Rates and Regulatory Affairs
Facsimile: 503.721.2532

NW Natural

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

October 4, 2006

NWN Advice No. OPUC 06-13A

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
550 Capitol Street, N.E., Suite 215
P.O. Box 2148
Salem, Oregon 97308-2148

Attn: Filing Center

Re: UG 174 Replacement Filing: Purchased Gas Cost and Technical Rate Adjustments (LSN Application Enclosed)

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith revisions and additions to its Tariff, P.U.C. Or. 24, as listed on the attached Table of Tariff Sheet Revisions. The Tariff sheets are stated to become effective with service on and after November 1, 2006.

This filing replaces NWN Advice No. 06-13 dated August 15, 2006 in the entirety. A request for approval on less than statutory notice is enclosed.

Introduction and Summary

The first purpose of this filing is to (a) revise rates for the effects of changes in purchased gas costs; (b) revise rates for the further effect of removing temporary rate adjustments incorporated into rates effective October 1, 2005; and (c) apply new temporary rate adjustments for inclusion in rates effective November 1, 2006. The Company revises rates for these purposes annually; its last filing was effective October 1, 2005.

The second purpose of this filing is to make temporary adjustments to base rates for (a) the costs associated with the Company's safety programs for bare steel and geo-hazard risk mitigation and for the pipeline Integrity Management Program; and (b) NW Natural's share of the construction contribution for the Coos County distribution system, pursuant to OPUC Order No. 04-702.

The third purpose of this filing is to make permanent adjustments to base rates for price elasticity effects of the rate increase reflected in this filing.

If the effects of the temporary rate increments were permanent, the result of all components of the rate changes would be an increase in the Company's revenues from its Oregon operations of about $32,910,639, or about 3.94%.

The average residential Schedule 2 bill will increase by 3.5%; the commercial Schedule 3 bill will increase by 3.8%; the commercial Schedule 31 bill will increase by 4.2%; and the bill for the average Schedule 32 industrial firm sales customer will increase by 6.4%.

The monthly bill of the average residential customer served under Schedule 2 using 56.9 therms per month will increase by $2.78. The monthly increase for the average commercial Schedule 3 customer using 242.1 therms is $11.22.

See Exhibit A of this filing for materials in support of the application of all adjustments to the applicable rate schedules.

Additional details about this combined filing are described below.

I. Purchased Gas Cost Adjustment (PGA)

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

This filing applies the methods for calculating the proposed Weighted Average Cost of Gas ("WACOG") that are set forth in Commission Order No. 05-852, entered July 14, 2005, in Docket UG 73. In addition, this filing proposes a new Winter Sales WACOG option that is available to Rate Schedules 31 and 32 sales service customers, as introduced by the Company in OPUC Advice No. 06-10, approved by the Commission at the July 27, 2006 public meeting.

This filing also applies the methods for treatment of storage inventory gas and Annual Sales WACOG calculations agreed to between the Staff and the Company.

The total effect of the PGA portion of this filing is to increase the Company's annual revenues by about $39,119,998. The effect of the change in gas costs is $16,739,547, which results in a proposed Annual Sales WACOG of $0.75951 per therm, and a proposed Winter Sales WACOG of $0.81905. The effect of the change in demand charge calculation is an increase in total demand charges of about $22,380,451, which results in a proposed firm service pipeline capacity charge of $0.13136 per therm, or $1.96 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01562 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.

II. Temporary Rate Adjustments

This portion of the filing makes a number of periodic temporary technical adjustments to rates in order to amortize credit or debit balances in its revenue and gas cost balancing accounts and certain other approved Federal Energy Regulatory Commission (FERC) deferred accounts, Accounts 186 and 191, respectively.

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

This filing does not require a review of earnings because the Company has adopted a 1/3 sharing option for purchased gas and related costs. For the purpose of recovering "other" deferred balances as outlined in ORS 757.259, the required earnings review covering the period(s) during which the deferrals in this filing occurred was performed with Staff's adoption of the 2005 Earnings Review. The total proposed average change being applied to billing rates is an increase of $3.1 million, which is below the current three percent limit of $27.0 million.

The net effect of this portion of the filing is to decrease the Company's annual revenues by $8,767,400; the effect of removing the temporary adjustments placed into rates October 1, 2005 is $11,832,359, and the effect of applying the new temporary rate adjustments is $3,064,959.

III. Base Rate Adjustments

The effect of this portion of the filing is to increase the Company's annual revenues by $2,558,041.

This portion of the filing makes a number of temporary and permanent adjustments to customer rates as follows:

Bare Steel/Geohazard. This filing applies temporary adjustments to permanent rates that relate to the Bare Steel/Geohazard programs, pursuant to a Stipulation and Agreement adopted by the Commission, as described in Schedule 177.

Integrity Management Program. This filing applies temporary adjustments to permanent rates that relate to the Integrity Management Program, pursuant to OPUC Order 04-390.

Price Elasticity. This filing applies the permanent effects of the price elasticity adjustment pursuant to a Stipulation and Agreement adopted by the Commission in Docket UG 143 and described in Schedule 163.

Coos Bay. This filing applies the permanent effects of the revenue requirement associated with the construction of the Coos County distribution system pursuant to OPUC Order No. 04-702.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after November 1, 2006.

Copies of this letter and the filing made herewith are available in the Company's main and district offices in Oregon.

Please address correspondence on this matter to me with copies to the following:

Kelley C. Miller, Staff Assistant
Rates & Regulatory Affairs
220 NW Second Avenue
Portland, Oregon 97209
Telecopier: (503) 721-2532
Telephone: (503) 226-4211, ext. 3589

Sincerely,

NW NATURAL

C. Alex Miller, Director
Regulatory Affairs and Forecasting

Attachments: Tariffs
Exhibit A

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

550 CAPITOL ST NE STE 215

SALEM, OR 97301-2551

IN THE MATTER OF THE APPLICATION OF)
NW NATURAL)
)
TO WAIVE STATUTORY NOTICE.)

UTILITY L.S.N. APPLICATION

NO. ____________________

NOTE: ATTACH EXHIBIT IF SPACE IS INSUFFICIENT

1. GENERAL DESCRIPTION OF THE PROPOSED SCHEDULE(S) ADDITION, DELETION OF CHANGE. (SCHEDULE INCLUDES ALL RATES, TOLLS AND CHARGES FOR SERVICE AND ALL RULES AND REGULATIONS AFFECTING THE SAME)

   This filing substitutes currently-proposed rate schedules and accompanying advice letter, exhibits and workpapers, as filed in NWN Advice No. OPUC 06-13, dated August 15, 2006 and docketed by the Commission as UG 174, which constitute a request to adjust currently-approved rates for gas cost and temporary (technical) adjustments.

2. APPLICANT DESIRES TO CHANGE THE SCHEDULE(S) NOW ON FILE KNOWN AND DESIGNATED AS: (INSERT SCHEDULE REFERENCE BY NUMBER, PAGE, AND ITEM)

   4th Rev. of Sheet 1-1, 4th Rev. of Sheet 2-1, 2nd Rev. of Sheet 3-3, 3rd Rev. of Sheet 19-1, Orig. Sheet 31-9, Orig. Sheet 31-10, Orig. Sheet 32-9, Orig. Sheet 32-10, Orig. Sheet 33-9, 4th Rev. of Sheet 54-1, 4th Rev. of Sheet 162-1, 3rd Rev. of Sheet 162-2, 5th Rev. of Sheet 163-1, 4th Rev. of Sheet 164-1, 4th Rev. of Sheet 176-1, 5th Rev. of Sheet 177-2, 3rd Rev. of Sheet 177-3, 2nd Rev. of Sheet 177-4, 5th Rev. of Sheet 190-1, 4th Rev. of Sheet 190-2, 3rd Rev. of Sheet 195-1, 3rd Rev. of Sheet 195-3, 2nd Rev. of Sheet 195-4, 1st Rev. of Sheet 195-5, 1st Rev. of Sheet 199-1, 1st Rev. of Sheet 199-2, 3rd Rev. of Sheet P-1, 3rd Rev. of Sheet P-2, 4th Rev. of Sheet P-3, and 6th Rev. of Sheet P-4.

3. THE PROPOSED SCHEDULE(S) SHALL BE AS FOLLOWS: (INSERT SCHEDULE REFERENCE BY NUMBER, PAGE, AND ITEM)

   5th Rev. of Sheet 1-1, 5th Rev. of Sheet 2-1, 3rd Rev. of Sheet 3-3, 4th Rev. of Sheet 19-1, 1st Rev. of Sheet 31-9, 1st Rev. of Sheet 31-10, 1st Rev. of Sheet 32-9, 1st Rev. of Sheet 32-10, 1st Rev. of Sheet 33-6, 5th Rev. of Sheet 54-1, 5th Rev. of Sheet 162-1, 4th Rev. of Sheet 162-2, 6th Rev. of Sheet 163-1, 5th Rev. of Sheet 164-1, Original Sheet 169-1, 5th Rev. of Sheet 176-1, 6th Rev. of Sheet 177-2, 4th Rev. of Sheet 177-3, 3rd Rev. of Sheet 177-4, 6th Rev. of Sheet 190-1, 5th Rev. of Sheet 190-2, 4th Rev. of Sheet 195-1, 4th Rev. of Sheet 195-3, 3rd Rev. of Sheet 195-4, 2nd Rev. of Sheet 195-5, 2nd Rev. of Sheet 199-1, 2nd Rev. of Sheet 199-2, 4th Rev. of Sheet P-1, 4th Rev. of Sheet P-2, 4th Rev. of Sheet P-3, 7th Rev. of Sheet P-4, and Original Sheet P-5.

4. REASONS FOR REQUESTING A WAIVER OF STATUTORY NOTICE:

   This substitute filing incorporates Staff's review of and recommendations to the company's currently-proposed purchased gas cost adjustment filing (UG 174).

5. REQUESTED EFFECTIVE DATE OF THE NEW SCHEDULE(S) OR CHANGES(S) 11/01/06

6. AUTHORIZED SIGNATURE:	TITLE	DATE
	Director, Regulatory Affairs & Forecasting	10/4/06

PUC USE ONLY

☐ APPROVED ☐ DENIED EFFECTIVE DATE OF APPROVED SCHEDULE(S) OR CHANGE

AUTHORIZED SIGNATURE: DATE

RATE SCHEDULE 1
GENERAL SALES SERVICE

AVAILABLE:
To all Residential and Commercial Customer classes in all territory served by the Company under the Tariff of which this Rate Schedule is a part, except that service under this Rate Schedule is not available for Standby Service to Commercial Customers. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Schedule, are subject to the provisions of **SCHEDULE X**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment including but not limited to one or any multiple or combination of the following:

(a) Non-ducted space heating equipment, including but not limited to fireplace inserts, free standing gas stoves, and room heaters;
(b) Standby space heating equipment used in residential applications, including but not limited to Natural Gas back-up to electric heat pumps,
(c) Water heating equipment used to serve single-family residential swimming pools, spas, and hot tubs;
(c) Other equipment including, but not limited to, log lighter, gas log, gas barbecue, tiki torch, Bunsen burner, Domestic cooking equipment, hobby kilns, refrigeration or Domestic clothes drying;
(d) Equipment installed for use in detached garages, shops, or outbuildings.

MONTHLY RATE: Effective: November 1, 2006 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160.**

	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment	Total Billing	
Customer Charge:	$5.00	---	---	---	---	**$5.00**	
Delivery Charge (per therm):							
Residential	$0.50455	$0.00900	$0.13136	$0.75951	$0.00451	**$1.40893**	(I)
Commercial	$0.47745	$0.00867	$0.13136	$0.75951	$(0.00046)	**$1.37653**	(I)

Minimum Monthly Bill: Customer Charge plus charges under **SCHEDULE C** and **SCHEDULE 15** (if applicable).

(continue to Sheet 1-2)

RATE SCHEDULE 2
RESIDENTIAL SALES SERVICE

AVAILABLE:
To Residential Customers in all territory served by the Company under the Tariff of which this Rate Schedule is a part. Seasonal or temporary Discontinuance of Service is allowed subject to Special Provision 1 of this Rate Schedule. The installation of Distribution Facilities, when required before service can be provided to equipment served under this Rate Schedule, are subject to the provisions of **SCHEDULE X**.

SERVICE DESCRIPTION:
Service under this Rate Schedule is Firm Sales Service to gas-fired equipment used in Residential dwellings that provide complete family living facilities in which the occupant normally cooks, eats, sleeps, and carries on the household operations incident to Domestic life, for at least one of the following purposes:

(a) Operation of ducted forced air Natural Gas space heating equipment that is the primary source for space heating requirements; and/or,
(b) Operation of fully automatic water heating equipment for primary water heating requirements.

Service under this Rate Schedule includes the use of gas for equipment installed in addition to (a) or (b).

MONTHLY RATE: Effective: November 1, 2006 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See Schedule 100 for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160.**

	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity	Temporary Adjustment	Total Billing
Customer Charge:	$6.00	---	---	---	---	**$6.00**
Volumetric Charge (per therm):	$0.43704	$0.00811	$0.13136	$0.75951	$0.00450	**$1.34052**

(I)

Minimum Monthly Bill: Customer Charge plus charges under **SCHEDULE C** or **SCHEDULE 15** (if applicable)

(continue to Sheet 2-2)

RATE SCHEDULE 3

BASIC FIRM SALES SERVICE - NON-RESIDENTIAL
(continued)

MONTHLY RATE: Effective: November 1, 2006 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160.**

FIRM SALES SERVICE CHARGES:						**Billing Rates [1]**	
Customer Charge (per month):						**$8.00**	
Volumetric Charges (per therm):	Base Rate	Base Rate Adjustment	Pipeline Capacity	Commodity Component [2]	Temporary Adjustment		
Commercial (3 CFS):	$0.34701	$0.00695	$0.13136	$0.75951	$(0.00047)	**$1.24436**	(I)
Industrial (3 IFS):	$0.31440	$0.00651	$0.13136	$0.75951	$0.00648	**$1.21826**	(I)
Standby Charge (per therm of MHDV) [3]:						**$10.00**	

[1] **SCHEDULE C** and **SCHEDULE 15** Charges shall apply, if applicable.
[2] The Commodity Component will be either Annual Sales WACOG or Monthly Incremental Cost of Gas.
[3] Applies to Standby Sales Service only.

Minimum Monthly Bill. The Minimum Monthly Bill shall be any **SCHEDULE C** and **SCHEDULE 15** Charges, plus:

(a) ***Firm Sales Service.*** Customer Charge.
(b) ***Firm Sales Standby Service.*** Customer Charge, plus Standby Service Charge.

FROZEN

RATE SCHEDULE 19
GAS LIGHT SERVICE

AVAILABLE:
In all territory served by the Company under the Tariff of which this Rate Schedule is a part for use exclusively in gas lighting devices to which Distribution Facilities were committed or installed prior to August 10, 1973.

SERVICE DESCRIPTION:
Firm unmetered gas service delivered on a continuous basis for use in gas lamps, not exceeding a rated capacity of 2.5 cubic feet per hour per Mantle or Mantle equivalent; and, only to approved installations using gas for mood or atmosphere lighting, for porch, patio or walkway lamps and for roadway or street lighting. Gas lamps installed downstream of the meter will be treated as additional equipment under the Rate Schedule appropriate for the existing service.

BILLING UNIT:
Rates for gas service under this Rate Schedule are expressed in units of the standard Mantle with a maximum rated capacity of 2.5 cubic feet per hour.

MONTHLY RATE: Effective: November 1, 2006 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

	Base Rate	Base Rate Adjustments	Temporary Adjustments	Billing Rate	
One mantle	$22.75	$0.05	$0.13	**$22.93**	(I)
All additional mantles	$22.14	$0.05	$0.13	**$22.32**	(I)
Minimum Monthly Bill: Amount based on number of mantles installed					

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

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Effective with service on
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RATE SCHEDULE 31
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS: (T)

Effective: November 1, 2006

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**. The rates for distributed generation customers are subject to **SCHEDULE 31-CHP**.

FIRM SALES SERVICE CHARGES (31 CSF) [1]:					Billing Rates	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.18494	$0.00483	$0.75951	$(0.00049)	**$0.94879**	(I)
Block 2: All additional therms	$0.16875	$0.00462	$0.75951	$(0.00049)	**$0.93239**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.13136**	(I)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.96**	(I)
INTERRUPTIBLE SALES SERVICE CHARGES (31 CSI) [1]:						
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component: [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.18494	$0.00483	$0.75951	$0.00075	**$0.95003**	(I)
Block 2: All additional therms	$0.16875	$0.00462	$0.75951	$0.00075	**$0.93363**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01562**	(I)
FIRM TRANSPORTATION SERVICE CHARGES (31 CTF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.18494	$0.00483		$(0.00695)	**$0.18282**	(R)
Block 2: All additional therms	$0.16875	$0.00462		$(0.00695)	**$0.16642**	(R)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 15.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 162 may not apply.

[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply.

(continue to Sheet 31-10)

RATE SCHEDULE 31
NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES FOR INDUSTRIAL CUSTOMER CLASS: Effective: November 1, 2006 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. **SEE SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for distributed generation customers are subject to **SCHEDULE 31-CHP**.

FIRM SALES SERVICE CHARGES (31 ISF) [1]:					Billing Rates	
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.16790	$0.00220	$0.75951	$0.00647	**$0.93608**	(I)
Block 2: All additional therms	$0.15172	$0.00198	$0.75951	$0.00647	**$0.91968**	(I)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.13136**	(I)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.96**	(I)
INTERRUPTIBLE SALES SERVICE CHARGES (31 ISI) [1]:						
Customer Charge (per month):					**$325.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component: [2]	Total Temporary Adjustments [3]		
Block 1: 1st 2,000 therms	$0.16790	$0.00220	$0.75951	$0.00771	**$0.93732**	(I)
Block 2: All additional therms	$0.15172	$0.00198	$0.75951	$0.00771	**$0.92092**	(I)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01562**	(I)
FIRM TRANSPORTATION SERVICE CHARGES (31 ITF):						
Customer Charge (per month):					**$325.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [4]		
Block 1: 1st 2,000 therms	$0.16790	$0.00220		$0.00001	**$0.17011**	(R)
Block 2: All additional therms	$0.15172	$0.00198		$0.00001	**$0.15371**	(R)

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C and Schedule 15.

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG, or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 162 may not apply.

[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply.

Issued October 4, 2006
NWN Advice No. OPUC 06-13A

Effective with service on
and after November 1, 2006

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES: Effective: November 1, 2006 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.
The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**. The rates for distributed generation customers are subject to **SCHEDULE 32-CHP**.

FIRM SALES SERVICE CHARGES (32 CSF or 32 ISF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$675.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 10,000 therms	$0.10007	$0.00132	$0.75951	$0.00647	**$0.86737**	(I)
Block 2: Next 20,000 therms	$0.08505	$0.00112	$0.75951	$0.00647	**$0.85215**	
Block 3: Next 20,000 therms	$0.06005	$0.00079	$0.75951	$0.00646	**$0.82681**	
Block 4: Next 100,000 therms	$0.03503	$0.00046	$0.75951	$0.00646	**$0.80146**	
Block 5: Next 600,000 therms	$0.02002	$0.00027	$0.75951	$0.00646	**$0.78626**	
Block 6: All additional therms	$0.01003	$0.00012	$0.75951	$0.00646	**$0.77612**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
Firm Sales Service Storage Charge (per therm of MDDV per month):					**$0.20415**	
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.13136**	
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.96**	(I)
INTERRUPTIBLE SALES SERVICE CHARGES (32 CSI or 32 ISI) [4]:						
Customer Charge (per month):					**$675.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]		
Block 1: 1st 10,000 therms	$0.10007	$0.00132	$0.75951	$0.00771	**$0.86861**	(I)
Block 2: Next 20,000 therms	$0.08505	$0.00112	$0.75951	$0.00771	**$0.85339**	
Block 3: Next 20,000 therms	$0.06005	$0.00079	$0.75951	$0.00770	**$0.82805**	
Block 4: Next 100,000 therms	$0.03503	$0.00046	$0.75951	$0.00770	**$0.80270**	
Block 5: Next 600,000 therms	$0.02002	$0.00027	$0.75951	$0.00770	**$0.78750**	
Block 6: All additional therms	$0.01003	$0.00012	$0.75951	$0.00770	**$0.77736**	(I)
Interruptible Pipeline Capacity Charge (per therm):					**$0.01562**	

[1] The Monthly Bill shall equal the sum of the Customer Charge, plus the Volumetric Charges, plus the Pipeline Capacity Charge selected by the Customer, plus any other charges that may apply from Schedule C or Schedule 15. (C)

[2] The stated rate is the Company's Annual Sales WACOG. However, the Commodity Component to be billed will be dependent on Customer's Service Type Selection and may instead be Winter Sales WACOG or Monthly Incremental Cost of Gas.

[3] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 162 may not apply.

[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments as set forth in Schedule 162 may also apply. (C)

(continue to Sheet 32-10)

Issued October 4, 2006
NWN Advice No. OPUC 06-13A

Effective with service on
and after November 1, 2006

RATE SCHEDULE 32
LARGE VOLUME NON-RESIDENTIAL SALES AND TRANSPORTATION SERVICE
(continued)

MONTHLY RATES: Effective: November 1, 2006 (T)
The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for distributed generation customers are subject to **SCHEDULE 32-CHP**.

FIRM TRANSPORTATION SERVICE CHARGES (32 CTF or 32 ITF) [1]:					**Billing Rates**	
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Total Temporary Adjustments [2]		
Block 1: 1st 10,000 therms	$0.10007	$0.00132		$0.00001	**$0.10140**	(I)
Block 2: Next 20,000 therms	$0.08505	$0.00112		$0.00001	**$0.08618**	
Block 3: Next 20,000 therms	$0.06005	$0.00079		$0.00000	**$0.06084**	
Block 4: Next 100,000 therms	$0.03503	$0.00046		$0.00000	**$0.03549**	
Block 5: Next 600,000 therms	$0.02002	$0.00027		$0.00000	**$0.02029**	
Block 6: All additional therms	$0.01003	$0.00012		$0.00000	**$0.01015**	(I)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (32 CTF or 32 ITF) [3]:						
Customer Charge (per month):					**$675.00**	
Transportation Charge (per month):					**$250.00**	
Volumetric Charges (per therm)	Base Rate	Base Rate Adjustment		Temporary Adjustments [2]		
Block 1: 1st 10,000 therms	$0.10007	$0.00132		$0.00001	**$0.10140**	(I)
Block 2: Next 20,000 therms	$0.08505	$0.00112		$0.00001	**$0.08618**	
Block 3: Next 20,000 therms	$0.06005	$0.00079		$0.00000	**$0.06084**	
Block 4: Next 100,000 therms	$0.03503	$0.00046		$0.00000	**$0.03549**	
Block 5: Next 600,000 therms	$0.02002	$0.00027		$0.00000	**$0.02029**	
Block 6: All additional therms	$0.01003	$0.00012		$0.00000	**$0.01015**	(I)

[1] For Firm Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus the Distribution Capacity Charge, plus any other charges that may apply from Schedule C or Schedule 15.

[2] Where applicable, the Account 191 Adjustments shall apply.

[3] For Interruptible Transportation Service, the Monthly Bill shall equal the sum of the Customer Charge, plus Transportation Charge, plus the Volumetric Charges, plus any other charges that may apply from Schedule C or Schedule 15.

[4] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Sales Service Temporary Adjustments (N)
as set forth in Schedule 162 may also apply. (N)

RATE SCHEDULE 33
HIGH VOLUME NON-RESIDENTIAL FIRM AND INTERRUPTIBLE TRANSPORTATION SERVICE
(continued)

MONTHLY RATE: Effective: November 1, 2006 (T)

The rates shown below may not always reflect actual billing rates. See **Schedule 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments.

FIRM TRANSPORTATION SERVICE CHARGES (33 TF)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	
Per therm, all therms		$0.00542	$0.00007	$0.00000	**$0.00549** (I)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748** (I)
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus Firm Service Distribution Capacity Charge , plus any other charges that may apply from SCHEDULE C and SCHEDULE 15.					

INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (33 TI)					
					Billing Rates
Customer Charge:					**$38,000.00**
Transportation Charge:					**$250.00**
Volumetric Charge:		Base Rate	Base Rate Adjustments	Total Temporary Adjustment [1]	(I)
Per therm, all therms		$0.00542	$0.00007	$0.00000	**$0.00549**
Minimum Monthly Bill: Customer Charge, plus Transportation Charge, plus any other charges that may apply from SCHEDULE C and SCHEDULE 15.					

[1] Where applicable, as set forth in this rate schedule, the Account 191 portion of the Temporary Adjustments as set forth in Schedule 162 shall apply.

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RATE SCHEDULE 54
EMERGENCY SALES SERVICE

AVAILABLE:
To Non-Residential Customers, in all territory served by the Company under the Tariff of which this Rate Schedule is a part, on a best efforts basis at times and in amounts determined in Company's sole judgment.

SERVICE DESCRIPTION:
Service under this Rate Schedule is for emergency purposes only. Customer must make a showing acceptable to Company that Customer's operations could not continue or that severe damage to Customer's facilities or the occupants of Customer's facilities would occur in the absence of service by Company under this schedule. Customer shall be obligated to exercise every reasonable effort to obtain and utilize an alternate supply of fuel to minimize the period that emergency service is required.

Gas supplied under this Rate Schedule will be limited to the maximum volume limits imposed on Customer by Company on an hourly or daily basis, or both, and/or as a total over the estimated period of Customer's emergency. These limits may be established by Company in verbal or written instructions given to any authorized representative of Customer. Gas taken under this Rate Schedule will not be applied to the minimum monthly bill requirements under Customer's primary Rate Schedule.

Any gas taken in excess of that permitted shall be unauthorized, subject to charges set forth in **SCHEDULE C**.

MONTHLY RATE: Effective: November 1, 2006 (T)

The rates shown in this Rate Schedule may not always reflect actual billing rates. See **SCHEDULE 100** for a list of applicable adjustments. Rates are subject to changes for purchased gas costs and technical rate adjustments. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160.**

	Base Rate	Temporary Adjustment	Billing Rate	
Usage Charge, per therm, all therms	$1.31151	$0.00649	**$1.31800**	(I)

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

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24

Fifth Revision of Sheet 162-1
Cancels Fourth Revision of Sheet 162-1

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	Schedule 54

APPLICATION TO RATE SCHEDULES:

Effective: November 1, 2006 (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	Total Temporary Adjustment	
1R		$(0.01816)	$(0.00111)	($0.00221)	**$0.00451**	(C)
1C		$(0.01816)	$(0.00111)	($0.00718)	**$(0.00046)**	
2		$(0.01816)	$(0.00111)	($0.00222)	**$0.00450**	
3 (CSF)		$(0.01816)	$(0.00111)	($0.00719)	**$(0.00047)**	
3 (ISF)		$(0.01816)	$(0.00111)	($0.00024)	**$0.00648**	
19		$(0.35)	$(0.02)	$0.00	**$0.13**	
31 (CSF)	Block 1	$(0.01816)	$(0.00111)	($0.00721)	**$(0.00049)**	
	Block 2	$(0.01816)	$(0.00111)	($0.00721)	**$(0.00049)**	
31(CTF)	Block 1	N/A	N/A	($0.00695)	**$(0.00695)**	
	Block 2	N/A	N/A	($0.00695)	**$(0.00695)**	
31 (CSI)	Block 1	$(0.01816)	$(0.00013)	($0.00708)	**$0.00075**	
	Block 2	$(0.01816)	$(0.00013)	($0.00708)	**$0.00075**	
31 (ISF)	Block 1	$(0.01816)	$(0.00111)	($0.00025)	**$0.00647**	
	Block 2	$(0.01816)	$(0.00111)	($0.00025)	**$0.00647**	
31 (ITF)	Block 1	N/A	N/A	$0.00001	**$0.00001**	
	Block 2	N/A	N/A	$0.00001	**$0.00001**	
31 (ISI)	Block 1	$(0.01816)	$(0.00013)	($0.00012)	**$0.00771**	
	Block 2	$(0.01816)	$(0.00013)	($0.00012)	**$0.00771**	(C)

(continue to Sheet 162-2)

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

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2006 (T)

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments	Total Temporary Adjustment	
32(SF)	Block 1	$(0.01816)	$(0.00111)	($0.00025)	**$0.00647**	(C)
	Block 2	$(0.01816)	$(0.00111)	($0.00025)	**$0.00647**	
	Block 3	$(0.01816)	$(0.00111)	($0.00026)	**$0.00646**	
	Block 4	$(0.01816)	$(0.00111)	($0.00026)	**$0.00646**	
	Block 5	$(0.01816)	$(0.00111)	($0.00026)	**$0.00646**	
	Block 6	$(0.01816)	$(0.00111)	($0.00026)	**$0.00646**	
32(TF)	Block 1	N/A	N/A	$0.00001	**$0.00001**	
	Block 2	N/A	N/A	$0.00001	**$0.00001**	
	Block 3	N/A	N/A	$0.00000	**$0.00000**	
	Block 4	N/A	N/A	$0.00000	**$0.00000**	
	Block 5	N/A	N/A	$0.00000	**$0.00000**	
	Block 6	N/A	N/A	$0.00000	**$0.00000**	
32(SI)	Block 1	$(0.01816)	$(0.00013)	($0.00012)	**$0.00771**	
	Block 2	$(0.01816)	$(0.00013)	($0.00012)	**$0.00771**	
	Block 3	$(0.01816)	$(0.00013)	($0.00013)	**$0.00770**	
	Block 4	$(0.01816)	$(0.00013)	($0.00013)	**$0.00770**	
	Block 5	$(0.01816)	$(0.00013)	($0.00013)	**$0.00770**	
	Block 6	$(0.01816)	$(0.00013)	($0.00013)	**$0.00770**	
32(TI)	Block 1	N/A	N/A	$0.00001	**$0.00001**	
	Block 2	N/A	N/A	$0.00001	**$0.00001**	
	Block 3	N/A	N/A	$0.00000	**$0.00000**	
	Block 4	N/A	N/A	$0.00000	**$0.00000**	
	Block 5	N/A	N/A	$0.00000	**$0.00000**	
	Block 6	N/A	N/A	$0.00000	**$0.00000**	
33(TI)		N/A	N/A	$0.00000	**$0.00000**	
33(TF)		N/A	N/A	$0.00000	**$0.00000**	
54		$(0.01816)	$(0.00111)	($0.00023)	**$0.00649**	(C)

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.

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SCHEDULE 163

SPECIAL ADJUSTMENT TO RATES PRICE ELASTICITY

PURPOSE:
To identify permanent adjustments to rates in the schedules listed below in accordance with a Stipulation and Agreement adopted by the Public Utility Commission of Oregon in Docket UG 143.

APPLICABLE:
To Residential and Commercial Customers served on the following schedules of this Tariff:

Residential	**Commercial**
Schedule 1	Schedule 1
Schedule 2	Schedule 3 (CSF)
	Schedule 31 (CSF)
	Schedule 31 (CTF)
	Schedule 31 (CSI)

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2006** (T)

The Base Adjustments stated in the above-listed rate schedules reflect the following adjustments (increase). NO FURTHER ADJUSTMENT TO RATES IS REQUIRED.

Residential Rate Schedules:	$0.00276 per therm	(C)
Commercial Rate Schedules:	$0.00124 per therm	(C)

GENERAL RULES AND REGULATIONS:
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.

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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 2
Schedule 3
Schedule 19
Schedule 31
Schedule 32
Schedule 54

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2006 (T)

Annual Sales WACOG [1]	$0.75951
Winter Sales WACOG [2]	$0.81905
Firm Sales Service Pipeline Capacity Component [3]	$0.13136
Firm Sales Service Pipeline Capacity Component [4]	$1.96
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01562

(C)

(C)

[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 Customers that request Winter Sales WACOG at the July 31 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, 2006

The above listed components shall be adjusted as follows: (T)

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

(C)

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.

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SCHEDULE 169
SPECIAL ADJUSTMENT TO RATES FOR STORAGE INVENTORIES

PURPOSE:
To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in the Company's storage inventories.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Schedule 1	Schedule 3	Schedule 31	Schedule 33
Schedule 2	Schedule 19	Schedule 32	Schedule 54

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2006

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		Schedule	Block	Account 191 Commodity Adjustment
1R		$0.02599		32(FS)	Block 1	$0.02599
1C		$0.02599			Block 2	$0.02599
2		$0.02599			Block 3	$0.02599
3 (CSF)		$0.02599			Block 4	$0.02599
					Block 5	$0.02599
3 (ISF)		$0.02599			Block 6	$0.02599
				32(FT)	Block 1	N/A
19		$0.50			Block 2	N/A
31 (CSF)	Block 1	$0.02599			Block 3	N/A
	Block 2	$0.02599			Block 4	N/A
31(CTF)	Block 1	N/A			Block 5	N/A
	Block 2	N/A			Block 6	N/A
31 (CSI)	Block 1	$0.02599		32(IS)	Block 1	$0.02599
	Block 2	$0.02599			Block 2	$0.02599
31 (ISF)	Block 1	$0.02599			Block 3	$0.02599
	Block 2	$0.02599			Block 4	$0.02599
31 (ITF)	Block 1	N/A			Block 5	$0.02599
	Block 2	N/A			Block 6	$0.02599
31 (ISI)	Block 1	$0.02599		32(IT)	Block 1	N/A
	Block 2	$0.02599			Block 2	N/A
					Block 3	N/A
					Block 4	N/A
					Block 5	N/A
					Block 6	N/A
				33(IT)		N/A
				33(FT)		N/A
				54		$0.02599

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SCHEDULE 176

ADJUSTMENTS TO RATES FOR COSTS RELATING TO SOUTH MIST PIPELINE EXTENSION PROJECT

PURPOSE:
The rate adjustments under this Schedule represent the rate treatment for the Oregon portion of the incremental cost of service relating to NW Natural's South Mist Pipeline Extension Project ("Mist Project").

The allocation of costs to customers under this Schedule is consistent with OPUC Order No. 03-507, in Docket UG 152.

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2006 (T)

The Base Adjustment in each of the following Rate Schedules includes the following amounts. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

(C)

Schedule	Adjustments
1(R)	$0.00000
1(C)	$0.00000
2	$0.00000
3 CSF	$0.00000
3 ISF	$0.00000
31C (SF/SI/TF):	
Block 1	$0.00000
Block 2	$0.00000
31I (SF/SI/TF):	
Block 1	$0.00000
Block 2	$0.00000
33 (All)	$0.00000

(C)

SPECIAL CONDITIONS:

Each Mist project phase shall be considered in service beginning on the date that NW Natural provides attestation by a corporate officer that the project meets the following minimum requirements:

(a) Completion of any operational testing required by the construction contract;
(b) Release of the plant operation to the system dispatcher for full commercial operation, and;
(c) Continuous operation for 24 hours.

(continue to Sheet 176-2)

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SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

BARE STEEL REPLACEMENT PROGRAM (continued)

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2006** (T)
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

(C)

Schedule	Block	70%	30%	Total Adjustment
1R		$0.00239	$0.00124	$0.00363
1C		$0.00239	$0.00118	$0.00357
2		$0.00239	$0.00107	$0.00346
3 (CSF)		$0.00239	$0.00086	$0.00325
3 (ISF)		$0.00239	$0.00077	$0.00316
19		$0.05	$0.00	$0.05
31 (CSF)	Block 1	$0.00239	$0.00046	$0.00285
	Block 2	$0.00239	$0.00042	$0.00281
31(CTF)	Block 1	$0.00239	$0.00046	$0.00285
	Block 2	$0.00239	$0.00042	$0.00281
31 (CSI)	Block 1	$0.00239	$0.00046	$0.00285
	Block 2	$0.00239	$0.00042	$0.00281
31 (ISF)	Block 1	$0.00000	$0.00041	$0.00041
	Block 2	$0.00000	$0.00037	$0.00037
31 (IFT)	Block 1	$0.00000	$0.00041	$0.00041
	Block 2	$0.00000	$0.00037	$0.00037
31 (ISI)	Block 1	$0.00000	$0.00041	$0.00041
	Block 2	$0.00000	$0.00037	$0.00037
32 (all)	Block 1	$0.00000	$0.00025	$0.00025
	Block 2	$0.00000	$0.00021	$0.00021
	Block 3	$0.00000	$0.00015	$0.00015
	Block 4	$0.00000	$0.00009	$0.00009
	Block 5	$0.00000	$0.00005	$0.00005
	Block 6	$0.00000	$0.00002	$0.00002
33 (all)		$0.00000	$0.00001	$0.00001
54		$0.00239	$0.00102	$0.00341

(C)

(continue to Sheet 177-3)

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SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

GEOHAZARD REPAIR AND RISK MITIGATION:
Each year, rates in the Rate Schedules listed below will be adjusted to recover the costs of geohazard repair and risk mitigation during the most recent 12-month period November 1 through (T) October 31. (T) Adjustments to rates shall be made coincident with the Company's annual Purchased Gas Adjustment (PGA) filing, or at such other time as the Commission may authorize.

TERM:
The Geohazard Repair and Risk Mitigation Program shall be in effect through December 31, 2006 or until such other time as the Commission may approve.

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2006 (T)
The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules.

Schedule	Block	Total Adjustment	
			(C)
1R		$0.00167	
1C		$0.00159	
2		$0.00145	
3 (CSF)		$0.00115	
3 (ISF)		$0.00104	
19		$0.00	
31C	Block 1	$0.00062	
	Block 2	$0.00056	
31I	Block 1	$0.00056	(N)
	Block 2	$0.00050	(N)
32 (all)	Block 1	$0.00033	
	Block 2	$0.00028	
	Block 3	$0.00020	
	Block 4	$0.00012	
	Block 5	$0.00007	
	Block 6	$0.00003	
33 (all)		$0.00002	
54		$0.00138	(C)

(continue to Sheet 177-4)

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Effective with service on
and after November 1, 2006

SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

INTEGRITY MANAGEMENT PROGRAM (IMP):

Each year, the costs of the Integrity Management Program during the most recent 12-month period November 1 through October 31, will be allocated to the Rate Schedules listed below on an equal percentage of margin basis, and within a Rate Schedule, spread on a declining block basis. Adjustments to rates shall be made coincident with the Company's annual Purchased Gas Adjustment (PGA) filing, or at such other time as the Commission may authorize. (T)

TERM:

The IMP adjustments shall be in effect through September 30, 2008 or until such other time as the Commission may approve.

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2006 (T)

The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules.

(C)

Schedule	Block	Total Adjustment
1R		$0.00396
1C		$0.00376
2		$0.00343
3 (CFS)		$0.00273
3 (IFS)		$0.00247
19		$0.00
31C	Block 1	$0.00146
	Block 2	$0.00134
31I	Block 1	$0.00132
	Block 2	$0.00119
32 (all)	Block 1	$0.00079
	Block 2	$0.00067
	Block 3	$0.00047
	Block 4	$0.00027
	Block 5	$0.00016
	Block 6	$0.00008
33 (all)		$0.00004
54		$0.00326

(N)
(N)

(C)

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SCHEDULE 190

PARTIAL DECOUPLING MECHANISM

PURPOSE:
To (a) describe the partial decoupling mechanism established in accordance with a Stipulation and Agreement adopted by the Oregon Public Utility Commission (OPUC) in Docket UG 143, Order No. 02-634, dated September 12, 2002, and later reauthorized, with modifications, in Docket UG 163, Order No. 05-934, dated August 25, 2005; and (b) identify the adjustment applicable to rates under the Rate Schedules listed below.

TERM:
This Schedule shall automatically terminate on September 30, 2009.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Residential	Commercial
Schedule 1	Schedule 1
Schedule 2	Schedule 3(SF)
	Schedule 3(TF)
	Schedule 31(SF)
	Schedule 31(SI)
	Schedule 31(TF)

ADJUSTMENT TO RATE SCHEDULES: **Effective: November 1, 2006** (T)
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Residential Rate Schedules: **$(0.00212)** per therm (C)
Commercial Rate Schedules: **$(0.00696)** per therm (C)

PARTIAL DECOUPLING DEFERRAL ACCOUNT:

1. Each month, the company will calculate the difference between weather-normalized usage and the calculated baseline usage for each Residential and Commercial Customer group. The resulting usage differential shall be multiplied by the per therm distribution margin for the applicable customer group.

   The Company shall defer and amortize, with interest, 100% of the distribution margin differential in a sub-account of Account 186. The deferral will be a credit (accruing a refund to customers) if the differential is positive, or a debit (accruing a recovery by the company) if the differential is negative.

(continue to Sheet 190-2)

SCHEDULE 190

PARTIAL DECOUPLING MECHANISM
(continued)

PARTIAL DECOUPLING DEFERRAL ACCOUNT (continued):

2. The baseline usage shall be determined from actual weather normalized usage for the Company's most recent rate case, as adjusted for any price elasticity effects since that rate case.

   The following is an example baseline usage calculation for the Residential Group:

Weather-normalized usage, divided by	330,164,716
Residential Customers, equal	450,709
Normalized use per therm per customer	733
October 1 price decrease	-10%
Usage increase due to price elasticity (-10% x -0.172)	1.72%
Estimated usage increase due to price elasticity (weather normalized usage x % of usage increase)	5,678,833
Total New Baseline Usage: (weather normalized usage plus estimated usage increase), divided by	335,843,549
customer count, equal	450,709
Reset baseline usage per therm per customer	745

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's last general rate case, Docket UG 152. The weather data is taken from the stations identified in **RULE 24**.

   Step One. For the heating season months October through May, usage is normalized by taking the difference between normal and actual heating degree days for each district using a base of 59 degrees for Residential and 58 degrees for Commercial. (C)

   Step Two. This step derives the per-therm customer variance by multiplying the heating degree-day difference by the usage coefficient of .1958 for Residential variances, and .7669 for Commercial variances.

   Step Three. The per-therm customer variance is multiplied by the appropriate customer count, by district, with the sum of the district results representing the normalized therm amount.

4. Baseline usage will be adjusted to reflect actual customers billed each month.

5. The per therm distribution margins to be used in the deferral calculation effective November 1, 2006 is $0.44703 per therm for Residential customers and $0.29977 per therm for Commercial customers. (T) (C)

(continue to Sheet 190-3)

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Effective with service on
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SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)

PURPOSE:
To describe the Weather Adjusted Rate Mechanism (WARM) adopted by the Public Utility Commission of Oregon in Docket UG 152, Order No. 03-507 entered August 22, 2003, and modified by Order No. 04-434 entered August 16, 2004.

APPLICABLE:
To Residential and Commercial Customers served on the following Rate Schedules of this Tariff:

Schedule 2	Schedule 3C (SF)

APPLICATION TO RATE SCHEDULES:
The WARM Adjustment will be applied as an adjustment to the per therm Billing Rate on applicable Residential and Commercial Customer bills issued during the WARM Period. The WARM Period covers bills that are generated based on meters read on or after December 1st and on or before May 15th. (T)

SPECIAL CONDITIONS:

1. The WARM Adjustment will apply to Customer bills that are based on applicable Residential Rate Schedule 2 or Commercial Rate Schedule 3 meters read on or after December 1st and on or before May 15th. (T)

2. Residential bills --The maximum WARM Adjustment increase that will be added to any regular monthly bill during the WARM Period will be twelve dollars ($12.00), or twenty-five percent (25%) of the usage portion of that bill, whichever is less. For any billing period in which the total monthly WARM adjustment exceeds either $12.00 or 25% of the usage, the balance of the WARM adjustment will be billed in accordance with Special Condition 5.

3. Commercial bills--The maximum WARM Adjustment increase that will be added to any regular monthly bill during the WARM Period will be thirty-five dollars ($35.00), or twenty-five percent (25%) of the usage portion of that bill, whichever is less. For any billing period in which the total monthly WARM adjustment exceeds either thirty-five dollars or 25% of the usage, the balance of the WARM adjustment will be billed in accordance with Special Condition 5.

4. The cent per therm rate applied to any customer bill during the WARM Period will never be less than the currently effective commodity rate, as shown in **SCHEDULE 164** of this Tariff.

5. Any amounts not applied to a customer's bill during the WARM Period due to the caps and floor described in Special Conditions 2, 3 and 4 will be applied to the customer's first bill issued following the end of the WARM Period, except that these amounts will be applied earlier in the following situations: (a) at the time the Company issues a closing bill on a customer account; and (b) at the time a customer changes their status in the WARM program.

(continue to Sheet 195-2)

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SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

SPECIAL CONDITIONS: (continued)

10. Upon request, the Company will provide Customer with historical billing information under both the opt-in and opt-out option for any month during the WARM Period.

11. The WARM Program is subject to other terms and conditions as set forth in the Partial Stipulation and in the Second Stipulation on record in Docket UG 152.

WARM FORMULA:

1. The Formula is: WARM Adjustment = $\sum_1^T (HDD_{n,t} - HDD_{a,t}) * B * Mrgn$

   Where:

   T = the days covered by the meter read dates for an individual customer's bill
   HDDn = the 25 year average of heating degree-days for each day (1976-2000) determined using a 25-year average temperature published by the National Oceanic and Atmospheric Administration (NOAA).
   HDDa = the actual heating degree-days for each day based on the individual customer's actual beginning and ending meter read dates
   B = the statistical coefficient relating heating degree-days to therm use determined in the most recent general rate case, or other Commission authorized proceeding.
   Mrgn = the relevant Rate Schedule margin defined as the current Billing Rate less the current Commodity Rate, Pipeline Capacity Charge, and any Temporary Adjustments.

2. For purposes of calculating the WARM Adjustment, the following shall apply:

   a. A Heating Degree Day (HDD) is defined as the extent by which the daily mean temperature falls below a specified set point on a specified day. The HDD calculation uses a set point temperature of 59 degrees Fahrenheit for the **RATE SCHEDULE 2** calculation, and 58 degrees Fahrenheit for the **RATE SCHEDULE 3** calculation;

   b. The statistical coefficients to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing November 15, 2003 are:

Schedule 2:	.1958	Schedule 3:	.7669

   c. The applicable margins to be used in the calculation of the WARM Adjustment Factor effective with the WARM Period commencing December 1, 2006 are: (T)

Schedule 2:	$0.44515	Schedule 3:	$0.35396	(I)

(continue to Sheet 195-4)

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NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24

Third Revision of Sheet 195-4
Cancels Second Revision of Sheet 195-4

SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM FORMULA: (continued)

Weather data used in the calculation of HDD for each customer shall be from the same weather stations and weather zones that are used in the determination of thermal units as set forth in **RULE 24.**

WARM BILL EFFECTS:

The following table depicts the impact on residential **RATE SCHEDULE 2** and commercial **RATE SCHEDULE 3** customer bills, respectively, at specified variations in HDDs.

	RESIDENTIAL			COMMERCIAL		
HDD Variance (+ or -)	Equivalent therms	Total Monthly WARM adjustment (+ or -) *		Equivalent therms	Total Monthly WARM adjustment (+ or -) *	
1	.1958	$0.09		.7669	$ 0.27	(I)
5	.9790	$0.44		3.8345	$ 1.36	
10	1.958	$0.87		7.669	$ 2.71	
15	2.937	$1.31		11.5035	$ 4.07	
20	3.916	$1.74		15.338	$ 5.43	
25	4.895	$2.18		19.1725	$ 6.79	
30	5.874	$2.61		23.007	$ 8.14	
35	6.853	$3.05		26.8415	$ 9.50	
40	7.832	$3.49		30.676	$10.86	
45	8.811	$3.92		34.5105	$12.22	
50	9.790	$4.36		38.345	$13.57	(I)

To calculate variations beyond or in-between specified levels, multiply the desired HDD variance by the applicable statistical coefficient, and then multiply that sum by the applicable margin.

To obtain the cent per therm effect of the Warm Adjustment, divide the WARM Adjustment by the number of therms used during the billing month.

(continue to Sheet 195-5)

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SCHEDULE 195
WEATHER ADJUSTED RATE MECHANISM
(WARM Program)
(continued)

WARM BILL EFFECTS: (continued)

Example Bill Calculation:

Here is the how the WARM adjustment is calculated for a residential **RATE SCHEDULE 2** customer where the base billing rate is $1.34052 cents per therm, the HDD variance is 50 HDDs colder than normal, and the monthly therm usage is 129 therms: (C)

HDD Differential:	Normal HDDs:	600 HDDs	
	Actual HDDs:	650 HDDs	
	HDD variance:	600 – 650 = -50 HDDs	
Equivalent Therms:	HDD variance:	-50 HDDs	
	Statistical coefficient:	.1958	
	Equivalent therms:	-50 x .1958 = -9.79 therms	
Total Warm Adjustment:	Equivalent therms:	-9.79 therms	
	Margin Rate:	$0.44515	(C)
	Total WARM Adj.:	-9.79 x $0.44515 = -$4.3580	
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	-$4.3580	
	Monthly usage:	129 therms	
	Cent/therm Adj.:	-$4.3580 ÷ 129 = -$0.03378	
Billing Rate per therm:	Current Rate/therm:	$1.34052	
	WARM cent/therm Adj.	-$0.03378	
	WARM Billing Rate:	$1.34052 + -$0.03378 = $1.30674	
Total WARM Bill:	Customer Charge:	$6.00	
	Usage Charge:	$1.30674	
	Total	(129 x $1.30674) + $6.00 = $174.57	(C)

(continue to Sheet 195-6)

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SCHEDULE 199
SPECIAL RATE ADJUSTMENT (UM 1148/UP 205)

PURPOSE

The purpose of this schedule is to reflect the effects of rate adjustments made pursuant to OPUC Order No. 04-439 in Docket UM 1148/UP 205.

APPLICABLE:

To the following Rate Schedules of this Tariff:

Schedule 1
Schedule 2
Schedule 3 (all)
Schedule 19 (all)
Schedule 31 (all)
Schedule 32 (all)
Schedule 33
Schedule 54

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2006 (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.

(C)

Schedule	Block	Temporary Adjustment	Base Rate Adjustment
1R		$0.00000	$0.00000
1C		$0.00000	$0.00000
2		$0.00000	$0.00000
3 (CFS)		$0.00000	$0.00000
3 (IFS)		$0.00000	$0.00000
19		$0.00	$0.00
31 (CFS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31(CFT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
1 (CIS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31 (IFS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31 (IFT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
31 (IIS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000

(D)
(D)

(C)

(continue to Sheet 199-2)

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Effective with service on
and after November 1, 2006

SCHEDULE 199
SPECIAL RATE ADJUSTMENT (UM 1148/UP 205)
(continued)

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2006 (T)

(C)

Schedule	Block	Temporary Adjustment	Base Rate Adjustment
32(FS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
32(FT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
32(IS)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
32(IT)	Block 1	$0.00000	$0.00000
	Block 2	$0.00000	$0.00000
	Block 3	$0.00000	$0.00000
	Block 4	$0.00000	$0.00000
	Block 5	$0.00000	$0.00000
	Block 6	$0.00000	$0.00000
33(IT)		$0.00000	$0.00000
33(FT)		$0.00000	$0.00000
54		$0.00000	$0.00000

(C)

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.

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Effective with service on
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SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS

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

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

This Schedule is an "automatic adjustment clause" as defined in *ORS 757.210(2003)*, and is subject to the customer notification requirements as described in OAR 860-022-0017. (N)

DEFINITIONS:

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

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

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

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

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

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

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SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

<u>DEFINITIONS (continued):</u>

7. <u>Estimated Annual Sales Weighted Average Cost of Gas (Annual Sales WACOG)</u>: The estimated Annual Sales WACOG is used for purposes of calculating the monthly gas cost deferral costs for entry into the PGA Balancing Account calculated by the following formula: (Normalized Purchases at Adjusted Contract Prices) divided by (last year's (i.e., July 1 – June 30) actual sales volumes, weather-normalized). (C)
   a. "Normalized Purchases" means last year's (July 1 – June 30) actual sales volumes, "weather-normalized", plus a percentage for distribution system LUFG.
   b. "Weather-normalized" means normalizing assumptions and methods set at the utility's last rate case.
   c. "Distribution system embedded LUFG" means the 5-year average of actual distribution system LUFG, not to exceed 2%.
   d. "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, 2006, the Estimated Annual Sales WACOG per therm is: $0.75951 (C)(I)

8. <u>Estimated Winter Sales WACOG</u>: The Company's weighted average Commodity Cost of Gas for the five- month period November through March, adjusted for revenue sensitive effects. (N)
   Effective November 1, 2006, the Estimated Winter Sales WACOG per therm is: $0.81905 (N)

9. <u>Estimated Non-Commodity Cost:</u> 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. <u>Estimated Non-Commodity Cost per Therm – Firm Sales Service</u>: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by last year's (i.e.; July 1 – June 30) actual Firm Sales Service volumes, weather normalized.
    Effective November 1, 2006, the Estimated Non-Commodity Cost per therm is: $0.13136 (I)(T)

11. <u>Estimated Non-Commodity Cost per Therm – Interruptible Sales Service:</u> The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by last year's (i.e.; July 1 – June 30) actual Interruptible Sales Service volumes. (D)
    Effective November 1, 2006, the Estimated Non-Commodity Cost per therm is: $0.01562 (I)

12. <u>Estimated Non-Commodity Cost per Therm – MDDV Based Sales Service:</u> The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.
    Effective November 1, 2006, the Estimated Non-Commodity Cost per Therm - MDDV Based Sales Service is: $1.96 (T) (I)

(continue to Sheet P-3)

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SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

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

15. Monthly MDDV Based Firm Sales Service Volumes (actual): 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. (T)

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. (C)

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.

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

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

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

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

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

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

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

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, 2006 through November 30, 2007 are: (C)

November 2006	$6,754,373	(C)
December 2006	$13,410,153	
January 2007	$12,633,985	
February	$10,593,818	
March	$9,535,319	
April	$7,166,669	
May	$4,730,318	
June	$2,507,809	
July	$1,121,585	
August	$1,004,680	
September	$ 2,202,844	
October	$ 6,030,248	
November	$10,014,610	
December 2006 - November 2007 ANNUAL TOTAL	$80,952,038	(C)

3. A debit or credit entry shall be made equal to 67% of the difference between the Actual
Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made (N)
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. (N)

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

(continue to Sheet P-5)

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SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

5. The cost differential entries shall be debited to the PGA Balancing Account if positive, and credited to the PGA Balancing Account if negative. (M)

6. Interest - The Company shall not compute interest on the deferrals accrued from November 2006 to October 2007, until amortization begins November 1, 2007. The Company shall computed interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission. (C) (C) (M)

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

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

TIME AND MANNER OF FILING:
Applications will be made to the Commission not less than sixty (60) days in advance of the requested effective date.

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

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

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Effective with service on
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Exhibit: A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 174

NW Natural

SUPPORTING MATERIALS

Purchased Gas and Technical Adjustments to Rates

NWN Advice No. OPUC 06-13A

October 4, 2006

NW Natural

Exhibit A
Supporting Materials

OPUC Docket No. UG 174; NWN Advice No. OPUC 06-13A

October 4, 2006

NW Natural
Rates & Regulatory Affairs
2006-2007 PGA Filing - Oregon (October 4, 2006 Refiling)
Calculation of Proposed Rates - SUMMARY

1										
2-6	Schedule	Block	10/1/2005 Billing Rates A	Net change WACOG B	Net change Demand [1] C	Proposed Rates PGA Only [1] D=A+B+C D	Net change Permanent Increments E	Net change Temporary Increments F	Elasticity Adjustment G	**Proposed 11/1/2006 Rates [1]** H=D+E+F+G H
7	1R		1.35982	0.02460	0.03670	1.42112	0.00317	(0.01812)	0.00276	1.40893
8	1C		1.32967	0.02460	0.03670	1.39097	0.00298	(0.01866)	0.00124	1.37653
9	2R		1.29167	0.02460	0.03670	1.35297	0.00271	(0.01792)	0.00276	1.34052
10	3C Firm Sales		1.19803	0.02460	0.03670	1.25933	0.00208	(0.01829)	0.00124	1.24436
11	Intentionally blank									
12	3I Firm Sales		1.15524	0.02460	0.03670	1.21654	0.00452	(0.00280)	0.00000	1.21826
13	Intentionally blank									
14	19	1st mantle	22.04	0.47	0.70	23.21	0.05	(0.34)	0.05	22.97
15	19	add'l mtls	21.43	0.47	0.70	22.60	0.05	(0.34)	0.05	22.36
16	31C Firm Sales	Block 1	1.03458	0.02460	0.03670	1.09588	0.00099	(0.01796)	0.00124	1.08015
17		Block 2	1.01822	0.02460	0.03670	1.07952	0.00089	(0.01790)	0.00124	1.06375
18	31C Firm Trans	Block 1	0.19694	0.00000	0.00000	0.19694	0.00099	(0.01635)	0.00124	0.18282
19		Block 2	0.18055	0.00000	0.00000	0.18055	0.00089	(0.01626)	0.00124	0.16642
20	31C Interr Sales	Block 1	0.93932	0.02460	0.00436	0.96828	0.00099	(0.00486)	0.00124	0.96565
21		Block 2	0.92296	0.02460	0.00436	0.95192	0.00089	(0.00480)	0.00124	0.94925
22	31I Firm Sales	Block 1	1.00758	0.02460	0.03670	1.06888	0.00108	(0.00252)	0.00000	1.06744
23		Block 2	0.99123	0.02460	0.03670	1.05253	0.00097	(0.00246)	0.00000	1.05104
24	31I Firm Trans	Block 1	0.16994	0.00000	0.00000	0.16994	0.00108	(0.00091)	0.00000	0.17011
25		Block 2	0.15356	0.00000	0.00000	0.15356	0.00097	(0.00082)	0.00000	0.15371
26	31I Interr Sales	Block 1	0.91232	0.02460	0.00436	0.94128	0.00108	0.01058	0.00000	0.95294
27		Block 2	0.89597	0.02460	0.00436	0.92493	0.00097	0.01064	0.00000	0.93654
28	32 Firm Sales	Block 1	0.93900	0.02460	0.03670	1.00030	0.00068	(0.00225)	0.00000	0.99873
29		Block 2	0.92383	0.02460	0.03670	0.98513	0.00059	(0.00221)	0.00000	0.98351
30		Block 3	0.89861	0.02460	0.03670	0.95991	0.00042	(0.00216)	0.00000	0.95817
31		Block 4	0.87338	0.02460	0.03670	0.93468	0.00024	(0.00210)	0.00000	0.93282
32		Block 5	0.85824	0.02460	0.03670	0.91954	0.00014	(0.00206)	0.00000	0.91762
33		Block 6	0.84817	0.02460	0.03670	0.90947	0.00005	(0.00204)	0.00000	0.90748
34	32 Firm Trans	Block 1	0.10118	0.00000	0.00000	0.10118	0.00068	(0.00046)	0.00000	0.10140
35		Block 2	0.08597	0.00000	0.00000	0.08597	0.00059	(0.00038)	0.00000	0.08618
36		Block 3	0.06069	0.00000	0.00000	0.06069	0.00042	(0.00027)	0.00000	0.06084
37		Block 4	0.03540	0.00000	0.00000	0.03540	0.00024	(0.00015)	0.00000	0.03549
38		Block 5	0.02023	0.00000	0.00000	0.02023	0.00014	(0.00008)	0.00000	0.02029
39		Block 6	0.01013	0.00000	0.00000	0.01013	0.00005	(0.00003)	0.00000	0.01015
40	32 Interr Sales	Block 1	0.84374	0.02460	0.00436	0.87270	0.00068	0.01085	0.00000	0.88423
41		Block 2	0.82857	0.02460	0.00436	0.85753	0.00059	0.01089	0.00000	0.86901
42		Block 3	0.80335	0.02460	0.00436	0.83231	0.00042	0.01094	0.00000	0.84367
43		Block 4	0.77812	0.02460	0.00436	0.80708	0.00024	0.01100	0.00000	0.81832
44		Block 5	0.76298	0.02460	0.00436	0.79194	0.00014	0.01104	0.00000	0.80312
45		Block 6	0.75291	0.02460	0.00436	0.78187	0.00005	0.01106	0.00000	0.79298
46	32 Interr Trans	Block 1	0.10118	0.00000	0.00000	0.10118	0.00068	(0.00046)	0.00000	0.10140
47		Block 2	0.08597	0.00000	0.00000	0.08597	0.00059	(0.00038)	0.00000	0.08618
48		Block 3	0.06069	0.00000	0.00000	0.06069	0.00042	(0.00027)	0.00000	0.06084
49		Block 4	0.03540	0.00000	0.00000	0.03540	0.00024	(0.00015)	0.00000	0.03549
50		Block 5	0.02023	0.00000	0.00000	0.02023	0.00014	(0.00008)	0.00000	0.02029
51		Block 6	0.01013	0.00000	0.00000	0.01013	0.00005	(0.00003)	0.00000	0.01015
52	54		1.26609	0.02460	0.03670	1.32739	0.00214	(0.01153)	0.00000	1.31800
53	33		0.00547	0.00000	0.00000	0.00547	0.00003	(0.00001)	0.00000	0.00549
54										
55	**Sources:**									
56	Direct Inputs		05-06 PGA							
57										
58	Rates in detail			Col F - Col B	Column G+H-C-D		Col K - Col J	Col M - Col L	Column O	
59										

60 [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 & Regulatory Affairs
2006-2007 PGA Filing - Oregon (October 4, 2006 Refiling)
PGA Effects on Average Bill by Rate Schedule

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	10/1/2005 Billing Rates E	10/1/2005 Current Average Bill F=D+(C * E) F	Proposed 11/1/2006 PGA Only Rates G	Proposed 11/1/2006 PGA Only Average Bill H=D+(C * G) H	Proposed 11/1/2006 PGA Only % Bill Change I =(H - F)/F I	Proposed 11/1/2006 Temp & Base Rates J	Proposed 11/1/2006 Temp & Base Average Bill K=D+(C * J) K	Proposed 11/1/2006 Temp & Base % Bill Change L =(K - F)/F L	Proposed 11/1/2006 Total Rates M	Proposed 11/1/2006 Total Average Bill K=D+(C * M) N	Proposed 11/1/2006 Total % Bill Change O =(N - F)/F O
1R		720,937	N/A	17.6	5.00	1.35982	28.93	1.42112	30.01	3.7%	1.34763	28.72	-0.7%	1.40893	29.80	3.0%
1C		90,499	N/A	41.2	5.00	1.32967	59.78	1.39097	62.31	4.2%	1.31523	59.19	-1.0%	1.37653	61.71	3.2%
2R		343,625,340	N/A	56.9	6.00	1.29167	79.50	1.35297	82.98	4.4%	1.27922	78.79	-0.9%	1.34052	82.28	3.5%
3C Firm Sales		155,463,822	N/A	242.1	8.00	1.19803	298.04	1.25933	312.88	5.0%	1.18306	294.42	-1.2%	1.24436	309.26	3.8%
Intentionally blank																
3I Firm Sales		3,979,172	N/A	1,228.1	8.00	1.15524	1,426.75	1.21654	1,502.03	5.3%	1.15696	1,428.86	0.1%	1.21826	1,504.15	5.4%
Intentionally blank																
19	1st mnth	29,766	N/A	124.0	22.04	22.04	22.04	23.21	23.21	5.3%	21.80	21.80	-1.1%	22.97	22.97	4.2%
19	add'l mths	0	N/A	0.0	21.43	21.43	21.43	22.60	22.60	5.5%	21.19	21.19	-1.1%	22.36	22.36	4.3%
31C Firm Sales	Block 1	26,883,444	2,000	4,560.1	325.00	1.03458	2,394.16	1.09588	2,516.76		1.01885	2,362.70		1.08015	2,485.30	
	Block 2	40,369,043	all additional			1.01822	2,606.75	1.07952	2,763.68		1.00245	2,566.37		1.06375	2,723.31	
	Total						**5,000.91**		**5,280.44**	5.6%		**4,929.07**	-1.4%		**5,208.61**	4.2%
31C Firm Trans	Block 1	0	2,000	0.0	325.00	0.19694	325.00	0.19694	325.00		0.18282	325.00		0.18282	325.00	
	Block 2	0	all additional			0.18055		0.18055			0.16642			0.16642		
	Total						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
31C Interr Sales	Block 1	4,016	2,000	0.0	325.00	0.93932	325.00	0.96828	325.00		0.93669	325.00		0.96565	325.00	
	Block 2	(1,135,187)	all additional			0.92296		0.95192			0.92029			0.94925		
	Total						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
31I Firm Sales	Block 1	6,400,995	2,000	7,671.7	325.00	1.00758	2,340.16	1.06888	2,462.76		1.00614	2,337.28		1.06744	2,459.88	
	Block 2	19,928,357	all additional			0.99123	5,621.96	1.05253	5,969.63		0.98974	5,613.51		1.05104	5,961.18	
	Total						**7,962.12**		**8,432.39**	5.9%		**7,950.79**	-0.1%		**8,421.06**	5.8%
31I Firm Trans	Block 1	73,509	2,000	8,773.0	325.00	0.16994	664.88	0.16994	664.88		0.17011	665.22		0.17011	665.22	
	Block 2	242,320	all additional			0.15356	1,040.06	0.15356	1,040.06		0.15371	1,041.08		0.15371	1,041.08	
	Total						**1,704.94**		**1,704.94**	0.0%		**1,706.30**	0.1%		**1,706.30**	0.1%
31I Interr Sales	Block 1	268,535	2,000	3,426.9	325.00	0.91232	2,149.64	0.94128	2,207.56		0.92398	2,172.96		0.95294	2,230.88	
	Block 2	595,039	all additional			0.89597	1,278.46	0.92493	1,319.78		0.90758	1,295.03		0.93654	1,336.35	
	Total						**3,428.10**		**3,527.34**	2.9%		**3,467.99**	1.2%		**3,567.23**	4.1%
32 Firm Sales	Block 1	11,286,946	10,000	44,813.7	675.00	0.93900	10,065.00	1.00030	10,678.00		0.93743	10,049.30		0.99873	10,662.30	
	Block 2	16,351,271	20,000			0.92383	18,476.60	0.98513	19,702.60		0.92221	18,444.20		0.98351	19,670.20	
	Block 3	6,939,889	20,000			0.89861	13,311.74	0.95991	14,219.82		0.89687	13,285.96		0.95817	14,194.04	
	Block 4	11,985,277	100,000			0.87338		0.93468			0.87152			0.93282		
	Block 5	5,599,809	600,000			0.85824		0.91954			0.85632			0.91762		
	Block 6	0	all additional			0.84817		0.90947			0.84618			0.90748		
	Total						**41,853.34**		**44,600.42**	6.6%		**41,779.46**	-0.2%		**44,526.54**	6.4%
32 Firm Trans	Block 1	1,968,870	10,000	72,830.7	675.00	0.10118	1,686.80	0.10118	1,686.80		0.10140	1,689.00		0.10140	1,689.00	
	Block 2	3,588,546	20,000			0.08597	1,719.40	0.08597	1,719.40		0.08618	1,723.60		0.08618	1,723.60	
	Block 3	2,815,246	20,000			0.06069	1,213.80	0.06069	1,213.80		0.06084	1,216.80		0.06084	1,216.80	
	Block 4	6,367,246	100,000			0.03540	808.21	0.03540	808.21		0.03549	810.26		0.03549	810.26	
	Block 5	8,857,246	600,000			0.02023		0.02023			0.02029			0.02029		
	Block 6	0	all additional			0.01013		0.01013			0.01015			0.01015		
	Total						**5,428.21**		**5,428.21**	0.0%		**5,439.66**	0.2%		**5,439.66**	0.2%
32 Interr Sales	Block 1	19,146,615	10,000	72,568.4	675.00	0.84374	9,112.40	0.87270	9,402.00		0.85527	9,227.70		0.88423	9,517.30	
	Block 2	28,295,262	20,000			0.82857	16,571.40	0.85753	17,150.60		0.84005	16,801.00		0.86901	17,380.20	
	Block 3	16,715,066	20,000			0.80335	16,067.00	0.83231	16,646.20		0.81471	16,294.20		0.84367	16,873.40	
	Block 4	31,035,117	100,000			0.77812	17,560.92	0.80708	18,214.50		0.78936	17,814.59		0.81832	18,468.17	
	Block 5	24,708,500	600,000			0.76298		0.79194			0.77416			0.80312		
	Block 6	20,301,612	all additional			0.75291		0.78187			0.76402			0.79298		
	Total						**59,311.72**		**61,413.30**	3.5%		**60,137.49**	1.4%		**62,239.07**	4.9%
32 Interr Trans	Block 1	3,875,760	10,000	284,418.9	675.00	0.10118	1,686.80	0.10118	1,686.80		0.10140	1,689.00		0.10140	1,689.00	
	Block 2	6,997,120	20,000			0.08597	1,719.40	0.08597	1,719.40		0.08618	1,723.60		0.08618	1,723.60	
	Block 3	5,384,515	20,000			0.06069	1,213.80	0.06069	1,213.80		0.06084	1,216.80		0.06084	1,216.80	
	Block 4	19,602,073	100,000			0.03540	3,540.00	0.03540	3,540.00		0.03549	3,549.00		0.03549	3,549.00	
	Block 5	43,015,238	600,000			0.02023	2,719.29	0.02023	2,719.29		0.02029	2,727.36		0.02029	2,727.36	
	Block 6	71,298,456	all additional			0.01013		0.01013			0.01015			0.01015		
	Total						**10,879.29**		**10,879.29**	0.0%		**10,905.76**	0.2%		**10,905.76**	0.2%
54		0	N/A	0.0	N/A	1.26609	N/A	1.32739	N/A	N/A	1.25670	N/A	N/A	1.31800	N/A	N/A
33		0	N/A	0.0	38,000.00	0.00547	38,000.00	0.00547	38,000.00	0.0%	0.00549	38,000.00	0.0%	0.00549	38,000.00	0.0%
Totals		963,675,287														
		0														

Sources:

Direct Inputs	▨ per Tariff	▨ per Tariff	▨		
Rates in summary	▨	Column A ▨	Column D ▨	Cols A+E+F+G ▨	Column H ▨

[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 & Regulatory Affairs
2006-2007 PGA Filing - Oregon
PGA Effects on Revenue

1		**Amount**	**Reference**
2	**Purchased Gas Cost Adjustment (PGA)**		
3			
4	Gas Cost Change	$16,739,547	2006_07 PGA Oregon JMR_FPF Exhibits V05 with Sept 29 60 day strip With Hedges and integrated data Oct 4 2006 112pm.xls
5			
6	Capacity Cost Change	22,380,451	2006_07 PGA Oregon JMR_FPF Exhibits V05 with Sept 29 60 day strip With Hedges and integrated data Oct 4 2006 112pm.xls
7			
8	**Total PGA Change**	39,119,998	
9			
10	**Temporary Rate Adjustments**		
11			
12	Proposed Temporary Increments	3,064,959	"NWN AL 2006-07 Oregon PGA re-filing.xls" on tab "Allocation equal ¢ per therm", row 4 col A through col Y; plus
13			tab "Allocation equal % of margin", row 4 column F
14	Removal of Current Temporary Increments	11,832,359	2005-2006 PGA filing
15			
16	**Total Net Temporary Rate Adjustment**	(8,767,400)	
17			
18	**Base Rate Adjustments**		
19			
20	Proposed Safety Program Costs	4,591,000	NWN/A Page 22 of 30
21			
22	Removal of Current Safety Program Costs	(3,081,000)	2005-2006 PGA filing
23			
24	Coos Bay Adjustment	(123,563)	Coos Bay workpaper
25			
26	Price Elasticity Adjustment	1,171,604	"NWN AL 2006-07 Oregon PGA re-filing.xls" on tab "Elasticity", row 46
27			
28	**Total Net Base Rate Adjustment**	2,558,041	
29			
30			
31	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**$32,910,639**	
32			
33			
34			
35	2005 Oregon Earnings Test Normalized Total Revenues	835,107,000	
36			
37	Affect of this filing, as a percentage change (line 31÷ line 35)	3.94%	

NW Natural
Rates and Regulatory Affairs
2006-2007 PGA Filing - Oregon
Basis for Revenue Related Costs

1		Twelve Months Ended 06/30/05		
2				
3	Total Billed Gas Sales Revenues	900,970,946		
4	Total Oregon Revenues	907,763,635		
5				
6	Regulatory Commission Fees [1]	2,269,409	0.250%	Statutory rate
7	City License and Franchise Fees	21,834,896	2.405%	Line 7 ÷ Line 4
8	Unbilled Franchise Accrual	(35,128)	-0.004%	Line 8 ÷ Line 4
9	Net Uncollectible Expense	3,582,825	0.395%	Line 9 ÷ Line 4
10				
11	Total	27,652,002	**3.046%**	Sum lines 6-9
12				
13				
14	**Note:**			
15	[1] Dollar figure is set at statutory level of 0.25% times Total Oregon Revenues (line 4)			
16				
17				
18				

NW NATURAL

Summary of Commodity and Non-Commodity Charges

OREGON

	(a)		(b) Present Demand	(c) Proposed Demand	(d) Proposed Change
1	*Cents Per Therm Firm Non-Commodity Cost---------------------------*		9.196	12.736	3.540
2	*After Revenue Sensitive Effects--------------*		9.466	13.136	3.670
3	*Cents Per Therm Int. Non-Commodity Cost---------------------------*		1.094	1.515	0.421
4	*After Revenue Sensitive Effects--------------*		1.126	1.562	0.436
4	*Firm Non-Commodity Cost - per Therm of MDDV--------------------------*		1.370	1.897	0.527
5	*After Revenue Sensitive Effects--------------*		1.410	1.960	0.550
	CURRENT AND PROPOSED ANNUAL SALES WACOG	Current Sales Wacog	Proposed Sales Wacog	Proposed Difference in Wacog	
6	***A. Before Revenue Sensitive***	**71.395**	**73.637**	**2.2423**	
7	***B. After Revenue Sensitiv***	**73.491**	**75.951**	**2.4598**	
8					
9					
10					
	CURRENT AND PROPOSED WINTER SALES WACOG	Current Winter Sales Wacog	Proposed Winter Sales Wacog		
11	***A. Before Revenue Sensitive***	**-**	**79.410**		
12	***B. After Revenue Sensitiv***	**-**	**81.905**		
13					
14					
15					
16					

NW Natural Gas

Derivation of Oregon per Therm Non-Commodity Charges

1	System Demand	$87,668,967
2	Oregon Allocation Factor	92.3%
3	Oregon Demand	$80,952,038
4	Oregon Firm Sales	623,697,347
5	Oregon Interruptible Sales	100,194,692
6	Demand Charges Generated by Proposed Rates	80,952,038
7	Current Demand Per Therm before Rev Sens	$0.09196
8	Current Interruptible Demand after Rev Sens	$0.01094
9	Proposed Firm Demand Charge Per Therm-before Rev Sens	$0.12736
10	Proposed Oregon Int. Demand per Therm before Rev Sens	$0.01515
11	Proposed Firm Demand Charge Per Therm after Rev Sens	$0.13136
12	Proposed Oregon Int. Demand per Therm after sensitive	$0.01562
13		
14	Current Firm Demand after Revenue Sensitive	$0.09466
15	Current Int. Demand after Revenue Sensitive	$0.01520
16	Current MDDV Demand Charge	$1.37
17	Current MDDV Demand Charge after Rev. Sensitive	$1.41
18	Percent Change in Demand	38.5%
19	Proposed MDDV Demand Charge	$1.90
20	Proposed MDDV Demand Charge after Rev. Sensitive	$1.96

NORTHWEST NATURAL

2006-07 Cost of Gas

Oregon - System

	2006: Nov	2006: Dec	2007: Jan	2007: Feb	2007: Mar	2007: Apr	2007: May	2007: Jun	2007: Jul	2007: Aug	2007: Sep	2007: Oct	Annual
Contract Commodity Gas Costs	$61,602,143	$75,668,596	$62,581,914	$56,299,510	$66,269,676	$48,521,800	$33,817,430	$20,519,785	$11,686,670	$11,534,447	$18,832,132	$42,750,524	$510,084,626
Annual Penalty Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Contract Reservation Charges	$354,000	$365,800	$365,800	$330,400	$365,800	$0	$0	$0	$0	$0	$0	$0	$1,781,800
Pipeline Volumetric Charges	$306,616	$329,587	$89,541	$88,925	$96,280	$79,882	$56,279	$32,134	$22,634	$19,565	$31,351	$68,833	$1,221,628
Variable Storage Costs	$0	$0	$0	$20,037	$0	$0	$0	$0	$0	$0	$0	$0	$20,037
Commodity Gas Cost from Storage	$2,986,472	$17,125,436	$24,481,499	$19,481,837	$4,906,344	$514,150	$141,863	$137,287	$141,863	$141,863	$137,287	$141,863	$70,337,765
Storage Withdrawal Fuel Cost	$17,380	$91,032	$125,203	$106,769	$22,465	$2,550	$2,635	$2,550	$2,635	$2,635	$2,550	$2,635	$381,040
Total Commodity Cost	$65,266,611	$93,580,451	$87,643,958	$76,327,479	$71,660,564	$49,118,382	$34,018,207	$20,691,756	$11,853,802	$11,698,510	$19,003,320	$42,963,855	$583,826,897
System Pipeline Demand Charges	$5,777,160	$5,873,381	$7,503,024	$7,058,711	$7,503,024	$7,354,920	$7,503,024	$7,354,920	$7,503,024	$7,503,024	$7,354,920	$7,503,024	$85,792,154
System Storage Demand Charges *	$138,131	$142,736	$162,745	$146,995	$162,745	$157,495	$162,745	$157,495	$162,745	$162,745	$157,495	$162,745	$1,876,813
Total System Demand Charges	$5,915,291	$6,016,117	$7,665,768	$7,205,706	$7,665,768	$7,512,414	$7,665,768	$7,512,414	$7,665,768	$7,665,768	$7,512,414	$7,665,768	$87,668,967
Total Gas Available to Serve Load	96,927,508	127,101,575	119,903,061	101,648,421	93,042,227	71,728,907	49,976,214	30,201,023	17,611,758	17,006,041	27,336,607	61,650,330	814,133,672
Storage Deliveries	4,844,254	27,841,100	39,778,099	29,697,100	7,932,990	809,738	217,000	210,000	217,000	217,000	210,000	217,000	112,191,280
Pipeline Commodity at Receipt Points	92,083,255	99,260,475	80,124,962	71,951,321	85,109,237	70,919,169	49,759,214	29,991,023	17,394,758	16,789,041	27,126,607	61,433,330	701,942,392
Pipeline Fuel Use	2,381,594	2,632,384	1,901,276	1,704,241	2,072,822	1,841,643	1,384,629	843,993	519,136	526,588	727,839	1,568,673	18,104,817
Pipeline Gas Arriving at City Gate	89,701,661	96,628,091	78,223,686	70,247,081	83,036,415	69,077,526	48,374,585	29,147,031	16,875,622	16,262,453	26,398,768	59,864,657	683,837,575
Storage Gas Deliveries	4,844,254	27,841,100	39,778,099	29,697,100	7,932,990	809,738	217,000	210,000	217,000	217,000	210,000	217,000	112,191,280
Total Gas At Citygate (Storage and Pipeline)	94,545,914	124,469,191	118,001,785	99,944,181	90,969,405	69,887,264	48,591,585	29,357,031	17,092,622	16,479,453	26,608,768	60,081,657	796,028,855
Purchases WACOG	$0.69032	$0.75184	$0.74273	$0.76370	$0.78774	$0.70282	$0.70008	$0.70483	$0.69350	$0.70988	$0.71418	$0.71509	$0.73342
Unaccounted for Gas	379,007	499,298	473,299	400,708	364,629	279,879	194,270	116,948	67,645	65,180	105,900	240,461	3,187,224
Load Served	94,166,907	123,969,893	117,528,486	99,543,473	90,604,776	69,607,385	48,397,314	29,240,083	17,024,977	16,414,273	26,502,869	59,841,196	792,841,631
Annual Sales WACOG	$0.69309	$0.75486	$0.74573	$0.76678	$0.79091	$0.70565	$0.70289	$0.70765	$0.69626	$0.71270	$0.71703	$0.71796	$0.73637
Annual Sales WACOG After Rev v	$0.71487	$0.77858	$0.76915	$0.79087	$0.81576	$0.72782	$0.72498	$0.72988	$0.71813	$0.73509	$0.73956	$0.74052	$0.75951
Average Unaccounted for	0.00402												
			58099404.81										$501,543,087

*** SGS, LS-1**

NW Natural

Derivation of Winter Sales WACOG - OREGON
$/Dth

Winter Wacog Calculation

	NIT Forward Strip	Average Nov-Mar	Annual Average	Ratio N-M to Average	Oregon Annual WACOG	Oregon Winter WACOG	Oregon Annual Sales WACOG after rev sens	Oregon Winter Sales WACOG after rev sens
Nov	$6.8197	$8.1627	$7.5693	$1.0784	$0.73637	$0.79410	$0.75951	$0.81905
Dec	$8.1514							
Jan	$8.6294							
Feb	$8.6706							
Mar	$8.5426							
Apr	$6.9950							
May	$6.9318							
Jun	$7.0331							
Jul	$7.1212							
Aug	$7.2219							
Sep	$7.3141							
Oct	$7.4012							

NW Natural

Demand Charges by Transport

Transport	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
ABC>YahkANG	$298,388	$298,388	$298,388	$298,388	$298,388	$298,388	$298,388	$298,388	$298,388	$298,388	$298,388	$298,388	$3,580,658
AECO>ABCNova	$562,890	$562,890	$562,890	$562,890	$562,890	$562,890	$562,890	$562,890	$562,890	$562,890	$562,890	$562,890	$6,754,678
EngageTStrn	$55,800	$50,400	$55,800	$54,000	$55,800	$54,000	$55,800	$55,800	$54,000	$55,800	$54,000	$55,800	$657,000
Hunt>CheNWP1	$1,401,497	$1,265,868	$1,401,497	$1,356,287	$1,401,497	$1,356,287	$1,401,497	$1,401,497	$1,356,287	$1,401,497	$861,332	$890,043	$15,495,085
Junc>PlyNWP	$3,005,794	$2,714,910	$3,005,794	$2,908,833	$3,005,794	$2,908,833	$3,005,794	$3,005,794	$2,908,833	$3,005,794	$1,847,300	$1,908,877	$33,232,347
KBPipeline	$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
Kings>StanGT	$574,830	$574,830	$574,830	$574,830	$574,830	$574,830	$574,830	$574,830	$574,830	$574,830	$574,830	$574,830	$6,897,954
Kingsv>Hunt	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SouthernXng	$681,409	$681,409	$681,409	$681,409	$681,409	$681,409	$681,409	$681,409	$681,409	$681,409	$681,409	$681,409	$8,176,912
TempCapacity	$128,143	$115,742	$128,143	$124,009	$128,143	$124,009	$128,143	$128,143	$124,009	$128,143	$124,009	$128,143	$1,508,779
TF-2 JP	$40,808	$40,808	$40,808	$40,808	$40,808	$40,808	$40,808	$40,808	$40,808	$40,808	$25,916	$25,916	$459,916
TF-2 Plymth	$17,481	$17,481	$17,481	$17,481	$17,481	$17,481	$17,481	$17,481	$17,481	$17,481	$11,102	$11,102	$197,015
Westcoast	$717,296	$717,296	$717,296	$717,296	$717,296	$717,296	$717,296	$717,296	$717,296	$717,296	$717,296	$717,296	$8,607,553
Grand Total	$7,503,024	$7,058,711	$7,503,024	$7,354,920	$7,503,024	$7,354,920	$7,503,024	$7,503,024	$7,354,920	$7,503,024	$5,777,160	$5,873,381	$85,792,154

ABC>YahkANG	ANG Pipeline
AECO>ABCNova	Nova Gas Transmission
EngageTStrn	Engage T South Transfer
Hunt>CheNWP1	NW Pipeline from British Columbia
Junc>PlyNWP	NW Pipeline from Alberta--Rockies
KBPipeline	KB pipeline to Beaver
Kings>StanGT	Gas Transmission North (GTN)
Kingsv>Hunt	NWP no charges
SouthernXng	Southern Crossing
TempCapacity	Temporary Capacity
TF-2 JP	Jackson Prairie TF-2
TF-2 Plymth	Plymouth LNG TF-2
Westcoast	Westcoast Pipeline BC

NW Natural
PGA 2006-7

Storage Costs and Volumes

Storage	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
Gasco	62,000	2,326,000	62,000	60,000	62,000	60,000	62,000	62,000	60,000	62,000	60,000	62,000	3,000,000
	$32,549	$1,221,127	$32,549	$31,499	$32,549	$31,499	$32,549	$32,549	$31,499	$32,549	$31,499	$32,549	$1,574,970
	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499	$0.52499
JP	1,258,452	7,825,100	1,518,990	599,738	0	0	0	0	0	0	0	0	11,202,280
	$790,786	$4,917,136	$954,503	$376,863	$0	$0	$0	$0	$0	$0	$0	$0	$7,039,289
	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838	$0.62838
Mist	38,302,647	10,442,000	6,197,000	0	0	0	0	0	0	0	4,634,254	27,624,100	87,200,000
	$23,548,850	$6,419,846	$3,809,978	$0	$0	$0	$0	$0	$0	$0	$2,849,185	$16,983,573	$53,611,432
	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481	$0.61481
NwpStr	155,000	4,315,000	155,000	150,000	155,000	150,000	155,000	155,000	150,000	155,000	150,000	155,000	6,000,000
	$109,314	$3,043,154	$109,314	$105,788	$109,314	$105,788	$109,314	$109,314	$105,788	$109,314	$105,788	$109,314	$4,231,500
	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525	$0.70525
Plymouth	0	4,789,000	0	0	0	0	0	0	0	0	0	0	4,789,000
	$0	$3,880,575	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,880,575
	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031	$0.81031
Grandtotal	39,778,099	29,697,100	7,932,990	809,738	217,000	210,000	217,000	217,000	210,000	217,000	4,844,254	27,841,100	112,191,280
	$24,481,499	$19,481,837	$4,906,344	$514,150	$141,863	$137,287	$141,863	$141,863	$137,287	$141,863	$2,986,472	$17,125,436	$70,337,765
	$0.61545	$0.65602	$0.61847	$0.63496	$0.65375	$0.65375	$0.65375	$0.65375	$0.65375	$0.65375	$0.61650	$0.61511	$0.62695

NW Natural

Oregon PGA 2006-7

Commodity Cost and Takes by Supply

Recent Hedge

Fixed Price in Original Filing

Supply		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
Albertaspot		5,490,602	4,539,641	10,467,003	8,470,477	26,994	0	0	0	0	6,742,612	19,835,696	24,603,925	80,176,951
		$4,723,181	$3,919,617	$8,863,040	$5,760,687	$18,088	$0	$0	$0	$0	$4,795,683	$13,193,713	$19,890,305	$61,164,314
		$0.86023	$0.86342	$0.84676	$0.68009	$0.67009	$0.67947	$0.68748	$0.69648	$0.70563	$0.71125	$0.66515	$0.80842	$0.76287
BC Spot		0	0	7,874	13,600	0	0	0	0	0	573,732	20,758	22,190	638,154
		$0	$0	$6,667	$9,249	$0	$0	$0	$0	$0	$408,067	$13,807	$17,939	$455,729
		$0.86023	$0.86342	$0.84676	$0.68009	$0.67009	$0.67947	$0.68748	$0.69648	$0.70563	$0.71125	$0.66515	$0.80842	$0.71414
BPCan2BCS2BS		1,550,000	1,400,000	1,550,000	1,500,000	1,550,000	1,500,000	37,500	0	0	1,550,000	1,500,000	1,550,000	13,687,500
	$6.580	$1,019,900	$921,200	$1,019,900	$987,000	$1,019,900	$987,000	$24,675	$0	$0	$1,019,900	$987,000	$1,019,900	$9,006,375
		$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800	$0.65800
BPCanABSCBS		3,100,000	2,800,000	3,100,000	3,000,000	3,100,000	569,376	3,100,000	3,100,000	3,000,000	3,100,000	3,000,000	3,100,000	34,069,376
	$5.135	$1,591,850	$1,437,800	$1,591,850	$1,540,500	$1,591,850	$292,374	$1,591,850	$1,591,850	$1,540,500	$1,591,850	$1,540,500	$1,591,850	$17,494,624
		$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350	$0.51350
BPCANABSTBS		3,100,000	2,800,000	3,100,000	3,000,000	3,100,000	3,000,000	1,350,000	0	0	2,407,068	3,000,000	3,100,000	27,957,068
		$2,675,114	$2,427,768	$2,648,206	$2,098,500	$2,148,858	$2,109,930	$961,362	$0	$0	$1,781,519	$2,045,910	$2,526,934	$21,424,101
		$0.86294	$0.86706	$0.85426	$0.69950	$0.69318	$0.70331	$0.71212	$0.72219	$0.73141	$0.74012	$0.68197	$0.81514	$0.76632
BPCanBCS2BS		1,240,000	1,120,000	1,240,000	1,200,000	1,240,000	1,200,000	540,000	0	0	1,240,000	1,200,000	1,240,000	11,460,000
	$5.960	$739,040	$667,520	$739,040	$715,200	$739,040	$715,200	$321,840	$0	$0	$739,040	$715,200	$739,040	$6,830,160
		$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600	$0.59600
BURLABSTBS		4,650,000	4,200,000	4,650,000	4,500,000	4,650,000	4,500,000	2,025,000	0	0	4,650,000	4,500,000	4,650,000	42,975,000
		$4,012,671	$3,641,652	$3,972,309	$3,147,750	$3,223,287	$3,164,895	$1,442,043	$0	$0	$3,441,558	$3,068,865	$3,790,401	$32,905,431
		$0.86294	$0.86706	$0.85426	$0.69950	$0.69318	$0.70331	$0.71212	$0.72219	$0.73141	$0.74012	$0.68197	$0.81514	$0.76569
CoralABSTBS		3,100,000	2,800,000	3,100,000	3,000,000	3,100,000	0	1,242,161	1,932,839	3,000,000	3,100,000	3,000,000	3,100,000	30,475,000
	$6.780	$2,101,800	$1,898,400	$2,101,800	$2,034,000	$2,101,800	$0	$842,185	$1,310,465	$2,034,000	$2,101,800	$2,034,000	$2,101,800	$20,662,050
		$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800	$0.67800
CoralBCS2BS		3,100,000	2,800,000	3,100,000	3,000,000	3,100,000	75,000	0	3,100,000	3,000,000	3,100,000	3,000,000	3,100,000	30,475,000
	$7.025	$2,177,750	$1,967,000	$2,177,750	$2,107,500	$2,177,750	$52,688	$0	$2,177,750	$2,107,500	$2,177,750	$2,107,500	$2,177,750	$21,408,688
		$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250	$0.70250
CoralRKBS		1,550,000	1,400,000	1,550,000	0	0	0	0	0	0	0	1,500,000	1,550,000	7,550,000
	$7.930	$1,229,150	$1,110,200	$1,229,150	$0	$0	$0	$0	$0	$0	$0	$1,189,500	$1,229,150	$5,987,150
		$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300	$0.79300
CoralRKSW		1,550,000	1,400,000	1,550,000	0	0	0	0	0	0	0	1,500,000	1,550,000	7,550,000
		$1,292,964	$1,171,912	$1,277,975	$0	$0	$0	$0	$0	$0	$0	$940,650	$1,205,497	$5,888,998
		$0.83417	$0.83708	$0.82450	$0.64937	$0.63691	$0.64580	$0.65090	$0.65919	$0.66830	$0.66818	$0.62710	$0.77774	$0.78000
HUSKYABSTBS		3,100,000	2,800,000	3,100,000	3,000,000	2,103,804	0	1,071,196	3,100,000	3,000,000	0	3,000,000	3,100,000	27,375,000
	$8.255	$2,559,050	$2,311,400	$2,559,050	$2,476,500	$1,736,690	$0	$884,273	$2,559,050	$2,476,500	$0	$2,476,500	$2,559,050	$22,598,063
		$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550	$0.82550
HUSKYBCS2BS		1,550,000	1,400,000	1,550,000	1,500,000	1,550,000	1,500,000	675,000	0	0	1,550,000	1,500,000	1,550,000	14,325,000
	$6.480	$1,004,400	$907,200	$1,004,400	$972,000	$1,004,400	$972,000	$437,400	$0	$0	$1,004,400	$972,000	$1,004,400	$9,282,600
		$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800	$0.64800

NW Natural

Oregon PGA 2006-7

Commodity Cost and Takes by Supply

Recent Hedge

Fixed Price in Original Filing

Supply	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
MistProd	406,100	366,800	406,100	393,000	406,100	9,825	0	406,100	393,000	406,100	393,000	406,100	3,992,225
	$290,037	$261,969	$290,037	$280,681	$290,037	$7,017	$0	$290,037	$280,681	$290,037	$280,681	$290,037	$2,851,247
	$0.71420	$0.71420	$0.71420	$0.71420	$0.71420	$0.71420	$0.00000	$0.71420	$0.71420	$0.71420	$0.71420	$0.71420	$0.71420
NATRKBS	1,550,000	1,400,000	1,550,000	0	0	0	0	0	0	0	1,500,000	1,550,000	7,550,000
	$1,292,964	$1,171,912	$1,277,975	$0	$0	$0	$0	$0	$0	$0	$940,650	$1,205,497	$5,888,998
	$0.83417	$0.83708	$0.82450	$0.64937	$0.63691	$0.64580	$0.65090	$0.65919	$0.66830	$0.66818	$0.62710	$0.77774	$0.78000
NATRKSW	1,550,000	1,400,000	1,550,000	0	0	0	0	0	0	0	1,500,000	1,550,000	7,550,000
	$1,292,964	$1,171,912	$1,277,975	$0	$0	$0	$0	$0	$0	$0	$940,650	$1,205,497	$5,888,998
	$0.83417	$0.83708	$0.82450	$0.64937	$0.63691	$0.64580	$0.65090	$0.65919	$0.66830	$0.66818	$0.62710	$0.77774	$0.78000
NexenBCS2BS	6,432,500	5,810,000	6,432,500	6,225,000	6,432,500	5,862,756	0	3,589,728	3,360,641	6,432,500	6,225,000	6,432,500	63,235,625
$6.95867	$4,476,184	$4,043,005	$4,476,184	$4,331,791	$4,476,184	$4,079,716	$0	$2,497,984	$2,338,569	$4,476,184	$4,331,791	$4,476,184	$44,003,774
	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587	$0.69587
ONEOKRKBS	3,100,000	2,800,000	3,100,000	0	0	0	0	0	0	0	3,000,000	3,100,000	15,100,000
$6.190	$1,918,900	$1,733,200	$1,918,900	$0	$0	$0	$0	$0	$0	$0	$1,857,000	$1,918,900	$9,346,900
	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900	$0.61900
ONEOKRKSW	3,100,000	2,800,000	3,100,000	0	0	0	0	0	0	0	3,000,000	3,100,000	15,100,000
	$2,585,927	$2,343,824	$2,555,950	$0	$0	$0	$0	$0	$0	$0	$1,881,300	$2,410,994	$11,777,995
	$0.83417	$0.83708	$0.82450	$0.64937	$0.63691	$0.64580	$0.65090	$0.65919	$0.66830	$0.66818	$0.62710	$0.77774	$0.78000
PrmStrBCS2BS	930,000	840,000	930,000	900,000	900,000	849,403	779,985	765,403	859,836	930,000	900,000	930,000	10,514,627
	$802,534	$728,330	$794,462	$629,550	$623,862	$597,394	$555,443	$552,766	$628,893	$688,312	$613,773	$758,080	$7,973,399
	$0.86294	$0.86706	$0.85426	$0.69950	$0.69318	$0.70331	$0.71212	$0.72219	$0.73141	$0.74012	$0.68197	$0.81514	$0.75831
Rockies Spot	20,675,760	18,674,880	20,675,760	25,217,092	12,299,816	7,924,664	2,123,915	719,971	7,513,130	22,551,319	20,008,800	20,675,760	179,060,867
1 = Ken, 2 = avg, 3 = cap	$17,785,909	$16,124,265	$17,507,407	$17,149,892	$8,241,984	$5,384,571	$1,460,149	$501,445	$5,301,490	$16,039,625	$13,308,853	$16,714,698	$135,520,289
3	$0.86023	$0.86342	$0.84676	$0.68009	$0.67009	$0.67947	$0.68748	$0.69648	$0.70563	$0.71125	$0.66515	$0.80842	$0.75684
SempABSCBS	3,100,000	2,800,000	3,100,000	3,000,000	3,100,000	0	3,100,000	75,000	3,000,000	3,100,000	3,000,000	3,100,000	30,475,000
$7.080	$2,194,800	$1,982,400	$2,194,800	$2,124,000	$2,194,800	$0	$2,194,800	$53,100	$2,124,000	$2,194,800	$2,124,000	$2,194,800	$21,576,300
	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800	$0.70800
SempraBCS2BS	3,100,000	2,800,000	3,100,000	3,000,000	3,100,000	3,000,000	1,350,000	0	0	0	3,000,000	3,100,000	25,550,000
$7.190	$2,228,900	$2,013,200	$2,228,900	$2,157,000	$2,228,900	$2,157,000	$970,650	$0	$0	$0	$2,157,000	$2,228,900	$18,370,450
	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900	$0.71900
WASATCHRKBS	1,550,000	1,400,000	1,550,000	0	0	0	0	0	0	0	1,500,000	1,550,000	7,550,000
	$1,292,964	$1,171,912	$1,277,975	$0	$0	$0	$0	$0	$0	$0	$940,650	$1,205,497	$5,888,998
	$0.83417	$0.83708	$0.82450	$0.64937	$0.63691	$0.64580	$0.65090	$0.65919	$0.66830	$0.66818	$0.62710	$0.77774	$0.78000
WASATCHRKSW	1,550,000	1,400,000	1,550,000	0	0	0	0	0	0	0	1,500,000	1,550,000	7,550,000
	$1,292,964	$1,171,912	$1,277,975	$0	$0	$0	$0	$0	$0	$0	$940,650	$1,205,497	$5,888,998
	$0.83417	$0.83708	$0.82450	$0.64937	$0.63691	$0.64580	$0.65090	$0.65919	$0.66830	$0.66818	$0.62710	$0.77774	$0.78000
GrandTotal	80,124,962	71,951,321	85,109,237	70,919,169	49,759,214	29,991,023	17,394,758	16,789,041	27,126,607	61,433,330	92,083,255	99,260,475	701,942,392
	$62,581,914	$56,299,510	$66,269,676	$48,521,800	$33,817,430	$20,519,785	$11,686,670	$11,534,447	$18,832,132	$42,750,524	$61,602,143	$75,668,596	$510,084,626
	$0.78105	$0.78247	$0.77864	$0.68418	$0.67962	$0.68420	$0.67185	$0.68702	$0.69423	$0.69588	$0.66898	$0.76232	$0.72668

NW Natural
Derivation of Seasonalized Fixed Charges - Oregon Specific
PGA Filing Effective November 1, 2006

		Normalized Residential Volumes	Normalized Commercial Volumes	Industrial Firm Volumes	Interruptible Volumes	Embedded Demand Increment - Firm Rates 11/1/06	Embedded Demand Increment - Int Rates 11/1/06	Seasonalized Fixed Charges
November	**2006**							$6,754,373
January	**2007**	56,107,710	36,012,100	5,972,010	9,305,755	0.12736	0.01515	$12,633,985
February	**2007**	46,568,995	29,755,521	5,781,392	9,029,124	0.12736	0.01515	10,593,818
March	**2007**	41,238,875	26,541,728	5,973,283	9,373,781	0.12736	0.01515	9,535,319
April	**2007**	30,645,010	19,762,849	4,814,939	8,811,455	0.12736	0.01515	7,166,669
May	**2007**	19,161,025	12,488,455	4,448,107	8,775,136	0.12736	0.01515	4,730,318
June	**2007**	8,629,399	5,740,026	4,253,772	8,976,047	0.12736	0.01515	2,507,809
July	**2007**	2,324,969	1,676,639	3,763,918	8,752,631	0.12736	0.01515	1,121,585
August	**2007**	1,631,493	1,230,722	3,927,689	9,237,988	0.12736	0.01515	1,004,680
September	**2007**	7,097,810	4,814,626	4,326,239	8,892,108	0.12736	0.01515	2,202,844
October	**2007**	25,370,806	16,563,806	4,353,841	8,908,130	0.12736	0.01515	6,030,248
November	**2007**	43,864,470	28,392,809	5,351,455	8,603,600	0.12736	0.01515	10,014,610
December	**2006**	59,658,078	38,408,477	6,159,787	8,967,038	0.12736	0.01515	13,410,153
		342,298,642	221,387,757	59,126,432	107,632,793			$80,952,038
							check	$80,952,038
							scale	0.994240143

Unscaled	**Residential**	**Commercial**	**Industrial Firm**	**Interruptible**
January	56,432,754	36,220,726	6,006,607	9,359,665
February	46,838,780	29,927,901	5,814,885	9,081,432
March	41,477,781	26,695,490	6,007,887	9,428,085
April	30,822,544	19,877,339	4,842,833	8,862,502
May	19,272,030	12,560,804	4,473,875	8,825,972
June	8,679,391	5,773,279	4,278,415	9,028,048
July	2,338,438	1,686,353	3,785,723	8,803,337
August	1,640,945	1,237,852	3,950,443	9,291,506
September	7,138,929	4,842,518	4,351,302	8,943,622
October	25,517,785	16,659,763	4,379,064	8,959,736
November	44,118,587	28,557,295	5,382,457	8,653,443
December	60,003,690	38,630,986	6,195,473	9,018,986
	344,281,655	222,670,307	59,468,965	108,256,334

	SYSTEM		**OREGON**	
	Res	**Com**	**Res**	**Com**
Jan	62,762,710	39,400,335	56,432,754	36,220,726
Feb	52,092,598	32,555,099	46,838,780	29,927,901
Mar	46,130,266	29,038,934	41,477,781	26,695,490
Apr	34,279,851	21,622,257	30,822,544	19,877,339
May	21,433,737	13,663,444	19,272,030	12,560,804
Jun	9,652,942	6,280,082	8,679,391	5,773,279
Jul	2,600,737	1,834,388	2,338,438	1,686,353
Aug	1,825,007	1,346,516	1,640,945	1,237,852
Sep	7,939,690	5,267,615	7,138,929	4,842,518
Oct	28,380,067	18,122,228	25,517,785	16,659,763
Nov	49,067,286	31,064,176	44,118,587	28,557,295
Dec	66,734,192	42,022,178	60,003,690	38,630,986
	382,899,081	242,217,252	344,281,655	222,670,307
			89.91%	91.93%

Thirtieth Revised Sheet No. 5 : Effective

Superseding: Twenty-Ninth Revised Sheet No. 5

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

Rate Schedule and Type of Rate	Base Tariff Rate Minimum	Base Tariff Rate Maximum	ACA(2)	Currently Effective Tariff Rate(3) Minimum	Currently Effective Tariff Rate(3) Maximum
Rate Schedule TF-1 (4)(5)					
Reservation					
(Large Customer)					
System-Wide	.00000	.27760	-	.00000	.27760
15 Year Evergreen Exp.	.00000	.39547	-	.00000	.39547
25 Year Evergreen Exp.	.00000	.37893	-	.00000	.37893
Volumetric					
(Large Customer)	.01225	.03000	.00180	.01405	.03180
(Small Customer) (6)	.01225	.58521	.00180	.01405	.58701
Scheduled Overrun	.01225	.30760	.00180	.01405	.30940
Rate Schedule TF-2 (4)(5)					
Reservation	.00000	.27760	-	.00000	.27760
Volumetric	.01225	.03000	-	.01225	.03000
Scheduled Daily Overrun	.01225	.30760	-	.01225	.30760
Annual Overrun	.01225	.30760	-	.01225	.30760
Rate Schedule TI-1					
Volumetric (7)	.01225	.30760	.00180	.01405	.30940
Scheduled Overrun	.01225	.30760	.00180	.01405	.30940

Fourteenth Revised Sheet No. 7 : Effective

Superseding: Thirteenth Revised Sheet No. 7

STATEMENT OF RATES (Continued)

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

(Dollars per Dth)

Effective (1) Maximum	Rate Schedule and Type of Rate	Currently Tariff Rate Minimum
	Rate Schedule SGS-2F (2)	
0.01689	Demand Charge	0.00000
0.00062	Capacity Demand Charge	0.00000
	Volumetric Bid Rates	
0.01689	Withdrawal Charge	0.00000
0.00062	Storage Charge	0.00000
	Rate Schedule SGS-2I	
0.00134	Volumetric	0.00000

Footnotes

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

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

Rates are also applicable to capacity release service. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The Withdrawal Charge and Storage Charge are applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

Sixteenth Revised Sheet No. 8 : Effective

Superseding: Fifteenth Revised Sheet No. 8

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STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedule LS-1

(Dollars per Dth)

Type of Rate	Currently Effective Tariff Rate (1)
Demand Charge (2)	0.02600
Capacity Charge (2)	0.00332
Liquefaction	0.55685
Vaporization	0.03030

Footnotes

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

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

NW Natural
Rates & Regulatory Affairs
2006-2007 PGA Filing - Oregon (October 4, 2006 Refiling)
Summary of Deferred Accounts

Account	Balance 06/30/06	Adjustment	Jul-Oct Est. Amortization	Jul-Oct Est. Interest	Est. Balance 10/31/2006	Est. Interest During Amortization	Total Est. Amount for (Refund) or Collection	Amounts Excluded from PGA Filing	Amounts Included in PGA Filing	Refer to NWN_AL file, "Allocation Equal ¢ per therm" tab		
A	B	C	D	E	F	G	H	I	J	K		
					F = sum B thru E		H = F + G	see note a	Excl. Rev Sens	see note b		
Decoupling Deferrals and Amortizations												
186277 RESIDENTIAL DECOUPLING AMORTIZATION	(259,411)		(537,176)	(13,317)	(809,904)							
186275 RESIDENTIAL DECOUPLING DEFERRAL	108,245		0	3,143	111,388							
Subtotal	(151,166)	0	(537,176)	(10,174)	(698,516)	(33,035)	(731,551)		(731,551)	Columns K-M		
186271 COMMERCIAL DECOUPLING AMORTIZATION	(41,611)		(282,680)	(4,726)	(329,016)							
186270 COMMERCIAL DECOUPLING DEFERRAL	(1,111,865)		0	(32,286)	(1,144,151)							
Subtotal	(1,153,476)	0	(282,680)	(37,012)	(1,473,168)	(69,671)	(1,542,839)		(1,542,839)	Columns N-P		
Intervenor Funding Deferrals and Amortizations												
186276 INTERVENER FUNDING	50,000		0	0	50,000							
186286 AMORT - CUB INTERVENER MATCHING FUND	877		(7,868)	(59)	(7,050)							
Subtotal	50,877	0	(7,868)	(59)	42,950	2,031	44,981		44,981	Columns T-V		
186278 NWIGU INTERVENOR MATCHING FUND	0		0	0	0							
186288 AMORT - NWIGU INTERVENER MATCHING FUND	(4,597)		2,369	(100)	(2,328)							
Subtotal	(4,597)	0	2,369	(100)	(2,328)	(110)	(2,438)	(2,438)				
Miscellaneous Amortizations												
186231 AMORT DSM LOST MARGIN	67,457	0	(223,750)	(738)	(157,030)	(7,426)	(164,456)		(164,456)	Columns Q-S		
186254 FISH/GARDEN BLOCK REFUNDS	34,726	0	665	1,016	36,407	1,722	38,129	38,129				
186269 AMORT WEST LINN DEFERRAL	(4,765)	0	6,653	(63)	1,825	86	1,911	1,911				
186251 CONTRA AMORT Y2K COSTS	(74,250)	0	71,912	(1,328)	(3,666)	(173)	(3,839)	(3,839)				
186274 AMORT OR PKG, OQ, VANC GAIN	6,056	0	(1,643)	157	4,570	216	4,786	4,786				
186267 AMORT COOS BAY DEFERRAL	179,432	0	(165,891)	3,246	16,788	794	17,582		17,582	COLUMNS F-H	"Allocation Equal % of margin" tab	
186243 SMPE AMORTIZATION	(27,274)	0	(11,226)	(921)	(39,421)	(1,864)	(41,285)	(41,285)				
Gas Cost Deferrals and Amortizations												
191401 AMORTIZE OREGON WACOG	(135,636)		632,207	4,123	500,694							
191400 WACOG - ACCRUE OREGON	(13,386,991)		0	(388,726)	(13,775,717)							
Subtotal	(13,522,627)	0	632,207	(384,603)	(13,275,023)	(627,818)	(13,902,841)		(13,902,841)	Columns B-D		
191030 STORAGE INVENTORY ADJUSTMENT	19,899,833	0	0	0	19,899,833	N/A	19,899,833		19,899,833	Columns W-Y		
191411 AMORTIZE DEMAND OREGON	265,184	0	(1,070,382)	(5,321)	(810,519)							
191410 DEMAND - ACCRUE OREGON	(2,724,417)	0	0	0	(2,724,417)							
191417 DEMAND - ACCRUE COOS BAY	233,952	(16,520)	0	0	217,432							
191450 OREGON DEMAND ACCRUE VOLUME	3,150,773	0	0	0	3,150,773							
191455 COLLECT VS DEFERRAL DEMAND INT OREGON	(504,067)	0	0	(14,637)	(518,704)							
Subtotal	421,425	(16,520)	(1,070,382)	(19,958)	(685,434)	(32,416)	(717,850)		(717,850)	Columns E-G	(699,575)	to FIRM
										Columns H-J	(18,275)	to INTERRUPTIBLE
GRAND TOTAL							2,900,123	(2,736)	2,902,859			

Notes

a. Per agreement with Staff and in order to streamline the temporary adjustment to rates, these accounts will not be included in the PGA filing due to their aggregated immateriality

b. Please refer to NWN workpapers or electronic file "NWN AL 2006-07 Oregon PGA re-filing.xls" for application of revenue sensitive effect and calculation of rate increments.

NW Natural
Rates & Regulatory Affairs
2006-2007 PGA Filing - Oregon (October 4, 2006 Refiling)
Elasticity Adjustment

			Elasticity Volumes	Monthly Service Charge	Customers	Current 2005-2006 Billing Rate	Proposed 2006-2007 Billing Rate Before Elasticity	Current 2005-2006 Revenue	Proposed 2006-2007 Revenue	Proposed 2006-2007 WACOG	Proposed 2006-2007 Demand	Proposed 2006-2007 Margin Rate	Proposed 2006-2007 Margin
								F=(D*A)+(B*C*12)	G=(E*A)+(B*C*12)			J = E - H - I	K = J * A
1	Schedule	Block	A	B	C	D	E	F	G	H	I	J	K
2	1R		720,718.9	$5.00	3,418	1.35982	1.40617	1,185,128	1,218,533	0.75951	0.13136	0.51530	371,386
3	1C		84,130.9	$5.00	183	1.32967	1.37529	122,846	126,684	0.75951	0.13136	0.48442	40,755
4	2R		343,491,452.1	$6.00	502,969	1.29167	1.33776	479,891,372	495,722,893	0.75951	0.13136	0.44689	153,502,895
5	3C Firm Sales		144,524,695.5	$8.00	53,502	1.19803	1.24312	178,281,113	184,797,731	0.75951	0.13136	0.35225	50,908,824
6	Intentionally blank												
7	3I Firm Sales												
8	Intentionally blank												
9	19	1st mantle			20								
10	19	add'l mtls			0								
11	31C Firm Sales	Block 1	24,991,805.6	$325.00	1,229	1.03458	1.07891	30,649,122	31,757,009	0.75951	0.13136	0.18804	4,699,459
12		Block 2	37,528,497.0			1.01822	1.06251	38,212,266	39,874,403	0.75951	0.13136	0.17164	6,441,391
13	31C Firm Trans	Block 1	0.0	$325.00	0	0.19694	0.18158	0	0	0.00000	0.00000	0.18158	0
14		Block 2	0.0			0.18055	0.16518	0	0	0.00000	0.00000	0.16518	0
15	31C Interr Sales	Block 1	0.0	$325.00	0	0.93932	0.96441	0	0	0.75951	0.01562	0.18928	0
16		Block 2	0.0			0.92296	0.94801	0	0	0.75951	0.01562	0.17288	0
17			551,341,300		561,321			728,341,847	753,497,253				215,964,711
18													
19	**Calculation of Class Prices and Margins:**					**05-06 Class Price**	**06-07 Class Price**	**05-06 Class Revenues**	**06-07 Class Revenues**			**Class Margin Rate**	**Class Margin**
20						Column F ÷ A	Column G ÷ A					Column K ÷ A	
21	**Residential (Line 2 + Line 4)**		344,212,171		506,387	**$1.39762**	**$1.44371**	481,076,500	496,941,426			**$0.44703**	153,874,281
22	**Commercial (Line 17 - Line 21)**		207,129,129		54,934	**$1.19377**	**$1.23863**	247,265,347	256,555,827			**$0.29977**	62,090,429
23			551,341,300		561,321			728,341,847	753,497,253				215,964,711
24													
25	**Sources for lines 1-17:**												
26	Direct Inputs			Per Tariff									
27													
28	Rates in Detail page					Column A	Column N			Column F	Columns G + H		
29	Volumes page		Column G		Column H								
30	PGA Effects page			Column D									

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32 ELASTICITY CALCULATION:

		Residential		Commercial	
33		Current	Proposed	Current	Proposed
34	Elasticity volumes		344,212,171		207,129,129
35					
36	Class prices (Columns D & E, lines 21, 22)	$1.39762	$1.44371	$1.19377	$1.23863
37					
38	Change in class prices		$0.04609		$0.04486
39					
40	Percentage change in class prices 10/1/05 to 11/1/06		3.3%		3.8%
41					
42	Volume change due to elasticity (Residential @ 0.172, Commercial @ 0.11)		0.6%		0.4%
43					
44	Volume change due to elasticity in therms (line 42 x line 34)		2,065,273		828,517
45					
46	Margin rate per therm (Columns J & K, lines 21, 22)		$0.44703		$0.29977
47					
48	**Margin Shortfall (line 44 x Line 46)**		**$923,239**		**$248,365**
49					
50	**Rate Change Due to Elasticity Effects (line 48 ÷ line 34)**		**$0.00268**		**$0.00120**
51					
52	**Rate Change Due to Elasticity Effects with revenue sensitive added**		**$0.00276**		**$0.00124**

NW Natural
Rates & Regulatory Affairs
2006-2007 PGA Filing - Oregon (October 4, 2006 Refiling)
Summary of PERMANENT Increments

		REMOVE Current Bare Steel	REMOVE Current Geo Hazard	REMOVE Current IMP	REMOVE Current Coos Bay	Current Subtotal	ADD Proposed Bare Steel 70%	ADD Proposed Bare Steel 30%	ADD Proposed Geo Hazard	ADD Proposed IMP	ADD Proposed Coos Bay	Proposed Subtotal	Net Effect of Permanent Items
						E=A+B+C+D						K=sum F thru J	L= K - E
Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L
1R		0.00414	0.00078	0.00116	(0.00025)	0.00583	0.00239	0.00124	0.00167	0.00396	(0.00026)	0.00900	0.00317
1C		0.00408	0.00074	0.00111	(0.00024)	0.00569	0.00239	0.00118	0.00159	0.00376	(0.00025)	0.00867	0.00298
2R		0.00394	0.00067	0.00100	(0.00021)	0.00540	0.00239	0.00107	0.00145	0.00343	(0.00023)	0.00811	0.00271
3C Firm Sales		0.00370	0.00054	0.00080	(0.00017)	0.00487	0.00239	0.00086	0.00115	0.00273	(0.00018)	0.00695	0.00208
Intentionally blank													
3I Firm Sales		0.00091	0.00050	0.00074	(0.00016)	0.00199	0.00239	0.00077	0.00104	0.00247	(0.00016)	0.00651	0.00452
Intentionally blank													
19	1st mantle	0.07	0.01	0.01	0.00	0.09	0.05	0.00	0.00	0.00	0.00	0.05	(0.04)
19	add'l mtls	0.07	0.01	0.01	0.00	0.09	0.05	0.00	0.00	0.00	0.00	0.05	(0.04)
31C Firm Sales	Block 1	0.00323	0.00028	0.00042	(0.00009)	0.00384	0.00239	0.00046	0.00062	0.00146	(0.00010)	0.00483	0.00099
	Block 2	0.00318	0.00025	0.00038	(0.00008)	0.00373	0.00239	0.00042	0.00056	0.00134	(0.00009)	0.00462	0.00089
31C Firm Trans	Block 1	0.00323	0.00028	0.00042	(0.00009)	0.00384	0.00239	0.00046	0.00062	0.00146	(0.00010)	0.00483	0.00099
	Block 2	0.00318	0.00025	0.00038	(0.00008)	0.00373	0.00239	0.00042	0.00056	0.00134	(0.00009)	0.00462	0.00089
31C Interr Sales	Block 1	0.00323	0.00028	0.00042	(0.00009)	0.00384	0.00239	0.00046	0.00062	0.00146	(0.00010)	0.00483	0.00099
	Block 2	0.00318	0.00025	0.00038	(0.00008)	0.00373	0.00239	0.00042	0.00056	0.00134	(0.00009)	0.00462	0.00089
31I Firm Sales	Block 1	0.00051	0.00028	0.00042	(0.00009)	0.00112	0.00000	0.00041	0.00056	0.00132	(0.00009)	0.00220	0.00108
	Block 2	0.00046	0.00025	0.00038	(0.00008)	0.00101	0.00000	0.00037	0.00050	0.00119	(0.00008)	0.00198	0.00097
31I Firm Trans	Block 1	0.00051	0.00028	0.00042	(0.00009)	0.00112	0.00000	0.00041	0.00056	0.00132	(0.00009)	0.00220	0.00108
	Block 2	0.00046	0.00025	0.00038	(0.00008)	0.00101	0.00000	0.00037	0.00050	0.00119	(0.00008)	0.00198	0.00097
31I Interr Sales	Block 1	0.00051	0.00028	0.00042	(0.00009)	0.00112	0.00000	0.00041	0.00056	0.00132	(0.00009)	0.00220	0.00108
	Block 2	0.00046	0.00025	0.00038	(0.00008)	0.00101	0.00000	0.00037	0.00050	0.00119	(0.00008)	0.00198	0.00097
32 Firm Sales	Block 1	0.00029	0.00016	0.00024	(0.00005)	0.00064	0.00000	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00068
	Block 2	0.00024	0.00013	0.00020	(0.00004)	0.00053	0.00000	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00059
	Block 3	0.00017	0.00009	0.00014	(0.00003)	0.00037	0.00000	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00042
	Block 4	0.00010	0.00006	0.00008	(0.00002)	0.00022	0.00000	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00024
	Block 5	0.00006	0.00003	0.00005	(0.00001)	0.00013	0.00000	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00014
	Block 6	0.00003	0.00002	0.00002	0.00000	0.00007	0.00000	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00005
32 Firm Trans	Block 1	0.00029	0.00016	0.00024	(0.00005)	0.00064	0.00000	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00068
	Block 2	0.00024	0.00013	0.00020	(0.00004)	0.00053	0.00000	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00059
	Block 3	0.00017	0.00009	0.00014	(0.00003)	0.00037	0.00000	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00042
	Block 4	0.00010	0.00006	0.00008	(0.00002)	0.00022	0.00000	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00024
	Block 5	0.00006	0.00003	0.00005	(0.00001)	0.00013	0.00000	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00014
	Block 6	0.00003	0.00002	0.00002	0.00000	0.00007	0.00000	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00005
32 Interr Sales	Block 1	0.00029	0.00016	0.00024	(0.00005)	0.00064	0.00000	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00068
	Block 2	0.00024	0.00013	0.00020	(0.00004)	0.00053	0.00000	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00059
	Block 3	0.00017	0.00009	0.00014	(0.00003)	0.00037	0.00000	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00042
	Block 4	0.00010	0.00006	0.00008	(0.00002)	0.00022	0.00000	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00024
	Block 5	0.00006	0.00003	0.00005	(0.00001)	0.00013	0.00000	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00014
	Block 6	0.00003	0.00002	0.00002	0.00000	0.00007	0.00000	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00005
32 Interr Trans	Block 1	0.00029	0.00016	0.00024	(0.00005)	0.00064	0.00000	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00068
	Block 2	0.00024	0.00013	0.00020	(0.00004)	0.00053	0.00000	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00059
	Block 3	0.00017	0.00009	0.00014	(0.00003)	0.00037	0.00000	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00042
	Block 4	0.00010	0.00006	0.00008	(0.00002)	0.00022	0.00000	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00024
	Block 5	0.00006	0.00003	0.00005	(0.00001)	0.00013	0.00000	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00014
	Block 6	0.00003	0.00002	0.00002	0.00000	0.00007	0.00000	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00005
54		0.00408	0.00074	0.00111	(0.00024)	0.00569	0.00239	0.00102	0.00138	0.00326	(0.00022)	0.00783	0.00214
33		0.00002	0.00001	0.00001	0.00000	0.00004	0.00000	0.00001	0.00002	0.00004	0.00000	0.00007	0.00003

Sources:

Direct Inputs	05-06 PGA	05-06 PGA	05-06 PGA	05-06 PGA							
Equal ¢ per therm						Column AB					
Equal % of margin							Column K	Column N	Column Q	Column T	

NW Natural
Rates & Regulatory Affairs
2006-2007 PGA Filing - Oregon (October 4, 2006 Refiling)
Summary of TEMPORARY Increments

		REMOVE	ADD	ADD	ADD	ADD	ADD	ADD	ADD	ADD	ADD		
		Current Temporaries	WACOG Deferral	Demand Deferral FIRM	Demand Deferral INTERR	Residential Decoupling	Commercial Decoupling	DSM & Weatherization	Intervenor Funding - CUB	Coos Bay	Storage Inventory Adjustment	Total Current Temps	Net Effect of Temps
												K=sum B thru J	L = K - A
Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L
1R		0.02263	(0.01816)	(0.00111)	0.00000	(0.00212)	0.00000	(0.00026)	0.00013	0.00004	0.02599	0.00451	(0.01812)
1C		0.01820	(0.01816)	(0.00111)	0.00000	0.00000	(0.00696)	(0.00026)	0.00000	0.00004	0.02599	(0.00046)	(0.01866)
2R		0.02242	(0.01816)	(0.00111)	0.00000	(0.00212)	0.00000	(0.00026)	0.00013	0.00003	0.02599	0.00450	(0.01792)
3C Firm Sales		0.01782	(0.01816)	(0.00111)	0.00000	0.00000	(0.00696)	(0.00026)	0.00000	0.00003	0.02599	(0.00047)	(0.01829)
Intentionally blank													
3I Firm Sales		0.00928	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00002	0.02599	0.00648	(0.00280)
Intentionally blank													
19	1st mantle	0.42	(0.35)	(0.02)	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.13	(0.29)
19	add'l mtls	0.42	(0.35)	(0.02)	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.13	(0.29)
31C Firm Sales	Block 1	0.01747	(0.01816)	(0.00111)	0.00000	0.00000	(0.00696)	(0.00026)	0.00000	0.00001	0.02599	(0.00049)	(0.01796)
	Block 2	0.01741	(0.01816)	(0.00111)	0.00000	0.00000	(0.00696)	(0.00026)	0.00000	0.00001	0.02599	(0.00049)	(0.01790)
31C Firm Trans	Block 1	0.00940	0.00000	0.00000	0.00000	0.00000	(0.00696)	0.00000	0.00000	0.00001	0.00000	(0.00695)	(0.01635)
	Block 2	0.00931	0.00000	0.00000	0.00000	0.00000	(0.00696)	0.00000	0.00000	0.00001	0.00000	(0.00695)	(0.01626)
31C Interr Sales	Block 1	0.00561	(0.01816)	0.00000	(0.00013)	0.00000	(0.00696)	0.00000	0.00000	0.00001	0.02599	0.00075	(0.00486)
	Block 2	0.00555	(0.01816)	0.00000	(0.00013)	0.00000	(0.00696)	0.00000	0.00000	0.00001	0.02599	0.00075	(0.00480)
31I Firm Sales	Block 1	0.00899	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00001	0.02599	0.00647	(0.00252)
	Block 2	0.00893	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00001	0.02599	0.00647	(0.00246)
31I Firm Trans	Block 1	0.00092	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001	(0.00091)
	Block 2	0.00083	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001	(0.00082)
31I Interr Sales	Block 1	(0.00287)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00001	0.02599	0.00771	0.01058
	Block 2	(0.00293)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00001	0.02599	0.00771	0.01064
32 Firm Sales	Block 1	0.00872	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00001	0.02599	0.00647	(0.00225)
	Block 2	0.00868	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00001	0.02599	0.00647	(0.00221)
	Block 3	0.00862	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00000	0.02599	0.00646	(0.00216)
	Block 4	0.00856	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00000	0.02599	0.00646	(0.00210)
	Block 5	0.00852	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00000	0.02599	0.00646	(0.00206)
	Block 6	0.00850	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00000	0.02599	0.00646	(0.00204)
32 Firm Trans	Block 1	0.00047	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001	(0.00046)
	Block 2	0.00039	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001	(0.00038)
	Block 3	0.00027	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00027)
	Block 4	0.00015	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00015)
	Block 5	0.00008	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00008)
	Block 6	0.00003	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00003)
32 Interr Sales	Block 1	(0.00314)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00001	0.02599	0.00771	0.01085
	Block 2	(0.00318)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00001	0.02599	0.00771	0.01089
	Block 3	(0.00324)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00000	0.02599	0.00770	0.01094
	Block 4	(0.00330)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00000	0.02599	0.00770	0.01100
	Block 5	(0.00334)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00000	0.02599	0.00770	0.01104
	Block 6	(0.00336)	(0.01816)	0.00000	(0.00013)	0.00000	0.00000	0.00000	0.00000	0.00000	0.02599	0.00770	0.01106
32 Interr Trans	Block 1	0.00047	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001	(0.00046)
	Block 2	0.00039	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00001	(0.00038)
	Block 3	0.00027	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00027)
	Block 4	0.00015	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00015)
	Block 5	0.00008	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00008)
	Block 6	0.00003	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00003)
54		0.01802	(0.01816)	(0.00111)	0.00000	0.00000	0.00000	(0.00026)	0.00000	0.00003	0.02599	0.00649	(0.01153)
33		0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)

Sources:

Direct Inputs	05-06 PGA									
Equal ¢ per therm		Column D	Column G	Column J	Column M	Column P	Column S	Column V		Column Y
Equal % of margin									Column H	

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

		Investment	Tracker Year Cost of Service
Bare Steel Program			
1	**Activity Ended September 30, 2002**	$2,665	$353
2	**Activity Ended September 30, 2003**	3,510	455
3	**Activity Ended September 30, 2004**	3,094	414
4	**Activity Ended September 30, 2005**	6,000	828
5	**Activity Ended September 30, 2006**	(695)	(107)
6	**Total Bare Steel Program**	$14,574	$1,944
Geohazard Program			
7	**Activity Ended September 30, 2002**	$1,714	$227
8	**Activity Ended September 30, 2003**	555	72
9	**Activity Ended September 30, 2004**	139	19
10	**Activity Ended September 30, 2005**	206	28
11	**Activity Ended September 30, 2006**	2,863	440
12	**Total Geohazard Program**	$5,477	$786
Integrity Management Program			
13	**Activity Ended September 30, 2005**	$3,476	$480
14	**Activity Ended September 30, 2006**	8,978	1,381
15	**Total Integrity Management Program**	$12,454	$1,861
GRAND TOTAL ALL PROGRAMS		**$32,505**	**$4,591**

Reflects Actuals through June 30, 2006

NW Natural
Rates and Regulatory Affairs
2006-2007 PGA Filing - Oregon (October 4, 2006 re-filing)
Estimated Revenue Effects for the 12 Months Beginning November 1, 2006

Line No.	Item	Total Increment Amounts	Limit For Increment Amounts
1	Commodity and Demand Deferrals	($15,080,029)	
2	Temporary Increments	18,144,988	
3	Total	$3,064,959	
4	2005 Utility Revenues		$900,652,262
5	@ 3% threshold		3.0%
6	Threshold for Annual Effect of Proposed Change in Amortization		$27,019,568

ORS 757.259 (6)

NW Natural

SUMMARY OF NW NATURAL'S GAS PURCHASING STRATEGY

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

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

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

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

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[1] "Design" year refers to the coldest heating season (currently 1985/86) plus the coldest weather event (currently centered around February 3, 1989) experienced over the past 20 years. Expected firm requirements are derived using the degree-days from those design weather conditions along with current firm customer counts and expected gas usage per degree-day per customer.

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

provide some opportunity to take advantage when spot prices are favorable; and (8) Avoid over-contracting gas on a take-or-pay basis, which could result in excess gas supplies that must be sold at a loss if requirements fail to materialize such as during a warm winter.

NWN has contracted with suppliers for approximately 1.2 million therms/day of firm deliveries on a daily basis over the upcoming November 2006 through October 2007 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 down slightly from the 1.3 million therms/day contracted for the Nov05-Oct06 period due to declining usage per customer and the need for more portfolio flexibility.

In addition, during the heating season (Nov06-Mar07), NWN contracts for another 0.5 million therms/day of supply, reflecting the higher consumption of customers and potentially more intense competition for supplies during those months. This compares with 1.5 million therms/day contracted for the Nov06-Mar06 period. The reduction will help avoid any potential oversupply situations and allow more opportunities for the use of storage supplies. As in previous years, about half of the winter contracted volume is purchased on a take-or-pay basis. The remaining contracted volumes are made available to NWN on a daily basis in exchange for payment of a fixed "reservation" charge, but there is no minimum daily, monthly or seasonal purchase requirement. These "swing" supplies 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 1.6 and 1.8 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. Spot purchases formerly accounted for roughly 10% of annual purchases, with many of those purchases occurring during the non-heating season, especially in late spring and early summer when storage injections are heaviest. With the changes mentioned above, the diversity of the supply portfolio between year-round term, winter term and spot purchases should improve.

NWN "swaps" monthly index prices for fixed prices through the use of financial instruments in order to increase price stability across the year. Volumes in storage provide another form of hedging. Overall, NWN's target this year is to hedge the prices of approximately 50% of its expected annual purchase volumes for the upcoming 12-month period commencing in November, the traditional start month for its supply contracts. This is a reduction from prior years due to the volatility of gas prices and the view that the current strength in future prices is not sustainable.

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2006/2007 Tracker Year

Supply Location	Duration	Baseload Quantity (Dth/day)	Swing Quantity (Dth/day)	Contract Termination Date
British Columbia (Station 2):				
BP Canada	Nov-Oct	5,000		10/31/2009
BP Canada	Nov-Oct	4,000		10/31/2007
Coral Energy Canada	Nov-Oct	10,000		10/31/2010
Husky Energy Marketing	Nov-Oct	5,000		10/31/2007
Nexen (assigned from Duke)	Nov-Oct	20,750		10/31/2008
PremStar Energy	Nov-Oct	3,000		10/31/2008
Sempra Energy Trading	Nov-Oct	10,000		10/31/2008
Alberta:				
BP Canada	Nov-Oct	10,000		10/31/2009
BP Canada	Nov-Oct	10,000		10/31/2009
Burlington Resources Canada	Nov-Oct	15,000		10/31/2007
Coral Energy Canada	Nov-Oct	10,000		10/31/2008
Husky Energy Marketing	Nov-Oct	10,000		10/31/2007
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
Rockies:				
Coral Energy Resources	Nov-Mar	5,000	5,000	3/31/2007
National Fuel Marketing	Nov-Mar	5,000	5,000	3/31/2007
ONEOK Energy Services	Nov-Mar	10,000	10,000	3/31/2007
Wasatch Energy	Nov-Mar	5,000	5,000	3/31/2007
Total Off-System Firm Contract Supply		147,750	25,000	

Notes:

1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.

Table 2

NW Natural
Firm Transportation Capacity
for the 2006/2007 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion	216,044	9/30/2013
1993 Expansion	34,000	9/30/2009
1995 Expansion	102,000	11/30/2011
Duke Capacity Acquisition	5,000	3/31/2008
Total NWP Capacity	357,044	
less recallable releases to -		
Portland General Electric	(30,000)	10/31/2010
Georgia Pacific	(7,000)	10/31/2003
Net NWP Capacity	320,044	
TransCanada's GTN System:		
Sales Conversion	3,616	10/31/2023
1993 Expansion	46,549	10/31/2023
1995 Rationalization	56,000	10/31/2005
Total GTN Capacity	106,165	
TransCanada's BC System:		
1993 Expansion	47,000	10/31/2008
1995 Rationalization	56,500	10/31/2005
Engage Capacity Acquisition	3,814	10/31/2008
2004 Capacity Acquisition	48,200	10/31/2016
Total TCPL-BC Capacity	155,514	
TransCanada's Alberta System:		
1995 Rationalization	57,000	10/31/2001
Burlington/Summit Cap. Assignments	23,561	10/31/2008
Engage Capacity Acquisition	3,861	10/31/2008
Engage Capacity Assignments	24,121	10/31/2008
2004 Capacity Acquisition	48,910	10/31/2016
Total TCPL-ALberta Capacity	157,453	
WEI T-South Capacity	60,000	10/31/2014
Southern Crossing Pipeline	47,200	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 and GP. Those two contracts require mutual agreement to continue.
2. The TCPL-Alberta, 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.

Table 3

NW Natural
Firm Storage Resources
for the 2006/2007 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2004
TF-2 (redelivery service)	32,624	839,046	10/31/2004
TF-2 (redelivery service)	13,406	281,242	3/31/2008
Plymouth LNG:			
LS-1	60,100	478,900	10/31/2004
TF-2 (redelivery service)	60,100	478,900	10/31/2004
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)	230,000	8,720,000	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	410,000	10,320,000	
Total Firm Storage Resource	516,130	11,919,188	

Notes:

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

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production for the 2006/2007 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Annual Recall (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	11/1/2010
Georgia Pacific - Toledo	7,000	35	upon 1 year notice
Weyerhaeuser 1	3,000	40	upon 1 year notice
Weyerhaeuser 2	5,000	40	upon 1 year notice
Total Recall Resource	45,000		
Citygate Deliveries:			
none			
Mist Production:			
Enerfin Resources	≈1,200	n/a	4/1/2005

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. An extension of the current contract is currently being negotiated to allow the addition of new wells.

Table 5

NW Natural
Firm Resource Summary
for the 2006/2007 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	320,044
Off-System Storage (Jackson Prairie and Plymouth)	106,130
On-System Storage (Mist, Portland LNG and Newport LNG)	410,000
Recallable Capacity and Supply Agreements	45,000
Citygate Deliveries	-
Nominal Mist Production Gas	1,200
Total Firm Resource	882,374