capacity Volume.

The tender by Shipper to Transporter shall be made by Shipper scheduling such tendered volumes on any day as transportation volumes delivered under an executed Service Agreement for liquefaction and storage.

Upon request of Shipper, Transporter may permit Shipper to nominate gas for liquefaction and storage during a Vaporization Period in replacement of gas vaporized during such Vaporization Period; provided, however, the liquefaction of such gas shall be at such times as may be agreed upon between Transporter and Shipper. Where necessary daily liquefaction capacity of Transporter shall be prorated among Shippers in proportion to the storage capacity volumes of Shippers desiring such liquefaction on such day.

TF0374 000004P126Original Sheet No. 74
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
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RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

8. VAPORIZATION FROM STORAGE AND DELIVERY TO SHIPPER

8.1 General Procedure. When Shipper desires the vaporization of gas on any day during the Vaporization Period, it shall give notice to Transporter's dispatcher, specifying the volume of gas it desires vaporized under this Rate Schedule during such day. Transporter shall vaporize and deliver for transportation the volume of gas so nominated out of Shipper's Storage Capacity Balance, subject to the limitations set forth in this Rate Schedule.

8.2 Notice Required. The notice given by Shipper to Transporter for vaporization on any day shall be prior to the commencement of such day; provided, however, that commencement of actual delivery for transportation shall be determined by system operating conditions. Shipper may request a change in the daily quantity scheduled for vaporization during the Intraday 1 and Intraday 2 Nomination Cycles pursuant to Section 14.1 of the General Terms and Conditions. In addition, and to the extent existing transportation and storage obligations are not compromised, Shipper may request up to two additional changes in the daily quantity scheduled for vaporization following the Intraday 2 Nomination Cycle for the remainder of the Gas Day, provided such change does not reduce the volume below any volume already taken during that day and subject as necessary to confirmation of the nomination changes for the related transportation service agreement.

8.3 Daily Vaporization in Excess of Shipper's Storage Demand Volume. Transporter may, upon request of Shipper, schedule for delivery for transportation on any day a volume of gas in excess of Shipper's Storag Demand Volume if in Transporter's judgment it can do so without adversely affecting its operations or curtailing other services.

8.4 Vaporization During a Liquefaction Period. Upon request of Shipper, Transporter may permit Shipper to nominate gas out of Shipper' Storage Capacity Balance for vaporization and delivery for transportation to Shipper on any day during the liquefaction period. However, such vaporization and delivery shall not adversely affect Transporter's operations or that of Transporter's other Shippers.

TF0375 000004P126Original Sheet No. 75
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

RATE SCHEDULE LS-1
Liquefaction-Storage Gas Service
(Continued)

9. EVERGREEN PROVISION

9.1 Grandfathered Unilateral Evergreen Provision. For Service Agreements under this Rate Schedule, the following grandfathered unilateral evergreen conditions will apply:

(a) The established rollover period will be one year, at Shipper's sole option.

(b) Shipper may terminate all or any portion of service under its Service Agreement either at the expiration of the primary term, or upon any anniversary thereafter, by giving written notice to Transporter so stating at least twelve months in advance.

(c) Shipper also will have the sole option to enter into a new Service Agreement for all or any portion of the service under it Service Agreement at or after the end of the primary term of its Service Agreement. It is Transporter's and Shipper's intent tha this provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurren pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR 284.221(d)(2)(i) as promulgated by Order No. 636 on May 8, 1992.

(d) The termination notice required under Section 8.1(b) will be deemed given when posted on Transporter's Designated Site.

10. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, except Sections 13, 16, 17, 18, 21, 22, 23, 25, 27 and 28 and except as modified in the executed Service Agreement, are applicable to this Rate Schedule and are hereby made a part hereof.

Northwest Natural Gas Company
PGA Portfolio Guidelines
2010-2011 Oregon PGA

CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

Index!A1

V.7.h For LDCs that own and operate storage:

a. The date and results of the last engineering study for that storage.

b. A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.

From: Roth, Clayton
Sent: Thursday, July 29, 2010 1:44 PM
To: *Gas Controllers; Tilgner, Doug; Halvorsen, Steve
Cc: Friedman, Randy; Stinson, Charlie; Brosy, Maria; Thomas, Todd; Geertz, Allen; Lee, Amy; Cole, Cindy; Mott, Michael; McAnally, Robert; Timmerman, Rick; Henderson, Denny; Redding, Mike; Wilkeson, Randy; Phelps, Wayne; Jaworski, William; Schmidt, R. Phil; Bekins, Todd; Pearce, Curtis; Dady, Robin; Buker, Ted
Subject: Mist Storage Status

This is a reminder to all recipients of this storage data that the information you are receiving is sensitive, Company confidential data. It is not to be shared with those outside the distribution list without consulting the sender and in no case should it be shared outside the Company. NW Natural storage customers and others can access weekly storage information on the NW Natural internet web site and customers can access their own account information using a personalized password. FERC has recently been focusing on storage information as a source of market volatility and is emphasizing, in part through enforcement action, that it takes very seriously any discriminatory sharing of this information. Please keep this in mind.

[redacted]

Please contact me if you have any questions.

Clayton Roth, PE
Reservoir Engineer
NW Natural
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