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August 31, 2011 NWN Advice No. OPUC 11-11

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 Relating to Docket UM 1496

Adjustments to Rates for System Integrity Program (SIP) and Storage Recall

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, 2011, as follows:

Twentieth Revision of Sheet v
"Tariff Index";

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

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

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

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

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

Tenth Revision of Sheet 164-1,
Schedule 164,
"Purchased Gas Cost Adjustments to Rates";

Eleventh Revision of Sheet 177-2,
Schedule 177,
"System Integrity Program Rate Adjustment (continued)";

Ninth Revision of Sheet 177-3,
Schedule 177,
"System Integrity Program Rate Adjustment (continued)";

Second Revision of Sheet 187-1,
Schedule 187,
"Special Rate Adjustment for Mist Capacity Recall";

Original Sheet 187-1.1,
Schedule 187,
"Special Rate Adjustment for Mist Capacity Recall (continued)";

I. Introduction and Summary

The purpose of this filing is to:

(1) Develop the temporary rate adjustments associated with the amortization of gas cost adjustments deferred under Docket UM 1496 proposed to be effective November 1, 2011, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2010;

(2) Develop the commodity and non-commodity purchased gas costs to be effective November 1, 2011; and

(3) Develop the permanent rate increments associated with: (a) the Company's System Integrity Program (SIP), and (b) the recall of Mist storage capacity.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2010.

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.

II. Amortization of Gas Cost Deferrals (UM 1496) and removal of Temporary Rate Adjustments Currently in Effect

The effect of the amortization of gas cost credit or debit balances in Federal Energy Regulatory Commission (FERC) deferred accounts, Account 191 deferred under Docket UM 1496, is a decrease to customer rates of $0.02494 per therm for firm sales service customers, and a decrease to customer rates of $0.02520 per therm for interruptible sales service customers.

The net effect of the removal of Account 191 temporary adjustments currently in effect and the application of the new Account 191 temporary increments is a net decrease to customer rates of $0.00193 per therm for firm sales service customers, and a net increase to customer rates of $0.00411 for interruptible sales service customers.

The effect of this portion of the filing is to decrease the Company's annual revenues by $1,203,529. The effect of removing the Account 191 temporary adjustments placed into rates November 1, 2010, is an increase of $15,727,625. The effect of applying the new Account 191 temporary rate adjustments for the amortization of gas costs deferred under Docket UM 1496 is a reduction of $16,931,154.

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 most recent Commission 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.

III. System Integrity Program (SIP) and Storage Recall

SIP and Geo-Hazard. For purposes of this filing, the temporary adjustments to permanent rates that relate to SIP include: Part A: Bare Steel, Part B: Transmission Integrity Management (TIMP); and Part C: Distribution Integrity Management (DIMP) pursuant to a Stipulation adopted by the Commission in Docket UM 1406, as described in Schedule 177. The temporary adjustments to permanent rates that relate to Geo-Hazard reflect the aging of amounts previously placed in rates for the Geo-Hazard program, which was implemented pursuant to a Stipulation and Agreement adopted by the Commission in Docket UM 1030 and which is now terminated. The effect of this portion of the filing (excluding revenue sensitive effects) is to increase the Company's annual revenues by $698,000.

The net effect of removing prior year amounts and applying new adjustments to customer rates is a net increase of $0.00110 on residential Schedule 2 customer rates, and a net increase of $0.00081 on commercial Schedule 3 rates. The adjustments for all other rate schedules can be found in Exhibit A to this filing at page 11.

Storage Recall. This portion of the filing represents the permanent rate effects of the recall of 100,000 therms per day of Mist reservoir capacity and 100,000 therms per day of compression capacity from upstream market activities for use by the Company's core customers. This adjustment is calculated in the same manner as all Mist expansion projects, as described in Schedule 176. The effect of this portion of the filing (excluding revenue sensitive effects) is to increase the Company's annual revenues by $110,180.

The net effect of applying the adjustment to customer rates is an increase of $0.00021 on residential Schedule 2 customer rates, and an increase of $0.00015 on commercial Schedule 3 rates. The adjustments for all other rate schedules can be found in Exhibit A to this filing at page 12.

IV. Purchased Gas Cost Adjustment (PGA)

The net effect of the PGA portion of this filing is to decrease the Company's annual revenues by about $8,726,205.

The effect of the change in gas costs is a decrease of $11,700,810, which results in a proposed Annual Sales WACOG of $0.49356 per therm, and a proposed Winter Sales WACOG of $0.50251. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales WACOG of $0.50805 and a proposed Winter Sales WACOG of $0.51727.

The effect of the change in demand charges is an increase in total demand charges of about $2,974,605, which results in a proposed firm service pipeline capacity charge of $0.12997 per therm, or $1.94 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01545 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.13379 per therm or $2.00 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01590 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.

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, as modified by the approval of a stipulation affirmed in OPUC Order NO. 11-176, Dockets UM 1520/UG 204, and as further prescribed by the PGA Filing Guidelines, Section III (1)(d) adopted in the most recent Commission Order in Docket UM 1286.

V. Combined Effect on Customer Bills

The average monthly bill impact of the changes proposed in this filing is shown in the table below:

Class	Rate Schedule	Average Monthly Bill Change ($)	Average Monthly Bill Change (%)
Residential	Schedule 2	$(0.82)	(1.2)%
Commercial	Schedule 3	$(3.56)	(1.5)%
Commercial Firm Sales	Schedule 31	$(75.45)	(2.3)%
Industrial Firm Sales	Schedule 32	$(439.91)	(2.9)%
Industrial Interruptible Sales	Schedule 32	$(661.63)	(2.1)%

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.

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.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after November 1, 2011.

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.

The Company waives paper service in this proceeding. Please address correspondence on this matter to me at eFiling@nwnatural.com, with copies to the following:

Kelley C. Miller, Rates Specialist
Rates & Regulatory Affairs
NW Natural
220 NW Second Avenue
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Sincerely,

NW NATURAL

/s/ Onita R. King

Onita R. King
Regulatory Affairs

Attachments: Exhibit A – Purchased Gas Cost Deferral Amortizations and Permanent Adjustments to Rates (SIP and Storage Recall)
Exhibit B – Purchased Gas Costs
Exhibit C – PGA Portfolio Guidelines Sections IV and V

TARIFF INDEX
(continued)

SHEET

ADJUSTMENT SCHEDULES

PROMOTIONAL CONCESSIONS

PUBLIC PURPOSES SCHEDULES

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)

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, 2011:
   Estimated Annual Sales WACOG per therm (w/ revenue sensitive): **$0.50805** (R)
   Estimated Annual Sales WACOG per therm (w/o revenue sensitive): **$0.49356** (R)

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, 2011:
   Estimated Winter Sales WACOG per therm (w/ revenue sensitive): **$0.51727** (R)
   Estimated Winter Sales WACOG per therm (w/o revenue sensitive): **$0.50251** (R)

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, 2011:
   Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): **$0.13379** (I)
   Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive: **$0.12997** (I)

(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, 2011:
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):
    $0.01590 (I)
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):
    $0.01545 (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, 2011:
    Estimated Non-Commodity Cost per therm - MDDV Based Sales (w/revenue sensitive):
    $2.00 (I)
    Estimated Non-Commodity Cost per therm- MDDV Based Sales (w/o revenue sensitive):
    $1.94 (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, 2011 through November 30, 2012 are: (T)

November 2011	$9,197,282	(C)
December 2011	$9,364,165	
January 2012	$13,035,236	
February	$12,634,887	
March	$10,543,532	
April	$9,053,757	
May	$6,599,642	
June	$4,295,903	
July	$2,838,475	
August	$2,574,929	
September	$2,569,792	
October	$2,698,848	
November	$5,481,739	
ANNUAL TOTAL	$81,690,905	(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. For any given tracker year, if the total activity subject to debit or credit entries that is related to the Gas Reserves transaction exceeds $10 million, amounts beyond $10 million will be recorded at 100%.

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

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

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

(continue to Sheet P-6)

Issued August 31, 2011 Effective with service on
NWN Advice No. OPUC 11-11 and after November 1, 2011

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

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, 2011 (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		$(0.02524)	$0.00030	$0.06488	**$0.03994**
1C		$(0.02524)	$0.00030	$0.02218	**$(0.00276)**
2		$(0.02524)	$0.00030	$0.05943	**$0.03449**
3 (CSF)		$(0.02524)	$0.00030	$0.01861	**$(0.00633)**
3 (ISF)		$(0.02524)	$0.00030	$0.02465	**$(0.00029)**
19		$(0.48)	$0.01	$0.01	**$(0.46)**
31 (CSF)	Block 1	$(0.02524)	$0.00030	$0.01358	**$(0.01136)**
	Block 2	$(0.02524)	$0.00030	$0.01262	**$(0.01232)**
31(CTF)	Block 1	N/A	N/A	$0.01493	**$0.01493**
	Block 2	N/A	N/A	$0.01454	**$0.01454**
31 (CSI)	Block 1	$(0.02524)	$0.00004	$0.01501	**$(0.01019)**
	Block 2	$(0.02524)	$0.00004	$0.01457	**$(0.01063)**
31 (ISF)	Block 1	$(0.02524)	$0.00030	$0.02007	**$(0.00487)**
	Block 2	$(0.02524)	$0.00030	$0.01902	**$(0.00592)**
31 (ITF)	Block 1	N/A	N/A	$0.00422	**$0.00422**
	Block 2	N/A	N/A	$0.00382	**$0.00382**
31 (ISI)	Block 1	$(0.02524)	$0.00004	$0.02361	**$(0.00159)**
	Block 2	$(0.02524)	$0.00004	$0.02299	**$(0.00221)**

(C)
(C)

[1] The sum of the adjustments identified in Schedules 161, 169, 170, 172, 178, 179, 188, 190 & 305.

(continue to Sheet 162-2)

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

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2011 (T)

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments [1]	Total Temporary Adjustment	
32 (CSF)	Block 1	$(0.02524)	$0.00030	$0.02071	$(0.00423)	(C)
	Block 2	$(0.02524)	$0.00030	$0.02027	$(0.00467)	
	Block 3	$(0.02524)	$0.00030	$0.01951	$(0.00543)	
	Block 4	$(0.02524)	$0.00030	$0.01876	$(0.00618)	
	Block 5	$(0.02524)	$0.00030	$0.01830	$(0.00664)	
	Block 6	$(0.02524)	$0.00030	$0.01800	$(0.00694)	
32 (ISF)	Block 1	$(0.02524)	$0.00030	$0.02061	$(0.00433)	
	Block 2	$(0.02524)	$0.00030	$0.02019	$(0.00475)	
	Block 3	$(0.02524)	$0.00030	$0.01948	$(0.00546)	
	Block 4	$(0.02524)	$0.00030	$0.01876	$(0.00618)	
	Block 5	$(0.02524)	$0.00030	$0.01833	$(0.00661)	
	Block 6	$(0.02524)	$0.00030	$0.01804	$(0.00690)	
32 (TF)	Block 1	N/A	N/A	$0.00257	$0.00257	
	Block 2	N/A	N/A	$0.00219	$0.00219	
	Block 3	N/A	N/A	$0.00157	$0.00157	
	Block 4	N/A	N/A	$0.00094	$0.00094	
	Block 5	N/A	N/A	$0.00056	$0.00056	
	Block 6	N/A	N/A	$0.00031	$0.00031	
32 (CSI)	Block 1	$(0.02524)	$0.00004	$0.02038	$(0.00482)	
	Block 2	$(0.02524)	$0.00004	$0.01997	$(0.00523)	
	Block 3	$(0.02524)	$0.00004	$0.01931	$(0.00589)	
	Block 4	$(0.02524)	$0.00004	$0.01864	$(0.00656)	
	Block 5	$(0.02524)	$0.00004	$0.01823	$(0.00697)	
	Block 6	$(0.02524)	$0.00004	$0.01797	$(0.00723)	
32 (ISI)	Block 1	$(0.02524)	$0.00004	$0.02043	$(0.00477)	
	Block 2	$(0.02524)	$0.00004	$0.02003	$(0.00517)	
	Block 3	$(0.02524)	$0.00004	$0.01936	$(0.00584)	
	Block 4	$(0.02524)	$0.00004	$0.01869	$(0.00651)	
	Block 5	$(0.02524)	$0.00004	$0.01829	$(0.00691)	
	Block 6	$(0.02524)	$0.00004	$0.01803	$(0.00717)	
32 (TI)	Block 1	N/A	N/A	$0.00245	$0.00245	
	Block 2	N/A	N/A	$0.00209	$0.00209	
	Block 3	N/A	N/A	$0.00150	$0.00150	
	Block 4	N/A	N/A	$0.00089	$0.00089	
	Block 5	N/A	N/A	$0.00054	$0.00054	
	Block 6	N/A	N/A	$0.00030	$0.00030	
33 (TI)		N/A	N/A	$0.00015	$0.00015	
33 (TF)		N/A	N/A	$0.00015	$0.00015	(C)

[1] The sum of the adjustments identified in Schedules 161, 169, 170, 172, 178, 179, 190, 188 & 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.

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, 2011 (T)

Annual Sales WACOG [1]	$0.50805	(R)
Winter Sales WACOG [2]	$0.51727	(R)
Firm Sales Service Pipeline Capacity Component [3]	$0.13379	(I)
Firm Sales Service Pipeline Capacity Component [4]	$2.00	(I)
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01590	(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, 2011 (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 August 31, 2011 Effective with service on
NWN Advice No. OPUC 11-11 and after November 1, 2011

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM RATE ADJUSTMENT
(continued)

SPECIAL PROVISIONS (Continued)

4. Beginning with the 2010-2011 PGA Year and effective November 1, every year thereafter, an adjustment reflecting the aging of amounts previously placed in rates for the GeoHazard Repair and Risk Mitigation program will be included in customer rates.

TERM:
The System Integrity Program shall remain in effect through December 31, 2021, or until such other time as the Commission may approve.

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2011** (T)
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	Part A		Part B	Part C	Geo-Haz Final	Total Adjustment	
		70%	30%					
1R		$0.00420	$0.00289	$0.01340	$0.00043	$0.00245	**$0.02337**	(C)
1C		$0.00420	$0.00194	$0.00902	$0.00029	$0.00165	**$0.01710**	
2		$0.00420	$0.00194	$0.00899	$0.00029	$0.01706	**$0.01706**	
3 (CSF)		$0.00420	$0.00137	$0.00636	$0.00021	$0.01330	**$0.01330**	
3 (ISF)		$0.00420	$0.00117	$0.00541	$0.00017	$0.00099	**$0.01194**	
19		$0.08	$0.00	$0.00	$0.00	$0.00	**$0.08**	
31 (CSF)	Block 1	$0.00420	$0.00096	$0.00447	$0.00014	$0.00082	**$0.01059**	
	Block 2	$0.00420	$0.00088	$0.00408	$0.00013	$0.00075	**$0.01004**	
31(CTF)	Block 1	$0.00420	$0.00073	$0.00339	$0.00011	$0.00062	**$0.00905**	
	Block 2	$0.00420	$0.00067	$0.00310	$0.00010	$0.00057	**$0.00864**	
31 (CSI)	Block 1	$0.00420	$0.00085	$0.00395	$0.00013	$0.00072	**$0.00985**	
	Block 2	$0.00420	$0.00078	$0.00360	$0.00012	$0.00066	**$0.00936**	
31 (ISF)	Block 1	$0.00000	$0.00078	$0.00363	$0.00012	$0.00066	**$0.00519**	
	Block 2	$0.00000	$0.00071	$0.00328	$0.00011	$0.00060	**$0.00470**	
31 (IFT)	Block 1	$0.00000	$0.00075	$0.00349	$0.00011	$0.00064	**$0.00499**	
	Block 2	$0.00000	$0.00068	$0.00315	$0.00010	$0.00058	**$0.00451**	
31 (ISI)	Block 1	$0.00000	$0.00093	$0.00431	$0.00014	$0.00079	**$0.00617**	
	Block 2	$0.00000	$0.00084	$0.00389	$0.00012	$0.00071	**$0.00556**	
32 (CSF)	Block 1	$0.00000	$0.00053	$0.00244	$0.00008	$0.00045	**$0.00350**	
	Block 2	$0.00000	$0.00045	$0.00207	$0.00007	$0.00038	**$0.00297**	
	Block 3	$0.00000	$0.00032	$0.00146	$0.00005	$0.00027	**$0.00210**	
	Block 4	$0.00000	$0.00018	$0.00085	$0.00003	$0.00016	**$0.00122**	
	Block 5	$0.00000	$0.00011	$0.00049	$0.00002	$0.00009	**$0.00071**	
	Block 6	$0.00000	$0.00005	$0.00024	$0.00001	$0.00004	**$0.00034**	(C)

(continue to Sheet 177-3)

SCHEDULE 177
SYSTEM INTEGRITY PROGRAM RATE ADJUSTMENT
(continued)

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2011** (T)
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	Part A		Part B	Part C	Geo-Haz Final	Total Adjustment	
		70%	30%					
32 (ISF)	Block 1	$0.00000	$0.00048	$0.00224	$0.00007	$0.00041	$0.00320	(C)
	Block 2	$0.00000	$0.00041	$0.00191	$0.00006	$0.00035	$0.00273	
	Block 3	$0.00000	$0.00029	$0.00135	$0.00004	$0.00025	$0.00193	
	Block 4	$0.00000	$0.00017	$0.00078	$0.00003	$0.00014	$0.00112	
	Block 5	$0.00000	$0.00010	$0.00045	$0.00001	$0.00008	$0.00064	
	Block 6	$0.00000	$0.00005	$0.00022	$0.00001	$0.00004	$0.00032	
32 (TF)	Block 1	$0.00000	$0.00043	$0.00197	$0.00006	$0.00036	$0.00282	
	Block 2	$0.00000	$0.00036	$0.00168	$0.00005	$0.00031	$0.00240	
	Block 3	$0.00000	$0.00026	$0.00118	$0.00004	$0.00022	$0.00170	
	Block 4	$0.00000	$0.00015	$0.00069	$0.00002	$0.00013	$0.00099	
	Block 5	$0.00000	$0.00009	$0.00039	$0.00001	$0.00007	$0.00056	
	Block 6	$0.00000	$0.00004	$0.00020	$0.00001	$0.00004	$0.00029	
32 (CSI)	Block 1	$0.00000	$0.00050	$0.00232	$0.00008	$0.00043	$0.00333	
	Block 2	$0.00000	$0.00043	$0.00198	$0.00006	$0.00036	$0.00283	
	Block 3	$0.00000	$0.00030	$0.00139	$0.00005	$0.00026	$0.00200	
	Block 4	$0.00000	$0.00018	$0.00081	$0.00003	$0.00015	$0.00117	
	Block 5	$0.00000	$0.00010	$0.00047	$0.00002	$0.00009	$0.00068	
	Block 6	$0.00000	$0.00005	$0.00023	$0.00001	$0.00004	$0.00033	
32 (ISI)	Block 1	$0.00000	$0.00044	$0.00205	$0.00007	$0.00037	$0.00293	
	Block 2	$0.00000	$0.00038	$0.00174	$0.00006	$0.00032	$0.00250	
	Block 3	$0.00000	$0.00026	$0.00123	$0.00004	$0.00022	$0.00175	
	Block 4	$0.00000	$0.00015	$0.00072	$0.00002	$0.00013	$0.00102	
	Block 5	$0.00000	$0.00009	$0.00041	$0.00001	$0.00007	$0.00058	
	Block 6	$0.00000	$0.00004	$0.00021	$0.00001	$0.00004	$0.00030	
32 (TI)	Block 1	$0.00000	$0.00040	$0.00187	$0.00006	$0.00034	$0.00267	
	Block 2	$0.00000	$0.00034	$0.00159	$0.00005	$0.00029	$0.00227	
	Block 3	$0.00000	$0.00024	$0.00112	$0.00004	$0.00021	$0.00161	
	Block 4	$0.00000	$0.00014	$0.00065	$0.00002	$0.00012	$0.00093	
	Block 5	$0.00000	$0.00008	$0.00037	$0.00001	$0.00007	$0.00053	
	Block 6	$0.00000	$0.00004	$0.00019	$0.00001	$0.00003	$0.00027	
33 (all)		$0.00000	$0.00002	$0.00011	$0.00000	$0.00002	$0.00015	(C)

Issued August 31, 2011 Effective with service on
NWN Advice No. OPUC 11-11 and after November 1, 2011

SCHEDULE 187
SPECIAL RATE ADJUSTMENT FOR MIST CAPACITY RECALL

PURPOSE:
The purpose of this schedule is to reflect the rate effects of the Company's recalling of Mist storage capacity for use by the Company's core customers.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1
Schedule 2
Schedule 3
Schedule 31
Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2011 (T)
The Total Adjustment amounts shown below are included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	Block	Mist Recall Base Rate Adjustment [1]
1R		$0.00032
1C		$0.00021
2		$0.00021
3CSF		$0.00015
3ISF		$0.00013
31CSF	Block 1	$0.00011
	Block 2	$0.00010
31ISF	Block 1	$0.00009
	Block 2	$0.00008
31CSI	Block 1	$0.00009
	Block 2	$0.00008
31ISI	Block 1	$0.00010
	Block 2	$0.00009
32CSF	Block 1	$0.00006
	Block 2	$0.00005
	Block 3	$0.00003
	Block 4	$0.00002
	Block 5	$0.00001
	Block 6	$0.00001
32I SF	Block 1	$0.00005
	Block 2	$0.00004
	Block 3	$0.00003
	Block 4	$0.00002
	Block 5	$0.00001
	Block 6	$0.00001

(C)
(C)

(continue to Sheet 187-1.1)

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

SCHEDULE 187
SPECIAL RATE ADJUSTMENT FOR MIST CAPACITY RECALL
(continued)
(N)

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2011 (T)
The Total Adjustment amounts shown below are included in the Base Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

Schedule	**Block**	**Mist Recall Base Rate Adjustment [1]**
32CSI	Block 1	$0.00005
	Block 2	$0.00005
	Block 3	$0.00003
	Block 4	$0.00002
	Block 5	$0.00001
	Block 6	$0.00001
32ISI	Block 1	$0.00005
	Block 2	$0.00004
	Block 3	$0.00003
	Block 4	$0.00002
	Block 5	$0.00001
	Block 6	$0.00000

(C)
(C)
(N)

EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL
SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations
UM 1496
and
Permanent Adjustments to Rates (SIP and Storage Recall)

NWN Advice No. OPUC 11-11
August 31, 2011

Exhibit A
Supporting Materials
Purchased Gas Cost Deferral Amortizations and
Permanent Adjustments to Rates (SIP and Storage Recall)
NWN Advice No. OPUC 11-11

NW Natural
Rates & Regulatory Affairs
OPUC Advice 11-11 EXHIBIT A
Summary of TEMPORARY Increments - Account 191

1								
2								
3				**ADD**	**ADD**	**ADD**		
4			**Current Temporaries (Account 191)**	**WACOG Deferral**	**Demand Deferral FIRM**	**Demand Deferral INTERR**	**Total Proposed Temps**	**Net Effect of Temps**
5								**(Y-A+H)**
6	Schedule	Block	**A**	**B**	**C**	**D**	**L**	**M**
7	1R		(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
8	1C		(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
9	2R		(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
10	3C Sales Firm		(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
11	Intentionally blank							
12	3I Sales Firm		(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
13	Intentionally blank							
14	19	1st mantle	(0.44)	(0.48)	0.01	0.00	(0.47)	(0.03)
15	19	add'l mtls	(0.44)	(0.48)	0.01	0.00	(0.47)	(0.03)
16	31C Sales Firm	Block 1	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
17		Block 2	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
18	31C Trans Firm	Block 1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
19		Block 2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
20	31C Sales Interr	Block 1	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
21		Block 2	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
22	31I Sales Firm	Block 1	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
23		Block 2	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
24	31I Trans Firm	Block 1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
25		Block 2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
26	31I Sales Interr	Block 1	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
27		Block 2	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
28	32C Sales Firm	Block 1	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
29		Block 2	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
30		Block 3	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
31		Block 4	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
32		Block 5	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
33		Block 6	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
34	32I Sales Firm	Block 1	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
35		Block 2	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
36		Block 3	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
37		Block 4	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
38		Block 5	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
39		Block 6	(0.02301)	(0.02524)	0.00030	0.00000	(0.02494)	(0.00193)
40	32 Trans Firm	Block 1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
41		Block 2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
42		Block 3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
43		Block 4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
44		Block 5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
45		Block 6	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
46	32C Sales Interr	Block 1	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
47		Block 2	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
48		Block 3	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
49		Block 4	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
50		Block 5	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
51		Block 6	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
52	32I Sales Interr	Block 1	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
53		Block 2	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
54		Block 3	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
55		Block 4	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
56		Block 5	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
57		Block 6	(0.02931)	(0.02524)	0.00000	0.00004	(0.02520)	0.00411
58	32 Trans Interr	Block 1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
59		Block 2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
60		Block 3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
61		Block 4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
62		Block 5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
63		Block 6	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
64	Intentionally blank						0.00000	0.00000
65	33		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
66								
67	**Sources:**							
68	**Direct Inputs**		Jun 11 Filing					
69								
70	**Equal ¢ per therm**			Column D	Column G	Column J		
71	**Equal % of margin**							
72								
73	**Tariff Schedules**							
74	**Rate Adjustment Schedule**			Sched 162	Sched 162	Sched 162		

NW Natural
Rates & Regulatory Affairs
OPUC Advice 11-11
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

1					**WACOG Deferral**			**Demand Deferral - FIRM**			**Demand Deferral - INTERRUPTIBLE**				**SIP: Bare Steel - 70%**		
2			**Oregon PGA**	**Proposed Amount:**	(16,631,621) Temporary Increment			181,556 Temporary Increment			1,957 Temporary Increment				2,441,600 PERMANENT Increment		
3			**Volumes page,**	**Revenue Sensitive Multiplier:**	2.853% add revenue sensitive factor			2.853% add revenue sensitive factor			2.853% add revenue sensitive factor				N/A rev sensitive factor is built in		
4			**Column F**	**Amount to Amortize:**	**(17,120,056)** to all sales			**186,888** to all firm sales			**2,014** to all interruptible sales				**2,441,600** to residential & commercial		
5					**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**		**Multiplier**	**Volumes**	**Increment**
6	Schedule	Block	**A**		**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**		**Z**	**AA**	**AB**
7	1R		720,574		1.0	720,574	(0.02524)	1.0	720,574	0.00030	0.0	0	0.00000		1.0	720,574	0.00420
8	1C		168,761		1.0	168,761	(0.02524)	1.0	168,761	0.00030	0.0	0	0.00000		1.0	168,761	0.00420
9	2R		357,106,580		1.0	357,106,580	(0.02524)	1.0	357,106,580	0.00030	0.0	0	0.00000		1.0	357,106,580	0.00420
10	3C Firm Sales		156,661,336		1.0	156,661,336	(0.02524)	1.0	156,661,336	0.00030	0.0	0	0.00000		1.0	156,661,336	0.00420
11	Intentionally blank																
12	3I Firm Sales		4,245,206		1.0	4,245,206	(0.02524)	1.0	4,245,206	0.00030	0.0	0	0.00000		1.0	4,245,206	0.00420
13	Intentionally blank																
14	19	1st mantle	15,303		1.0	15,303	(0.48)	1.0	15,303	0.01	0.0	0	0.00		1.0	15,303	0.08
15	19	add'l mtls	0														
16	31C Firm Sales	Block 1	24,513,627		1.0	24,513,627	(0.02524)	1.0	24,513,627	0.00030	0.0	0	0.00000		1.0	24,513,627	0.00420
17		Block 2	35,374,819		1.0	35,374,819	(0.02524)	1.0	35,374,819	0.00030	0.0	0	0.00000		1.0	35,374,819	0.00420
18	31C Firm Trans	Block 1	185,073		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		1.0	185,073	0.00420
19		Block 2	1,652,315		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		1.0	1,652,315	0.00420
20	31C Interr Sales	Block 1	161,570		1.0	161,570	(0.02524)	0.0	0	0.00000	1.0	161,570	0.00004		1.0	161,570	0.00420
21		Block 2	864,968		1.0	864,968	(0.02524)	0.0	0	0.00000	1.0	864,968	0.00004		1.0	864,968	0.00420
22	31I Firm Sales	Block 1	5,061,961		1.0	5,061,961	(0.02524)	1.0	5,061,961	0.00030	0.0	0	0.00000		0.0	0	0.00000
23		Block 2	13,993,811		1.0	13,993,811	(0.02524)	1.0	13,993,811	0.00030	0.0	0	0.00000		0.0	0	0.00000
24	31I Firm Trans	Block 1	99,991		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
25		Block 2	511,039		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
26	31I Interr Sales	Block 1	126,977		1.0	126,977	(0.02524)	0.0	0	0.00000	1.0	126,977	0.00004		0.0	0	0.00000
27		Block 2	156,929		1.0	156,929	(0.02524)	0.0	0	0.00000	1.0	156,929	0.00004		0.0	0	0.00000
28	32C Firm Sales	Block 1	4,891,766		1.0	4,891,766	(0.02524)	1.0	4,891,766	0.00030	0.0	0	0.00000		0.0	0	0.00000
29		Block 2	4,815,433		1.0	4,815,433	(0.02524)	1.0	4,815,433	0.00030	0.0	0	0.00000		0.0	0	0.00000
30		Block 3	1,399,458		1.0	1,399,458	(0.02524)	1.0	1,399,458	0.00030	0.0	0	0.00000		0.0	0	0.00000
31		Block 4	169,202		1.0	169,202	(0.02524)	1.0	169,202	0.00030	0.0	0	0.00000		0.0	0	0.00000
32		Block 5	0		1.0	0	(0.02524)	1.0	0	0.00030	0.0	0	0.00000		0.0	0	0.00000
33		Block 6	0		1.0	0	(0.02524)	1.0	0	0.00030	0.0	0	0.00000		0.0	0	0.00000
34	32I Firm Sales	Block 1	4,506,637		1.0	4,506,637	(0.02524)	1.0	4,506,637	0.00030	0.0	0	0.00000		0.0	0	0.00000
35		Block 2	5,781,297		1.0	5,781,297	(0.02524)	1.0	5,781,297	0.00030	0.0	0	0.00000		0.0	0	0.00000
36		Block 3	2,064,850		1.0	2,064,850	(0.02524)	1.0	2,064,850	0.00030	0.0	0	0.00000		0.0	0	0.00000
37		Block 4	361,936		1.0	361,936	(0.02524)	1.0	361,936	0.00030	0.0	0	0.00000		0.0	0	0.00000
38		Block 5	(0)		1.0	(0)	(0.02524)	1.0	(0)	0.00030	0.0	0	0.00000		0.0	0	0.00000
39		Block 6	0		1.0	0	(0.02524)	1.0	0	0.00030	0.0	0	0.00000		0.0	0	0.00000
40	32 Firm Trans	Block 1	6,531,553		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
41		Block 2	10,291,976		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
42		Block 3	6,744,921		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
43		Block 4	14,560,419		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
44		Block 5	14,810,823		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
45		Block 6	259,978		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
46	32C Interr Sales	Block 1	3,272,604		1.0	3,272,604	(0.02524)	0.0	0	0.00000	1.0	3,272,604	0.00004		0.0	0	0.00000
47		Block 2	4,919,412		1.0	4,919,412	(0.02524)	0.0	0	0.00000	1.0	4,919,412	0.00004		0.0	0	0.00000
48		Block 3	2,817,505		1.0	2,817,505	(0.02524)	0.0	0	0.00000	1.0	2,817,505	0.00004		0.0	0	0.00000
49		Block 4	3,946,719		1.0	3,946,719	(0.02524)	0.0	0	0.00000	1.0	3,946,719	0.00004		0.0	0	0.00000
50		Block 5	194,623		1.0	194,623	(0.02524)	0.0	0	0.00000	1.0	194,623	0.00004		0.0	0	0.00000
51		Block 6	0		1.0	0	(0.02524)	0.0	0	0.00000	1.0	0	0.00004		0.0	0	0.00000
52	32I Interr Sales	Block 1	7,572,262		1.0	7,572,262	(0.02524)	0.0	0	0.00000	1.0	7,572,262	0.00004		0.0	0	0.00000
53		Block 2	9,692,007		1.0	9,692,007	(0.02524)	0.0	0	0.00000	1.0	9,692,007	0.00004		0.0	0	0.00000
54		Block 3	4,999,427		1.0	4,999,427	(0.02524)	0.0	0	0.00000	1.0	4,999,427	0.00004		0.0	0	0.00000
55		Block 4	8,493,596		1.0	8,493,596	(0.02524)	0.0	0	0.00000	1.0	8,493,596	0.00004		0.0	0	0.00000
56		Block 5	3,174,949		1.0	3,174,949	(0.02524)	0.0	0	0.00000	1.0	3,174,949	0.00004		0.0	0	0.00000
57		Block 6	5,975,027		1.0	5,975,027	(0.02524)	0.0	0	0.00000	1.0	5,975,027	0.00004		0.0	0	0.00000
58	32 Interr Trans	Block 1	9,106,332		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
59		Block 2	15,529,327		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
60		Block 3	10,921,668		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
61		Block 4	30,029,500		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
62		Block 5	62,381,728		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
63		Block 6	73,722,561		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
64	Intentionally blank																
65	33		0		0.0	0	0.00000	0.0	0	0.00000	0.0	0	0.00000		0.0	0	0.00000
66																	
67	TOTALS		935,560,335			678,221,131	(0.02524)		621,852,556	0.00030		56,368,575	0.00004			581,670,131	0.00420
68												0					
69	**Sources for line 2 above:**																
70	**Inputs page**				Line 49			Line 51			Line 53				Line 33		
71																	
72	**Tariff Schedules**																
73	**Rate Adjustment Schedule**				Sched 162			Sched 162			Sched 162				Sched 177 A		

NW Natural
Rates & Regulatory Affairs
OPUC Advice No. 11-11 **Exhibit A**
Summary of Deferred Accounts Included in the PGA

	Account	Balance 6/30/2011	Adjustment	Jul Actual + Aug-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2011	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		2.01%	H = F + G2		Excl. Rev Sens
35											
36	**Gas Cost Deferrals and Amortizations**										
37	191401 AMORTIZE OREGON WACOG	(4,737,441)		3,287,978	(24,925)	(1,474,388)					
38	191400 WACOG - ACCRUE OREGON	(14,461,846)		(93,265)	(422,452)	(14,977,563)					
39	Subtotal	(19,199,287)	0	3,194,713	(447,377)	(16,451,951)	2.01%	(179,670)	(16,631,621)		**(16,631,621)**
40											
41											
42											
43	191411 AMORTIZE DEMAND OREGON	2,242,512		(708,334)	14,568	1,548,746					
44	191410 DEMAND - ACCRUE OREGON	1,361,248		266,897	46,298	1,674,444					
45	191417 DEMAND - ACCRUE COOS BAY	248,340		36,851	0	285,191					
46	191450 OREGON DEMAND ACCRUE VOLUME	(2,932,763)		(301,283)	(92,804)	(3,326,850)					
47	Subtotal	919,337	0	(705,870)	(31,937)	181,531	2.01%	1,982	183,513		**183,513**
48											
49											
50	**GRAND TOTAL**	**7,206,467**							**4,631,258**	**0**	**4,631,258**
51											
52											
53	Notes										
54											
55	Please refer to NWN workpapers or electronic file "NWN 2011-12 Oregon PGA rate development file August Filing.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

1 Debit (Credit)

Line	Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(e2)	(f)	(g)
7	Beginning Balance							
51	Jan-10		4,686,910.99		(44,681.30)	2.05%	4,642,229.69	(23,856,130.53)
52	Feb-10		3,496,884.62		(37,767.30)	2.05%	3,459,117.32	(20,397,013.21)
53	Mar-10		3,098,842.84		(32,197.97)	2.05%	3,066,644.87	(17,330,368.34)
54	Apr-10		3,024,257.29		(27,022.83)	2.05%	2,997,234.46	(14,333,133.88)
55	May-10		2,349,961.32		(22,478.51)	2.05%	2,327,482.81	(12,005,651.07)
56	Jun-10		1,832,968.70		(18,943.99)	2.05%	1,814,024.71	(10,191,626.36)
57	Jul-10		1,221,957.01		(16,366.94)	2.05%	1,205,590.07	(8,986,036.29)
58	Aug-10		1,054,267.69		(14,450.63)	2.05%	1,039,817.06	(7,946,219.23)
59	Sep-10		1,132,711.61		(12,607.27)	2.05%	1,120,104.34	(6,826,114.89)
60	Oct-10		1,406,423.05		(10,459.96)	2.05%	1,395,963.09	(5,430,151.80)
61	Nov-10	old rates	1,054,050.11		(8,376.17)	2.05%	1,045,673.94	(4,384,477.86)
62		new rates 1	986,672.11	(17,304,991.56)	(31,381.76)	2.24%	(16,349,701.21)	(20,734,179.07)
63	Dec-10		2,796,096.42		(36,094.11)	2.24%	2,760,002.31	(17,974,176.76)
64	Jan-11		3,224,984.34		(30,541.81)	2.24%	3,194,442.53	(14,779,734.23)
65	Feb-11		2,593,138.64		(25,168.57)	2.24%	2,567,970.07	(12,211,764.16)
66	Mar-11		2,732,565.42		(20,244.90)	2.24%	2,712,320.52	(9,499,443.64)
67	Apr-11		2,069,042.83		(15,801.19)	2.24%	2,053,241.64	(7,446,202.00)
68	May-11		1,632,021.74		(12,376.36)	2.24%	1,619,645.38	(5,826,556.62)
69	Jun-11		1,098,966.59		(9,850.54)	2.24%	1,089,116.05	(4,737,440.57)
70	Jul-11		725,713.24		(8,165.89)	2.24%	717,547.35	(4,019,893.22)
71	Aug-11	forecast	585,974.90		(6,956.89)	2.24%	579,018.01	(3,440,875.21)
72	Sep-11	forecast	648,076.09		(5,818.10)	2.24%	642,257.99	(2,798,617.22)
73	Oct-11	forecast	1,328,213.29		(3,984.42)	2.24%	1,324,228.87	(1,474,388.35)

76 **History truncated for ease of viewing**

78 NOTES:

79 1 - Transfer in from deferral account 191400, and in 2010, residual from account 186306

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon Demand Deferral
Account Number: 191411

1	Debit (Credit)							
2								
3						Interest		
4	Month/Year	Note	Amortization	Transfers	Interest	Rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)		(f)	(g)
6								
7	Beginning Balance							
51	Jan-10		633,413.70		(4,789.74)	2.24%	628,623.96	(2,254,016.58)
52	Feb-10		460,439.86		(3,777.75)	2.24%	456,662.11	(1,797,354.47)
53	Mar-10		402,882.40		(2,979.04)	2.24%	399,903.36	(1,397,451.11)
54	Apr-10		382,446.87		(2,251.62)	2.24%	380,195.25	(1,017,255.86)
55	May-10		288,265.92		(1,629.83)	2.24%	286,636.09	(730,619.77)
56	Jun-10		219,500.42		(1,158.96)	2.24%	218,341.46	(512,278.31)
57	Jul-10		146,991.66		(819.06)	2.24%	146,172.60	(366,105.71)
58	Aug-10		122,006.17		(569.52)	2.24%	121,436.65	(244,669.06)
59	Sep-10		132,458.71		(333.09)	2.24%	132,125.62	(112,543.44)
60	Oct-10		166,806.30		(54.40)	2.24%	166,751.90	54,208.46
61	Nov-10	old rates	246,696.89		331.44	2.24%	247,028.33	301,236.79
62		new rates 1	(168,958.75)	5,556,204.32	10,213.89	2.24%	5,397,459.46	5,698,696.25
63	Dec-10		(445,074.28)		10,222.16	2.24%	(434,852.12)	5,263,844.13
64	Jan-11		(748,032.22)		9,127.68	2.24%	(738,904.54)	4,524,939.59
65	Feb-11		(597,858.37)		7,888.55	2.24%	(589,969.82)	3,934,969.77
66	Mar-11		(631,307.86)		6,756.06	2.24%	(624,551.80)	3,310,417.97
67	Apr-11		(472,114.39)		5,738.81	2.24%	(466,375.58)	2,844,042.39
68	May-11		(369,127.82)		4,964.36	2.24%	(364,163.46)	2,479,878.93
69	Jun-11		(241,770.38)		4,403.45	2.24%	(237,366.93)	2,242,512.00
70	Jul-11		(152,748.06)		4,043.46	2.24%	(148,704.60)	2,093,807.40
71	Aug-11	forecast	(120,558.18)		3,795.92	2.24%	(116,762.26)	1,977,045.14
72	Sep-11	forecast	(135,289.13)		3,564.21	2.24%	(131,724.92)	1,845,320.22
73	Oct-11	forecast	(299,739.07)		3,164.84	2.24%	(296,574.23)	1,548,745.99
74								
75	**History truncated for ease of viewing**							
76								
77	NOTES:							
78	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 1496
Current Reauthorization was granted in Order No. 10-442

Narrative: Deferral of customer's share of the difference between actual core commodity cost incurred and the Annual Sales WACOG 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			Commodity Deferral /3	8.618% Interest	Adjustment	Storage Adjustment 2/	Hedge Adjustment	Transfer	Activity	Deferral Plus Int. GL Balance
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
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			(199,101)	(100,702)		(2,743)	0		(302,546)	(14,223,752)
Aug-10			(303,342)	(103,250)		(2,852)	0		(409,444)	(14,633,196)
Sep-10			(1,215,664)	(109,467)		(3,041)	0		(1,328,172)	(15,961,368)
Oct-10			(1,243,806)	(119,114)		(5,244)	0		(1,368,164)	(17,329,532)
Nov-10	1/		(1,618,763)	(5,887)		(20,704)	0	17,329,532	15,684,178	(1,645,354)
Dec-10			(1,359,405)	(16,788)		(25,054)	0		(1,401,247)	(3,046,601)
Jan-11			(991,559)	(25,534)		(26,156)	0		(1,043,249)	(4,089,850)
Feb-11			(3,363,913)	(41,541)		(24,964)	0		(3,430,418)	(7,520,268)
Mar-11			(1,935,496)	(61,036)		(21,582)	0		(2,018,114)	(9,538,381)
Apr-11			(3,402,461)	(80,781)		(17,236)			(3,500,478)	(13,038,859)
May-11			(757,390)	(96,402)		(11,637)			(865,429)	(13,904,289)
Jun-11			(448,870)	(101,494)		(7,194)			(557,558)	(14,461,846)
Jul-11			(93,265)	(104,216)		(5,838)			(203,319)	(14,665,165)
Aug-11				(105,320)					(105,320)	(14,770,486)
Sep-11				(106,077)					(106,077)	(14,876,562)
Oct-11				(106,839)					(106,839)	(14,983,401)

History truncated for ease of viewing

NOTES:

1/ - Transfer to amortization account 191401

2/ - Adjustment for storage true up

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Demand cost deferral
Account Number: 191.410
Current docket is UM 1496
Current Reauthorization was granted in Order No. 10-442

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.

1 Debit (Credit)

Line	Month/Year		Refer to pg #	Demand Deferral	8.618% Interest*	Adjustment	Transfer	Activity	Deferral GL Balance
4	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
5									
46	Jan-10			226,245	(752)			225,493	7,645
47	Feb-10			119,566	484			120,050	127,695
48	Mar-10			594,213	3,051			597,264	724,959
49	Apr-10			509,075	7,034			516,109	1,241,068
50	May-10			321,943	10,069			332,012	1,573,080
51	Jun-10			440,773	12,880			453,653	2,026,733
52	Jul-10			364,593	15,865			380,458	2,407,191
53	Aug-10			328,989	18,469			347,458	2,754,649
54	Sep-10			451,636	21,405			473,041	3,227,690
55	Oct-10			319,167	24,326			343,493	3,571,183
56	Nov-10	A/		512,707	1,841		(3,571,183)	(3,056,635)	514,548
57	Dec-10			(316,979)	2,557			(314,422)	200,126
58	Jan-11			96,057	1,782			97,839	297,966
59	Feb-11			241,984	3,009			244,993	542,958
60	Mar-11			219,512	4,688			224,200	767,158
61	Apr-11			247,356	6,398			253,754	1,020,912
62	May-11			(39,651)	7,189			(32,462)	988,450
63	Jun-11			364,391	8,407			372,798	1,361,248
64	Jul-11			266,897	10,734			277,631	1,638,880
65	Aug-11				11,770			11,770	1,650,650
66	Sep-11				11,854			11,854	1,662,504
67	Oct-11				11,940			11,940	1,674,444

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

73 **History truncated for ease of viewing**

75 NOTES
76 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 1496
	Current Reauthorization was granted in Order No. 10-442
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.

1	Debit (Credit)									Deferral
2				Demand	8.618%					Plus Int.
3	Month/Year	Note	Refer to pg #	Deferral	Interest*		Transfer		Activity	GL Balance
4	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
5										
46	Jan-10			2,426,982	(1,601)				2,425,381	988,968
47	Feb-10			2,018,891	14,352				2,033,243	3,022,212
48	Mar-10			427,365	23,239				450,604	3,472,816
49	Apr-10			(527,889)	23,045				(504,844)	2,967,972
50	May-10			(634,421)	19,037				(615,384)	2,352,587
51	Jun-10			(566,552)	14,861				(551,691)	1,800,896
52	Jul-10			(237,583)	12,080				(225,503)	1,575,393
53	Aug-10			(319,222)	10,168				(309,054)	1,266,339
54	Sep-10			(154,135)	8,541				(145,595)	1,120,745
55	Oct-10			652,039	10,390				662,429	1,783,174
56	Nov-10	1		(774,261)	(2,780)		(1,783,174)		(2,560,215)	(777,041)
57	Dec-10			1,587,140	119				1,587,259	810,218
58	Jan-11			800,350	8,693				809,042	1,619,260
59	Feb-11			(1,013,999)	7,988				(1,006,011)	613,249
60	Mar-11			(798,925)	1,535				(797,390)	(184,141)
61	Apr-11			(1,367,972)	(6,235)				(1,374,206)	(1,558,347)
62	May-11			(964,901)	(14,656)				(979,557)	(2,537,904)
63	Jun-11			(375,285)	(19,574)				(394,859)	(2,932,763)
64	Jul-11			(301,283)	(22,144)				(323,427)	(3,256,190)
65	Aug-11				(23,385)				(23,385)	(3,279,575)
66	Sep-11				(23,553)				(23,553)	(3,303,128)
67	Oct-11				(23,722)				(23,722)	(3,326,850)

68

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

70

71 **History truncated for ease of viewing**

72

73 NOTES

74 1 - transfer to Amorization account 191411

75

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

1 Narrative: Deferral of transportation charge payable by NW Natural for use of the natural gas
2 transmission pipeline owned by Coos County.
3

Line	Date	Deferral	Adjustment (b)	Transfer (c)	Reference	Interest (a)	Activity	Balance
4								
5								
46	1/31/2010	21,725.00	(6,646.34)				15,078.66	43,209.27
47	2/28/2010	21,308.03	(5,565.85)				15,742.18	58,951.45
48	3/31/2010	21,674.75	(5,382.49)				16,292.26	75,243.71
49	4/30/2010	21,689.82	(5,393.22)				16,296.60	91,540.31
50	5/31/2010	21,678.19	(4,259.59)				17,418.60	108,958.91
51	6/30/2010	21,674.75	(3,886.21)				17,788.54	126,747.45
52	7/31/2010	21,674.75	(2,855.42)				18,819.33	145,566.78
53	8/31/2010	21,674.75	(3,096.20)				18,578.55	164,145.33
54	9/30/2010	21,674.75	(2,681.91)				18,992.84	183,138.17
55	10/31/2010	21,674.75	(2,965.26)				18,709.49	201,847.66
56	11/30/2010	21,674.75	(4,672.86)	(201,847.66)			(184,845.77)	17,001.89
57	12/31/2010	21,698.28	(6,251.13)				15,447.15	32,449.04
58	1/31/2011	41,669.00	(6,874.52)				34,794.48	67,243.52
59	2/28/2011	41,669.00	(5,817.10)				35,851.90	103,095.42
60	3/31/2011	41,669.00	(6,626.42)				35,042.58	138,138.00
61	4/30/2011	41,669.00	(5,533.47)				36,135.53	174,273.53
62	5/31/2011	41,669.00	(5,197.99)				36,471.01	210,744.54
63	6/30/2011	41,669.00	(4,073.27)				37,595.73	248,340.27
64	7/31/2011	41,669.00	(4,818.44)				36,850.56	285,190.83
65	8/31/2011						0.00	285,190.83
66	9/30/2011						0.00	285,190.83
67	10/31/2011						0.00	285,190.83

68
69 **History truncated for ease of viewing**
70
71 Notes:
72 a. No interest is applied to this activity
73 b. Per Order 03-236 in docket UG-152; the amount collected via the Coos County 2¢ surcharge
74 should be applied toward this deferral with the balance recoverable statewide as part of the PGA.
75 c. Balance transferred to account 191411.

NW Natural
Bare Steel, Geohazard and Integrity Management Programs
Cost of Service Summary - PGA 2011-12
Thousands of Dollars

		Investment	Tracker Year Cost of Service
Bare Steel Program			
1	Activity Ended September 30, 2002	$2,665	$297
2	Activity Ended September 30, 2003	3,510	389
3	Activity Ended September 30, 2004	3,094	354
4	Activity Ended September 30, 2005	6,000	709
5	Activity Ended September 30, 2006	(695)	(83)
6	Activity Ended September 30, 2007	430	53
7	Activity Ended September 30, 2008	3,850	494
8	Activity Ended October 31, 2009	4,002	531
9	Activity Ended October 31, 2010	2,624	362
10	Activity Ended October 31, 2011	2,478	382
11	Total Bare Steel Program	$27,959	$3,488
Geohazard Program			
12	Activity Ended September 30, 2002	$1,714	$191
13	Activity Ended September 30, 2003	555	62
14	Activity Ended September 30, 2004	139	16
15	Activity Ended September 30, 2005	206	24
16	Activity Ended September 30, 2006	2,863	343
17	Activity Ended September 30, 2007	254	31
18	Activity Ended September 30, 2008 (Oct 07-Dec 07 ONLY)	1,441	185
19	Final true-up of final program activity (through Dec 07 only)	272	36
20	Total Geohazard Program	$7,443	$888
Integrity Management Program (as of October 2008, "TIMP")			
21	Activity Ended September 30, 2005	$3,476	$411
22	Activity Ended September 30, 2006	8,978	1,076
23	Activity Ended September 30, 2007	2,604	323
24	Activity Ended September 30, 2008	9,680	1,242
25	Activity Ended October 31, 2009	3,446	458
26	Activity Ended October 31, 2010	5,707	788
27	Activity Ended October 31, 2011	3,621	557
28	Total Transmission Integrity Management Program	$37,511	$4,855
Distribution Integrity Management Program ("DIMP")			
29	Activity Ended October 31, 2009	$0	$0
30	Activity Ended October 31, 2010	136	21
31	Activity Ended October 31, 2011	882	136
32	Total Distribution Integrity Management Program	$1,019	$157
GRAND TOTAL ALL PROGRAMS		**$73,932**	**$9,388**

Reflects Actuals through June 30, 2011

NW Natural
Rates & Regulatory Affairs
OPUC 11-11 Exhibit A
Summary of PERMANENT Increments

Line	Schedule	Block	REMOVE Current Bare Steel	REMOVE Current Geo Hazard	REMOVE Current SIP: DIMP	REMOVE Current SIP: TIMP	Permanent Increments to Remove Subtotal	ADD Proposed SIP: Bare Steel 70%	ADD Proposed SIP: Bare Steel 30%	ADD Vintaged Geo-Haz	ADD Proposed SIP: DIMP	ADD Proposed SIP: TIMP	Proposed Subtotal	Net Effect of Permanent Items
5														
6	Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L
7	1R		0.00664	0.00254	0.00006	0.01246	0.02170	0.00420	0.00289	0.00245	0.00043	0.01340	0.02337	0.00167
8	1C		0.00581	0.00176	0.00004	0.00864	0.01625	0.00420	0.00194	0.00165	0.00029	0.00902	0.01710	0.00085
9	2R		0.00577	0.00172	0.00004	0.00843	0.01596	0.00420	0.00194	0.00164	0.00029	0.00899	0.01706	0.00110
10	3C Firm Sales		0.00524	0.00122	0.00003	0.00600	0.01249	0.00420	0.00137	0.00116	0.00021	0.00636	0.01330	0.00081
11	Intentionally blank													
12	3I Firm Sales		0.00505	0.00104	0.00002	0.00508	0.01119	0.00420	0.00117	0.00099	0.00017	0.00541	0.01194	0.00075
13	Intentionally blank													
14	19	1st mantle	0.08	0.00	0.00	0.00	0.08	0.08	0.00	0.00	0.00	0.00	0.08	0.00
15	19	add'l mtls	0.08	0.00	0.00	0.00	0.08	0.08	0.00	0.00	0.00	0.00	0.08	0.00
16	31C Firm Sales	Block 1	0.00486	0.00086	0.00002	0.00421	0.00995	0.00420	0.00096	0.00082	0.00014	0.00447	0.01059	0.00064
17		Block 2	0.00478	0.00078	0.00002	0.00385	0.00943	0.00420	0.00088	0.00075	0.00013	0.00408	0.01004	0.00061
18	31C Firm Trans	Block 1	0.00466	0.00067	0.00002	0.00329	0.00864	0.00420	0.00073	0.00062	0.00011	0.00339	0.00905	0.00041
19		Block 2	0.00460	0.00061	0.00001	0.00301	0.00823	0.00420	0.00067	0.00057	0.00010	0.00310	0.00864	0.00041
20	31C Interr Sales	Block 1	0.00473	0.00073	0.00002	0.00360	0.00908	0.00420	0.00085	0.00072	0.00013	0.00395	0.00985	0.00077
21		Block 2	0.00466	0.00067	0.00002	0.00329	0.00864	0.00420	0.00078	0.00066	0.00012	0.00360	0.00936	0.00072
22	31I Firm Sales	Block 1	0.00076	0.00072	0.00002	0.00351	0.00501	0.00000	0.00078	0.00066	0.00012	0.00363	0.00519	0.00018
23		Block 2	0.00068	0.00065	0.00001	0.00317	0.00451	0.00000	0.00071	0.00060	0.00011	0.00328	0.00470	0.00019
24	31I Firm Trans	Block 1	0.00066	0.00063	0.00001	0.00309	0.00439	0.00000	0.00075	0.00064	0.00011	0.00349	0.00499	0.00060
25		Block 2	0.00060	0.00057	0.00001	0.00279	0.00397	0.00000	0.00068	0.00058	0.00010	0.00315	0.00451	0.00054
26	31I Interr Sales	Block 1	0.00099	0.00094	0.00002	0.00461	0.00656	0.00000	0.00093	0.00079	0.00014	0.00431	0.00617	(0.00039)
27		Block 2	0.00090	0.00085	0.00002	0.00416	0.00593	0.00000	0.00084	0.00071	0.00012	0.00389	0.00556	(0.00037)
28	32C Firm Sales	Block 1	0.00048	0.00045	0.00001	0.00223	0.00317	0.00000	0.00053	0.00045	0.00008	0.00244	0.00350	0.00033
29		Block 2	0.00041	0.00039	0.00001	0.00189	0.00270	0.00000	0.00045	0.00038	0.00007	0.00207	0.00297	0.00027
30		Block 3	0.00029	0.00027	0.00001	0.00134	0.00191	0.00000	0.00032	0.00027	0.00005	0.00146	0.00210	0.00019
31		Block 4	0.00017	0.00016	0.00000	0.00078	0.00111	0.00000	0.00018	0.00016	0.00003	0.00085	0.00122	0.00011
32		Block 5	0.00010	0.00009	0.00000	0.00045	0.00064	0.00000	0.00011	0.00009	0.00002	0.00049	0.00071	0.00007
33		Block 6	0.00005	0.00005	0.00000	0.00022	0.00032	0.00000	0.00005	0.00004	0.00001	0.00024	0.00034	0.00002
34	32I Firm Sales	Block 1	0.00046	0.00043	0.00001	0.00211	0.00301	0.00000	0.00048	0.00041	0.00007	0.00224	0.00320	0.00019
35		Block 2	0.00039	0.00037	0.00001	0.00180	0.00257	0.00000	0.00041	0.00035	0.00006	0.00191	0.00273	0.00016
36		Block 3	0.00027	0.00026	0.00001	0.00127	0.00181	0.00000	0.00029	0.00025	0.00004	0.00135	0.00193	0.00012
37		Block 4	0.00016	0.00015	0.00000	0.00074	0.00105	0.00000	0.00017	0.00014	0.00003	0.00078	0.00112	0.00007
38		Block 5	0.00009	0.00009	0.00000	0.00042	0.00060	0.00000	0.00010	0.00008	0.00001	0.00045	0.00064	0.00004
39		Block 6	0.00005	0.00004	0.00000	0.00021	0.00030	0.00000	0.00005	0.00004	0.00001	0.00022	0.00032	0.00002
40	32 Firm Trans	Block 1	0.00040	0.00038	0.00001	0.00185	0.00264	0.00000	0.00043	0.00036	0.00006	0.00197	0.00282	0.00018
41		Block 2	0.00034	0.00032	0.00001	0.00158	0.00225	0.00000	0.00036	0.00031	0.00005	0.00168	0.00240	0.00015
42		Block 3	0.00024	0.00023	0.00001	0.00111	0.00159	0.00000	0.00026	0.00022	0.00004	0.00118	0.00170	0.00011
43		Block 4	0.00014	0.00013	0.00000	0.00065	0.00092	0.00000	0.00015	0.00013	0.00002	0.00069	0.00099	0.00007
44		Block 5	0.00008	0.00008	0.00000	0.00037	0.00053	0.00000	0.00009	0.00007	0.00001	0.00039	0.00056	0.00003
45		Block 6	0.00004	0.00004	0.00000	0.00019	0.00027	0.00000	0.00004	0.00004	0.00001	0.00020	0.00029	0.00002
46	32C Interr Sales	Block 1	0.00043	0.00040	0.00001	0.00198	0.00282	0.00000	0.00050	0.00043	0.00008	0.00232	0.00333	0.00051
47		Block 2	0.00036	0.00034	0.00001	0.00169	0.00240	0.00000	0.00043	0.00036	0.00006	0.00198	0.00283	0.00043
48		Block 3	0.00026	0.00024	0.00001	0.00119	0.00170	0.00000	0.00030	0.00026	0.00005	0.00139	0.00200	0.00030
49		Block 4	0.00015	0.00014	0.00000	0.00070	0.00099	0.00000	0.00018	0.00015	0.00003	0.00081	0.00117	0.00018
50		Block 5	0.00009	0.00008	0.00000	0.00040	0.00057	0.00000	0.00010	0.00009	0.00002	0.00047	0.00068	0.00011
51		Block 6	0.00004	0.00004	0.00000	0.00020	0.00028	0.00000	0.00005	0.00004	0.00001	0.00023	0.00033	0.00005
52	32I Interr Sales	Block 1	0.00043	0.00040	0.00001	0.00197	0.00281	0.00000	0.00044	0.00037	0.00007	0.00205	0.00293	0.00012
53		Block 2	0.00036	0.00034	0.00001	0.00168	0.00239	0.00000	0.00038	0.00032	0.00006	0.00174	0.00250	0.00011
54		Block 3	0.00026	0.00024	0.00001	0.00118	0.00169	0.00000	0.00026	0.00022	0.00004	0.00123	0.00175	0.00006
55		Block 4	0.00015	0.00014	0.00000	0.00069	0.00098	0.00000	0.00015	0.00013	0.00002	0.00072	0.00102	0.00004
56		Block 5	0.00009	0.00008	0.00000	0.00039	0.00056	0.00000	0.00009	0.00007	0.00001	0.00041	0.00058	0.00002
57		Block 6	0.00004	0.00004	0.00000	0.00020	0.00028	0.00000	0.00004	0.00004	0.00001	0.00021	0.00030	0.00002
58	32 Interr Trans	Block 1	0.00038	0.00036	0.00001	0.00176	0.00251	0.00000	0.00040	0.00034	0.00006	0.00187	0.00267	0.00016
59		Block 2	0.00032	0.00031	0.00001	0.00150	0.00214	0.00000	0.00034	0.00029	0.00005	0.00159	0.00227	0.00013
60		Block 3	0.00023	0.00022	0.00000	0.00106	0.00151	0.00000	0.00024	0.00021	0.00004	0.00112	0.00161	0.00010
61		Block 4	0.00013	0.00013	0.00000	0.00062	0.00088	0.00000	0.00014	0.00012	0.00002	0.00065	0.00093	0.00005
62		Block 5	0.00008	0.00007	0.00000	0.00035	0.00050	0.00000	0.00008	0.00007	0.00001	0.00037	0.00053	0.00003
63		Block 6	0.00004	0.00004	0.00000	0.00018	0.00026	0.00000	0.00004	0.00003	0.00001	0.00019	0.00027	0.00001
64	Intentionally blank													
65	33		0.00002	0.00002	0.00000	0.00010	0.00014	0.00000	0.00002	0.00002	0.00000	0.00011	0.00015	0.00001
66														
67	**Sources:**													
68	Direct Inputs		10-11 PGA	10-11 PGA	10-11 PGA	10-11 PGA								
69														
70	Equal ¢ per therm							Column AB						
71	Equal % of margin								Column R	Column U	Column X	Column AA		

NW Natural
Rates & Regulatory Affairs
2011-2012 PGA Filing - Oregon: August Filing
Calculation of Increments Allocated on the EQUAL PERCENTAGE OF MARGIN BASIS
ALL VOLUMES IN THERMS

1					**SIP: Bare Steel - 30%**			**Geo-Haz: Vintaging/aging**			**SIP: DIMP**			**SIP: TIMP**			**Storage Recall for Core**		
2			Oregon PGA	Proposed Amount:	1,046,400	PERMANENT Increment		888,000	PERMANENT Increment		157,000	PERMANENT Increment		4,855,000	PERMANENT Increment		110,180	PERMANENT Increment	
3			Volumes page,	Revenue Sensitive Multiplier:	N/A	rev sensitive factor is built in		N/A	rev sensitive factor is built in		N/A	rev sensitive factor is built in		N/A	rev sensitive factor is built in		N/A	rev sensitive factor is built in	
4			Column F	Amount to Amortize:	**1,046,400**	to all classes and schedules		**888,000**	to all classes and schedules		**157,000**	to all classes and schedules		**4,855,000**	to all classes and schedules		**110,180**	to all sales	
5					**Multiplier**	Allocation to RS	**Increment**	**Multiplier**	Allocation to RS	**Increment**	**Multiplier**	Allocation to RS	**Increment**	**Multiplier**	Allocation to RS	**Increment**	**Multiplier**	Allocation to RS	**Increment**
6	Schedule	Block	**A**		**P**	**Q**	**R**	**S**	**T**	**U**	**V**	**W**	**X**	**Y**	**Z**	**AA**	**AB**	**AC**	**AD**
7	1R		720,574		1.0	2,081	0.00289	1.0	1,766	0.00245	1.0	312	0.00043	1.0	9,657	0.01340	1.0	227	0.00032
8	1C		168,761		1.0	328	0.00194	1.0	279	0.00165	1.0	49	0.00029	1.0	1,523	0.00902	1.0	36	0.00021
9	2R		357,106,580		1.0	691,565	0.00194	1.0	586,879	0.00164	1.0	103,761	0.00029	1.0	3,208,667	0.00899	1.0	75,501	0.00021
10	3C Firm Sales		156,661,336		1.0	214,760	0.00137	1.0	182,250	0.00116	1.0	32,222	0.00021	1.0	996,424	0.00636	1.0	23,446	0.00015
11	Intentionally blank																		
12	3I Firm Sales		4,245,206		1.0	4,948	0.00117	1.0	4,199	0.00099	1.0	742	0.00017	1.0	22,958	0.00541	1.0	540	0.00013
13	Intentionally blank																		
14	19	1st mantle	15,303		1.0	14	0.00	1.0	12	0.00	1.0	2	0.00	1.0	66	0.00	1.0	2	0.00
15	19	add'l mtls																	
16	31C Firm Sales	Block 1	24,513,627		1.0	54,758	0.00096	1.0	46,469	0.00082	1.0	8,216	0.00014	1.0	254,059	0.00447	1.0	5,978	0.00011
17		Block 2	35,374,819		1.0		0.00088	1.0		0.00075	1.0		0.00013	1.0		0.00408	1.0		0.00010
18	31C Firm Trans	Block 1	185,073		1.0	1,238	0.00073	1.0	1,051	0.00062	1.0	186	0.00011	1.0	5,745	0.00339	0.0	0	0.00000
19		Block 2	1,652,315		1.0		0.00067	1.0		0.00057	1.0		0.00010	1.0		0.00310	0.0		0.00000
20	31C Interr Sales	Block 1	161,570		1.0	810	0.00085	1.0	687	0.00072	1.0	121	0.00013	1.0	3,756	0.00395	1.0	88	0.00009
21		Block 2	864,968		1.0		0.00078	1.0		0.00066	1.0		0.00012	1.0		0.00360	1.0		0.00008
22	31I Firm Sales	Block 1	5,061,961		1.0	13,848	0.00078	1.0	11,752	0.00066	1.0	2,078	0.00012	1.0	64,253	0.00363	1.0	1,512	0.00009
23		Block 2	13,993,811		1.0		0.00071	1.0		0.00060	1.0		0.00011	1.0		0.00328	1.0		0.00008
24	31I Firm Trans	Block 1	99,991		1.0	422	0.00075	1.0	358	0.00064	1.0	63	0.00011	1.0	1,959	0.00349	0.0	0	0.00000
25		Block 2	511,039		1.0		0.00068	1.0		0.00058	1.0		0.00010	1.0		0.00315	0.0		0.00000
26	31I Interr Sales	Block 1	126,977		1.0	249	0.00093	1.0	212	0.00079	1.0	37	0.00014	1.0	1,158	0.00431	1.0	27	0.00010
27		Block 2	156,929		1.0		0.00084	1.0		0.00071	1.0		0.00012	1.0		0.00389	1.0		0.00009
28	32C Firm Sales	Block 1	4,891,766		1.0	5,190	0.00053	1.0	4,404	0.00045	1.0	779	0.00008	1.0	24,080	0.00244	1.0	567	0.00006
29		Block 2	4,815,433		1.0		0.00045	1.0		0.00038	1.0		0.00007	1.0		0.00207	1.0		0.00005
30		Block 3	1,399,458		1.0		0.00032	1.0		0.00027	1.0		0.00005	1.0		0.00146	1.0		0.00003
31		Block 4	169,202		1.0		0.00018	1.0		0.00016	1.0		0.00003	1.0		0.00085	1.0		0.00002
32		Block 5	0		1.0		0.00011	1.0		0.00009	1.0		0.00002	1.0		0.00049	1.0		0.00001
33		Block 6	0		1.0		0.00005	1.0		0.00004	1.0		0.00001	1.0		0.00024	1.0		0.00001
34	32I Firm Sales	Block 1	4,506,637		1.0	5,214	0.00048	1.0	4,425	0.00041	1.0	782	0.00007	1.0	24,193	0.00224	1.0	569	0.00005
35		Block 2	5,781,297		1.0		0.00041	1.0		0.00035	1.0		0.00006	1.0		0.00191	1.0		0.00004
36		Block 3	2,064,850		1.0		0.00029	1.0		0.00025	1.0		0.00004	1.0		0.00135	1.0		0.00003
37		Block 4	361,936		1.0		0.00017	1.0		0.00014	1.0		0.00003	1.0		0.00078	1.0		0.00002
38		Block 5	(0)		1.0		0.00010	1.0		0.00008	1.0		0.00001	1.0		0.00045	1.0		0.00001
39		Block 6	0		1.0		0.00005	1.0		0.00004	1.0		0.00001	1.0		0.00022	1.0		0.00001
40	32 Firm Trans	Block 1	6,531,553		1.0	11,654	0.00043	1.0	9,890	0.00036	1.0	1,749	0.00006	1.0	54,072	0.00197	0.0	0	0.00000
41		Block 2	10,291,976		1.0		0.00036	1.0		0.00031	1.0		0.00005	1.0		0.00168	0.0		0.00000
42		Block 3	6,744,921		1.0		0.00026	1.0		0.00022	1.0		0.00004	1.0		0.00118	0.0		0.00000
43		Block 4	14,560,419		1.0		0.00015	1.0		0.00013	1.0		0.00002	1.0		0.00069	0.0		0.00000
44		Block 5	14,810,823		1.0		0.00009	1.0		0.00007	1.0		0.00001	1.0		0.00039	0.0		0.00000
45		Block 6	259,978		1.0		0.00004	1.0		0.00004	1.0		0.00001	1.0		0.00020	0.0		0.00000
46	32C Interr Sales	Block 1	3,272,604		1.0	5,293	0.00050	1.0	4,492	0.00043	1.0	794	0.00008	1.0	24,558	0.00232	1.0	578	0.00005
47		Block 2	4,919,412		1.0		0.00043	1.0		0.00036	1.0		0.00006	1.0		0.00198	1.0		0.00005
48		Block 3	2,817,505		1.0		0.00030	1.0		0.00026	1.0		0.00005	1.0		0.00139	1.0		0.00003
49		Block 4	3,946,719		1.0		0.00018	1.0		0.00015	1.0		0.00003	1.0		0.00081	1.0		0.00002
50		Block 5	194,623		1.0		0.00010	1.0		0.00009	1.0		0.00002	1.0		0.00047	1.0		0.00001
51		Block 6	0		1.0		0.00005	1.0		0.00004	1.0		0.00001	1.0		0.00023	1.0		0.00001
52	32I Interr Sales	Block 1	7,572,262		1.0	10,159	0.00044	1.0	8,621	0.00037	1.0	1,524	0.00007	1.0	47,135	0.00205	1.0	1,109	0.00005
53		Block 2	9,692,007		1.0		0.00038	1.0		0.00032	1.0		0.00006	1.0		0.00174	1.0		0.00004
54		Block 3	4,999,427		1.0		0.00026	1.0		0.00022	1.0		0.00004	1.0		0.00123	1.0		0.00003
55		Block 4	8,493,596		1.0		0.00015	1.0		0.00013	1.0		0.00002	1.0		0.00072	1.0		0.00002
56		Block 5	3,174,949		1.0		0.00009	1.0		0.00007	1.0		0.00001	1.0		0.00041	1.0		0.00001
57		Block 6	5,975,027		1.0		0.00004	1.0		0.00004	1.0		0.00001	1.0		0.00021	1.0		0.00000
58	32 Interr Trans	Block 1	9,106,332		1.0	23,867	0.00040	1.0	20,254	0.00034	1.0	3,581	0.00006	1.0	110,737	0.00187	0.0	0	0.00000
59		Block 2	15,529,327		1.0		0.00034	1.0		0.00029	1.0		0.00005	1.0		0.00159	0.0		0.00000
60		Block 3	10,921,668		1.0		0.00024	1.0		0.00021	1.0		0.00004	1.0		0.00112	0.0		0.00000
61		Block 4	30,029,500		1.0		0.00014	1.0		0.00012	1.0		0.00002	1.0		0.00065	0.0		0.00000
62		Block 5	62,381,728		1.0		0.00008	1.0		0.00007	1.0		0.00001	1.0		0.00037	0.0		0.00000
63		Block 6	73,722,561		1.0		0.00004	1.0		0.00003	1.0		0.00001	1.0		0.00019	0.0		0.00000
64	Intentionally blank																		
65	33		0		1.0	0	0.00002	1.0	0	0.00002	1.0	0	0.00000	1.0	0	0.00011	1.0	0	0.00000
66																			
67	TOTALS		935,560,335		291,260,781	1,046,398		291,260,781	888,000		291,260,781	156,998		291,260,781	4,855,000		280,911,383	110,180	
68																			
69	**Sources for line 2 above:**																		
70	**Inputs page**				Line 35			Line 37			Line 39			Line 41			Line 45		
71																			
72	**Tariff Schedules**																		
73	**Rate Adjustment Schedule**				Sched 177 A			Sched 177 other			Sched 177 C			Sched 177 B			Sched 187		
74																			

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL
SUPPORTING MATERIALS

Purchased Gas Costs

NWN Advice No. OPUC 11-11
August 31, 2011

Exhibit B
Supporting Materials
Purchased Gas Costs
NWN Advice No. OPUC 11-11

Commodity and Non-Commodity Costs

Combined Effects of PGA Costs

NW Natural
2011-2012 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

SYSTEM COSTS

Line	(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**		$39,440,715	$40,801,077	$37,033,232	$26,171,013	$31,116,842	$27,567,794	$18,743,881	$12,874,643	$11,850,652	$11,797,136	$12,415,680	$23,627,059	$293,439,723
6	tab commodity cost from supply, column bf, lines 93-105 plus														
7	tab commodity cost from gas reserve, column J, lines 59-70														
8	**Volumetric Pipeline Chgs**		$270,647	$305,137	$255,109	$203,996	$210,039	$191,698	$127,550	$86,316	$78,462	$78,375	$82,483	$161,581	$2,051,393
9	tab commodity cost from vol pipe, column e, line 78-90														
10	**Commodity Cost from Storage**		$131,165	$15,514,044	$17,517,732	$19,280,894	$8,208,192	$131,165	$135,538	$131,165	$135,538	$135,538	$131,165	$135,538	$61,587,674
11	tab Commodity Cost from Storage, column h, line 61-73														
12	**Commodity Cost from Gas Reserves**		$599,051	$728,233	$832,838	$938,587	$1,024,109	$1,107,789	$1,143,555	$1,223,234	$1,279,766	$1,367,143	$1,406,788	$1,471,127	$13,122,219
13	tab Commodity Cost from Gas Reserve, column I, line 59-70														
14	**Total Commodity Cost**		$40,441,578	$57,348,491	$55,638,910	$46,594,489	$40,559,182	$28,998,446	$20,150,524	$14,315,359	$13,344,418	$13,378,192	$14,036,116	$25,395,305	$370,201,009
15															
16	**VOLUMES**														
17	Pipeline Commodity at Receipt Points		87,176,893	88,963,604	80,288,141	56,684,274	67,649,951	62,484,237	41,891,703	28,561,740	26,077,194	26,049,620	27,330,544	52,778,784	645,936,685
18	Pipeline Fuel Use		2,296,614	2,361,664	2,086,836	1,511,347	1,767,829	1,662,920	1,155,248	775,684	728,780	728,320	745,883	1,374,298	17,195,423
19	Pipeline Gas Arriving at City Gate		84,880,279	86,601,940	78,201,305	55,172,927	65,882,122	60,821,317	40,736,455	27,786,056	25,348,414	25,321,300	26,584,661	51,404,486	628,741,262
20	Storage Gas Deliveries		240,000	30,388,073	35,308,411	39,940,080	16,575,523	240,000	248,000	240,000	248,000	248,000	240,000	248,000	124,164,087
21	Total Gas At Citygate (Storage and Pipeline)		85,120,279	116,990,013	113,509,716	95,113,007	82,457,645	61,061,317	40,984,455	28,026,056	25,596,414	25,569,300	26,824,661	51,652,486	752,905,349
22															
23	Unaccounted for Gas		327,289	333,928	301,536	212,740	254,034	234,522	157,074	107,138	97,741	97,635	102,506	198,211	2,424,354
24															
25	Load Served		84,792,990	116,656,085	113,208,180	94,900,267	82,203,611	60,826,795	40,827,381	27,918,918	25,498,673	25,471,665	26,722,155	51,454,275	750,480,995
															0
26	**Gas Reserves Supply:**														
27	Total cost (line 12 above)		$599,051	$728,233	$832,838	$938,587	$1,024,109	$1,107,789	$1,143,555	$1,223,234	$1,279,766	$1,367,143	$1,406,788	$1,471,127	$13,122,219
28	Load served by gas reserves		1,004,205	1,251,654	1,446,182	1,683,471	1,855,447	2,018,809	2,038,723	2,157,887	2,227,127	2,362,835	2,380,680	2,477,324	22,904,345
29															
30	**Washington WACOG Calculation**														
31															
32	Total System Commodity Cost (line 14 above)		$40,441,578	$57,348,491	$55,638,910	$46,594,489	$40,559,182	$28,998,446	$20,150,524	$14,315,359	$13,344,418	$13,378,192	$14,036,116	$25,395,305	$370,201,009
33	Less: Commodity Cost of Gas Reserves (from line 12)		$599,051	$728,233	$832,838	$938,587	$1,024,109	$1,107,789	$1,143,555	$1,223,234	$1,279,766	$1,367,143	$1,406,788	$1,471,127	$13,122,219
34	Total System Commodity Cost of traditional supplies		$39,842,527	$56,620,258	$54,806,073	$45,655,903	$39,535,073	$27,890,657	$19,006,969	$13,092,124	$12,064,652	$12,011,049	$12,629,328	$23,924,178	$357,078,790
35															
36	Total System Load Served (from line 25)		84,792,990	116,656,085	113,208,180	94,900,267	82,203,611	60,826,795	40,827,381	27,918,918	25,498,673	25,471,665	26,722,155	51,454,275	750,480,995
37	Less: load served by gas reserves (from line 28)		1,004,205	1,251,654	1,446,182	1,683,471	1,855,447	2,018,809	2,038,723	2,157,887	2,227,127	2,362,835	2,380,680	2,477,324	22,904,345
38	Total System load served by traditional supplies		83,788,785	115,404,431	111,761,998	93,216,796	80,348,164	58,807,986	38,788,658	25,761,031	23,271,546	23,108,830	24,341,475	48,976,951	727,576,650
39															
40	**Washington Sales WACOG** (line 34 ÷ line 38)		$0.47551	$0.49062	$0.49038	$0.48978	$0.49205	$0.47427	$0.49001	$0.50821	$0.51843	$0.51976	$0.51884	$0.48848	$0.49078
41															
42	**WASHINGTON BILLING WACOG**		$0.49725	$0.51305	$0.51280	$0.51217	$0.51455	$0.49595	$0.51241	$0.53144	$0.54213	$0.54352	$0.54256	$0.51081	$0.51322
43															
44	**Oregon WACOG Calculation**														
45															
46	Oregon load served		76,549,855	105,422,028	102,269,940	85,670,612	74,200,915	54,864,151	36,882,199	25,320,673	23,334,068	23,294,353	24,216,998	46,195,338	678,221,130
47	Less: load served by gas reserves (from line 28)		1,004,205	1,251,654	1,446,182	1,683,471	1,855,447	2,018,809	2,038,723	2,157,887	2,227,127	2,362,835	2,380,680	2,477,324	22,904,345
48	Oregon load served by traditional supplies		75,545,650	104,170,374	100,823,758	83,987,141	72,345,468	52,845,342	34,843,476	23,162,786	21,106,941	20,931,518	21,836,318	43,718,014	655,316,785
49															
50	Times Sales WACOG without Gas Reserves (from line 40)		$0.47551	$0.49062	$0.49038	$0.48978	$0.49205	$0.47427	$0.49001	$0.50821	$0.51843	$0.51976	$0.51884	$0.48848	
51															
52	Oregon's Commodity Cost from traditional supplies (line 50 * line 48)		$35,922,712	$51,108,069	$49,441,955	$41,135,222	$35,597,588	$25,062,960	$17,073,652	$11,771,559	$10,942,471	$10,879,366	$11,329,555	$21,355,375	$321,620,484
53	Plus: commodity cost of gas reserves (line 12 above)		$599,051	$728,233	$832,838	$938,587	$1,024,109	$1,107,789	$1,143,555	$1,223,234	$1,279,766	$1,367,143	$1,406,788	$1,471,127	$13,122,219
54	Total Oregon Commodity Cost		$36,521,763	$51,836,302	$50,274,792	$42,073,809	$36,621,697	$26,170,749	$18,217,207	$12,994,794	$12,222,237	$12,246,508	$12,736,343	$22,826,502	$334,742,703
55															
56	**Oregon Sales WACOG** (line 54 ÷ line 46)		$0.47710	$0.49170	$0.49159	$0.49111	$0.49355	$0.47701	$0.49393	$0.51321	$0.52379	$0.52573	$0.52593	$0.49413	$0.49356
57															
58	**OREGON BILLING WACOG**		$0.49111	$0.50614	$0.50603	$0.50553	$0.50804	$0.49102	$0.50844	$0.52828	$0.53917	$0.54117	$0.54138	$0.50864	$0.50805

NW Natural
2011-2012 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	29	31	30	31	30	31	31	30	31	366
Transport charges by transporter:														
Northwest Pipeline		$3,994,861	$4,150,096	$4,128,021	$3,861,698	$4,128,021	$3,995,385	$4,128,563	$3,995,385	$4,128,563	$4,128,563	$3,995,385	$4,128,563	$48,763,104
GTN		517,197	534,437	574,162	537,118	574,162	467,603	483,190	467,603	483,190	483,190	467,603	574,162	6,163,617
TCPL BC		390,258	463,475	463,475	463,475	463,475	413,157	413,157	413,157	413,157	413,157	413,157	463,475	5,186,576
NOVA		935,369	839,991	839,991	839,991	839,991	839,991	839,991	839,991	839,991	839,991	839,991	839,991	10,175,273
Terasen (Southern Crossing)		629,109	818,714	818,714	765,894	818,714	792,304	818,714	792,304	818,714	818,714	792,304	818,714	9,502,913
Spectra (Westcoast)		770,299	902,235	902,235	896,837	902,235	899,536	902,235	899,536	902,235	902,235	899,536	902,235	10,681,389
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	224,258
Total System Demand		$7,255,781	$7,727,636	$7,745,286	$7,383,701	$7,745,286	$7,426,665	$7,604,539	$7,426,665	$7,604,539	$7,604,539	$7,426,665	$7,745,828	$90,697,130

Detail in file "NOVA ANG Monthly Summary for Tracker 2011-12 final 8-22-11 w new CAD.xls"

NW Natural

2011-2012 PGA - OREGON: August Filing

Derivation of Oregon per therm Non-Commodity Charges

ALL VOLUMES IN THERMS

Oregon Derivation of Demand Increments

Line				
1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$90,697,130	
5	Oregon Allocation Factor 1/		90.07%	
6	Oregon Demand		$81,690,905	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		621,852,556	
9	Oregon Interruptible Sales Forecasted Normal Volumes		56,368,575	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.12997	$0.13379
13	Proposed Interruptible Demand 2/		$0.01545	$0.01590
14	Proposed MDDV Demand Charge		$1.94	$2.00
15				
16	Current Firm Demand Per Therm		$0.12734	$0.13101
17	Current Interruptible Demand		$0.01514	$0.01558
18	Current MDDV Demand Charge		$1.90	$1.95
19				
20	Percent Change in Firm Demand		2.07%	
21				
22				
23	1/Allocation Factor: Actual 12 months ended 06/30/10 firm sales volumes:			
24		Washington	Oregon	System
25	Residential	46,784,384	370,273,885	417,058,269
26	Commercial	20,705,483	231,889,980	252,595,463
27	Industrial	2,708,554	34,798,737	37,507,291
28	Total	70,198,421	636,962,602	707,161,023
29		9.93%	90.07%	100.00%
30				
31	2/Calculation of Proposed Demand Rates:			
32				
33	Demand change factor		1.021	
34				
35	Firm Demand (line 8 * line 35)		$0.12997	$80,819,883
36	Interruptible Demand (line 9 * line 36)		$0.01545	$871,022
37				$81,690,905
38				$0

NW Natural
2011-2012 PGA - SYSTEM: August Filing
Calculation of Winter WACOG
Prices are per therm

		AECO/NIT	Without Rev Sensitive	WITH Rev Sensitive	
1	Forecast price for AECO gas:				
2					
3		AECO/NIT			
4					
5	November	$0.42221			
6	December	$0.43963			
7	January	$0.44567			
8	February	$0.44453			
9	March	$0.44081			
10	April	$0.42402			
11	May	$0.42078			
12	June	$0.42162			
13	July	$0.42252			
14	August	$0.42470			
15	September	$0.42837			
16	October	$0.43429			
17					
18					
19	Average price, November-March		$0.43857		average lines 5-9
20					
21	Annual average price, November-October		$0.43076		average lines 5-16
22					
23	Ratio of winter to annual		1.01813		line 19 ÷ line 21
24					
25			Without Rev	WITH Rev	
26			Sensitive	Sensitive	
OR	Oregon Annual WACOG		$0.49356	$0.50805	
OR	Oregon Winter WACOG		$0.50251	$0.51727	
			line 23 * $0.49356		
WA	Washington Annual WACOG		$0.49078	$0.51322	
WA	Washington Winter WACOG		$0.49968	$0.52252	
			line 23 * $0.49078		

NW Natural
2011-2012 PGA - OREGON: August Filing
Derivation of Oregon Seasonalized Fixed Charges

		Normalized Residential Volumes	Normalized Commercial Volumes	Firm Industrial Volumes	Interruptible Volumes	Total	Firm Demand Increment Eff. 11/01/11	Interr. Demand Increment Eff. 11/01/11	Seasonalized Fixed Charges
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
November	2011								$9,197,282
December	2011	42,691,634	25,393,378	3,358,565	5,106,278	76,549,855	$0.12997	$0.01545	$9,364,165
January	2012	60,502,130	35,123,896	3,979,381	5,816,621	105,422,028	$0.12997	$0.01545	$13,035,236
February	2012	58,547,609	34,075,869	3,911,204	5,735,258	102,269,940	$0.12997	$0.01545	$12,634,887
March	2012	48,541,857	28,508,625	3,461,227	5,158,903	85,670,612	$0.12997	$0.01545	$10,543,532
April	2012	41,056,158	24,637,074	3,356,653	5,151,030	74,200,915	$0.12997	$0.01545	$9,053,757
May	2012	29,082,681	18,222,471	2,923,331	4,635,668	54,864,151	$0.12997	$0.01545	$6,599,642
June	2012	17,423,696	12,465,285	2,648,454	4,344,764	36,882,199	$0.12997	$0.01545	$4,295,903
July	2012	10,117,170	8,876,940	2,376,354	3,950,210	25,320,674	$0.12997	$0.01545	$2,838,475
August	2012	8,538,519	8,388,612	2,409,981	3,996,955	23,334,067	$0.12997	$0.01545	$2,574,929
September	2012	8,518,995	8,368,680	2,409,933	3,996,745	23,294,353	$0.12997	$0.01545	$2,569,792
October	2012	9,385,663	8,556,988	2,357,442	3,916,905	24,216,998	$0.12997	$0.01545	$2,698,848
November	2012	23,436,345	15,376,583	2,823,172	4,559,239	46,195,339	$0.12997	$0.01545	$5,481,739
		357,842,457	227,994,401	36,015,697	56,368,576	678,221,131			$81,690,905

Encana Gas Reserves Deal		Projected November 2011	Projected December 2011	Projected January 2012	Projected February 2012	Projected March 2012	Projected April 2012	Projected May 2012	Projected June 2012	Projected July 2012	Projected August 2012	Projected September 2012	Projected October 2012	
1 Therms Delivered (000s)														
2 Total Therms		1,021.26	1,272.91	1,470.74	1,712.06	1,886.96	2,053.10	2,073.35	2,194.54	2,264.95	2,402.97	2,421.11	2,519.40	
3 Rate per Therm (Depletion Rate)		0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	
4 Delivery Value		247.17	308.08	355.96	414.36	456.69	496.90	501.81	531.14	548.18	581.58	585.97	609.76	
5														
6 Opex / Severance / Ad Valorem														
7 Operating Cost		76.15	93.85	109.63	123.87	135.57	146.95	150.41	162.97	171.03	188.33	192.00	201.55	
8 Severance and Ad Valorem Taxes		57.73	75.72	88.44	102.55	110.98	116.36	116.20	121.58	131.36	140.01	138.98	145.43	
9 Total		133.88	169.58	198.07	226.42	246.55	263.31	266.61	284.56	302.39	328.35	330.98	346.98	
10														
11 Average Rate Base		26,384.83	31,055.12	34,877.14	37,881.99	40,851.83	43,791.82	46,712.89	49,617.72	52,501.66	55,362.25	58,201.57	61,019.70	
12														
13 Carrying Cost														
14 Equity	10.1588%	112.08	131.92	148.16	160.93	173.54	186.03	198.44	210.78	223.03	235.18	247.24	259.22	
15 Equity % of Cap Struct	50.1800%													
16 Equity Pretax	39.4589%	140.60	159.48	176.48	186.68	201.01	219.11	238.12	261.97	275.17	294.81	319.09	335.37	
17 Debt	7.0660%	77.40	91.10	102.31	111.13	119.84	128.47	137.04	145.56	154.02	162.41	170.74	179.01	
18 Total Carrying Cost		218.00	250.58	278.80	297.81	320.86	347.58	375.15	407.53	429.19	457.22	489.83	514.38	
19														
20 Total Cost		599.05	728.24	832.83	938.59	1,024.10	1,107.79	1,143.56	1,223.22	1,279.76	1,367.14	1,406.79	1,471.12	13,122.21
21 Total Volume		1,021.26	1,272.91	1,470.74	1,712.06	1,886.96	2,053.10	2,073.35	2,194.54	2,264.95	2,402.97	2,421.11	2,519.40	
22 Total Rate Per Therm		0.587	0.572	0.566	0.548	0.543	0.540	0.552	0.557	0.565	0.569	0.581	0.584	

NW Natural
Mist Recall to Core from Interstate - May 2011
Determination of Cost of Service ($000)

Input Capital Costs and Rates

Cost of Capital	% of Capital	Cost	Weighted Cost
Debt	49.82%	7.07%	3.52%
Preferred Equity	0.68%	7.16%	0.05%
Common Equity	49.50%	10.20%	5.05%
	100.00%		8.62%
State Tax Rate			6.24%
Federal Tax Rate			35.00%
Revenue Sensitive Rate			3%
Depreciation Rate			
Property Tax Rate			1%
Investment			$725,361

		System	OR share
1	Depreciation	26,894	24,223
2	Property Taxes	7,399	6,664
	Taxes on Equity Return		
3	State	3,716	3,347
4	Federal	19,541	17,601
5	Total Taxes	23,257	20,948
	Return on Rate Base		
6	Debt	25,061	22,573
7	Preferred Equity	347	312
8	Common Equity	35,945	32,375
9	Total Return	61,353	55,260
10	Subtotal Cost of Service	118,902	107,095
11	Revenue Sensitive Items	3,424	3,084
12	Total Cost of Service	$122,327	$110,180

	System	OR share
Rate Base - (Plant less Depreciation & Deferred Taxes)	$711,914	$641,221
Income Taxes		
Gross up of Equity Return	59,548	53,635
Less: State tax	3,716	3,347
Federal Taxable Income	55,833	50,288
Less: Federal Tax	19,541	17,601
Return	36,291	32,687

NW Natural
Rates & Regulatory Affairs
OPUC Advice 11-11
PGA Effects on Revenue - Staff's Attachment A

Line		Including Revenue Sensitve Amount	Change to Revenues Increase Or (Decrease)
1			
2	**Purchased Gas Cost Adjustment (PGA - UG ___)**		
3			
4	Commodity Cost Change	($11,700,810)	
5	Demand Capacity Cost Change	2,974,605	
6	**Gas Cost Change**		**(8,726,205)**
7	Amortization of 191.xxx Account Gas Costs		
8	(Demand, Coos Bay Demand & Commodity)	(16,931,154)	
9			
10	**NonGas Cost-related Temporary Increments**		
11	Amortization of Industrial DSM (UG 198/Advice 11-8)	1,816,229	
12			
13	Amortization of Decoupling (Residential & Commercial)	19,360,703	
14	Amortization of Intervenor Funding -	142,742	
15	CUB & NWIGU		
16	Earnings Test Sharing	(189,834)	
17	Amortization of AMR deferral	0	
18	Total Proposed Amortizations NonGas Deferrals	4,198,686	
19	Removal of Current Temporary Increment	3,719,588	
20	**Total Net Temporary Rate Adjustment**		**479,098**
21			
22	**Permanent Rate Adjustments**		
23	Addition of Proposed Bare Steel Program Costs	3,488,000	
24	Addition of Proposed Geo-Hazard Program Costs	888,000	
25	Addition of Proposed Integrity Management Program Costs	4,855,000	
26	Addition of Proposed Distribution Integrity Program Costs	157,000	
27	Storage Recall for Core	110,180	
28	Price Elasticity Adjustment (UG 203/Advice 11-9)	(301,968)	
29	**Total Permanent Rate Adjustment**	9,196,212	
30	Removal of Current Permanent Rate Adjustment	(8,690,000)	
31	**Total Net Permanent Rate Adjustment**		**506,212**
32	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**		**($7,740,895)**
33			
34	**Three Percent Test**		
35	Gross Revenue For 12 Months Ended 12/31/10	751,352,000	
36	Proposed Change to Revenues	($7,740,895)	
37	Percent Change to Revenues	-1.03%	

NW Natural
Rates and Regulatory Affairs
OPUC Advice 11-11
Estimated Revenue Effects for the 12 Months Beginning November 1, 2011

Line No.	Item	Earnings Sharing Increment Amount	Total Increment Amounts	Limit For Increment Amounts
1	Commodity and Demand Deferrals		($16,931,154)	
2	Temporary Increments	(189,833)	(189,833)	
3	Total	($189,833)	($17,120,987)	
4	2010 Oregon Utility Revenues			$715,078,000
5	@ 3% threshold			3.0%
6	Threshold for Annual Effect of Proposed Change in Amortization			$21,452,340

ORS 757.259 (6)

NW Natural
Rates & Regulatory Affairs
OPUC Advice 11-11
Effects on Average Bill by Rate Schedule
ALL VOLUMES IN THERMS

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

Schedule	Block	Oregon PGA Normalized Volumes page, Column D A	Therms in Block B	Normal Therms Monthly Average use C	Minimum Monthly Charge D	6/1/2011 Billing Rates E	6/1/2011 Current Average Bill F=D+(C * E) F	Proposed 11/1/2011 PGA, SIP & Recall Rates J	Proposed 11/1/2011 PGA, SIP & Recall Average Bill K=D+(C * J) K	Advice 11-9 Proposed 11/1/2011 **PGA, SIP & Recall** **% Bill Change** L =(K - F)/F L
1R		720,574	N/A	16.0	5.00	1.19240	24.08	1.17827	23.85	-1.0%
1C		168,761	N/A	76.0	5.00	1.13596	91.33	1.12090	90.19	-1.2%
2R		357,106,580	N/A	55.0	6.00	1.11756	67.47	1.10275	66.65	-1.2%
3C Firm Sales		156,661,336	N/A	235.0	8.00	1.00306	243.72	0.98790	240.16	-1.5%
Intentionally blank										
3I Firm Sales		4,245,206	N/A	1,268.0	8.00	0.97003	1,238.00	0.95479	1,218.67	-1.6%
Intentionally blank										
19	1st mantle	15,303	N/A	85.0	22.04	16.87	16.87	16.57	16.57	-1.8%
19	add'l mtls	0	N/A	0.0	21.43	16.26	16.26	15.96	15.96	-1.8%
31C Firm Sales	Block 1	24,513,627	2,000	4,152.0	325.00	0.70457	1,734.14	0.68642	1,697.84	
	Block 2	35,374,819	all additional			0.68728	1,479.03	0.66909	1,439.88	
	Total						**3,213.17**		**3,137.72**	-2.3%
31C Firm Trans	Block 1	185,073	2,000	1,928.0	325.00	0.20084	712.22	0.20125	713.01	
	Block 2	1,652,315	all additional			0.18439		0.18480		
	Total						**712.22**		**713.01**	0.1%
31C Interr Sales	Block 1	161,570	2,000	7,129.0	325.00	0.70135	1,727.70	0.68935	1,703.70	
	Block 2	864,968	all additional			0.68444	3,510.49	0.67238	3,448.64	
	Total						**5,238.19**		**5,152.34**	-1.6%
31I Firm Sales	Block 1	5,061,961	2,000	7,121.0	325.00	0.68423	1,693.46	0.66560	1,656.20	
	Block 2	13,993,811	all additional			0.66677	3,414.53	0.64814	3,319.12	
	Total						**5,107.99**		**4,975.32**	-2.6%
31I Firm Trans	Block 1	99,991	2,000	8,487.0	325.00	0.17118	667.36	0.17178	668.56	
	Block 2	511,039	all additional			0.15467	1,003.34	0.15521	1,006.85	
	Total						**1,670.70**		**1,675.41**	0.3%
31I Interr Sales	Block 1	126,977	2,000	3,943.0	325.00	0.68464	1,694.28	0.67149	1,667.98	
	Block 2	156,929	all additional			0.66733	1,296.62	0.65419	1,271.09	
	Total						**2,990.90**		**2,939.07**	-1.7%
32C Firm Sales	Block 1	4,891,766	10,000	16,780.0	675.00	0.61473	6,822.30	0.59622	6,637.20	
	Block 2	4,815,433	20,000			0.59929	4,063.19	0.58071	3,937.21	
	Block 3	1,399,458	20,000			0.57358		0.55490		
	Block 4	169,202	100,000			0.54786		0.52909		
	Block 5	0	600,000			0.53243		0.51361		
	Block 6	0	all additional			0.52214		0.50327		
	Total						**10,885.49**		**10,574.41**	-2.9%
32I Firm Sales	Block 1	4,506,637	10,000	23,546.0	675.00	0.61507	6,825.70	0.59641	6,639.10	
	Block 2	5,781,297	20,000			0.59959	8,122.05	0.58089	7,868.74	
	Block 3	2,064,850	20,000			0.57380		0.55505		
	Block 4	361,936	100,000			0.54797		0.52916		
	Block 5	(0)	600,000			0.53250		0.51365		
	Block 6	0	all additional			0.52218		0.50331		
	Total						**14,947.75**		**14,507.84**	-2.9%
32 Firm Trans	Block 1	6,531,553	10,000	70,370.0	675.00	0.10190	1,694.00	0.10208	1,695.80	
	Block 2	10,291,976	20,000			0.08660	1,732.00	0.08675	1,735.00	
	Block 3	6,744,921	20,000			0.06115	1,223.00	0.06126	1,225.20	
	Block 4	14,560,419	100,000			0.03568	726.80	0.03575	728.23	
	Block 5	14,810,823	600,000			0.02039		0.02042		
	Block 6	259,978	all additional			0.01022		0.01024		
	Total						**5,375.80**		**5,384.23**	0.2%
32C Interr Sales	Block 1	3,272,604	10,000	24,756.0	675.00	0.60821	6,757.10	0.59591	6,634.10	
	Block 2	4,919,412	20,000			0.59281	8,747.50	0.58043	8,564.83	
	Block 3	2,817,505	20,000			0.56716		0.55463		
	Block 4	3,946,719	100,000			0.54149		0.52883		
	Block 5	194,623	600,000			0.52608		0.51334		
	Block 6	0	all additional			0.51583		0.50303		
	Total						**15,504.60**		**15,198.93**	-2.0%
32I Interr Sales	Block 1	7,572,262	10,000	51,963.0	675.00	0.60818	6,756.80	0.59549	6,629.90	
	Block 2	9,692,007	20,000			0.59279	11,855.80	0.58008	11,601.60	
	Block 3	4,999,427	20,000			0.56714	11,342.80	0.55437	11,087.40	
	Block 4	8,493,596	100,000			0.54147	1,062.91	0.52867	1,037.78	
	Block 5	3,174,949	600,000			0.52607		0.51324		
	Block 6	5,975,027	all additional			0.51583		0.50299		
	Total						**31,018.31**		**30,356.68**	-2.1%
32 Interr Trans	Block 1	9,106,332	10,000	188,849.0	675.00	0.10202	1,695.20	0.10218	1,696.80	
	Block 2	15,529,327	20,000			0.08672	1,734.40	0.08685	1,737.00	
	Block 3	10,921,668	20,000			0.06123	1,224.60	0.06133	1,226.60	
	Block 4	30,029,500	100,000			0.03571	3,571.00	0.03576	3,576.00	
	Block 5	62,381,728	600,000			0.02041	792.91	0.02044	794.07	
	Block 6	73,722,561	all additional			0.01024		0.01025		
	Total						**9,018.11**		**9,030.47**	0.1%
Intentionally blank										
33		0	N/A	0.0	38,000.00	0.00553	38,000.00	0.00554	38,000.00	0.0%
Totals		935,560,335								
		0								

Sources:

Direct Inputs		per Tariff		per Tariff			
Rates in summary					Column A	Column D+E+H	
Permanents							
Temporaries						Add: Cols B+C+D	
PRIOR YEAR Temporaries						Less: Cols B+C+D	

[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 32.

NW Natural
Rates and Regulatory Affairs
2011-2012 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/11		
1				
2				
3	Total Billed Gas Sales Revenues	718,353,725		
4	Total Oregon Revenues	745,491,461		
5				
6	Regulatory Commission Fees [1]	1,863,729	0.250%	Statutory rate
7	City License and Franchise Fees	17,576,325	2.358%	Line 7 ÷ Line 4
8	Net Uncollectible Expense	1,823,551	0.245%	Line 8 ÷ Line 4
9				
10	Total	21,263,605	**2.853%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.25% times Total Oregon Revenues (line 4)
15
16
17

NW Natural
Rates & Regulatory Affairs
2011-2012 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Tariff Advice 11-11: PGA Gas Costs, Gas Cost Deferrals, SIP and Storage Recall

Line		Excluding Revenue Sensitve Amount	Including Revenue Sensitve Amount
3	**Purchased Gas Cost Adjustment (PGA)**		
5	Commodity Cost Change	($11,366,986)	($11,700,810)
7	Demand Capacity Cost Change	2,889,740	2,974,605
9	**Total Gas Cost Change**	**(8,477,246)**	**(8,726,205)**
11	**Temporary Increments**		
13	Removal of Current Temporary Increments		
15	Amortization of 191.xxx Account Gas Costs	15,287,409	15,727,625
19	Addition of Proposed Temporary Increments		
21	Amortization of 191.xxx Account Gas Costs	(16,448,108)	(16,931,154)
22	(Demand, Coos Bay Demand & Commodity)		
24	**Net Temporary Rate Adjustment**	**(1,160,699)**	**(1,203,529)**
26	**Permanent Rate Adjustments**		
28	Storage Recall for Core	107,037	110,180
30	SIP Program Costs		
32	Addition of Proposed Bare Steel Program Costs	3,388,000	3,488,000
34	Removal of Current Bare Steel Program Costs	(3,150,000)	(3,241,000)
36	Addition of Proposed Geo-Hazard Program Costs	863,000	888,000
38	Removal of Current Geo-Hazard Program Costs	(893,000)	(919,000)
40	Addition of Proposed Integrity Management Program Costs	4,716,000	4,855,000
42	Removal of Current Integrity Management Program Costs	(4,383,000)	(4,509,000)
44	Addition of Proposed Distribution Integrity Program Costs	153,000	157,000
46	Removal of Current Distribution Integrity Program Costs	(21,000)	(21,000)
48	**Subtotal SIP Program Costs**	673,000	698,000
50	**Net Permanent Rate Adjustment**	**780,037**	**808,180**
53	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($8,857,908)**	**($9,121,554)**
57	2010 Oregon Earnings Test Normalized Total Revenues	$751,352,000	$751,352,000
59	Effect of this filing, as a percentage change (line 53 ÷ line 57)	-1.18%	-1.21%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL
SUPPORTING MATERIALS

Purchased Gas Costs

NWN Advice No. OPUC 11-11
August 31, 2011

OPUC ORDER No. 11-196
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. 11-196
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. 11-196
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.		
V.8	**Attestation as to Consistency**	See IV.1.c	

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Section IV.	**1 General Information**
a)	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).

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 ("Dodd-Frank"), a piece of legislation totaling more than 2,300 pages, was signed into law in July 2010 with the expectation that it would take effect in July 2011. However, the process of writing the rules that would clarify Dodd-Frank's multitude of provisions is still on-going and the implementation of many provisions is now delayed till at least the end of 2011. Accordingly, it is still unknown whether or to what degree NW Natural's financial hedging activities will be affected. 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 continue to follow this process closely

Similarly, it is too early to know the ramifications of the September 9, 2010 fatal explosion of a 30" natural gas pipeline owned by PG&E in San Bruno, California. This matter might seem to be outside the scope of a gas portfolio discussion, but any new requirements on gas pipeline operators could affect the design of NW Natural's supply portfolio. For example, any mandated reductions in pipeline operating pressures would reduce the supplies that can be delivered over those pipelines, requiring augmentation from other/new supply sources. However, since the possible implications of new safety regulations on pipeline operators could be far-ranging, this is likely to be a long process with appropriate time for feedback and implementation.

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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 and
8	Attestation of verification of consistency

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)*	$0	Exhibit B, Page 3
B) Percent *(To .1 percent)*	0.00%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	0	Exhibit B, Page 3
B) Remove Last Year's Temporary Increment Total	0	"
C) Add New Temporary Increment	0	"
D) Other Additions or Subtractions (*Break out & List each below -- Attach additional sheet if necessary*)		
1) Net Safety Programs	0	Exhibit B, Page 3
2) Storage Recall	0	"
3) Elasticity	0	"
4)	0	"
5)	-	"
6)	-	
E) Total Proposed Change	0	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$0.70457	Exhibit B, Page 2
2) Proposed Billing Rate per Therm	$0.68260	"
3) Rate Change Per Therm	($0.02197)	
4) Percent Change per Therm *(to .1%)*	-3.1%	
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	4152.0	Exhibit B, Page 2
2) Customer Charge	$325.00	"
3) Current Average Monthly Bill	$1,734.14	"
4) Proposed Average Monthly Bill	$1,690.20	"
5) Change in Average Monthly Bill	($43.94)	"
6) Percent change in Average Monthly Bill *(to .1%)*	#REF!	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	106.0	N/A
2) Customer Charge	$325.00	N/A
3) Current Average January Bill	$399.68	N/A
4) Proposed Average January Bill	$397.36	N/A
5) Change in Average January Bill	($2.32)	N/A
6) Percent change in Average January Bill (*to .1%*)	-0.6%	N/A
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)	$0	N/A
e) Total Storage Cost (assoc. w/ supply)	0	
f) Other	$0	N/A
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	0	N/A
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	

	Amount	Location in Company Filing (cite)
i. Total Demand, Capacity, or Reservation Cost	0	N/A
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$0	N/A
4) Capacity Release Credits	0	
5) Total Gas Costs	$0	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)	$0	Exhibit B, Page 6
f) Total Storage Cost (assoc. w/ supply)	0	
g) Other (A&G Benchmark Savings)	$0	Exhibit B, Page 6
2) Total Transportation Cost *(Pipeline related)*	0	
a) Total Upstream Canadian Toll	0	
i.Total Demand, Capacity, or Reservation Cost	0	N/A
ii. Total Volumetric Cost	0	
b) Total Domestic Cost	0	
i. Total Demand, Capacity, or Reservation Cost	0	N/A
ii. Total Volumetric Cost	0	
3) Total Storage Costs	$0	N/A
4) Capacity Release Credits	0	
5) Total Gas Costs	$0	N/A
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.00000	N/A
b. Without revenue sensitive	$0.00000	N/A
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.00000	N/A
b. Without revenue sensitive	$0.00000	N/A
B) Proposed for New Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.00000	Exhibit B, Page 6 and Page 9
b. Without revenue sensitive	$0.00000	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.00000	Exhibit B, Page 8
b. Without revenue sensitive	$0.00000	"
6) Therms Sold	0	N/A
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	"

NW Natural
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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.

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/NIT, to maximize buying 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.

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) Take advantage of favorable pricing opportunities to use supply-basin storage when possible; (7) 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; (8) Structure the portfolio to provide some opportunity to take advantage when spot prices are favorable; and (9) 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.

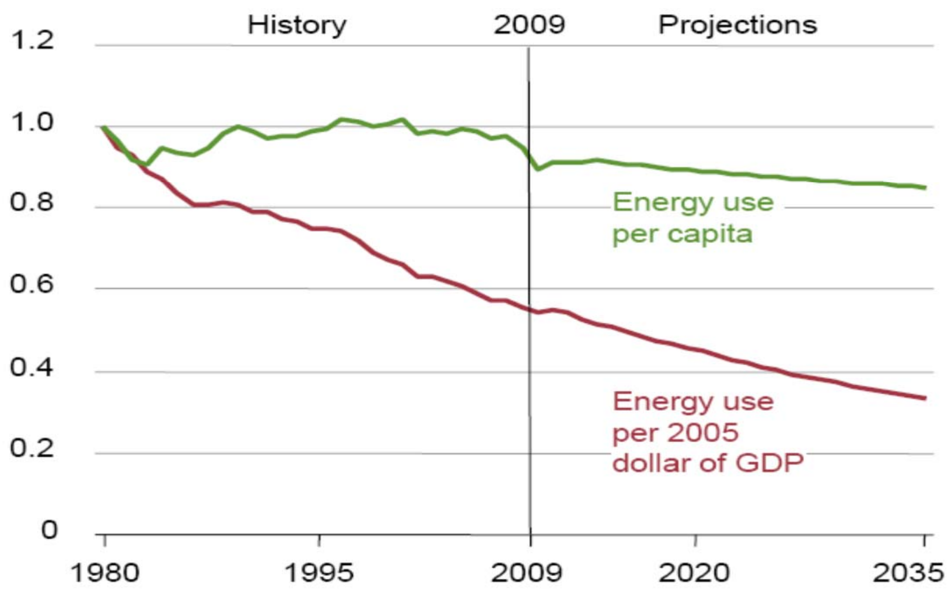
[1] "Design" year is based on the 85% probability of the coldest heating season in the last 20 years. The design year is augmented by the coldest historical coincident system-weighted average day observed during the last 20 years. In addition, the days prior to and following the peak day are also included 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. 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.

U.S. average energy use per person and per dollar of GDP declines through 2035

Figure 55. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980 = 1)



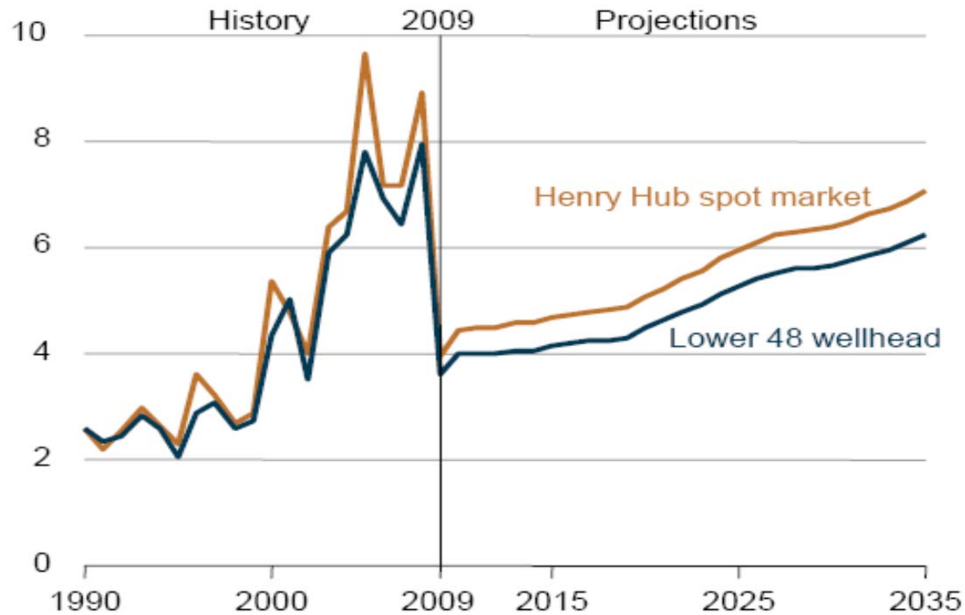
Source: EIA 2011 Annual Energy Outlook

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 2011 Annual Energy Outlook (AEO) as released in April 2011.

Figure 86. Annual average lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2035 (2009 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 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 a variety of 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 2%) 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.

Three changes have occurred in the company's physical supply resources over the past year, as follows:

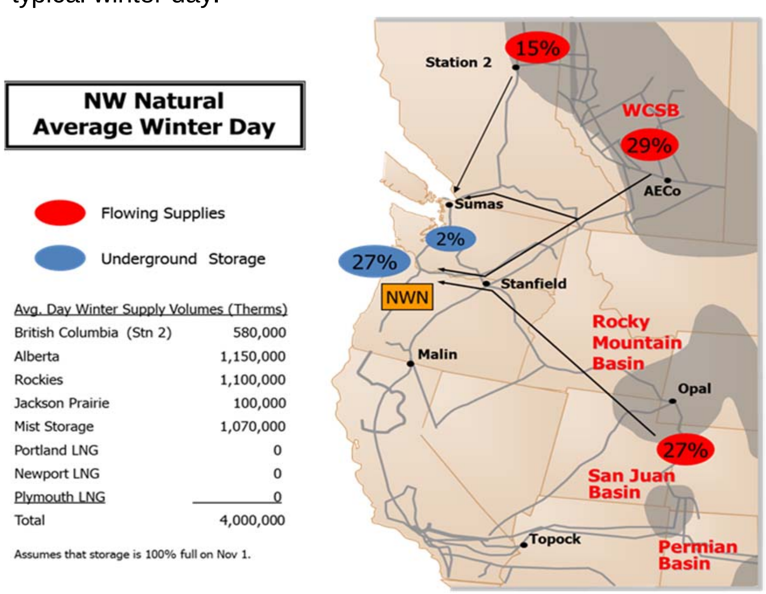
1. Effective May 1, 2011, we recalled 10,000 Dth/day of Mist deliverability along with approximately 223,000 Dth of related inventory capacity. This capacity is needed to meet general load growth in

2. We added a storage arrangement in a supply basin, specifically Alberta, to take advantage of favorable summer gas prices and low-cost storage opportunities.

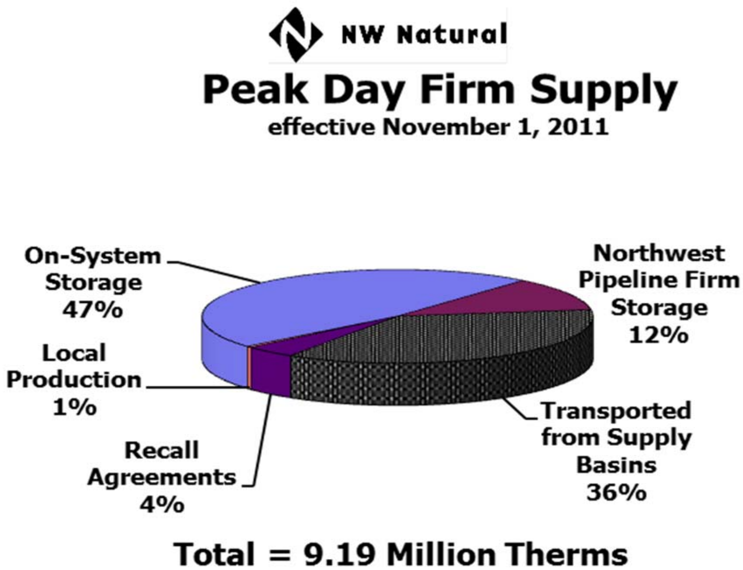
3. Effective April 1, 2012, we will change our Northwest Pipeline (NWP) capacity arrangements with Occidental Energy Marketing (Oxy). We will be terminating 5,000 Dth/day of previously-held Oxy capacity that has primary delivery points in the Portland area, while replacing it with 5,046 Dth/day of Oxy capacity that has a variety of firm delivery points including a small portion (600 Dth/day) to the Eugene area. Hence, the net resource change is trivial (46 Dth/day), but from an IRP standpoint we will gain vintage-priced NWP capacity to a region that is typically the most difficult/costly to serve due to the relatively small size of its load growth increases coupled with its relatively long distance from the major sections of the company's distribution system that tie to storage facilities such as Mist, as well as from the NWP mainline.

A significant change to the company's portfolio is the addition of gas reserves purchased under an agreement with Encana. This agreement was approved by the OPUC in April 2011 to serve Oregon customers, and its details will not be further described here. It is worth noting, however, that the agreement functions essentially as a financial tool, i.e., it displaces financial derivatives that the company otherwise would have executed. For the purposes of this filing, though, the Encana agreement has no impact on the company's physical supply portfolio.

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



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 700,000 therms per day of firm deliveries on a daily basis over the upcoming November 2011 through October 2012 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 is slightly higher than last year to reflect a modest amount of load growth.

For the November 2011 through March 2012 heating season, NWN will have contracts for an additional 1.575 million therms/day of supply under baseload and peaking (swing) agreements. This reflects the higher consumption of customers during those months and is slightly less than the volumes contracted for last winter due to the additional Alberta storage arrangement 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 (900,000 therms/day) is purchased on a take-or-pay basis. The remaining 675,000 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 1.0 and 1.7 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, including the new supply-basin storage arrangement, provide another form of hedging. And the newly-approved Encana gas reserves deal now provides a hedge for Oregon customers in a completely different form. 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 19% of annual purchase quantities, and gas reserves will amount to roughly 3.5% for this tracker year, approximately 52.5% is left to be financially hedged. This is a drop from prior years when typically 57% to 59% of expected purchases were hedged with financial derivatives. 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 and one supply-basin storage arrangement 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. The supply-basin storage arrangement is with Tenaska Marketing Canada (TMC).

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 2011/2012 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
IGI Resources	Nov-Oct	5,000		10/31/2012
Macquarie Energy Canada	Nov-Oct	10,000		10/31/2012
TD Energy Trading	Nov-Oct	5,000		10/31/2012
ConocoPhillips Canada	Nov-Oct	5,000		10/31/2012
AltaGas Energy	Nov-Oct	5,000		10/31/2012
Husky Energy Marketing	Nov-Oct	10,000		10/31/2012
Shell Energy Canada	Nov-Mar	5,000		3/31/2012
Suncor Energy Marketing	Nov-Mar	5,000		3/31/2012
Alberta:				
JP Morgan	Nov-Oct	10,000		10/31/2014
Husky Energy Marketing	Nov-Mar	10,000		3/31/2012
Shell Energy North America (Canada)	Nov-Mar	5,000		3/31/2012
ConocoPhillips Canada	Nov-Mar	5,000		3/31/2012
IGI Resources	Nov-Mar	5,000		3/31/2012
Powerex	Nov-Mar	5,000		3/31/2012
Nobel America's Gas & Power	Nov-Mar	5,000		3/31/2012
Macquarie Energy Canada	Nov-Mar	5,000		3/31/2012
pending	Nov-Mar		10,000	3/31/2012
pending	Apr-Oct		10,000	10/31/2012
Rockies:				
Societe General	Nov-Mar	10,000		3/31/2012
IGI Resources	Nov-Mar	5,000		3/31/2012
Anadarko Energy Services	Nov-Mar	10,000		3/31/2012
National Fuel Marketing	Nov-Mar	5,000		3/31/2012
Ultra Resources	Nov-Oct	10,000		10/31/2012
Shell Energy North America (US)	Nov-Mar	5,000		3/31/2012
ConocoPhillips Company	Nov-Oct	5,000		10/31/2013
Encana Marketing (USA)	Nov-Oct	5,000		12/31/2015
Encana Marketing (USA)	Jan-Oct		7,500	12/31/2015
ONEOK Energy Services	Nov-Mar		5,000	3/31/2012
Kansas Energy	Nov-Mar		10,000	3/31/2012
Kansas Energy	Nov-Mar		10,000	3/31/2012
ConocoPhillips Company	Nov-Mar		5,000	3/31/2012
Kansas Energy	Apr-Oct		10,000	10/31/2012
pending	Nov-Mar	5,000		3/31/2012
Total Off-System Firm Contract Supply		160,000	67,500	

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 and Jan-Oct "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.
3. "*pending*" represents contracts to be finalized prior to October updated filing.
4. Encana swing deal continues through 12/31/2015 but the contract volumes increase each calendar year, with the above volume (7,500) actually in effect through 12/31/2012.

Table 2

NW Natural
Firm Transportation Capacity
for the 2011/2012 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion	214,889	9/30/2018
1993 Expansion	35,155	9/30/2044
1995 Expansion	102,000	11/30/2016
Occidental (formerly Duke) Cap. Acq.	5,000	3/31/2012
Occidental	1,046	3/31/2014
Occidental	4,000	3/31/2025
International Paper Cap. Acq.	4,147	11/30/2016
Total NWP Capacity	361,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2012
Net NWP Capacity	331,237	
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	106,165	
TransCanada's BC System:		
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	48,754	10/31/2016
Total TCPL-BC Capacity	157,606	
TransCanada's Alberta System:		
1993 Expansion	48,135	10/31/2015
1995 Rationalization	57,909	10/31/2015
Engage Capacity Acquisition	3,739	Upon 1-year notice
2004 Capacity Acquisition	49,138	10/31/2015
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. Total and Net NWP Capacity above exclude the Occidental 5,000/day because it expires 3/31/2012, but include the two new Occidental capacity acquisitions totaling 5,046/day that commence on 4/1/2012.

Table 3

NW Natural
Firm Storage Resources
for the 2011/2012 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)	260,000	9,642,470	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	440,000	11,242,470	
Total Firm Storage Resource	546,130	12,841,658	

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.
5. The company also has a supply-basin storage arrangement with Tenaska Marketing Canada in the amount of 1,985,000 Dth. It is not included above because its deliverability relies on portions of the same upstream pipeline capacity already included in Table 2.

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2011/2012 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2012
International Paper	8,000	40	10/31/2015
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	39,000		
Citygate Deliveries:			
none			
Mist Production:			
Enerfin Resources	≈3,000	n/a	12/31/2011

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 2011/2012 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	331,237
Off-System Storage (Jackson Prairie and Plymouth)	3,616
On-System Storage (Mist, Portland LNG and Newport LNG)	57,417
Recallable Capacity and Supply Agreements	39,000
Citygate Deliveries	-
Nominal Mist Production Gas	3,000
Total Firm Resource	434,270

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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.

	2011/2012
Forecast Annual Demand (therms)	TO BE PROVIDED
Forecast Peak Demand (therms) - Normal	
Forecast Peak Demand (therms) - Design	
Forecast DSM Annual (therms)	
Forecast DSM Peak (therms) - Design Peak	
Forecast Annual Demand with Forecast DSM	
Forecast Peak Demand with Forecast DSM - Normal	
Forecast Peak Demand with Forecast DSM - Design	

NW Natural
PGA Portfolio Guidelines
OPUC Order No. 11-196, 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
PGA Portfolio Guidelines
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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
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November 1, 2011 - October 31, 2012
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
EnCana Marketing (USA) Inc.	6/1/2011	12/31/2015	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Frontier
Ultra Resources, Inc. (1)	11/1/2011	10/31/2012	[redacted]	IFGMR-NWP Rockies FOM	10,000		[redacted]		Opal/Frontier
ConocoPhillips Company (1)	11/1/2011	10/31/2012	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Opal
Shell Energy North America (US), LP (2)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Opal
IGI Resources, Inc.(2)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Opal
Anadarko Energy Services Company (3)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Wyoming Pool
PENDING (4)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Wyoming Pool
National Fuel Marketing Company, LLC (5)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Rocky Mountain Pool / Cla
Societe Generale Energy Corp. (6)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM	5,000		[redacted]		Rocky Mountain Pool / Igna
Kansas Energy, LLC (7)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM		10,000	[redacted]	NWN Winter Call	Opal
ConocoPhillips Company (7)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Opal
Oneok Energy Services Company, LP (7)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM		5,000	[redacted]	NWN Winter Call	Shute Creek
Kansas Energy, LLC (8)	11/1/2011	3/31/2012	[redacted]	IFGMR-NWP Rockies FOM		10,000	[redacted]	NWN Winter Call	Opal
Kansas Energy, LLC (8)	4/1/2012	10/31/2012	[redacted]	IFGMR-NWP Rockies FOM		10,000	[redacted]	Kansas Put Option	Opal
EnCana	1/1/2012	12/31/2015	[redacted]	IFGMR-NWP Rockies FOM		See Note 1	[redacted]		Frontier

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		[redacted]	Price
(5) Rocky Mountain Pool	6	[redacted]	Price
(6) Rocky Mountain Pool	6	[redacted]	Price
(7) Winter Call - Reservation Fee	5	[redacted]	Price
(8) Winter Call - Summer Put	1	[redacted]	Price & volume

Northwest Natural Gas Company
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November 1, 2011 - October 31, 2012

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
IGI Resources Inc. (previously listed as BP Canada)	11/1/2009	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000
Macquarie Energy Canada Ltd (1)	11/1/2011	10/31/2012		CGPR AECO FOM (7A) $US/Dth	10,000
TD Energy Trading Inc. (2)	11/1/2011	10/31/2012		CGPR AECO FOM (7A) $US/Dth	5,000
ConocoPhillips Canada Marketing & Trading ULC (3)	11/1/2011	10/31/2012		CGPR AECO FOM (7A) $US/Dth	5,000
AltaGas Energy Limited Partnership (3)	11/1/2011	10/31/2012		CGPR AECO FOM (7A) $US/Dth	5,000
Husky Energy Marketing Inc. (4)	11/1/2011	10/31/2012		CGPR AECO FOM (7A) $US/Dth	10,000
Suncor Energy Marketing Inc (5)	11/1/2011	3/31/2012		CGPR AECO FOM (7A) $US/Dth	5,000
Shell Energy North America (Canada) Inc. (6)	11/1/2011	3/31/2012		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)	4	[redacted]	Price
(2)	4		Price
(3)	5		Price
(4)	3		Price
(5)	3		Price
(6)	3		Price, Non-winning bidders had 2011-2012 term deals in place

Northwest Natural Gas Company
PGA Filing Guidelines

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November 1, 2011 - October 31, 2012
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
JP Morgan Commodities Canada Inc. (formally Sempra)	11/1/2004	10/31/2014	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000		
Powerex Corp (1)	11/1/2011	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
ConocoPhillips Canada Marketing & Trading ULC (1)	11/1/2011	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Macquarie Energy Canada Ltd (1)	11/1/2011	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Husky Energy Marketing Inc (1)	11/1/2011	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000		
Noble Americas Gas & Power Corp. (1)	11/1/2011	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
IGI Resources, Inc (2)	11/1/2011	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
Shell Energy North America (Canada) Inc. (3)	11/1/2011	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000		
PENDING	11/1/2011	3/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth			NWN Winter Call
PENDING	4/1/2012	10/31/2012	[redacted]	CGPR AECO FOM (7A) $US/Dth			Sequent Put Option

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	8	[redacted]	Price
(2)	4	[redacted]	Price
(3)	4	[redacted]	Price

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 2011-2012 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 2011-2012, 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.

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2011-2012 FINANCIAL HARD HEDGES (counterparty does not own option)

Date	Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Remain Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT
29-May-09	2009-26	[redacted]	[redacted]	AECO	Nov09-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
16-Jun-09	2009-28	[redacted]	[redacted]	AECO	Nov09-Oct12	731	2,500	1,827,500	[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	731	2,500	1,827,500	[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	731	2,500	1,827,500	[redacted]	[redacted]
30-Sep-09	2009-62	[redacted]	[redacted]	AECO	Nov09-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
1-Oct-09	2009-63	[redacted]	[redacted]	AECO	Nov09-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
1-Oct-09	2009-64	[redacted]	[redacted]	Sumas	Nov09-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
6-Oct-09	2009-65	[redacted]	[redacted]	Sumas	Nov09-Oct12	731	2,500	1,827,500	[redacted]	[redacted]
27-Jul-10	2010-75	[redacted]	[redacted]	Rockies	Apr12-Oct12	152	2,500	380,000	[redacted]	[redacted]
27-Jul-10	2010-75	[redacted]	[redacted]	Rockies	Nov11-Mar12, Nov12-Oct13	579	2,500	1,447,500	[redacted]	[redacted]
27-Jul-10	2010-78	[redacted]	[redacted]	Stn 2	Nov10-Oct13	731	2,500	1,827,500	[redacted]	[redacted]
9-Aug-10	2010-80	[redacted]	[redacted]	AECO	3 Winters 10-13	303	2,500	757,500	[redacted]	[redacted]
9-Aug-10	2010-81	[redacted]	[redacted]	Stn 2	Nov10-Oct13	731	2,500	1,827,500	[redacted]	[redacted]
10-Aug-10	2010-82	[redacted]	[redacted]	AECO	3 Winters 10-13	303	2,500	757,500	[redacted]	[redacted]
13-Aug-10	2010-87	[redacted]	[redacted]	AECO	3 Winters 10-13	303	2,500	757,500	[redacted]	[redacted]
16-Aug-10	2010-88	[redacted]	[redacted]	AECO	3 Winters 10-13	303	2,500	757,500	[redacted]	[redacted]
16-Aug-10	2010-90	[redacted]	[redacted]	AECO	3 Winters 10-13	303	2,500	757,500	[redacted]	[redacted]
7-Sep-10	2010-98	[redacted]	[redacted]	AECO	3 Winters 10-13	303	2,500	757,500	[redacted]	[redacted]
13-Sep-10	2010-100	[redacted]	[redacted]	Stn 2	Sept 11, 12, 13	60	7,500	450,000	[redacted]	[redacted]
16-Sep-10	2010-102	[redacted]	[redacted]	AECO	Feb12-Mar12	60	2,500	150,000	[redacted]	[redacted]
16-Sep-10	2010-102	[redacted]	[redacted]	AECO	Nov11-Jan12	243	2,500	607,500	[redacted]	[redacted]
16-Sep-10	2010-103	[redacted]	[redacted]	Stn 2	June 11, 12, 13	60	7,500	450,000	[redacted]	[redacted]
16-Sep-10	2010-104	[redacted]	[redacted]	Stn 2	June-Sept 11-13	244	2,500	610,000	[redacted]	[redacted]
29-Nov-10	2010-114	[redacted]	[redacted]	Stn 2	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
29-Nov-10	2010-115	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
15-Dec-10	2010-116	[redacted]	[redacted]	Stn 2	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
16-Dec-10	2010-117	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
26-Jan-11	2011-1	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
31-Jan-11	2011-2	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
1-Mar-11	2011-3	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
11-Mar-11	2011-4	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
14-Mar-11	2011-5	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
16-Mar-11	2011-6	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
21-Mar-11	2011-7	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
21-Mar-11	2011-8	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
28-Mar-11	2011-9	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
30-Mar-11	2011-10	[redacted]	[redacted]	AECO	Nov11-Mar12	152	2,500	380,000	[redacted]	[redacted]
30-Mar-11	2011-11	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
30-Mar-11	2011-12	[redacted]	[redacted]	Stn 2	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]
26-Apr-11	2011-15	[redacted]	[redacted]	Rockies	Nov11-Jan12	92	10,000	920,000	[redacted]	[redacted]
2-May-11	2011-16	[redacted]	[redacted]	Stn 2	Mar 12	31	5,000	155,000	[redacted]	[redacted]
2-May-11	2011-16	[redacted]	[redacted]	Stn 2	Apr 12	30	5,000	150,000	[redacted]	[redacted]
2-May-11	2011-16	[redacted]	[redacted]	Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]
2-May-11	2011-17	[redacted]	[redacted]	Stn 2	Nov11-Mar12	152	2,500	380,000	[redacted]	[redacted]
9-May-11	2011-18	[redacted]	[redacted]	Stn 2	Nov11-Jan12	92	5,000	460,000	[redacted]	[redacted]
12-May-11	2011-19	[redacted]	[redacted]	Stn 2	Nov11-Dec11	61	5,000	305,000	[redacted]	[redacted]
18-May-11	2011-20	[redacted]	[redacted]	Stn 2	Apr 12	30	5,000	150,000	[redacted]	[redacted]
18-May-11	2011-20	[redacted]	[redacted]	Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]
18-May-11	2011-21	[redacted]	[redacted]	Stn 2	Oct 12	31	10,000	310,000	[redacted]	[redacted]
18-May-11	2011-21	[redacted]	[redacted]	Stn 2	Oct 12	31	5,000	155,000	[redacted]	[redacted]
20-May-11	2011-22	[redacted]	[redacted]	Stn 2	Apr 12	30	10,000	300,000	[redacted]	[redacted]
20-May-11	2011-22	[redacted]	[redacted]	Stn 2	Apr 12	30	5,000	150,000	[redacted]	[redacted]
24-May-11	2011-23	[redacted]	[redacted]	Stn 2	Dec 11	31	5,000	155,000	[redacted]	[redacted]
26-May-11	2011-24	[redacted]	[redacted]	AECO	Nov11-Jan12	92	5,000	460,000	[redacted]	[redacted]
31-May-11	2011-25	[redacted]	[redacted]	Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]
31-May-11	2011-25	[redacted]	[redacted]	Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]
31-May-11	2011-25	[redacted]	[redacted]	AECO	Apr 12	30	10,000	300,000	[redacted]	[redacted]

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2011-2012 FINANCIAL HARD HEDGES (counterparty does not own option)

Date	Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Remain Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT
18-Aug-11	2011-26	[redacted]		Rockies	Apr 12	30	5,000	150,000	[redacted]	[redacted]
18-Aug-11	2011-27	[redacted]		Rockies	Oct 12	31	5,000	155,000	[redacted]	[redacted]
18-Aug-11	2011-28	[redacted]		AECO	Apr 12	30	5,000	150,000	[redacted]	[redacted]
18-Aug-11	2011-29	[redacted]		AECO	May 12	31	5,000	155,000	[redacted]	[redacted]
18-Aug-11	2011-30	[redacted]		Stn 2	Oct 12	31	5,000	155,000	[redacted]	[redacted]
23-Aug-11	2011-31	[redacted]		Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]
Total Hard Hedges								**51,895,000**	[redacted]	[redacted]

CONFIDENTIAL

2011-2012 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
18-Apr-11	2011-13	[redacted]		Rockies	Nov11-Jan12	92	10,000	920,000	[redacted]	[redacted]	$5.500
18-Apr-11	2011-14	[redacted]		AECO	Nov11-Jan12	92	10,000	920,000	[redacted]	[redacted]	$5.250
Total Soft Hedges								**1,840,000**	[redacted]	[redacted]	
Total Hard and Soft Hedges								**53,735,000**	[redacted]	[redacted]	
Hedges by Counterparty:									[redacted]	[redacted]	
		[redacted]						305,000	[redacted]	[redacted]	
		[redacted]						760,000	[redacted]	[redacted]	
		[redacted]						2,825,000	[redacted]	[redacted]	
		[redacted]						3,650,000	[redacted]	[redacted]	
		[redacted]						3,655,000	[redacted]	[redacted]	
		[redacted]						2,815,000	[redacted]	[redacted]	
		[redacted]						925,000	[redacted]	[redacted]	
		[redacted]						3,500,000	[redacted]	[redacted]	
		[redacted]						12,950,000	[redacted]	[redacted]	
		[redacted]						7,137,500	[redacted]	[redacted]	
		[redacted]						11,860,000	[redacted]	[redacted]	
		[redacted]						3,352,500	[redacted]	[redacted]	
Total of Hedges by Counterparty:								**53,735,000**	[redacted]	[redacted]	

HEDGED PERCENTAGE

2011-2012 FINANCIAL HEDGES (that apply only to 2011-2012, not multi-year portions)

Trade Date	Internal Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	2011-12 Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT	MULTI-YEAR
29-May-09	2009-26	[redacted]		AECO	Nov09-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
16-Jun-09	2009-28	[redacted]		AECO	Nov09-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
30-Jun-09	2009-32	[redacted]		Stn 2	Nov10-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
15-Jul-09	2009-41	[redacted]		Stn 2	Nov10-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
1-Sep-09	2009-52	[redacted]		Rockies	Nov10-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
1-Sep-09	2009-56	[redacted]		Rockies	Nov09-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
1-Sep-09	2009-57	[redacted]		Rockies	Nov10-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000

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2011-2012 FINANCIAL HARD HEDGES (counterparty does not own option)

Date	Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Remain Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT	
1-Sep-09	2009-58	[redacted]	[redacted]	Rockies	Nov09-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
30-Sep-09	2009-62	[redacted]	[redacted]	AECO	Nov09-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
1-Oct-09	2009-63	[redacted]	[redacted]	AECO	Nov09-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
1-Oct-09	2009-64	[redacted]	[redacted]	Sumas	Nov11-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
6-Oct-09	2009-65	[redacted]	[redacted]	Sumas	Nov11-Oct12	366	2,500	915,000	[redacted]	[redacted]	915,000
27-Jul-10	2010-75	[redacted]	[redacted]	Rockies	Apr12-Oct12	152	2,500	380,000	[redacted]	[redacted]	380,000
27-Jul-10	2010-75	[redacted]	[redacted]	Rockies	Nov11-Mar12, Nov12-Oct13	214	2,500	535,000	[redacted]	[redacted]	535,000
27-Jul-10	2010-78	[redacted]	[redacted]	Stn 2	Nov10-Oct13	366	2,500	915,000	[redacted]	[redacted]	915,000
9-Aug-10	2010-80	[redacted]	[redacted]	AECO	3 Winters 10-13	152	2,500	380,000	[redacted]	[redacted]	380,000
9-Aug-10	2010-81	[redacted]	[redacted]	Stn 2	Nov10-Oct13	366	2,500	915,000	[redacted]	[redacted]	915,000
10-Aug-10	2010-82	[redacted]	[redacted]	AECO	3 Winters 10-13	152	2,500	380,000	[redacted]	[redacted]	380,000
13-Aug-10	2010-87	[redacted]	[redacted]	AECO	3 Winters 10-13	152	2,500	380,000	[redacted]	[redacted]	380,000
16-Aug-10	2010-88	[redacted]	[redacted]	AECO	3 Winters 10-13	152	2,500	380,000	[redacted]	[redacted]	380,000
16-Aug-10	2010-90	[redacted]	[redacted]	AECO	3 Winters 10-13	152	2,500	380,000	[redacted]	[redacted]	380,000
7-Sep-10	2010-98	[redacted]	[redacted]	AECO	3 Winters 10-13	152	2,500	380,000	[redacted]	[redacted]	380,000
13-Sep-10	2010-100	[redacted]	[redacted]	Stn 2	Sept 11, 12, 13	30	7,500	225,000	[redacted]	[redacted]	225,000
15-Sep-10	2010-102	[redacted]	[redacted]	AECO	Feb12-Mar12	60	2,500	150,000	[redacted]	[redacted]	150,000
16-Sep-10	2010-102	[redacted]	[redacted]	AECO	Nov11-Jan12	92	2,500	230,000	[redacted]	[redacted]	230,000
16-Sep-10	2010-103	[redacted]	[redacted]	Stn 2	June 11, 12, 13	30	7,500	225,000	[redacted]	[redacted]	225,000
16-Sep-10	2010-104	[redacted]	[redacted]	Stn 2	June-Sept 11-13	122	2,500	305,000	[redacted]	[redacted]	305,000
29-Nov-10	2010-114	[redacted]	[redacted]	Stn 2	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
29-Nov-10	2010-115	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
15-Dec-10	2010-116	[redacted]	[redacted]	Stn 2	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
16-Dec-10	2010-117	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
26-Jan-11	2011-1	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
31-Jan-11	2011-2	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
1-Mar-11	2011-3	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
11-Mar-11	2011-4	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
14-Mar-11	2011-5	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
16-Mar-11	2011-6	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
21-Mar-11	2011-7	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
21-Mar-11	2011-8	[redacted]	[redacted]	Rockies	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
28-Mar-11	2011-9	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
30-Mar-11	2011-10	[redacted]	[redacted]	AECO	Nov11-Mar12	152	2,500	380,000	[redacted]	[redacted]	
30-Mar-11	2011-11	[redacted]	[redacted]	AECO	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
30-Mar-11	2011-12	[redacted]	[redacted]	Stn 2	Nov11-Mar12	152	5,000	760,000	[redacted]	[redacted]	
18-Apr-11	2011-13	[redacted]	[redacted]	Rockies	Nov11-Jan12	92	10,000	920,000	[redacted]	[redacted]	
18-Apr-11	2011-14	[redacted]	[redacted]	AECO	Nov11-Jan12	92	10,000	920,000	[redacted]	[redacted]	
26-Apr-11	2011-15	[redacted]	[redacted]	Rockies	Nov11-Jan12	92	10,000	920,000	[redacted]	[redacted]	
2-May-11	2011-16	[redacted]	[redacted]	Stn 2	Mar 12	31	5,000	155,000	[redacted]	[redacted]	
2-May-11	2011-16	[redacted]	[redacted]	Stn 2	Apr 12	30	5,000	150,000	[redacted]	[redacted]	
2-May-11	2011-16	[redacted]	[redacted]	Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]	
2-May-11	2011-17	[redacted]	[redacted]	AECO	Nov11-Mar12	152	2,500	380,000	[redacted]	[redacted]	
9-May-11	2011-18	[redacted]	[redacted]	Stn 2	Nov11-Jan12	92	5,000	460,000	[redacted]	[redacted]	
12-May-11	2011-19	[redacted]	[redacted]	Stn 2	Nov11-Dec11	61	5,000	305,000	[redacted]	[redacted]	
18-May-11	2011-20	[redacted]	[redacted]	Stn 2	Apr12-May12	61	5,000	305,000	[redacted]	[redacted]	
18-May-11	2011-21	[redacted]	[redacted]	Stn 2	Oct12	31	10,000	310,000	[redacted]	[redacted]	
19-May-11	2011-21	[redacted]	[redacted]	Stn 3	Oct 12	31	5,000	155,000	[redacted]	[redacted]	
20-May-11	2011-22	[redacted]	[redacted]	Stn 2	Apr 12	30	10,000	300,000	[redacted]	[redacted]	
21-May-11	2011-22	[redacted]	[redacted]	Stn 3	Apr 12	30	5,000	150,000	[redacted]	[redacted]	
24-May-11	2011-23	[redacted]	[redacted]	Stn 2	Dec 11	31	5,000	155,000	[redacted]	[redacted]	
26-May-11	2011-24	[redacted]	[redacted]	AECO	Nov11-Jan12	92	5,000	460,000	[redacted]	[redacted]	

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2011-2012 FINANCIAL HARD HEDGES (counterparty does not own option)

Date	Ref. #	Counterparty	Associated Supply	Supply or Ref. Pt.	Term	Remain Days	Daily Volume	Trade Volume	SWAP PRICE	NOTIONAL AMOUNT
31-May-11	2011-25	[redacted]	[redacted]	Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]
31-May-11	2011-25	[redacted]	[redacted]	Stn 2	May 12	31	5,000	155,000	[redacted]	[redacted]
31-May-11	2011-25	[redacted]	[redacted]	AECO	Apr 12	30	10,000	300,000	[redacted]	[redacted]
18-Aug-11	2011-26	[redacted]	[redacted]	Rockies	Apr 12	30	5,000	150,000	[redacted]	[redacted]
18-Aug-11	2011-27	[redacted]	[redacted]	Rockies	Oct 12	31	5,000	155,000	[redacted]	[redacted]
18-Aug-11	2011-28	[redacted]	[redacted]	AECO	Apr 12	30	5,000	150,000	[redacted]	[redacted]
18-Aug-11	2011-29	[redacted]	[redacted]	AECO	May 12	31	5,000	155,000	[redacted]	[redacted]
18-Aug-11	2011-30	[redacted]	[redacted]	Stn 2	Oct 12	31	5,000	155,000	[redacted]	[redacted]
19-Aug-11	2011-31	[redacted]	[redacted]	Stn 3	Oct 13	31	5,000	155,000	[redacted]	[redacted]
Total 2011-2012 Hedges								**36,650,000**	[redacted]	[redacted]

17,140,000

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

	Customer Cnt Aug-10	Revenue Aug-10	Customer Cnt Sep-10	Revenue Sep-10	Customer Cnt Oct-10	Revenue Oct-10
Total	**667,114**	$ 28,224,908.46	**666,903**	**$ 30,145,775.91**	**667,920**	$ 36,325,076.19
Oregon	598,377	25,297,172.36	598,097	27,036,701.04	599,046	32,653,745.10
Washington	68,737	2,927,736.10	68,806	3,109,074.87	68,874	3,671,331.09
Total Residential	604,425	13,552,225.17	604,327	14,684,595.91	605,297	18,553,207.32
Total Commercial	61,762	8,783,944.10	61,643	9,261,822.27	61,690	10,873,409.81
Total Industrial	596	2,156,011.18	602	2,399,390.17	600	2,658,294.66
Total Interruptible	149	2,575,017.00	149	2,654,287.07	149	3,050,744.80
Total Transportation - Commercial Firm	12	24,946.30	13	27,551.01	14	32,922.33
Total Transportation - Industrial Firm	72	451,526.29	72	444,253.57	71	465,828.84
Total Transportation - Interruptible	98	681,238.42	97	673,875.91	99	690,668.43
Unbilled Revenue		1,546,162.00		1,265,345		15,305,192.00
Agency Fees		0		-		
Net Balancing/Overrun		0		-		0
Total Gas Operating Revenue		**$ 29,771,070.46**		**$ 31,411,121.06**		**$ 51,630,268.19**

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2011-2012 Oregon PGA

V.3.a Customer count and revenue by r

	Customer Cnt Nov-10	Revenue Nov-10	Customer Cnt Dec-10	Revenue Dec-10	Customer Cnt Jan-11	Revenue Jan-11
Total	**670,720**	$ 60,847,493.70	**673,997**	$ 110,803,975.33	**675,553**	$ 130,261,937.97
Oregon	601,664	55,051,740.98	604,619	99,791,963.41	606,055	117,393,511.76
Washington	69,056	5,795,752.72	69,378	11,012,011.92	69,498	12,868,426.21
Total Residential	607,812	35,924,086.19	610,598	70,121,983.10	611,925	83,215,773.28
Total Commercial	61,980	17,577,504.47	62,476	32,781,841.85	62,701	38,779,959.92
Total Industrial	588	2,705,054.32	585	3,011,811.72	589	3,218,152.42
Total Interruptible	146	3,299,181.74	147	3,528,118.05	146	3,662,157.31
Total Transportation - Commercial Firm	14	52,092.69	-	54,282.86	-	55,372.86
Total Transportation - Industrial Firm	80	532,410.05	78	546,343.67	80	538,791.96
Total Transportation - Interruptible	100	757,164.24	100	759,594.08	99	791,730.22
Unbilled Revenue		27,306,764.88		6,028,312.92		(12,647,300.21)
Agency Fees						
Net Balancing/Overrun		0		0		0
Total Gas Operating Revenue		**$ 88,154,258.58**		**$ 116,832,288.25**		**$ 117,614,637.76**

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2011-2012 Oregon PGA

V.3.a Customer count and revenue by r

	Customer Cnt Feb-11	Revenue Feb-11	Customer Cnt Mar-11	Revenue Mar-11	Customer Cnt Apr-11	Revenue Apr-11
Total	**676,073**	$ 105,814,713.26	**676,446**	$ 103,713,545.60	**676,155**	$ 80,065,240.54
Oregon	606,493	95,449,281.55	606,814	92,837,973.16	606,504	71,725,803.14
Washington	69,580	10,365,431.71	69,632	10,875,572.44	69,651	8,339,437.40
Total Residential	612,425	66,658,183.70	612,738	64,280,873.81	612,508	48,825,550.21
Total Commercial	62,726	31,461,815.41	62,787	31,646,472.30	62,729	24,048,885.32
Total Industrial	588	3,021,611.34	586	2,966,674.16	583	2,620,485.78
Total Interruptible	144	3,338,422.75	145	3,481,954.35	145	3,246,937.30
Total Transportation - Commercial Firm	13	52,484.08	13	49,705.48	13	46,782.32
Total Transportation - Industrial Firm	79	523,538.75	79	528,644.34	79	516,292.63
Total Transportation - Interruptible	98	758,657.23	98	759,221.16	98	760,306.98
Unbilled Revenue		(465,367.32)		(9,250,889.93)		(6,734,512.43)
Agency Fees						
Net Balancing/Overrun		0		0		0
Total Gas Operating Revenue		**$ 105,349,345.94**		**$ 94,462,655.67**		**$ 73,330,728.11**

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V.3.a Customer count and revenue by r

	Customer Cnt May-11	Revenue May-11	Customer Cnt Jun-11	Revenue Jun-11	Customer Cnt Jul-11	Revenue Jul-11
Total	**675,794**	$ 63,968,973.27	**675,002**	$ 33,186,778.30	**673,702**	$ 31,451,511.20
Oregon	606,105	57,271,596.34	605,351	28,748,922.62	604,071	28,250,125.95
Washington	69,689	6,697,376.93	69,651	4,437,855.68	69,631	3,201,385.25
Total Residential	612,271	38,075,849.00	611,564	18,781,757.56	610,395	15,868,467.53
Total Commercial	62,604	19,158,642.80	62,519	9,711,808.03	62,386	9,849,818.46
Total Industrial	584	2,473,050.47	584	1,573,757.09	583	2,049,014.36
Total Interruptible	144	2,951,279.90	143	1,829,340.16	145	2,396,892.14
Total Transportation - Commercial Firm	13	41,320.70	13	37,430.38	13	33,552.46
Total Transportation - Industrial Firm	79	507,202.50	79	496,170.20	80	486,829.41
Total Transportation - Interruptible	99	761,627.90	100	756,514.88	100	766,936.84
Unbilled Revenue		(9,939,242.41)		(10,535,956.36)		(2,115,810.64)
Agency Fees						
Net Balancing/Overrun		0		52		27
Total Gas Operating Revenue		**$ 54,029,730.86**		**$ 22,650,873.94**		**$ 29,335,727.56**

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

	2011/2012 Forecasted [1]	2010 [2]	2009 [2]	2008 [2]	2007 [2]	2006 [2]
System peak demand (therms)	TO BE PROVIDED	TO BE PROVIDED	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 2011/2012**	**2010/2011**	**2009/2010**	**2008/2009**	**2007/2008**	**2006/2007**
Annual Demand (therms)	TO BE PROVIDED	TO BE PROVIDED	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 2011/2012**	**2010/2011 [1]**	**2009/2010 [1]**	**2008/2009 [1]**	**2007/2008**	**2006/2007**
Residential (therms)	TO BE PROVIDED	TO BE PROVIDED	396,259,291	403,419,481	435,212,254	395,702,901
Commercial (therms)			240,251,834	249,432,740	267,646,613	248,760,365
Industrial Firm (therms)			37,528,316	40,798,724	47,873,776	53,828,063
Industrial Interruptible (therms)			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 2011-2012	2010/2011[1]	2009/2010[1]	2008/2009[1]	2007/2008	2006/2007
November	TO BE PROVIDED	TO BE PROVIDED	22,368,074	23,287,321	25,070,006	26,190,648
December			23,309,822	24,085,841	25,827,339	26,743,482
January			23,367,602	24,512,946	25,673,977	26,116,496
February			20,987,986	21,870,814	24,358,834	25,455,856
March			23,184,270	24,107,559	25,171,242	25,226,067
April			22,392,041	22,955,784	24,947,798	24,684,614
May			23,123,968	23,728,867	24,495,722	24,762,960
June			22,206,833	22,918,154	25,098,765	25,393,815
July			22,939,571	23,582,019	25,062,882	25,303,961
August			23,388,626	23,561,523	24,974,191	25,381,941
September			22,650,442	22,875,547	25,266,815	25,298,427
October			23,442,459	23,690,099	24,441,090	24,878,078
Annual			273,361,694	281,176,475	300,388,661	305,436,346

[1] Updated for actuals

NW Natural

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2010-2011 Oregon PGA

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 2011/2012	2010/2011[1]	2009/2010[1]	2008/2009 [1]	2007/2008	2006/2007
November	TO BE PROVIDED	TO BE PROVIDED	41,313,882	33,595,043	43,762,463	38,998,713
December			83,307,972	69,578,284	79,693,312	77,658,460
January			91,849,305	106,271,855	101,915,519	103,367,842
February			61,712,656	92,276,003	99,041,078	93,338,223
March			50,195,196	78,889,604	68,842,326	62,999,517
April			47,177,713	55,529,796	67,165,395	41,287,841
May			29,743,398	26,806,441	38,226,764	27,259,608
June			18,397,682	8,694,151	17,272,557	10,263,521
July			4,870,382	2,359,545	5,532,941	3,248,045
August			354,520	0	1,811,539	1,654,431
September			3,487,037	2,714,748	3,328,953	3,096,795
October			29,634,606	11,228,575	13,438,716	18,517,788
Annual			462,044,348	487,944,044	540,031,563	481,690,784

[1] Updated for actuals

NW Natural
UM1286 PGA Portfolio Guidelines
2011-2012 Oregon PGA

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 2011/2012	**Albany**	**Astoria**	**The Dalles (OR**	**Eugene**	**Newport/LC**	**Portland**	**Salem**	**Vancouver**
November								
December								
January					TO BE PROVIDED			
February								
March								
April								
May								
June								
July								
August								
September								
October								
Annual								

2010/2011 [1]	**Albany**	**Astoria**	**The Dalles (OR**	**Eugene**	**Newport/LC**	**Portland**	**Salem**	**Vancouver**
November								
December								
January								
February								
March					TO BE PROVIDED			
April								
May								
June								
July								
August								
September								
October								

Annual

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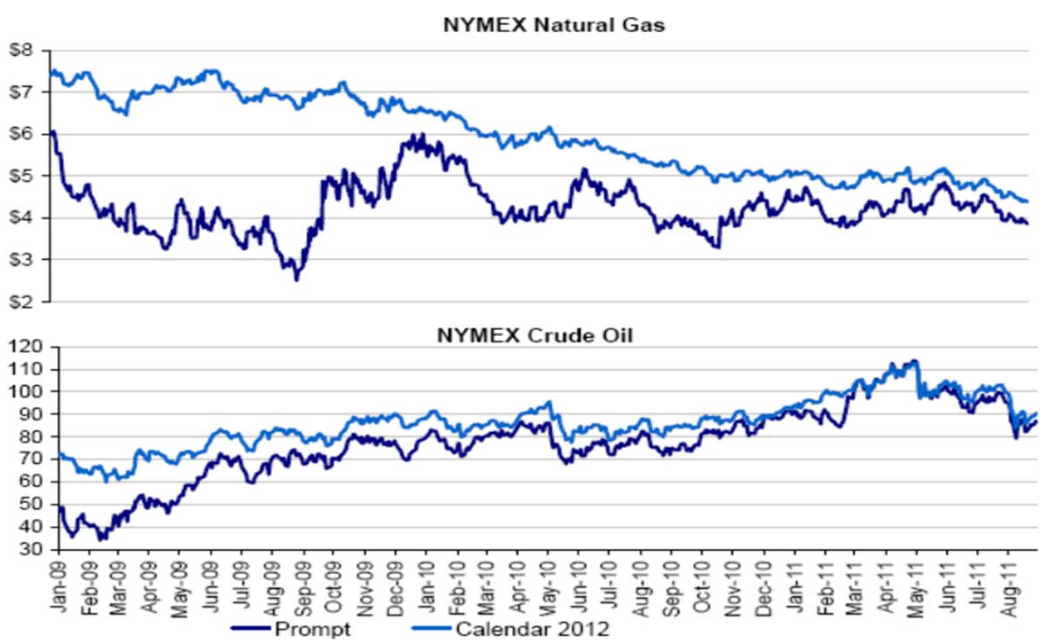
V.4 Market Information:
General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply,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

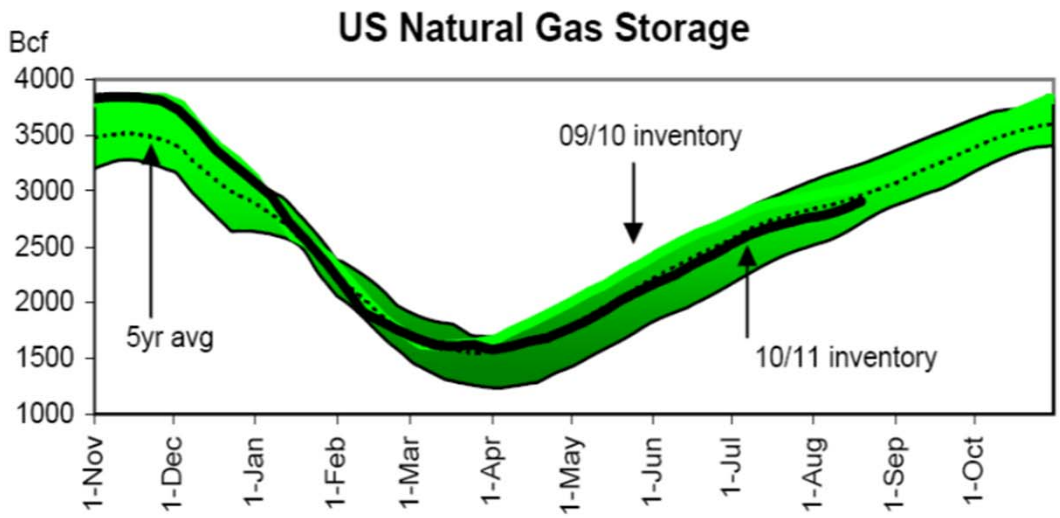
Over the last year oil prices ranged between $70 and $105/barrel. Financial crises in countries such as Greece, along with political upheavals extending across the Middle East and North Africa (most recently Libya), helped oil rebound from prices as low as $35/barrel in 2009 in spite of world-wide economic weakness. Meanwhile, ample supplies of North American natural gas have suppressed its price, demonstrating yet again the weakness if not total lack of correlation between natural gas and oil prices in recent times.

In its August 2011 Short Term Energy Outlook, EIA expects the natural gas (Henry Hub) spot price to average $4.24/Dth in 2011, a $0.15/Dth drop from the 2010 average. EIA expects natural gas prices to begin tightening in 2012 with a Henry Hub average price for the year of $4.41/Dth. A graphical depiction of the course of natural gas and oil prices since the beginning of 2009 is shown below.



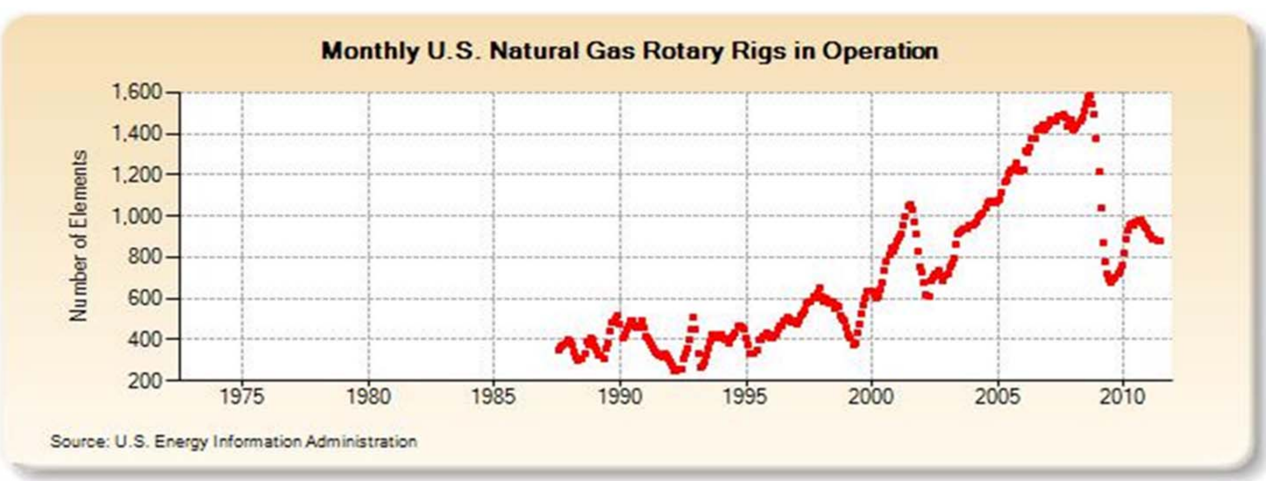
All prices are mid-market indications as of the close of NYMEX .

Nationwide, storage levels were at or near all-time highs in November 2010, but since the beginning of spring have generally tracked EIA's 5-year average. Weekly storage levels through early August 2011 are depicted in the following chart.



Hurricane activity in the Gulf of Mexico becomes less of a factor every year as burgeoning on-shore production, i.e., shale gas, is unaffected by such events. Indeed, the very recent experience with Hurricane Irene, with its load dampening effect on East Coast markets, may indicate that a new paradigm is developing in which hurricane activity is negatively correlated to gas prices. That is, the more active the season, the more likely it is that gas prices will trend lower.

Meanwhile, the sharp drop in natural gas prices a couple of years ago took its toll on drilling activity, as shown in the next graph, but this has yet to affect the availability of natural gas supplies.



Accordingly, 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, public concerns over shale gas development, specifically hydraulic fracturing (“fracking”) practices, 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.

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.

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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2011-2012 Oregon PGA

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 - NW Natural General Procedure 110 "Gas Supply Risk Management Policy".
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

Northwest Natural Gas Company
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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 2011-2012 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. In an effort to maximize the value of our gas storage, we contract with an independent energy marketing company that optimized our unused capacity when those assets are not serving the needs of our core utility customers. This optimization service produces cost savings that reduce our utility's cost of gas sold.

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 2011-2012 PGA included the following:

Facility	Max. Daily Rate (Dth/day)	lax. 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
AECO Storage:	20,000	1,985,000	March 2012
Total Firm Off-system Storage:			
Withdrawal/Vaporization	126,130	3,584,188	
TF-2 Redelivery	126,130	3,584,188	
Firm On-System Storage Plants:			
Mist (reserved for core)	260,000	9,642,470	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	440,000	11,242,470	
Total Firm Storage Resource	566,130	14,826,658	

Based on Mist core and interstate capacity allocations, Sendout recommended the following monthly core activity from that storage facility during 2011-2012 to meet the stated objectives in the IRP:

2011-2012	2011 Mist Storage Allocation		
Dth	**Core**	**Interstate**	**Total**
Working Gas	9,642,470	6,451,880	16,094,350
Withdrawal (Dth/day)	260,000	260,150	520,150

2011-2012	Mist PGA
Month	Withdrawal
November	0
December	1,727,806
January	3,093,434
February	3,188,488
March	1,632,742
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				
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

Northwest Natural Gas Company
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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)

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					
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

Northwest Natural Gas Company
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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)

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
Aug	120,926,164	$ 67,142,996.83	0.55524	405,287	$ 249,157.52	5,090,346	$ 2,304,088.84	0.45264	125,611,223	$ 69,197,928.15	0.55089
Sep	125,611,223	$ 69,197,928.15	0.55089	271,651	$ 167,341.59	13,753,326	$ 4,504,967.37	0.32755	139,092,898	$ 73,535,553.93	0.52868
Oct	139,092,898	$ 73,535,553.93	0.52868	2,687,797	$ 1,156,185.84	14,129,691	$ 4,843,395.19	0.34278	150,534,792	$ 77,222,763.28	0.51299
Nov	150,534,792	$ 77,222,763.28	0.51299	10,700,976	$ 4,746,126.96	5,072,131	$ 1,953,821.35	0.38521	144,905,947	$ 74,430,457.67	0.51365
Dec	144,905,947	$ 74,430,457.67	0.51365	7,060,485	$ 3,161,021.50	1,684,010	$ 679,171.39	0.40331	139,529,472	$ 71,948,607.56	0.51565
TOTAL 2010 ACTIVITY				61,699,394	$ 31,861,516.53	77,871,488	$ 31,164,506.59				
Jan-11	139,529,472	$ 71,948,607.56	0.51565	16,536,581	$ 7,960,155.79	4,534,550	$ 1,898,587.33	0.41869	127,527,441	$ 65,887,039.10	0.51665
Feb	127,527,441	$ 65,887,039.10	0.51665	12,055,968	$ 6,039,266.36	3,407,810	$ 1,383,289.09	0.40592	118,879,283	$ 61,231,061.83	0.51507
Mar	118,879,283	$ 61,231,061.83	0.51507	7,076,302	$ 3,517,454.99	2,822,600	$ 1,085,126.04	0.38444	114,625,581	$ 58,798,732.88	0.51296
Apr	114,625,581	$ 58,798,732.88	0.51296	5,732,315	$ 2,519,434.50	2,628,886	$ 1,088,941.38	0.41422	111,522,152	$ 57,368,239.76	0.51441
May	111,522,152	$ 57,368,239.76	0.51441	10,792,274	$ 5,520,359.51	3,546,961	$ 1,499,222.91	0.42268	104,276,839	$ 53,347,103.16	0.51159
Jun	104,276,839	$ 53,347,103.16	0.51159	278,481	$ 153,669.85	4,613,636	$ 2,022,089.98	0.43829	108,611,994	$ 55,215,523.29	0.50837
Jul	108,611,994	$ 55,215,523.29	0.50837	348,655	$ 193,744.00	20,717,911	$ 8,891,484.55	0.42917	128,981,250	$ 63,913,263.84	0.49552
				52,820,576	$ 25,904,085.00	42,272,354	$ 17,868,741.28				

Northwest Natural Gas Company
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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 unhedged discretionary sources first: i.e., spot gas first, then swing, and base load term supplies last. If storage injections exceed unhedged gas purchases, then average cost of hedged gas would be used to value the remainder of the storage injections.) 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 (priced as per tab #29) to create the end of the month cost, which then becomes the beginning of the month cost for the next month.

NW Natural

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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 Attachmenst to this Exhibit C. titled: "V.7.g. Contracts and Agreements.pdf"; "V.7.g. Svc Agreement NW Pipeline Rate Sch SGS-2F.pdf"; and "V.7.g. Svc Agreement NW Pipeline Rate Sch LS-1.pdf"

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: [signature]
Joe H. Fields
Attorney-In-Fact

1/12/9?
RES

ATTEST:

"SHIPPER"
NORTHWEST NATURAL GAS COMPANY

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

By: ______________________

By: [signature]
Name: Dwayne L. Foley
Title: Sr. Vice President

TF0370 000004P126Original Sheet No. 70
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.

TF0371 010004P126First Revised Sheet No. 71
TF04 Original Sheet No. 71
TF05Laren M. Gertsch, Director
TF06040708 050808
TF07

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.

TF0372 000004P126Original Sheet No. 72
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.

TF0373 000004P126Original Sheet No. 73
TF04
TF05Laren M. Gertsch, Director
TF06121907021897RP97-180 013108
TF077861157

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
TF07

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.

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 tc 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.

TF0355 000004P126Original Sheet No. 55
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
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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
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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:

TF0357 000004P126Original Sheet No. 57
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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.

TF0358 000004P126Original Sheet No. 58
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

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.

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.

TF0355 000004P126Original Sheet No. 55
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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:

TF0357 000004P126Original Sheet No. 57
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
TF07

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.

TF0358 000004P126Original Sheet No. 58
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

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: [signature]
Joe H. Fields
Attorney-In-Fact

1/12/9?
PES

ATTEST:

"SHIPPER"
NORTHWEST NATURAL GAS COMPANY

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

By: ____________________

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

TF0370 000004P126Original Sheet No. 70
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.

TF0371 010004P126First Revised Sheet No. 71
TF04 Original Sheet No. 71
TF05Laren M. Gertsch, Director
TF06040708 050808
TF07

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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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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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.

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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.

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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
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CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

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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.

Roth, Clayton
Friday, August 26, 2011 3:23 PM
*Gas Controllers; Tilgner, Doug; Halvorsen, Steve
Friedman, Randy; Stinson, Charlie; Brosy, Maria; Geertz, Allen; Lee, Amy; Cole, Cindy; Mott, Michael; McAnally, Robert; Timmerman, Rick; Redding, Mike; Wilkeson, Randy; Jaworski, William; Schmidt, R. Phil; Pearce, Curtis; Dady, Robin; Buker, Ted; Weber, Dave; Henderson, Dennis
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

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