Rates and Regulatory Affairs
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August 31, 2007 NWN Advice No. OPUC 07-7

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: Annual Purchased Gas Cost and Technical Rate Adjustments

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith revisions 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, 2007.

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 November 1, 2006; and (c) apply new temporary rate adjustments for inclusion in rates effective November 1, 2007. The Company revises rates for these purposes annually; its last filing was effective November 1, 2006.

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 Geohazard 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 (a) the revenue requirement associated with the construction of the Coos County distribution system pursuant to OPUC Order No. 04-702, and; (b) 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 a decrease in the Company's revenues from its Oregon operations of about $59,116,947 or about 6.5%.

The average residential Schedule 2 bill will decrease by 5.7%; the commercial Schedule 3 bill will decrease by 7.1%; the commercial Schedule 31 bill will decrease by 8.1%, and; the bill for the average Schedule 32 industrial firm sales customer will decrease by 8.9%.

The monthly bill of the average residential customer served under Schedule 2 using 56 therms per month will decrease by $4.65. The monthly decrease for the average commercial Schedule 3 customer using 231 therms is $21.04.

See Exhibit B 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. <u>Purchased Gas Cost Adjustment (PGA)</u>

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.

See Exhibit A of this filing for a summary of the Company's gas purchasing strategy and a summary of the gas cost forecast strategy.

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 revises the Winter Sales WACOG option that is available to Rate Schedule 31 and 32 sales service customers.

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 in August, 2001, as described in more detail in the Company's PGA filing dated August 14, 2001, NWN Advice No. OPUC 01-18.

The total effect of the PGA portion of this filing is to decrease the Company's annual revenues by about $19,231,519. The effect of the change in gas costs is $14,401,426, which results in a proposed Annual Sales WACOG of $0.73728 per therm, and a proposed Winter Sales WACOG of $0.75788. The effect of the change in demand charge calculation is a decrease in total demand charges of about $4,830,273, which results in a proposed firm service pipeline capacity charge of $0.12312 per therm, or $1.83 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01465 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 2006 Earnings Review. Page 17 of Exhibit B shows the total proposed average change being applied to approximately $35.5 million, which is more than the current three percent limit of $30.0 million. However, because the result is a benefit (rate decrease) to customers, the Company respectfully requests a waiver of the three percent limit.

The net effect of this portion of the filing is to decrease the Company's annual revenues by $38,565,710. The effect of removing the temporary adjustments placed into rates November 1, 2006 is $3,064,959. The effect of applying the new temporary rate adjustments is $35,500,751.

III. Base Rate Adjustments

The effect of this portion of the filing is to decrease the Company's annual revenues by $1,319,718.

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 County. 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, 2007.

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

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

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Sincerely,

NW NATURAL

/s/ Onita R. King

Onita R. King, Manager
Tariffs and Regulatory Compliance

Attachments: Tariffs
Exhibits A and B

TABLE OF TARIFF SHEET REVISIONS
PROPOSED TO BECOME EFFECTIVE NOVEMBER 1, 2007

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
Second Revision of Sheet 00.8	First Revision of Sheet 00.8	"General Rules and Regulations"
Sixth Revision of Sheet 1-1	Fifth Revision of Sheet 1-1	Schedule 1 "General Sales Service"
Sixth Revision of Sheet 2-1	Fifth Revision of Sheet 2-1	Schedule 2 "Residential Sales Service"
Fourth Revision of Sheet 3-3	Third Revision of Sheet 3-3	Schedule 3 "Basic Firm Sales Service – Non-Residential"
Fifth Revision of Sheet 19-1	Fourth Revision of Sheet 19-1	Schedule 19 "Gas Light Service"
Second Revision of Sheet 31-9	First Revision of Sheet 31-9	Schedule 31 "Non-Residential Sales and Transportation Service"
Third Revision of Sheet 31-10	Second Revision of Sheet 31-10	Schedule 31 "Non-Residential Sales and Transportation Service"
Second Revision of Sheet 32-9	First Revision of Sheet 32-9	Schedule 32 "Large Volume Non-Residential Sales and Transportation Service"
Fourth Revision of Sheet 32-10	Third Revision of Sheet 32-10	Schedule 32 "Large Volume Non-Residential Sales and Transportation Service"
Third Revision of Sheet 33-6	Second Revision of Sheet 33-9	Schedule 33 "High-Volume Non-Residential Firm and Interruptible Transportation Service"
Sixth Revision of Sheet 54-1	Fifth Revision of Sheet 54-1	Schedule 54 "Emergency Sales Service"
Sixth Revision of Sheet 100-1	Fifth Revision of Sheet 100-1	Schedule 100 "Summary of Adjustments"
Sixth Revision of Sheet 162-1	Fifth Revision of Sheet 162-1	Schedule 162 "Temporary (Technical) Adjustments to Rates"
Fifth Revision of Sheet 162-2	Fourth Revision of Sheet 162-2	Schedule 162 "Temporary (Technical) Adjustments to Rates"
Seventh Revision of Sheet 163-1	Sixth Revision of Sheet 163-1	Schedule 163 "Special Adjustment to Rates Price Elasticity"
Sixth Revision of Sheet 164-1	Fifth Revision of Sheet 164-1	Schedule 164 "Purchased Gas Cost Adjustment to Rates"

PROPOSED REVISION	CANCELS REVISION	SCHEDULE TITLE
First Revision of Sheet 169-1	Original Sheet 169-1	Schedule 169 “Special Adjustment to Rates for Storage Inventories”
Seventh Revision of Sheet 177-2	Sixth Revision of Sheet 177-2	Schedule 177 “Adjustments to Rates for Safety Programs”
Fifth Revision of Sheet 177-3	Fourth Revision of Sheet 177-3	Schedule 177 “Adjustments to Rates for Safety Programs”
Fourth Revision of Sheet 177-4	Third Revision of Sheet 177-4	Schedule 177 “Adjustments to Rates for Safety Programs”
Eighth Revision of Sheet 190-1	Seventh Revision of Sheet 190-1	Schedule 190 “Partial Decoupling Mechanism”
Sixth Revision of Sheet 190-2	Fifth Revision of Sheet 190-2	Schedule 190 “Partial Decoupling Mechanism”
Fourth Revision of Sheet 195-4	Third Revision of Sheet 195-4	Schedule 195 “Weather Adjusted Rate Mechanism (WARM Program)”
Third Revision of Sheet 195-5	Second Revision of Sheet 195-5	Schedule 195 “Weather Adjusted Rate Mechanism (WARM Program)”
Fourth Revision of Sheet P-2	Third Revision of Sheet P-2	Schedule P “Purchased Gas Cost Adjustments”
Fifth Revision of Sheet P-3	Fourth Revision of Sheet P-3	Schedule P “Purchased Gas Cost Adjustments”
Seventh Revision of Sheet P-5	Sixth Revision of Sheet P-5	Schedule P “Purchased Gas Cost Adjustments”

GENERAL RULES AND REGULATIONS
(continued)

Definitions (continued):

Schedule 3 ISF or 3 (ISF). Refers to Rate Schedule 3, Industrial Firm Sales Service.

Schedule 31 CSF or 31 (CSF). Refers to Rate Schedule 31, Commercial Firm Sales Service.

Schedule 31 CTF or 31 (CTF). Refers to Rate Schedule 31, Commercial Firm Transportation Service.

Schedule 31 CSI or 31 (CSI). Refers to Rate Schedule 31, Commercial Interruptible Sales Service

Schedule 31 ISF or 31 (ISF). Refers to Rate Schedule 31, Industrial Firm Sales Service.

Schedule 31 ITF or 31 (ITF). Refers to Rate Schedule 31 Industrial Firm Transportation Service.

Schedule 31 ISI or 31 (ISI). Refers to Rate Schedule 31 Industrial Interruptible Sales Service.

Schedule 32 CSF or 32 (CSF). Refers to Rate Schedule 32 Commercial Firm Sales Service. (C)

Schedule 32 ISF or 32 (ISF). Refers to Rate Schedule 32 Industrial Firm Sales Service. (N)

Schedule 32 TF or 32 (TF). Refers to Rate Schedule 32 Firm Transportation Service.

Schedule 32 SI or 32 (SI). Refers to Rate Schedule 32 Interruptible Sales Service.

Schedule 32 TI or 32 (TI). Refers to Rate Schedule 32 Interruptible Transportation Service.

Schedule 33 TF or 33 (TF). Refers to Rate Schedule 33 Firm Transportation Service.

Rate Schedule 33 TI or 33 (TI). Refers to Rate Schedule 33 Interruptible Transportation Service.

Service Agreement. The oral or written agreement between Company and Customer for gas service.

Service Election. The term used to describe customer's choice of service options.

Service Line. The piping that runs from the Main to the Delivery Point at Customer's service site.

Special Contract. A negotiated contract with unique rates and terms and conditions that must be approved by the Commission and must meet the criteria established by ORS 757.210 and OPUC Order No. 87-402.

Standby Service. Service to equipment that is available in lieu of or as a supplement to the usual source of supply; or service to equipment that is used for the protection of equipment or commodity during cold weather.

(continue to Sheet 00.9)

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, is subject to the provisions of **SCHEDULE X**. (C)

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.

(T)

MONTHLY RATE: Effective: November 1, 2007

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	$0.50042	$0.00989	$0.12312	$0.73728	$(0.04531)	**$1.32540**	(R)
Commercial	$0.47589	$0.00950	$0.12312	$0.73728	$(0.06142)	**$1.28437**	(R)

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, is subject to the provisions of **SCHEDULE X**. (C)

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, 2007 (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):	$0.43291	$0.00890	$0.12312	$0.73728	$(0.04465)	**$1.25756**

(R)

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)

(T)

MONTHLY RATE: Effective: November 1, 2007

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 CSF):	$0.34545	$0.00756	$0.12312	$0.73728	$(0.06014)	**$1.15327**	(C)(R)
Industrial (3 ISF):	$0.31440	$0.00708	$0.12312	$0.73728	$(0.05123)	**$1.13065**	(C)(R)
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.

(T)

MONTHLY RATE: Effective: November 1, 2007

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	$22.08	$0.05	$(0.91)	**$21.22**	(R)
All additional mantles	$21.47	$0.05	$(0.91)	**$20.61**	(R)
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.

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

MONTHLY RATES FOR COMMERCIAL CUSTOMER CLASS:

Effective: November 1, 2007 (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 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	$0.18338	$0.00516	$0.73728	$(0.05856)	**$0.86726**	(R)
Block 2: All additional therms	$0.16719	$0.00493	$0.73728	$(0.05839)	**$0.85101**	(R)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.12312**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.83**	(R)
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	$0.18338	$0.00516	$0.73728	$(0.05650)	**$0.86932**	(R)
Block 2: All additional therms	$0.16719	$0.00493	$0.73728	$(0.05633)	**$0.85307**	(R)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01465**	(R)
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	$0.18338	$0.00516		$(0.01037)	**$0.17817**	(R)
Block 2: All additional therms	$0.16719	$0.00493		$(0.01020)	**$0.16192**	(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, 2007** (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 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	$0.00248	$0.73728	$(0.04977)	**$0.85789**	(R)
Block 2: All additional therms	$0.15172	$0.00223	$0.73728	$(0.04961)	**$0.84162**	(R)
Pipeline Capacity Charge Options (select one):						
Firm Pipeline Capacity Charge - Volumetric option (per therm):					**$0.12312**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV):					**$1.83**	(R)
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	$0.00248	$0.73728	$(0.04771)	**$0.85995**	(R)
Block 2: All additional therms	$0.15172	$0.00223	$0.73728	$(0.04755)	**$0.84368**	(R)
Plus: Interruptible Pipeline Capacity Charge - Volumetric (per therm):					**$0.01465**	(R)
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	$0.00248		$(0.00158)	**$0.16880**	(R)
Block 2: All additional therms	$0.15172	$0.00223		$(0.00142)	**$0.15253**	(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.

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

MONTHLY RATES: Effective: November 1, 2007 (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 [1]:						
Customer Charge (per month, all service types):					**$675.00**	(C)
	Base Rate	Base Rate Adjustment	Commodity Component [2]	Total Temporary Adjustments [3]	**Billing Rates**	
32 CSF Volumetric Charges (per therm):						(C)
Block 1: 1st 10,000 therms	$0.10007	$0.00147	$0.73728	$(0.04916)	**$0.78966**	(R)
Block 2: Next 20,000 therms	$0.08505	$0.00125	$0.73728	$(0.04903)	**$0.77455**	
Block 3: Next 20,000 therms	$0.06005	$0.00089	$0.73728	$(0.04877)	**$0.74945**	
Block 4: Next 100,000 therms	$0.03503	$0.00052	$0.73728	$(0.04852)	**$0.72431**	
Block 5: Next 600,000 therms	$0.02002	$0.00029	$0.73728	$(0.04838)	**$0.70921**	
Block 6: All additional therms	$0.01003	$0.00014	$0.73728	$(0.04828)	**$0.69917**	(R)
32 ISF Volumetric Charges (per therm):						(N)
Block 1: 1st 10,000 therms	$0.10007	$0.00147	$0.73728	$(0.04910)	**$0.78972**	
Block 2: Next 20,000 therms	$0.08505	$0.00125	$0.73728	$(0.04897)	**$0.77461**	
Block 3: Next 20,000 therms	$0.06005	$0.00089	$0.73728	$(0.04871)	**$0.74951**	
Block 4: Next 100,000 therms	$0.03503	$0.00052	$0.73728	$(0.04846)	**$0.72437**	
Block 5: Next 600,000 therms	$0.02002	$0.00029	$0.73728	$(0.04832)	**$0.70927**	
Block 6: All additional therms	$0.01003	$0.00014	$0.73728	$(0.04822)	**$0.69923**	(N)
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):					**$0.12312**	(R)
Firm Pipeline Capacity Charge - Peak Demand option (per therm of MDDV per month):					**$1.83**	(R)
INTERRUPTIBLE SALES SERVICE CHARGES [4]:						
Customer Charge (per month):					**$675.00**	
32 ISI Volumetric Charges (per therm):						(C)
Block 1: 1st 10,000 therms	$0.10007	$0.00147	$0.73728	$(0.04704)	**$0.79178**	(R)
Block 2: Next 20,000 therms	$0.08505	$0.00125	$0.73728	$(0.04691)	**$0.77667**	
Block 3: Next 20,000 therms	$0.06005	$0.00089	$0.73728	$(0.04665)	**$0.75157**	
Block 4: Next 100,000 therms	$0.03503	$0.00052	$0.73728	$(0.04640)	**$0.72643**	
Block 5: Next 600,000 therms	$0.02002	$0.00029	$0.73728	$(0.04626)	**$0.71133**	
Block 6: All additional therms	$0.01003	$0.00014	$0.73728	$(0.04616)	**$0.70129**	
Interruptible Pipeline Capacity Charge (per therm):					**$0.01465**	(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 32-10)

Issued August 31, 2007 Effective with service on
NWN Advice No. OPUC 07-7 and after November 1, 2007

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

<u>MONTHLY RATES</u>: Effective: November 1, 2007 (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 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	$0.00147		$(0.00091)	**$0.10063**	(R)
Block 2: Next 20,000 therms	$0.08505	$0.00125		$(0.00078)	**$0.08552**	
Block 3: Next 20,000 therms	$0.06005	$0.00089		$(0.00052)	**$0.06042**	
Block 4: Next 100,000 therms	$0.03503	$0.00052		$(0.00027)	**$0.03528**	
Block 5: Next 600,000 therms	$0.02002	$0.00029		$(0.00013)	**$0.02018**	
Block 6: All additional therms	$0.01003	$0.00014		$(0.00003)	**$0.01014**	(R)
Firm Service Distribution Capacity Charge (per therm of MDDV per month):					**$0.15748**	
INTERRUPTIBLE TRANSPORTATION SERVICE CHARGES (32 ITI) [3]:						(C)
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	$0.00147		$(0.00091)	**$0.10063**	(R)
Block 2: Next 20,000 therms	$0.08505	$0.00125		$(0.00078)	**$0.08552**	
Block 3: Next 20,000 therms	$0.06005	$0.00089		$(0.00052)	**$0.06042**	
Block 4: Next 100,000 therms	$0.03503	$0.00052		$(0.00027)	**$0.03528**	
Block 5: Next 600,000 therms	$0.02002	$0.00029		$(0.00013)	**$0.02018**	
Block 6: All additional therms	$0.01003	$0.00014		$(0.00003)	**$0.01014**	(R)

[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 as set forth in Schedule 162 may also apply.

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

MONTHLY RATE: Effective: November 1, 2007 (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. The rates for Coos County customers are subject to the additional adjustment set forth in **SCHEDULE 160**.

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	$0.00008	$(0.00005)	**$0.00545**	(R)
Firm Service Distribution Capacity Charge: Per therm of MDDV per month					**$0.15748**	
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]		
Per therm, all therms:		$0.00542	$0.00008	$(0.00005)	**$0.00545**	(R)
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.

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**. (T)

MONTHLY RATE: Effective: November 1, 2007

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	$1.28176	$(0.05225)	**$1.22951**

(R)

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.

SCHEDULE 100
SUMMARY OF ADJUSTMENTS

PURPOSE:

The purpose of this Schedule is to list and summarize the adjustment Schedules applicable to each of the Company's Rate Schedules.

(N)

SCHEDULE	A	160	162	163	164	167	169	176	177	185	186	190	195	199	301
1R	ADD	ADD	INC	INC	INC	INC	INC	INC	INC	ADD	ADD	INC		INC	ADD
1C	ADD	ADD	INC	INC	INC	INC	INC	INC	INC	ADD	ADD	INC		INC	ADD
2	ADD	ADD	INC	INC	INC	INC	INC	INC	INC	ADD	ADD	INC	ADD	INC	ADD
3 (CSF)	ADD	ADD	INC	INC	INC	INC	INC	INC	INC	ADD	ADD	INC	ADD	INC	ADD
3 (ISF)	ADD	ADD	INC		INC	INC	INC	INC	INC	ADD	ADD			INC	ADD
15	ADD					INC									
19	ADD		INC		INC	INC	INC		INC					INC	
31 (CSF)	ADD	ADD	INC	INC	INC	INC	INC	INC	INC	ADD	ADD	INC		INC	ADD
31 (CSI)	ADD	ADD	INC	INC	INC	INC	INC	INC	INC		ADD	INC		INC	ADD
31 (CTF)	ADD		INC	INC		INC		INC	INC			INC		INC	
31 (ISF)	ADD	ADD	INC		INC	INC	INC	INC	INC	ADD	ADD			INC	
31 (ISI)	ADD	ADD	INC		INC	INC	INC	INC	INC		ADD			INC	
31 (ITF)	ADD		INC			INC		INC	INC					INC	
32 (SF)	ADD	ADD	INC		INC	INC	INC		INC	ADD	ADD			INC	
32 (SI)	ADD	ADD	INC		INC	INC	INC		INC		ADD			INC	
32 (TF)	ADD		INC			INC			INC					INC	
32 (TI)	ADD		INC			INC			INC					INC	
33 (TI)	ADD		INC			INC		INC	INC					INC	
33 (TF)	ADD		INC			INC		INC	INC					INC	
54	ADD	ADD	INC		INC	INC	INC		INC					INC	
60	ADD					INC									

Table Code Key:

ADD This adjustment is added to the billing rates at the time the bill is issued.
INC This adjustment is included in the billing rates shown on the Rate Schedule.

(continue to Sheet 100-2)

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, 2007 (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		$(0.04934)	$(0.00224)	$0.00279	**$(0.04879)**	(C)
1C		$(0.04934)	$(0.00224)	$(0.01332)	**$(0.06490)**	
2		$(0.04934)	$(0.00224)	$0.00345	**$(0.04813)**	
3 (CSF)		$(0.04934)	$(0.00224)	$(0.01204)	**$(0.06362)**	
3 (ISF)		$(0.04934)	$(0.00224)	$(0.00313)	**$(0.05471)**	
19		$(0.94)	$(0.04)	$0.00	**$(0.98)**	
31 (CSF)	Block 1	$(0.04934)	$(0.00224)	$(0.01046)	**$(0.06204)**	
	Block 2	$(0.04934)	$(0.00224)	$(0.01029)	**$(0.06187)**	
31(CTF)	Block 1	N/A	N/A	$(0.01037)	**$(0.01037)**	
	Block 2	N/A	N/A	$(0.01020)	**$(0.01020)**	
31 (CSI)	Block 1	$(0.04934)	$(0.00027)	$(0.01037)	**$(0.05998)**	
	Block 2	$(0.04934)	$(0.00027)	$(0.01020)	**$(0.05981)**	
31 (ISF)	Block 1	$(0.04934)	$(0.00224)	$(0.00167)	**$(0.05352)**	
	Block 2	$(0.04934)	$(0.00224)	$(0.00151)	**$(0.05309)**	
31 (ITF)	Block 1	N/A	N/A	$(0.00158)	**$(0.00158)**	
	Block 2	N/A	N/A	$(0.00142)	**$(0.00142)**	
31 (ISI)	Block 1	$(0.04934)	$(0.00027)	$(0.00158)	**$(0.05119)**	
	Block 2	$(0.04934)	$(0.00027)	$(0.00142)	**$(0.05103)**	(C)

(continue to Sheet 162-2)

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

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2007 (T)

Schedule	Block	Account 191 Commodity Adjustment	Account 191 Pipeline Capacity Adjustment	Account 186 Net Adjustments	Total Temporary Adjustment	
32(CSF)	Block 1	$(0.04934)	$(0.00224)	$(0.00106)	**$(0.05264)**	(C)
	Block 2	$(0.04934)	$(0.00224)	$(0.00093)	**$(0.05251)**	
	Block 3	$(0.04934)	$(0.00224)	$(0.00067)	**$(0.05225)**	
	Block 4	$(0.04934)	$(0.00224)	$(0.00042)	**$(0.05200)**	
	Block 5	$(0.04934)	$(0.00224)	$(0.00028)	**$(0.05186)**	
	Block 6	$(0.04934)	$(0.00224)	$(0.00018)	**$(0.05176)**	
32(ISF)	Block 1	$(0.04934)	$(0.00224)	$(0.00100)	**$(0.05258)**	
	Block 2	$(0.04934)	$(0.00224)	$(0.00087)	**$(0.05245)**	(C)
	Block 3	$(0.04934)	$(0.00224)	$(0.00061)	**$(0.05219)**	
	Block 4	$(0.04934)	$(0.00224)	$(0.00036)	**$(0.05194)**	
	Block 5	$(0.04934)	$(0.00224)	$(0.00022)	**$(0.05180)**	
	Block 6	$(0.04934)	$(0.00224)	$(0.00012)	**$(0.05170)**	
32(SI)	Block 1	$(0.04934)	$(0.00027)	$(0.00091)	**$(0.05052)**	(C)
	Block 2	$(0.04934)	$(0.00027)	$(0.00078)	**$(0.05039)**	
	Block 3	$(0.04934)	$(0.00027)	$(0.00052)	**$(0.05013)**	
	Block 4	$(0.04934)	$(0.00027)	$(0.00027)	**$(0.04988)**	
	Block 5	$(0.04934)	$(0.00027)	$(0.00013)	**$(0.04974)**	
	Block 6	$(0.04934)	$(0.00027)	$(0.00003)	**$(0.04964)**	
32(TI)	Block 1	N/A	N/A	$(0.00091)	**$(0.00091)**	
	Block 2	N/A	N/A	$(0.00078)	**$(0.00078)**	
	Block 3	N/A	N/A	$(0.00052)	**$(0.00052)**	
	Block 4	N/A	N/A	$(0.00027)	**$(0.00027)**	
	Block 5	N/A	N/A	$(0.00013)	**$(0.00013)**	
	Block 6	N/A	N/A	$(0.00003)	**$(0.00003)**	
33(TI)		N/A	N/A	$(0.00005)	**$(0.00005)**	
33(TF)		N/A	N/A	$(0.00005)	**$(0.00005)**	
54		$(0.04934)	$(0.00224)	$(0.00415)	**$(0.05573)**	(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.

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, 2007** (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:	$(0.00413) per therm	(C)
Commercial Rate Schedules:	$(0.00156) 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.

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

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

APPLICABLE:
To the following Rate Schedules of this Tariff:

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

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2007 (T)

Annual Sales WACOG [1]	$0.73728
Winter Sales WACOG [2]	$0.75778
Firm Sales Service Pipeline Capacity Component [3]	$0.12312
Firm Sales Service Pipeline Capacity Component [4]	$1.83
Interruptible Sales Service Pipeline Capacity Component [5]	$0.01465

(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 Sales Customers that request Winter Sales WACOG at the September 15 Annual Service Election. (C)
[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).

(T)

ADJUSTMENTS TO RATE COMPONENTS: Effective: November 1, 2007

The above listed components shall be adjusted as follows:

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

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

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 54 (D)
Schedule 2 Schedule 19 Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2007 (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		Schedule	Block	Account 191 Commodity Adjustment
1R		$0.00348		32(CSF/ISF)	Block 1	$0.00348
1C		$0.00348			Block 2	$0.00348
2		$0.00348			Block 3	$0.00348
3 (CSF)		$0.00348			Block 4	$0.00348
					Block 5	$0.00348
3 (ISF)		$0.00348			Block 6	$0.00348
				32(TF)	Block 1	N/A
19		$0.07			Block 2	N/A
31 (CSF)	Block 1	$0.00348			Block 3	N/A
	Block 2	$0.00348			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	$0.00348		32(SI)	Block 1	$0.00348
	Block 2	$0.00348			Block 2	$0.00348
31 (ISF)	Block 1	$0.00348			Block 3	$0.00348
	Block 2	$0.00348			Block 4	$0.00348
31 (ITF)	Block 1	N/A			Block 5	$0.00348
	Block 2	N/A			Block 6	$0.00348
31 (ISI)	Block 1	$0.00348		32(TI)	Block 1	N/A
	Block 2	$0.00348			Block 2	N/A
					Block 3	N/A
					Block 4	N/A
					Block 5	N/A
					Block 6	N/A
				33(TI)		N/A
				33(TF)		N/A
				54		$0.00348

(C)

(C)

SCHEDULE 177
ADJUSTMENTS TO RATES FOR SAFETY PROGRAM
(continued)

BARE STEEL REPLACEMENT PROGRAM (continued)

APPLICATION TO RATE SCHEDULES: **Effective: November 1, 2007** (T)
The Adjustments shown below are included in the Base Adjustments in the listed Rate Schedules:

Schedule	Block	70%	30%	Total Adjustment
1R		$0.00241	$0.00125	$0.00366
1C		$0.00241	$0.00119	$0.00360
2		$0.00241	$0.00109	$0.00350
3 (CSF)		$0.00241	$0.00086	$0.00327
3 (ISF)		$0.00241	$0.00078	$0.00319
19		$0.05	$0.00	$0.05
31 (CSF)	Block 1	$0.00241	$0.00046	$0.00287
	Block 2	$0.00241	$0.00042	$0.00283
31(CTF)	Block 1	$0.00241	$0.00046	$0.00287
	Block 2	$0.00241	$0.00042	$0.00283
31 (CSI)	Block 1	$0.00241	$0.00046	$0.00287
	Block 2	$0.00241	$0.00042	$0.00283
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		$0.00241	$0.00103	$0.00344

(C)

(C)

(continue to Sheet 177-3)

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 October 31. 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, 2007 or until such other time as the Commission may approve. (C)

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2007 (T)
The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules.

(C)

Schedule	Block	Total Adjustment
1R		$0.00164
1C		$0.00155
2		$0.00142
3 (CSF)		$0.00113
3 (ISF)		$0.00102
19		$0.00
31C	Block 1	$0.00060
	Block 2	$0.00055
31I	Block 1	$0.00054
	Block 2	$0.00049
32 (all)	Block 1	$0.00032
	Block 2	$0.00027
	Block 3	$0.00019
	Block 4	$0.00011
	Block 5	$0.00006
	Block 6	$0.00003
33 (all)		$0.00002
54		$0.00134

(C)

(continue to Sheet 177-4)

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.

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, 2007 (T)
The Adjustments shown below are included in the Base Rate Adjustments in the above-listed Rate Schedules.

Schedule	Block	Total Adjustment
1R		$0.00488
1C		$0.00462
2		$0.00423
3 (CSF)		$0.00336
3 (ISF)		$0.00305
19		$0.00
31C	Block 1	$0.00180
	Block 2	$0.00165
31I	Block 1	$0.00162
	Block 2	$0.00146
32 (all)	Block 1	$0.00096
	Block 2	$0.00082
	Block 3	$0.00058
	Block 4	$0.00034
	Block 5	$0.00019
	Block 6	$0.00010
33 (all)		$0.00005
54		$0.00400

(C)
(T)
(T)
(C)

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, 2007** (T)
The Temporary Adjustments for Residential and Commercial Customers taking service on the above-listed Rate Schedules includes the following adjustment:

Residential Rate Schedules: **$ 0.00767** per therm (C)
Commercial Rate Schedules: **$(0.00853)** 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 Residential Customers, equal Normalized use per therm per customer	330,164,716 450,709 733
October 1 price decrease Usage increase due to price elasticity (-10% x -0.172) Estimated usage increase due to price elasticity (weather normalized usage x % of usage increase)	-10% 1.72% 5,678,833
Total New Baseline Usage: (weather normalized usage plus estimated usage increase), divided by customer count, equal Reset baseline usage per therm per customer	 335,843,549 450,709 745

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.

   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, 2007 is $0.44608 per therm for Residential customers and $0.30322 per therm for Commercial customers. (T)(C)

(continue to Sheet 190-3)

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	(C)
5	.9790	$0.43		3.8345	$ 1.35	
10	1.958	$0.87		7.669	$ 2.71	
15	2.937	$1.30		11.5035	$ 4.06	
20	3.916	$1.73		15.338	$ 5.41	
25	4.895	$2.16		19.1725	$ 6.77	
30	5.874	$2.60		23.007	$ 8.12	
35	6.853	$3.03		26.8415	$ 9.48	
40	7.832	$3.46		30.676	$10.83	
45	8.811	$3.89		34.5105	$12.18	
50	9.790	$4.33		38.345	$13.54	(C)

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)

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 $1.25756 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	
	Total WARM Adj.:	-9.79 x $0.44181 = -$4.3253	(R)
Total WARM Adjustment converted to cents per therm:	Total WARM Adj.	-$4.3253	(R)
	Monthly usage:	129 therms	
	Cent/therm Adj.:	-$4.3253 ÷ 129 = -$0.03353	(R)
Billing Rate per therm:	Current Rate/therm:	$1.25756	(R)
	WARM cent/therm Adj.	-$0.03353	(R)
	WARM Billing Rate:	$1.25756 + -$0.03353 = $1.22403	(R)
Total WARM Bill:	Customer Charge:	$6.00	
	Usage Charge:	$1.22403	(R)
	Total	(129 x $1.22403) + $6.00 = $163.90	(R)

(continue to Sheet 195-6)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

7. Estimated Annual Sales Weighted Average Cost of Gas (Annual Sales WACOG): The estimated Annual Sales WACOG is used for purposes of calculating the monthly gas cost deferral costs for entry into the Account 191 sub-accounts 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).
   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, 2007: (T)
   Estimated Annual Sales WACOG per therm (w/ revenue sensitive): **$0.73728** (C)
   Estimated Annual Sales WACOG per therm (w/o revenue sensitive): $0.71670 (C)

8. Estimated Winter Sales WACOG: The Company's weighted average Commodity Cost of Gas for the five-month period November through March.
   Effective November 1, 2007: (T)
   Estimated Winter Sales WACOG per therm (w/ revenue sensitive): **$0.75778** (C)
   Estimated Winter Sales WACOG per therm (w/o revenue sensitive): $0.73662 (C)

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

10. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by last year's (i.e., July 1 – June 30) actual Firm Sales Service volumes, weather normalized.
    Effective November 1, 2007: (T)
    Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): **$0.12312** (C)
    Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive: $0.11968 (C)

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

11. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by last year's (i.e., July 1 – June 30) actual Interruptible Sales Service volumes.
    Effective November 1, 2007: (T)
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):
    $0.01465 (C)
    Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):
    $0.01424 (C)

12. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.
    Effective November 1, 2007: (T)
    Estimated Non-Commodity Cost per therm - MDDV Based Sales (w/revenue sensitive):
    $1.83 (C)
    Estimated Non-Commodity Cost per therm- MDDV Based Sales (w/o revenue sensitive):
    $1.78 (C)

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

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

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

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

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

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

(continue to Sheet P-4)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

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

2. A debit or credit entry shall be made equal to 100% of any monthly difference between Embedded Non-Commodity Costs and Monthly Seasonalized Fixed Charges. The monthly Seasonalized Fixed Charges for the period November 1, 2007 through November 30, 2008 are: (T)

November 2007	$6,341,766	(R)
December 2007	$12,073,358	
January 2008	$11,821,776	
February	$9,872,251	
March	$8,455,621	
April	$6,000,379	
May	$4,180,822	
June	$2,806,743	
July	$2,390,466	
August	$2,371,647	
September	$2,640,437	
October	$5,049,248	
November	$8,593,868	
ANNUAL TOTAL	$76,256,616	(R)

3. For the 2007-2008 PGA Year commencing November 1, 2007, a debit or credit entry shall be made equal to 67% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost up to the first $15 million difference, and for the amount in excess of $15 million, a debit or credit entry shall be made equal to 90% of the difference. If by November 1, 2008 a different sharing ratio has not been approved by the Commission, then effective with the PGA Year commencing November 1, 2008, the debit or credit entry shall be made equal to 67% of the entire difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing.

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

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

6. Interest - The Company shall not compute interest on the deferrals accrued from November 2007 to October 2008, until amortization begins November 1, 2008. The Company shall compute interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission. (T)

(continue to Sheet P-6)

Exhibit: A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW Natural

SUPPORTING MATERIALS

TO

GAS PURCHASING STRATEGY,
CONTRACT SUMMARIES, AND
GAS COST FORECAST

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 07-7

August 31, 2007

Exhibit A
Supporting Materials

NWN Advice No. OPUC 07-7

Gas Purchasing Strategy, Contract Summaries and Gas Cost Forecast:

Summary of NW Natural's Gas Purchasing Strategy .... 1 – 2

Firm Off-System Gas Supply Contracts (Table 1) 3

Firm Transportation Capacity (Table 2) 4

Firm Storage Resources (Table 3) 5

Other Resources: Recall Agreements, Citygate Deliveries and
Mist Production (Table 4) 6

Firm Resource Summary (Table 5) 7

Summary of Gas Cost Forecast 8

Gas Daily, EIA Defends Its Gas Supply, Demand Projections,
Friday, August 24, 2008 .... 9 – 15

Public Utilities Fortnightly, Betting on Bad Numbers;
Considine, Timothy J., Ph.D. and Clemente, Frank A., Ph.D. .... 16 – 22

August 31, 2007

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 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.

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[1] "Design" year refers to the coldest heating season (currently 1992/93) 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.

RSF 8/28/2007

NWN has contracted with suppliers for approximately 1.2 million therms/day of firm deliveries on a daily basis over the upcoming November 2007 through October 2008 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 the same as that contracted for the Nov06-Oct07 period and very slightly less than the 1.3 million therms/day contracted during the Nov05-Oct06 period.

In addition, during the heating season (Nov07-Mar08), NWN contracts for another 1.0 million therms/day of supply under baseload and peaking contracts, reflecting the higher consumption of customers and potentially more intense competition for supplies during those months. This compares with 0.5 million therms/day contracted for the Nov06-Mar07 period and 1.5 million therms/day contracted for the Nov05-Mar06 period. The reduction from 2005/06 to 2006/07 helped avoid any potential oversupply situations while reflecting the relative abundance of spot gas buying opportunities in the Rockies. The increase in winter contract volumes from 2006/07 to 2007/08 takes into account pipeline projects in the Rockies, most notably phase 2 of Rockies Express, which are expected to siphon off Rockies gas to mid-continent markets starting in early 2008. Most of the winter contracted volume (800/000 therms/day) 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 peaking or "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 1.1 and 1.3 million therms/day of upstream capacity could be available during the heating season for spot (one month and shorter duration) purchases as and when needed. Accordingly, on days when all upstream capacity is in use, purchases will be split among three roughly equal categories – year-round contracts, winter term contracts and spot purchases.

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 75% of its expected annual purchase volumes for the upcoming 12-month period commencing in November, the traditional start month for its supply contracts. This target is the same as last year, but is lower than in prior years when NWN would hedge roughly 90% of its expected purchase volumes. The current 75% target could change in reaction to market conditions or other factors as the year processes.

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2007/2008 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
Coral Energy Canada	Nov-Oct	10,000		10/31/2010
Husky Energy Marketing	Nov-Oct	5,000		10/31/2009
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
TD Commodities	Nov-Mar	4,000		3/31/2008
Alberta:				
BP Canada	Nov-Oct	10,000		10/31/2009
BP Canada	Nov-Oct	10,000		10/31/2009
Coral Energy Canada	Nov-Oct	10,000		10/31/2008
Husky Energy Marketing	Nov-Mar	10,000		3/31/2008
ONEOK Energy Services Canada	Nov-Mar	10,000		3/31/2008
Sempra Energy Trading	Nov-Oct	10,000		10/31/2014
TD Commodities	Nov-Mar	10,000		3/31/2008
Rockies:				
BP Energy	Nov-Oct	10,000		10/31/2008
BP Energy	Nov-Mar		10,000	3/31/2008
ConocoPhillips	Nov-Mar	10,000		3/31/2008
Coral Energy Resources	Nov-Mar	15,000	0	3/31/2008
ONEOK Energy Services	Nov-Mar	10,000	10,000	3/31/2008
PPM Energy	Nov-Oct	10,000	0	10/31/2008
Western Gas Resources	Nov-Mar	10,000	0	3/31/2008
Western Gas Resources	Nov-Oct	5,000	0	10/31/2010
Total Off-System Firm Contract Supply		197,750	20,000	

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 2007/2008 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	3/30/2008
Weyerhauser Capacity Acquisition	5,200	12/31/2007
Total NWP Capacity	362,244	
less recallable releases to -		
Portland General Electric	(30,000)	10/31/2010
Georgia Pacific	(7,000)	10/31/2003
Net NWP Capacity	325,244	
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 2007/2008 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 2007/2008 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 2007/2008 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	325,244
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	887,574

NW Natural

Summary of Gas Cost Forecast

In preparing our WACOG, NW Natural utilized a forecast based on a 60-day NYMEX average. NW Natural used a similar method to develop its WACOG in the 2006 PGA, and continues to believe that the most accurate and reliable method to forecast market values for the PGA is to use actual forward market values averaged over a period of time to minimize the impact of daily price volatility. Because the NYMEX reflects a liquid market for trading natural gas derivatives, we believe it is an appropriate yardstick for setting WACOG.

In discussions in the UM 1286 docket, Staff indicated its preference for the utilities to consult a fundamentals forecast along with market indices to develop WACOG for the PGA. NW Natural did consult two fundamentals forecasts in development of its WACOG. The first was a forecast prepared by the U.S. Energy Information Administration (EIA), which is publicly available. The other was a proprietary forecast developed by Wood Mackenzie, a widely-recognized consulting service to which NW Natural subscribes.

NW Natural has considered the EIA forecast in the past, but has not utilized it due to a lack of confidence in its methodology. A recent study performed at Pennsylvania State University claims to have found inherent flaws in EIA's forecast, which has reinforced our concern. (EIA Defends Its Gas Supply, Demand Projections; *Gas Daily*, August 24, 2008, and, Betting on Bad Numbers; *Public Utilities Fortnightly*, July, 2007.) Therefore, NW Natural did not utilize EIA in its development of its forecast.

NW Natural also considered an expected value forecast from Wood Mackenzie. An "expected value" forecast, unlike a base case or "most likely" forecast, takes into account the skewed distribution of possible prices over the forecast period. As a result, an expected value forecast may be different than a most likely forecast, but is also more accurate in representing the range of possible outcomes.

The Wood Mackenzie forecast we received was higher than the NYMEX 60-day average, and in addition, was produced in June, so it included the most "stale" data we considered. Based on this, and our belief that NYMEX data is the most appropriate source for development of our forecast, NW Natural did not use the Wood Mackenzie forecast.

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Gas Daily

Friday, August 24, 2007

NYMEX stabilizes; Florida cash takes a beating

THE MARKET

After a three-day, 20% decline, the September NYMEX gas futures contract firmed up Thursday to settle 4.4 cents higher at $5.622/MMBtu. But cash prices continued to fall in most regions, with Florida markets particularly hard-hit.

The contract started the day at $5.64 and traded in and out of positive territory between $5.55 and $5.695. Brokers and analysts said a mildly supportive storage inventory report (*see story, page 3*) combined with some technical shortcovering to create a floor of support.

(continued on page 2)

Pioneer selling Canada assets to Abu Dhabi firm

Pioneer Natural Resources has agreed to sell its Canadian subsidiary to the Abu Dhabi National Energy Company for $540 million, the Dallas-based independent said Thursday.

The acquisition is the latest in a series for the Abu Dhabi firm, also known as TAQA, which is pursuing and assembling Canadian properties under its new subsidiary, TAQA North, to expand its international presence. The deal is expected to close during the fourth quarter.

"The Pioneer business is a great addition to TAQA's existing operations in Canada," said Peter Barker-Homek, CEO of TAQA. "The acquisi-

(continued on page 6)

EIA defends its gas supply, demand projections

Inherent flaws in how the Energy Information Administration derives its natural gas supply and demand forecasts could have "widespread socioeconomic implications," particularly in the form of unsound climate change legislation, two Pennsylvania State University professors assert.

But EIA defended its methodology and cautioned that its forecasts should be viewed merely as a "starting point" in developing energy policy.

In an analysis of EIA's National Energy Modeling System and its forecasts of gas markets, Frank Clemente, professor of social science and energy policy, and Timothy Considine, professor of natural resources,

(continued on page 4)

Under pressure, firm suspends drilling near park

A Denver-based gas producer has abandoned plans to drill on two sites near a national park in New Mexico — but what happens to the firm's outstanding leases there remains unresolved.

Cimarex Energy spokesman Mark Burford said Wednesday that the company has opted not to drill on state land near the entrance of Chaco Culture National Historical Park because of concerns about potential harm to environmental and cultural resources. But he said the company would seek some form of redress from the New Mexico State Land Office if Cimarex can't exercise its lease rights there.

(continued on page 3)

Daily price survey ($/MMBtu)

NATIONAL AVERAGE PRICE: 5.540

Trans. date: 8/23
Flow date(s): 8/24

	Midpoint	Absolute	Common	Volume	Deals
Permian Basin Area					
El Paso, Permian Basin	5.355	5.25-5.38	5.32-5.38	1161	170
Waha	5.475	5.25-5.52	5.41-5.52	557	101
Transwestern, Permian Basin	5.275	5.27-5.30	5.27-5.28	13	2
East Texas-North Louisiana Area					
Carthage Hub	5.620	5.58-5.70	5.59-5.65	220	41
NGPL, Texok zone	5.480	5.35-5.55	5.43-5.53	1072	161
Texas Eastern, ETX	5.580	5.55-5.62	5.56-5.60	33	11
Texas Gas, zone 1	5.720	5.68-5.76	5.70-5.74	83	19
East-Houston-Katy					
Houston Ship Channel	5.595	5.55-5.68	5.56-5.63	491	48
Katy	5.575	5.55-5.65	5.55-5.60	625	77
South-Corpus Christi					
Agua Dulce Hub	5.595	5.50-5.63	5.56-5.63	163	10
NGPL, STX	5.610	5.56-5.67	5.58-5.64	115	24
Tennessee, zone 0	5.615	5.60-5.63	5.61-5.62	55	11
Texas Eastern, STX	5.600	5.59-5.65	5.59-5.62	237	42
Transco, zone 1	5.595	5.57-5.61	5.59-5.61	43	14
Louisiana-Onshore South					
ANR, La.	5.715	5.64-5.79	5.68-5.75	186	37
Columbia Gulf, La.	5.730	5.68-5.78	5.71-5.76	301	56
Columbia Gulf, mainline	5.660	5.62-5.75	5.63-5.69	570	81
Florida Gas, zone 1	5.700	5.69-5.75	5.69-5.72	15	5
Florida Gas, zone 2	5.960	5.81-6.06	5.90-6.02	71	10
Florida Gas, zone 3	7.360	6.12-8.10	6.87-7.86	324	31
Henry Hub	5.730	5.68-5.80	5.70-5.76	1437	179
NGPL, La.	5.680	5.67-5.70	5.67-5.69	3	3
Southern Natural, La.	5.970	5.92-6.05	5.94-6.00	414	52
Tennessee, La., 500 Leg	5.860	5.82-5.96	5.83-5.90	491	107
Tennessee, La., 800 Leg	5.745	5.67-5.83	5.71-5.79	174	44
Texas Eastern, WLA	5.735	5.66-5.79	5.70-5.77	399	77
Texas Eastern, ELA	5.760	5.67-5.83	5.72-5.80	244	66
Texas Gas, zone SL	5.715	5.65-5.81	5.68-5.76	238	38
Transco, zone 2	5.805	5.71-5.90	5.76-5.85	167	25
Transco, zone 3	6.070	5.81-6.24	5.96-6.18	441	76
Trunkline, WLA	5.760	5.76-5.76	5.76-5.76	5	1
Trunkline, ELA	5.760	5.72-5.88	5.72-5.80	58	14
Oklahoma					
ANR, Okla.	5.340	5.30-5.35	5.33-5.35	55	14
CenterPoint, East	5.510	5.48-5.58	5.49-5.54	276	40
NGPL, Midcontinent	5.265	5.21-5.30	5.24-5.29	390	73
Oneok, Okla.	5.345	5.30-5.38	5.33-5.37	55	11
Panhandle, Tx.-Okla.	5.260	5.22-5.29	5.24-5.28	175	41
Southern Star, Tx.-Okla.-Kan.	5.265	5.22-5.28	5.25-5.28	26	6
New Mexico-San Juan Basin					
El Paso, Bondad	5.070	5.04-5.15	5.04-5.10	51	9
El Paso, San Juan Basin	5.090	5.00-5.25	5.03-5.15	929	116

NYMEX contract gains 4.4 cents ... *from page 1*

Some sources said the contract could invariably press lower, although a couple cautioned that it might meet with several areas of technical congestion along the way. “We can probably shave off another 50 cents and not feel bad about it,” an analyst said.

In the spot market, prices at most Florida points took a beating as National Weather Service forecasts called for rain and milder weather across much of the state through early next week. “Demand was coming off pretty good,” a trader said.

Florida Gas Transmission’s zone 3 tumbled about 50 cents, while the Florida city-gates plummeted $1.40.

Losses at other Gulf Coast points were far less dramatic. Henry Hub cash lost more than a dime, while Houston Ship Channel and Katy slid almost 15 cents.

Most Northeast prices went against the grain and inched higher as forecasts called for a brief blast of intense heat today and Saturday. Daytime highs in the Boston area are expected to peak in the mid-90s, about 15 degrees above normal.

One trader said that while most prices started the day around the previous day’s midpoints, “the power guys came in late and started Hoovering up all the gas.” Sources also said some traders were getting a jump on securing gas to meet weekend cooling demand.

Transcontinental Gas Pipe Line zone 6-New York gained more than a nickel, while the Algonquin Gas Transmission city-gates ticked up around 15 cents.

Moderating weather softens spot prices

But Appalachian prices lost ground as storage buying diminished ahead of a steamy weekend across the Eastern Seaboard. Columbia Gas Transmission fell a dime or so.

A mid-morning rally wasn’t enough to push upper Midwest averages into positive territory. With temperatures expected to cool into the low 80s today, the Chicago and Michigan city-gates slid about 5 cents, ANR Pipeline’s ML 7 zone sank more than 10 cents and Viking Gas Transmission’s Emerson point shed a few pennies.

Spot prices in the Midcontinent continued to fall despite some overnight strength on the September NYMEX. While forecasts calling for a mild weekend dampened regional utility demand and suppressed trading activity, prices firmed somewhat after the Energy Information Administration reported a lower-than-expected storage build.

Southern Star Central Gas Pipeline gave back about a dime, while ANR in Oklahoma fell almost as much and CenterPoint’s East zone shed more than a nickel.

In the Pacific Northwest and western Canada, prices pulled back for a fourth consecutive day as cooler weather diminished utility demand. Losses were less severe than in previous days, however, which prompted one western Canadian trader to deem Thursday’s market “pretty stable … things popped up slightly but they came right back down.”

Prices at AECO-NIT in Alberta fell a couple of pennies, and the spread between AECO and Gas Transmission Northwest’s Kingsgate point continued to offer players a healthy profit even as Kingsgate slid around 15 cents. Westcoast Energy’s station 2 in British Columbia dropped about a dime and Sumas, Washington, sloughed off about a nickel.

In the Rockies, Kern River Gas Transmission at the Opal, Wyoming, plant fell around a dime, Northwest Pipeline’s Wyoming pool lost about 20 cents, as did Colorado Interstate Gas.

Daily price survey ($/MMBtu)

Trans. date: 8/23
Flow date(s): 8/24

	Midpoint	Absolute	Common	Volume	Deals
Rockies					
CIG, Rocky Mountains	2.990	2.88-3.10	2.94-3.05	30	11
Kern River, Opal plant	3.105	2.95-3.15	3.06-3.15	604	89
Stanfield, Ore.	5.065	5.03-5.14	5.04-5.09	145	18
Questar, Rocky Mountains	3.125	2.96-3.15	3.08-3.15	24	5
Cheyenne Hub	3.025	2.95-3.18	2.97-3.08	67	15
Northwest, Wyo. Pool	3.040	3.00-3.05	3.03-3.05	28	4
Northwest, s. of Green River	3.030	2.99-3.05	3.02-3.05	15	4
Canadian Gas					
Iroquois, receipts	5.850	5.83-5.90	5.83-5.87	451	58
Niagara	5.820	5.73-5.88	5.78-5.86	365	40
Northwest, Can. bdr. (Sumas)	5.005	4.97-5.04	4.99-5.02	267	35
TCPL Alberta, AECO-C*	C4.395	C4.35-4.45	C4.37-4.42	1428	122
Emerson, Viking GL	4.985	4.92-5.03	4.96-5.01	215	30
Dawn, Ontario	5.695	5.58-5.74	5.66-5.74	1160	139
GTN, Kingsgate	4.940	4.90-5.00	4.92-4.97	295	28
Westcoast, station 2*	C4.530	C4.49-4.60	C4.50-4.56	326	41
Appalachia					
Dominion, North Point	6.125	6.05-6.20	6.09-6.16	20	2
Dominion, South Point	6.100	6.05-6.17	6.07-6.13	394	78
Leidy Hub	6.520	6.52-6.52	6.52-6.52	2	1
Columbia Gas, Appalachia	5.770	5.70-5.98	5.70-5.84	1252	165
Mississippi-Alabama					
Texas Eastern, M-1 (Kosi)	6.055	6.00-6.07	6.04-6.07	47	12
Transco, zone 4	6.320	6.20-6.45	6.26-6.38	704	75
Others					
Algonquin, receipts	6.250	6.25-6.25	6.25-6.25	10	1
SoCal Gas	5.375	5.25-5.47	5.32-5.43	979	108
PG&E, South	5.370	5.35-5.40	5.36-5.38	259	36
PG&E, Malin	5.315	5.31-5.36	5.31-5.33	454	69
Alliance, into interstates	5.660	5.60-5.71	5.63-5.69	316	34
ANR, ML 7	5.810	5.74-5.83	5.79-5.83	178	14
NGPL, Amarillo receipt	5.345	5.30-5.37	5.33-5.36	39	10
Northern, Ventura	5.405	5.35-5.48	5.37-5.44	402	49
Northern, demarc	5.430	5.38-5.45	5.41-5.45	223	38
Dracut, Mass.	6.135	6.04-6.30	6.07-6.20	155	22
Citygates					
Chicago city-gates	5.670	5.59-5.73	5.64-5.71	998	160
Consumers Energy city-gate	5.730	5.65-5.76	5.70-5.76	345	52
Mich Con city-gate	5.710	5.66-5.78	5.68-5.74	332	48
PG&E city-gate	5.615	5.57-5.68	5.59-5.64	654	84
Florida city-gates	8.075	7.60-8.90	7.75-8.40	104	9
Algonquin, city-gates	6.400	6.24-6.54	6.33-6.48	190	32
Tennessee, zone 6 delivered	6.305	6.18-6.44	6.24-6.37	93	22
Iroquois, zone 2	6.275	6.25-6.42	6.25-6.32	117	13
Texas Eastern, M-3	6.305	6.18-6.45	6.24-6.37	678	129
Transco, zone 5 delivered	6.305	6.05-6.52	6.19-6.42	175	13
Transco, zone 6 non-N.Y.	6.415	6.26-6.50	6.36-6.48	92	30
Transco, zone 6 N.Y.	6.385	6.25-6.65	6.29-6.49	535	94
Kern River, delivered	5.395	5.38-5.40	5.39-5.40	60	8

***NOTE: Price in C$ per gj; C$1=US$0.9463**
Volume in 000 MMBtu/day

Market coverage

More information about Platts natural gas market coverage, including explanations of methodology and descriptions of delivery points, is available at www.platts.com/Natural Gas/Resources/Methodology & Specifications/.

Questions may also be directed to our market editors: Tom Castleman, (713) 658-3263, tom_castleman@platts.com and Liane Kucher, (202) 383-2147, liane_kucher@platts.com.

Southwest and West Coast prices lost ground as utility demand waned in the face of cooler weather. But pockets of hot weather across interior California buoyed late deals at some points, sources agreed. The Pacific Gas and Electric citygate shed around 15 cents, while Malin, Oregon, fell about 20 cents.

Meanwhile, El Paso Natural Gas in the San Juan Basin fell 20 cents or so and El Paso in the Permian Basin dropped almost 15 cents. — Market Staff Reports

Surplus narrows with 23-Bcf gas storage injection

The Energy Information Administration on Thursday reported a lower-than-expected 23-Bcf storage build for the week ending August 17, when gas demand soared thanks to temperatures that were 17% above normal nationwide.

The injection — which failed to rally the NYMEX gas futures contract (*see story, page 1*) — raised stocks to 2.926 Tcf, narrowing the surplus over the year-ago level to 77 Bcf from 108 Bcf and the surplus over the five-year average to 333 Bcf from 371 Bcf.

Analyst Antoine Halff of Fimat USA said the smaller-than-average builds this month were a short-term phenomenon driven by heat-related demand and a diversion of spot liquefied natural gas cargoes to Asian markets. "Inventories are already exceptionally high for the season and look on course to peak at a new record ahead of the peak winter-demand season," he said.

Adding to the bearish sentiment, Halff said, are recent forecasts for a warmer-than-average autumn and, in turn, a potentially late start to the heating season.

According to analyst Martin King of FirstEnergy Capital in Calgary, the gas futures market "is still on a generally downward slide. I wouldn't be surprised if we hit $4/MMBtu" at times before the storage injection season ends November 1.

As a result, King said producers could begin shutting in production as soon as late September and "it's not going to be pretty."

John Gerdes, who heads The Gerdes Group, said the country should end the refill season "on the cusp" of a new record. "Our trajectory at one point reached over 3.6 Tcf. Now we're a little more than 3.5 Tcf. It's narrowed some with the weather intensity."

According to EIA's data, inventories are now 137 Bcf above the five-year average in the East, 51 Bcf above the average in the West and 146 Bcf above the average in the producing region. JMM/SGS

Estimated working gas in storage

(week ending Aug 17)

	This Week (Bcf)	Last Week (Bcf)	Change (Bcf)
Consuming Region East	1,613	1,573	40
Consuming Region West	409	411	-2
Producing Region	904	919	-15
Total U.S.	2,926	2,903	23

	This Week Last Yr. (Bcf)	Prior 5 Year Average (Bcf)
Consuming Region East	1,632	1,476
Consuming Region West	390	358
Producing Region	827	758
Total U.S.	2,849	2,593

Source: Energy Information Administration

Cimarex cancels drilling plans near park ... *from page 1*

Burford said Cimarex is still interested in drilling for gas in the region and is doing some preliminary environment assessment work nearby. "We're looking to find less sensitive areas," he said. "We're still moving ahead in that area, but we're trying to be sensitive to some of the groups out there."

Russ Bodnar, public information officer for the Chaco park, said concerns about Cimarex's operations didn't arise until a few months ago, when construction of a drill site began near the park's visitor center.

"The park staff noticed there was some slagging outside the park boundary but within close proximity, between one and two miles, in a direct line of sight of the center," Bodnar said. After making inquiries, park officials learned that the state had issued drilling permits to Cimarex.

Report: Using regasified LNG to fuel electric generation may be ill-advised

Burning revaporized liquefied natural gas in new US power plants could produce more greenhouse gas emissions than coal-fired facilities that use advanced technologies, researchers at Carnegie Mellon University in Pittsburgh said this week.

In a report, the researchers said imported LNG used for electricity generation could have 35% higher lifecycle GHG emissions than those produced by advanced coal-fired plants. The report is scheduled to be published in the September 1 issue of *Science Digest*.

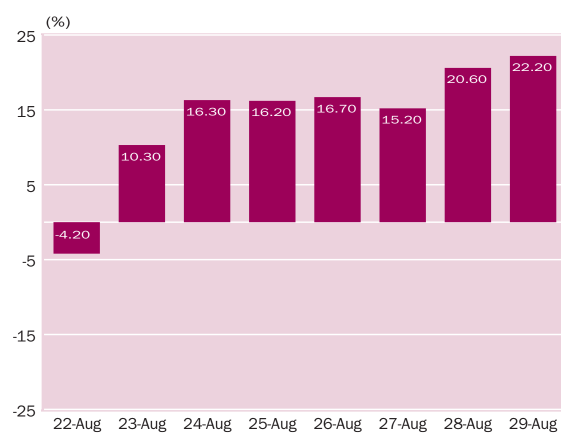
"Investing in LNG infrastructure today could make sense if it helps moderate natural gas prices and keeps existing natural gas power plants running. But making this investment ultimately locks us into certain technologies that make it harder for us to change paths in an increasingly carbon-constrained world," H. Scott Matthews, an associate professor in Carnegie Mellon's Civil and Environmental Engineering Department, said in a statement.

Increased imports of LNG, and the indirect effects associated with them, could eliminate the environmental benefits of natural gas over coal when future carbon mitigation technologies are adopted, the report maintained. It noted that LNG is extracted in a foreign country, liquefied, put into a tanker to cross oceans and then regasified and put into pipelines when it reaches the US — and that each of those steps leads to indirect environmental impacts such as carbon dioxide emissions.

The Carnegie Mellon team also argued that the US shouldn't rush to invest large amounts in new LNG import facilities without first analyzing all of the direct and indirect implications. The researchers also said utilities and the government should put more emphasis on conservation and energy efficiency that could help reduce the need for such investments.

"As the options grow more complicated, the choices become harder and harder," said Michael Griffin, a Carnegie Mellon researcher. "We just want to make certain that all the choices and their impacts are understood." RAW

Dominion's U.S. energy use forecast



This section of the Dominion Energy Index represents a national forecast for home heating and cooling requirements above or below normal with the baseline of 0 representing normal for that day based on historical data.

Source: Dominion

At first, park officials began working with state land officials and Cimarex to mitigate the impact of drilling on the park's operations. "We have an astronomy presentations we do several nights a week at the visitor center and we figured if there were lights on the rigs, maybe we could work with Cimarex to reduce the amount of light pollution," he said.

But Bodnar said state officials, led by Land Commissioner Pat Lyons, were soon talking about ways to prevent gas drilling near the visitor center altogether. "They said they would like to work with Cimarex to find other locations. They were hoping Cimarex and the state could work out a deal and maybe find suitable locations elsewhere that wouldn't impact the park."

Chaco, which was designated as a World Heritage site in 1987, contains historic architecture representative of the Puebloan Native American culture. "For about 300 years, from about 850 to about 1150, Chaco was the center of ceremony and culture and trading," Bodnar explained. "The architectural remains of the buildings are still magnificent even in partial deterioration."

He said between 60,000 and 80,000 visitors from all over the world travel to the park each year. "We basically talk about the Pueblo people's use of the night sky as something important to their culture."

John Bemis, New Mexico's assistant land commissioner for oil, natural gas and minerals, told Platts that the decision to suspend drilling was made by Cimarex, not the government. "Cimarex voluntarily put this thing on hold to consider the different impacts that there might be on Chaco Canyon and things related to the park."

Bemis suggested that the company might have decided it didn't want to meet the stringent rules the state would have imposed. "The requirements around Chaco would have been for the company to show that it had minimal or no impact on Chaco because it's a registered historical site," he said.

Regardless, Bemis said Cimarex's decision was "a good resolution to the issue. If it doesn't make everyone happy, at least it's an acceptable resolution."

Burford said that while Cimarex eyes drilling opportunities on other leases it holds nearby, the issue of the two leases near the visitor center "hasn't been fully resolved as far as the couple of permits we have, how we will replace those. We're still working with the state to see if we can exchange those leases for other areas or be reimbursed for the bids that we did pay."

A Land Office spokeswoman said Thursday that talks were continuing with Cimarex over the possibility of a lease swap. JM

EIA defends gas market projections ... *from page 1*

said a reliable forecasting model would show random errors with no set pattern of consistent over- or under-estimations.

But that isn't the case with EIA's NEMS model, which consistently underestimates the price of gas while overestimating supply, the pair contended in an article first published in *Public Utilities Fortnightly* last month.

EIA began publishing its baseline projections via NEMS in each year's *Annual Energy Outlook* starting in 1994. The model was developed by EIA's Office of Integrated Analysis and Forecasting to assist lawmakers in forming policy analysis.

According to a study by Clemente and Considine, year-ahead average price forecasts from 1998 through 2006 posted an absolute error of 16%, or $1/Mcf. That percentage steadily rose the farther out the predictions ran, with the four-year-ahead forecast off by more than 45%, or $2.60/Mcf, they said.

For instance, EIA's *AEO 2002* predicted the cost of gas to electric generators in 2006 would be $3.82/Mcf, in 2006 dollars. However, the professors said the actual cost ultimately averaged $7.15/Mcf.

The article said EIA's forecasts for gas consumption from power generators tend to run consistently below actual use. "This is somewhat counterintuitive because given that EIA underestimates prices paid for natural gas by electric generators, it would seem that lower prices would imply higher, not lower, natural gas consumption," it said.

Clemente and Considine said the absolute error for year-ahead forecasts is more than 900 Bcf, or more than 15% of actual gas use by the generation sector.

At the same time, the authors asserted that EIA's NEMS model consistently overestimates gas production and imports — particularly imports of liquefied natural gas. "Hence, the overall optimistic picture of ample natural gas supplies and growing consumption with either falling or constant real prices has not been supported by actual experience," they wrote.

For example, Clemente and Considine said that in 2005, EIA predicted that LNG receipts would reach 1.14 Tcf by 2006; actual imports for the year were just over half that at 583 Bcf.

Such "flawed" forecasts could have dire results when it comes to climate legislation, the professors said. "The systematic overestimation of [gas] production suggests that EIA's forecast of the supply response from climate demand is too ... large. Hence, the costs of carbon regulation may be significantly underestimated," Clemente and Considine said in an e-mail to Platts.

Agency acknowledges gas trends tough to forecast

In a review of its *AEO* forecasts from 1982 through 2006 initially published in March, EIA acknowledged that, of all the commodities it forecasts, natural gas tends to post the largest disparity between projections and actual data.

"As regulatory reforms that increased the role of competitive markets were implemented in the mid-1980s, the behavior of natural gas was especially difficult to predict," EIA said. "The technological improvement expectations embedded in early *AEO*s proved conservative, and advances that made petroleum and natural gas less costly to produce were missed."

Still, Andy Kydes, senior technical advisor in EIA's Office of Integrated Analysis and Forecasting, defended the administration's NEMS projections. He told Platts that EIA performs a large number of "what-if" scenarios — from baseline to best-case to worst-case — and argued that its outlooks should not be viewed as definitive forecasts.

"Forecasts are always going to be wrong," Kydes said. "For planning purposes, the user really needs to exercise some judgment and look at the scenario that best fits their view of the world."

Congress has that option as well when crafting energy-related legislation, he added. "The way we use the forecast in any project is [as] a starting point," with the baseline model serving as the initial benchmark for cost analysis.

"The important part is: What's the change from the reference or baseline in terms of magnitude and direction if you impose certain policies?" Kydes said. "That's the only way you should use these projections, really."

Kydes criticized the Penn State professors' analysis, saying their statistics cov-

Gas Daily basis forwards assessments, Aug 23

	Sep 2007	Oct 2007	Summer 2007*	Winter 2007-08	Summer 2008	Winter 2008-09
Transco Zone 6-NY	48.750	50.250	49.500	224.500	69.750	270.000
Texas Eastern, M-3	45.750	46.750	46.250	141.500	60.500	153.250
Columbia Gas, Appalachia	13.250	15.500	14.500	25.000	32.500	24.250
Transco, zone 3	9.500	9.000	9.250	7.000	5.250	5.500
Trunkline, LA	-6.000	-6.750	-6.500	-7.000	-7.500	-7.500
Houston Ship Channel	-25.250	-34.750	-30.000	-48.750	-26.750	-41.250
Chicago city-gates	-16.250	-17.000	-16.500	-11.500	-8.750	-0.500
MichCon city-gate	3.500	2.000	2.750	-8.500	15.000	5.000
Panhandle, Tx.-Okla.	-72.500	-85.250	-78.750	-120.250	-115.750	-118.000
Waha	-50.250	-69.000	-59.500	-83.750	-52.750	-71.000
El Paso, Permian Basin	-61.250	-80.500	-71.000	-100.000	-85.500	-97.750
El Paso, San Juan Basin	-79.750	-99.250	-92.000	-111.500	-98.750	-99.500
SoCal Gas	-42.250	-65.500	-54.000	-75.750	-53.000	-67.000
Northwest Pipe, Rockies	-269.500	-285.750	-277.500	-197.500	-147.000	-147.500

Prices in cents/MMBtu. Summer season is April-October. Winter is November-March.

*balance-of-season

NYMEX Henry Hub gas futures contract, Aug 23

	Settlement	High	Low	+/-	Volume
Sep 2007	5.622	5.695	5.550	+4.4	53377
Oct 2007	5.845	5.900	5.765	+5.5	34676
Nov 2007	6.805	6.865	6.755	+3.5	10644
Dec 2007	7.735	7.780	7.720	+5.5	5064
Jan 2008	8.140	8.140	8.140	+4.0	4411
Feb 2008	8.160	8.160	8.160	+3.4	1492
Mar 2008	7.985	7.985	7.985	+3.5	3339
Apr 2008	7.492	7.570	7.492	+0.7	1435
May 2008	7.483	7.500	7.470	+0.6	850
Jun 2008	7.558	7.558	7.557	+0.1	451
Jul 2008	7.651	7.670	7.651	-0.1	431
Aug 2008	7.716	7.716	7.716	-0.3	275
Sep 2008	7.759	7.770	7.759	-0.5	213
Oct 2008	7.882	7.895	7.882	-0.7	1443
Nov 2008	8.322	8.322	8.322	-1.2	39
Dec 2008	8.762	8.762	8.762	-2.2	36
Jan 2009	9.042	9.042	9.042	-2.2	874
Feb 2009	9.045	9.045	9.045	-2.9	43
Mar 2009	8.795	8.795	8.795	-2.9	523
Apr 2009	7.760	7.764	7.760	-5.4	1441
May 2009	7.665	7.665	7.665	-5.5	1016
Jun 2009	7.730	7.770	7.730	-5.7	27
Jul 2009	7.805	7.805	7.805	-5.9	27
Aug 2009	7.861	7.861	7.861	-6.0	27
Sep 2009	7.898	7.898	7.898	-6.0	27
Oct 2009	7.990	7.990	7.990	-6.0	132
Nov 2009	8.335	8.335	8.335	-6.0	42
Dec 2009	8.670	8.670	8.670	-6.0	27
Jan 2010	8.900	8.900	8.900	-5.5	0
Feb 2010	8.900	8.900	8.900	-5.5	0
Mar 2010	8.635	8.635	8.635	-5.5	50
Apr 2010	7.510	7.510	7.510	-8.0	53
May 2010	7.400	7.400	7.400	-8.0	0
Jun 2010	7.470	7.470	7.470	-8.0	0
Jul 2010	7.542	8.900	8.900	-8.0	0
Aug 2010	7.590	7.590	7.590	-8.0	4

Contract data for Wednesday

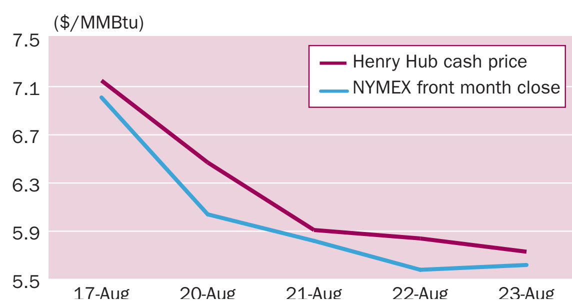
Volume of contracts traded: 122,642

Front-months open interest:

SEP, 33,846 ; OCT, 97,794 ; NOV, 69,923

Total open interest: 771,729

Henry Hub/NYMEX spread



Platts oil prices, Aug 23

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid	57.25-57.35	9.11
3% Resid	51.90-52.00	8.26
Crude spot		
WTI (Aug)	70.07-70.09	12.03
New York spot		
No.2	81.52-81.63	14.00
0.3% Resid HP	60.50-60.70	9.64
0.3% Resid LP	63.40-63.60	10.10
0.7% Resid	55.10-55.30	8.78
1% Resid HP	52.55-52.65	8.37

ered too small a time period. If they had studied EIA's projections from 1991 through 2006 and done "exactly the same analysis, they'd have found the results have very little bias in natural gas prices."

Kydes also said *AEO*'s year-ahead and two-year-ahead projections are based off their short-term energy outlook model — another system used to predict near-term trends — while projections three years ahead or more are based off NEMS. "There are two models really in play. In the short term, STEO is king."

In the meantime, Kydes said EIA is in the process of reviewing the structure of NEMS, "and we've put in for large amounts of money to totally redo the methodologies that need to be redone." JMM

Pioneer selling Canadian subsidiary … *from page 1*

tion provides further scale and efficiencies to our existing businesses by adding 27% to daily production, increasing [proved and probable] reserves by 35%, and providing a reserve life index in excess of 17 years."

The properties are located in northeastern British Columbia, northwestern Alberta and south-central Alberta and are focused on shallow gas and coalbed methane. TAQA said they contain 59 million barrels of oil equivalent in proved and probable reserves, along with production of around 10,000 boe/d.

That joins the 142 million boe of proved gas and oil reserves that TAQA obtained through its $2 billion acquisition of Pogo Producing's Canadian subsidiary Northrock Resources (*GD 5/30)*.

And the firm might not be done snapping up properties in Canada, observed Greg Stringham, vice president of markets and fiscal policy for the Canadian Association of Petroleum Producers.

Stringham told Platts that TAQA said earlier this year that it planned to spend around $3 billion on Canadian acquisitions in 2007, which leaves roughly $460 million still available.

Stringham said TAQA's strategy is "unique" in that the company is avoiding the rush to Canada's oil sands in favor of more conventional gas plays. "It's almost contrarian," he said.

Pioneer said it would use the proceeds from the sale for share buybacks, debt reduction and possible acquisitions in existing operating areas. "The sale of these assets now will allow us to effectively redeploy capital and enhance our financial flexibility," Chairman and CEO Scott Sheffield said.

Robert Morris of Bank of America Equity Research said the sale "will reduce our projection for Pioneer's total 'organic' production growth," but overall, "from a valuation perspective, we view this transaction as essentially neutral."

Pioneer's stock closed Thursday at $40.80/share, a 2.44% decline. MT

Cow power: California approves biogas supply contract for PG&E

The California Public Utilities Commission on Thursday approved a contract that will allow Pacific Gas and Electric to buy up to 8,000 Mcf/d of biogas that environmental technology firm Microgy makes from dairy cow waste.

The 10-year deal calls for the delivery of pipeline-quality renewable gas from select dairies throughout California's Central Valley *(GD 10/13)*. The gas equates to about 389,000 MWh of electricity, the PUC noted.

"The projects financed by this contract provide environmental benefits, particularly in terms of captured methane, which is an extremely potent greenhouse gas, while also providing a new income stream for dairies," said PUC Energy Division Director Sean Gallagher.

Commissioner Timothy Alan Simon remarked that the project has the potential to reduce farm runoff as well. Referring to the spinach contamination scare earlier this year, Simon said the deal would improve food safety in the state.

California's Renewables Portfolio Standard program requires utilities to obtain 20% of their retail sales from renewable energy sources by 2010. SGS

Oklahoma's Chesapeake plans 'Eastern headquarters' in W.Va.

Chesapeake Energy on Thursday unveiled plans for a new Eastern headquarters building in Charleston, West Virginia.

The Oklahoma City-based gas producer said its November 2005 purchase of Columbia Natural Resources made it "the largest leasehold owner, the most active driller and the second-largest natural gas producer in the Appalachian Basin."

Of the company's 6,000 US employees, about 535 work in Appalachia, 220 of them in Charleston. "In the 21 months since Chesapeake acquired CNR, Chesapeake has created more than 200 new Appalachian Basin jobs, of which 180 have been in West Virginia," the firm said. "More job creation is expected as the company continues to expand its Appalachian operations and prepares to move into its new headquarters in late 2009."

CEO Aubrey McClendon said the new building's design "has been inspired by the art and science of natural gas exploration. It is semi-circular with its design reflecting the rotation of a drill bit." MD

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- Wind M&A/consolidation — Asset valuation/acquisition analysis
  - Iberdrola's purchase of Competitive Power Ventures/ScottishPower
  - EDP's Horizon Wind Energy transaction
- Wind portfolios — Horizon Wind Energy NY wind
- Mergers — USPowerGen/Astoria
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- IPPs move from defense to offense — How much aggression is good?
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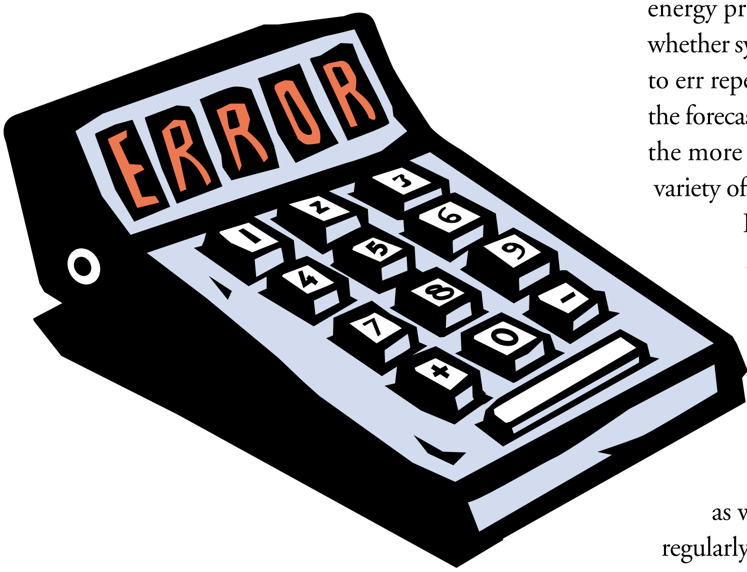
Gas-Market Forecasts

BETTING ON BAD NUMBERS

Why predictions from the Energy Information Administration may contain systematic errors.



The difficulties of predicting future trends in energy are widely recognized (*see Reference [4], p. 61*). Even the most sophisticated of forecasting models cannot account fully for a myriad of complex and generally uncontrollable variables. Thus, energy policy-makers necessarily must anticipate a wide range of possible outcomes in formulating energy plans.

The issue here, however, is not how difficult it is to predict energy prices, supply, and demand. Our question, rather, is whether systematic biases are built into forecasts, causing them to err repeatedly in the same direction. And the more visible the forecast (and the more likely also that it will be used), then the more likely it is that the error will be compounded in a variety of settings.

In the case of the U.S. Energy Information Administration (EIA), for example, natural gas (NG) data and projections are used widely in regulatory proceedings, energy planning, scientific research, investment decisions, litigation, and legislation. In such cases, systematic bias can have profound socioeconomic implications—not only within the United States but in other nations as well. Indeed, the National Energy Board of Canada regularly includes EIA NG forecasts in its projections. Even OPEC scholars use EIA projections as a benchmark in their research.

This widespread use of EIA forecasts follows the organization's own view of its nature and purpose. In fact, the EIA has

BY TIMOTHY J. CONSIDINE, PH.D. AND FRANK A. CLEMENTE, PH.D.

indicated that it designs its forecasts specifically to aid policymakers by providing "a policy-neutral reference case that can be used to analyze policy initiatives." However, while the EIA may strive to make its reference case forecasts "policy neutral," the question still remains: Are they "substantively neutral" in a forecasting sense? In other words, are they removed from the sort of systematic bias in which predictions deviate from actual observations in a distinct pattern?

Over the past decade, it increasingly has become apparent that EIA forecasts for NG differ substantially from actual outcomes. Some commentators [1] have suggested that EIA forecasts present a consistently "optimistic" view of NG that, for instance, underestimate price and overestimate supply. On the surface, this concern has face validity based upon forecasts from the EIA's *Annual Energy Outlook* series:

- In 2002, the EIA projected the cost of NG to electric generators in 2006 would be $ 3.82 per thousand cubic feet (Mcf). Actual cost per Mcf was $7.15 (all in 2006 dollars)
- In 2003, the EIA overestimated domestic NG production in 2006 by almost 2 trillion cubic feet—more than the annual production of Oklahoma.
- In 2005, the EIA projected liquefied natural gas (LNG) imports would reach 1,140 bcf in 2006. Actual imports in 2006 were only 583 Bcf—off by more than 550 Bcf just one year out.

To shed light upon the question of bias, we conducted an error decomposition analysis of EIA NG projections of key variables—price, supply, and consumption—from 1998 to 2006. Error-decomposition analysis is used commonly to evaluate economic forecasting models by identifying those components of the forecast errors or the proportions attributed to bias, the model, or randomness. A reliable model would display random errors with no discernable pattern of consistent under- or over-predictions. Thus, the proportions of forecast errors attributed to bias and model components would be minimal.

In our case, we evaluated one-, two-, three-, and four-year-ahead forecasts made by EIA from 1998 to 2006 for six key variables: (1) wellhead price; (2) price to electric generators; (3) consumption by electric generators; (4) domestic production; (5) imports from Canada; and (6) LNG imports.

Selecting Data for Review

Bolinger and Wiser [5] provides a graphical illustration of how EIA wellhead-gas prices forecasts going back to 1985 track actual prices. Their graph clearly illustrates that price forecasts during the 1980s turned out to be too high while forecasts made during the early 2000s appear too low. Graphical techniques, however, do not quantify the size or systematic tendencies of these forecasts errors. This study attempts to extend their analysis by applying the error decomposition methods discussed above.

During December of each year, EIA publishes a forecast that forms the basis of the *Annual Energy Outlook,* or *AEO*, [8] for the subsequent year. (Note: The EIA each year releases its reference case in December. Then in the following February, the EIA releases its full report, with sensitivity cases.)

So, for example, the 2006 *AEO* report released in December 2005 [9] contains a forecast of 2006 prices. This study examines their forecasts published from 1998 to 2006 because EIA posts the detailed forecast tables on its Web site, which is accessible to the public. Auffhammer [2] uses a larger sample and finds that the EIA forecasts of NG consumption, production, imports, and prices do not exhibit the necessary conditions for rationality under symmetric loss. (*Note: The EIA uses the National Energy Modeling System, or NEMS. See "Appendix: Methods of Forecast Evaluation," p. 58, describing our evaluation of EIA's forecasting methods.*)

While each EIA forecast extends 20 years or more, the maximum length of the forecast horizon examined in this study is four years. A three- to four-year forecast for prices is likely of most interest to industry because natural-gas-fired electricity generating plants take roughly three years to build. Moreover, going any more than four years out would not be meaningful given the small size of our sample. Given the sample of forecasts from 1998 to 2006, there are nine one-year-ahead forecasts, eight two-year forecasts, seven three-year forecasts, and six four-year forecasts. While comparing each published *AEO* forecast with actual data over its entire forecast horizon is insightful, economists typically stratify forecasts by length of time not necessarily when they are made. Hence, the forecasts are sorted by length of forecast horizon.

Evaluating the EIA Forecasts

To keep the analysis manageable and comprehensible, our decomposition analysis is conducted for three pairs of variables in the natural-gas market involving prices, domestic flows, and imports. The two prices are the average wellhead price and prices paid for natural gas by electricity producers. The flow variables include dry natural-gas production and consumption by electricity producers. The later was selected because the electricity sector comprises the most dynamic, market-sensitive component of natural-gas consumption along with industrial sector use. Imports include those from Canada and imports of LNG.

Prices. The EIA forecasts natural-gas prices in constant dollars. To establish a consistent basis for comparison, these constant price forecasts are inflated by the corresponding forecasts for the price deflator for gross domestic product (GDP). Once the forecasts are sorted, the prices are converted back to 2006 dollars using the latest GDP price deflator.

The forecast evaluation metrics for the one- through four-year-ahead forecasts from 1998 to 2006 appear in Table 1. On average, the one-year-ahead average percentage forecast error for the wellhead natural-gas price is 16 percent with an absolute error of $1/Mcf. These errors steadily rise and reach more than 45 percent with the four-year-ahead forecast and $2.60/Mcf.

TABLE 1 EVALUATION OF EIA NATURAL GAS-PRICE FORECASTS, 1998-2006

	Years Ahead			
	One	Two	Three	Four
	Average Wellhead NG Prices			
Average Percentage Error	-16.0%	-30.3%	-41.8%	-45.5%
Average Absolute Error ($/Mcf)	1.055	1.749	2.340	2.652
Root Mean Squared Error	34.9%	48.9%	54.3%	57.3%
Decomposition of MSE (proportion)				
Bias	0.547	0.651	0.876	0.845
Model	0.006	0.013	0.029	0.027
Random	0.447	0.336	0.095	0.128
	Electric Generator's NG Prices			
Average Percentage Error	-16.0%	-29.1%	-39.5%	-43.0%
Average Absolute Error ($/Mcf)	1.153	1.893	2.537	2.861
Root Mean Squared Error	33.4%	44.8%	50.8%	52.5%
Decomposition of MSE (proportion)				
Bias	0.565	0.672	0.868	0.854
Model	0.024	0.006	0.022	0.014
Random	0.412	0.322	0.110	0.131

Source: Annual Energy Outlook (annually, 1998-2006), U.S. Energy Information Administration, Table 14.

The RMSE (root mean squared error), which penalizes large errors more severely than the average percentage error (*see "Appendix," p. 58 for full explanation*), is almost 35 percent for the one-year-ahead forecast. Like the average percentage error, it too rises with the forecast horizon, reaching more than 57 percent with the four-year-ahead forecasts.

TABLE 2 EVALUATION OF EIA GAS CONSUMPTION AND PRODUCTION FORECASTS, 1998-2006

	Years Ahead			
	One	Two	Three	Four
	Electric Generator's NG Consumption			
Average Percentage Error	-15.3%	-15.0%	-14.6%	-14.7%
Average Absolute Error (TCF)	0.913	0.871	0.800	0.816
Root Mean Squared Error	19.7%	21.4%	20.1%	17.9%
Decomposition of MSE (% Contribution)				
Bias	0.575	0.548	0.577	0.704
Model	0.353	0.390	0.348	0.234
Random	0.072	0.062	0.075	0.062
	Dry NG Production			
Average Percentage Error	1.6%	4.1%	5.5%	7.8%
Average Absolute Error (TCF)	0.590	1.053	1.152	1.527
Root Mean Squared Error	3.9%	6.1%	7.0%	9.2%
Decomposition of MSE (% Contribution)				
Bias	0.189	0.444	0.615	0.707
Model	0.472	0.417	0.285	0.221
Random	0.340	0.139	0.100	0.07

Source: Annual Energy Outlook (annually, 1998-2006), U.S. Energy Information Administration, Table 13.

The decomposition of the MSE (mean squared error) for the one-year-ahead wellhead natural-gas price forecast errors indicates that 54.7 percent of the errors can be attributed to systematic bias. This bias crests to almost 88 percent for the three-year-ahead forecasts. While random disturbances are substantial for the one-year-ahead forecast, the large proportion attributed to bias is noteworthy. A plot of the actual time series for wellhead natural-gas prices and the four different forecasts appears in Fig. 1 and illustrates the tendency of the EIA price forecasts to systematically under-predict actual prices. The results for electric generator's natural-gas costs are very similar to those for wellhead natural-gas prices.

Market Flows. Table 2 shows the forecast errors for natural-gas consumption by electricity generators and for dry natural-gas production. The forecast errors are much smaller than those associated with the forecast errors for prices, which is a common phenomenon. Price forecasting often is more difficult than forecasting demand and production series, which often contain a sizeable trend component or signal. Nevertheless, the forecast errors for these two key natural-gas market flows are substantial.

The EIA forecasts for natural-gas consumption in electricity generation consistently are below actual observations of gas use in this sector (*see the average percentage errors in Table 2*). This is somewhat counter-intuitive because given that EIA under-estimates prices paid for natural gas by electric generators, it would seem that lower prices would imply higher, not lower, natural-gas consumption, all other things held equal. One of the big changes affecting the electricity sector's use of fuels has been the sulfur-dioxide emissions-trading program. That program has exerted a dramatic effect on the opportunities for fuel substitution in power generation, as shown by Considine and Larson [6]. Whether the NEMS correctly mod-

TABLE 3 **EVALUATION OF EIA NATURAL GAS IMPORT FORECASTS, 1998-2006**

	Years Ahead			
	One	Two	Three	Four
	NG Imports from Canada			
Average Percentage Error	-4.4%	-3.1%	2.0%	4.9%
Average Absolute Error (TCF)	0.184	0.245	0.285	0.347
Root Mean Squared Error	8.1%	8.9%	8.8%	10.9%
Decomposition of MSE (% Contribution)				
Bias	0.464	0.126	0.044	0.205
Model	0.246	0.613	0.669	0.625
Random	0.290	0.261	0.287	0.170
	LNG Imports			
Average Percentage Error	-11.2%	-5.6%	-7.1%	-25.1%
Average Absolute Error (TCF)	0.146	0.160	0.193	0.155
Root Mean Squared Error	65.6%	53.4%	67.4%	59.8%
Decomposition of MSE (% Contribution)				
Bias	0.151	0.104	0.093	0.420
Model	0.455	0.255	0.515	0.036
Random	0.394	0.641	0.393	0.544

Source: *Annual Energy Outlook* (annually, 1998-2006), U.S. Energy Information Administration, Table 13.

els the role of permits in power-sector fuel demand and fuel switching could be an important question.

The absolute error for the one-year-ahead forecast for electric generators natural-gas consumption is more than 900 billion cubic feet, which is more than 15 percent of consumption in this sector. In addition, the RMSEs are around 20 percent, nearly four times the errors found in econometric forecasting models of energy demand. [7] Like prices, the error decomposition analysis for natural-gas consumption by electric generators reveals a substantial bias across all four forecast horizons.

The forecast errors for dry natural-gas production reveal further problems. As the average percentage errors indicate, EIA consistently over-predicts dry natural-gas production. The absolute errors are quite sizeable in relation to marginal supplies of gas, specifically imports of LNG. For example, the one-year-ahead forecast error for production is 590 billion cubic feet, which is about equal to LNG imports in 2006. The two- through four-year-ahead forecast errors exceed one trillion cubic feet.

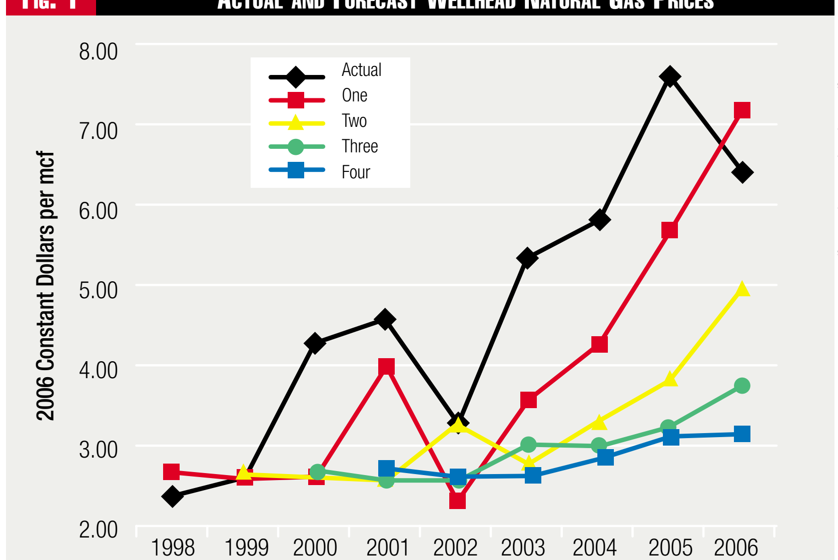
The mean squared error decomposition for natural-gas production also reveals sizeable bias, especially for the three- and four-year forecasts. Unlike prices and consumption forecast errors, the model component of the errors is more than 40 percent for the one- and two-year forecasts. This fact suggests that the model itself is generating systematic errors for the near-term forecast horizon. The time path of each forecast depicted in Fig. 2 illustrates that even though EIA has been scaling back its projections of natural-gas production, the model still portrays an upward track for production albeit from a lower base during each forecast year.

Imports. Another important factor influencing natural-gas markets is imports. The largest external source of natural gas into the United States is Canada, although EIA expects imports of LNG to become significant in the future. Among the forecast errors examined in this study, those associated with EIA's projection of imports from Canada are the lowest. Similar to the other forecast errors, however, the forecasts contain either bias or systematic errors arising from the model.

The projections of LNG imports are not as accurate as those for Canadian imports. The RMSEs are quite large and, while the bias components are relatively small, the proportion of the forecast errors associated with the model remains substantial, especially for the first and third year-ahead forecasts. This finding could be associated with the rather idiosyncratic nature of the LNG import forecasts.

To understand what is happening in the LNG forecast error decomposition, a scatter plot of the actual versus predicted LNG imports appears in Fig. 3. A perfect forecast in which the predictions are equal to the actual observations is plotted on the solid line. A "good" forecasting model should generate

FIG. 1 **ACTUAL AND FORECAST WELLHEAD NATURAL GAS PRICES**



Note: Forecast published in January

Fig 1 Source: *Annual Energy Outlook* (annually, 1998-2006), U.S. Energy Information Administration, Table 14.

forecasts close to the line of perfect forecasts and randomly scattered around it. As Fig. 3 illustrates, there are several very large over-predictions of LNG imports. The small number of these very large errors most likely accounts for the erratic swings in the mean squared error components reported above in Table 3. Indeed, as Fig. 4 illustrates EIA substantially over-estimated LNG imports in each of the preceding three years.

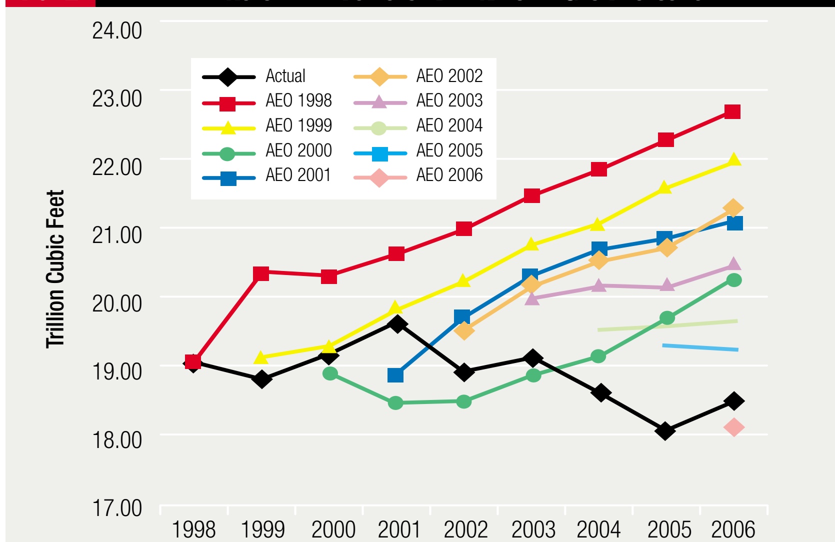
Policy Implications

As the independent research branch of the Department of Energy, the EIA forecasts for NG possess an imprimatur that stretches across the panorama of energy policy and analysis. Thus, the socioeconomic implications of systematic bias are profound indeed.

Several important conclusions can be drawn from this research. First, the NEMS model used by EIA to generate the *AEO* forecasts tends to over-estimate NG production and to under-estimate NG consumption by electricity producers. While EIA forecasts of NG imports from Canada fare somewhat better, projections of LNG imports are over-estimated substantially. These errors are associated with significant under-predictions of market prices. Hence, the overall optimistic picture of ample NG supplies, and growing consumption with either falling or constant real prices has not been supported by actual experience.

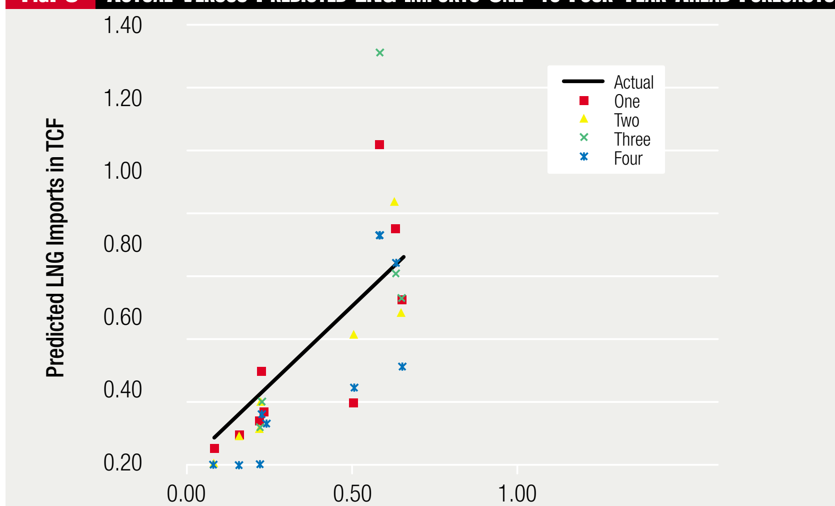
Moreover, an error-decomposition analysis demonstrated that the variation in EIA's forecast errors generally are not reflective of random chance but instead contain evidence of systematic bias, either arising from a fixed, linear bias or

FIG. 2 ACTUAL AND FORECAST DRY NATURAL-GAS PRODUCTION



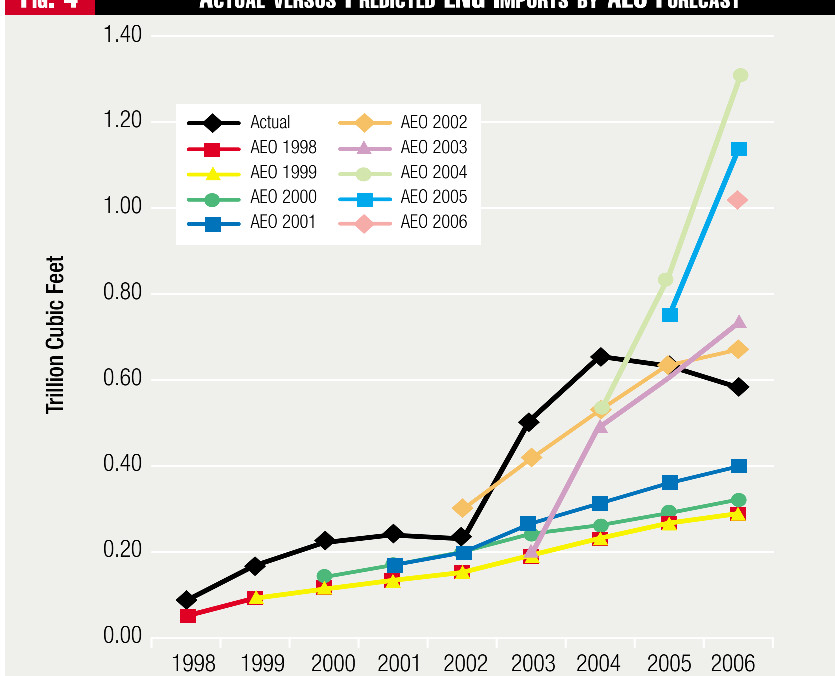
Source: Annual Energy Outlook (annually, 1998-2006), U.S. Energy Information Administration, Table 13.

FIG. 3 ACTUAL VERSUS PREDICTED LNG IMPORTS ONE- TO FOUR-YEAR-AHEAD FORECASTS



Source: *Annual Energy Outlook* (annually, 1998-2006), U.S. Energy Information Administration, Table 13.

FIG. 4 ACTUAL VERSUS PREDICTED LNG IMPORTS BY AEO FORECAST



Source: *Annual Energy Outlook* (annually, 1998-2006), U.S. Energy Information Administration, Table 13.

APPENDIX

Methods of Forecast Evaluation

There are a variety of metrics available to evaluate forecasts. No one measure tells the complete story but rather a suite of metrics and graphics must be employed to evaluate forecasts.

Since the National Energy Modeling System (NEMS) used by EIA to generate its forecasts equilibrates supply and demand, it seems most appropriate here to employ methods of economic-forecast evaluation in order to evaluate EIA forecasts of natural-gas markets. These methods all involve the computation of a variety of metrics that compare actual observations with predicted values.

The first metric is the average percentage error defined as:

$$APE_t = \frac{1}{n}\sum_{t=1}^{n} 100 * \frac{(P_t - A_t)}{A_t}$$

where t denotes the time period for a forecast horizon of n periods, P_t is the prediction from the model for period t, and A_t is the actual realized value of the variables in that period. As Auffhammer (*see Reference [2], p. 61*) observes, the problem with this metric is that large positive and negative values can cancel each other out. A similar metric is the average absolute error:

$$AAE = \frac{1}{n}\sum_{t=1}^{n} |A_t - P_t|,$$

which provides an estimate of the average magnitude of the forecast errors.

The third measure employed in this study is the mean squared error, which is defined as

$$MSE = \frac{1}{n}\sum_{t=1}^{n}\left(\frac{(P_t - A_t)}{A_{t-1}}\right)^2 = \frac{1}{n}\sum_{t=1}^{n}(p_t - a_t)^2$$

where $p_t = (P_t - A_{t-1})/A_{t-1}$ and $a_t = (A_t - A_{t-1})/A_{t-1}$. Notice unlike the common average percent error, the mean square error compares predicted versus actual changes. In addition, squaring the errors has the effect of disproportionately penalizing large errors, either negative or positive. The square root of the mean squared error, often referred to as the root mean squared error (RMSE), is more commonly reported because the square root operator on changes closely approximates percent change.

Ideally, model forecast errors should be random, displaying no discernible tendencies to either over or under-predict, or no patterns of either getting smaller or larger over time. Economists and statisticians have developed a variety of methods to determine whether forecast errors exhibit randomness or systematic bias. These methods involve decomposing the mean squared error into various error components. There are a variety of methods to decompose the MSE into its various components. An approach devised by Theil [14], and later recommended by Maddalla [13], and subsequently used in many studies since involves the computation of the following three components:

$$B = Bias = \frac{(\bar{p} - \bar{a})^2}{MSE}$$

$$M = Model = \frac{(S_p - rS_a)^2}{MSE}$$

$$R = Random = \frac{(1 - r^2)S_a^2}{MSE}$$

where S_p is the population standard deviation of p, r is the correlation coefficient between p and a and S_a is the standard deviation of a, and all three measures sum to one, *i.e.* $B + M + R = 1$. Maddalla and Theil note that the bias and the model components measure what can be called "systematic" errors. If B is large, then the average predicted change deviates substantially from the actual average change. This is a serious error because forecasters should be able to reduce such errors in the course of time. In short, if B is close to 1, the forecast is considered biased. The model component of the forecast error reflects the linear association between the actual and predicted values. If M is relatively large then this would suggest that the model itself is generating systematic errors. In a perfect forecast, both M and B would be zero so that if the following regression was estimated:

$$A_t = \alpha + \beta P_t$$

$\hat{\alpha} = 0$ and $\hat{\beta} = 1$ so that $A_t = P_t$. A regression model is not estimated in this study because our sample of forecasts is relatively small. Therefore, we do not attempt to estimate statistical confidence intervals around our forecast evaluation metrics because the power of these tests would be weak given the small sample.—***TJC, FAC***

from a systematic error coming from the model itself. This evidence of forecast bias arising from perhaps the most comprehensive energy market forecasting system in the world illustrates the enormous difficulty of forecasting these markets. The emergence of a natural-gas cartel will add even greater uncertainty to the forecasting.

These results offer several lessons and suggest certain concerns about current and future forecasts at EIA:

1. Gas Production. First, the consistent over-predictions of NG production in the United States should raise serious questions about the reliability of the premise that large supplies would become available with higher prices.

2. Gas Use for Generation. Second, the under-prediction of NG use in electric-power production even with unrealistically low prices suggests that other factors, such as sulfur-dioxide pollution permit costs, may be stimulating NG use in this sector. (This lesson suggests that the NEMS may not be adequately modeling factors that determine the electric-power sector's consumption of NG.)

3. LNG Imports. Third, the large over-estimates of LNG imports suggest fundamental problems with the trade side of the model. Each of these three problems presents daunting challenges for energy market modelers.

4. A Bias Toward Optimism. Current EIA forecasts exhibit a continuing optimism. In the 2007 *AEO*, for example, NG prices are forecasted to decline over the next decade—despite the fact that wellhead prices have increased more than 100 percent in the last five years and that the EIA did not project the vast bulk of those increases. Further, the EIA forecasts that NG production will increase 11 percent by 2020. Yet the EIA has overestimated production substantially in virtually every forecast since 1998.

5. A Failure to Recognize the Problem. Despite the biased divergence between their NG forecasts and actual outcomes, the EIA has published virtually nothing on the question of asymmetrical error. In fact, EIA's model evaluation methodology may itself camouflage the problem. For example, Auffhammer [2] has commented that, "The EIA conducts its own forecast evaluation…[but] this type of evaluation ignores potentially persistent biases in the forecasting model."

The analysis reported here suggests that considerable caution should be exercised when using EIA forecasts relating to the future price, supply, and consumption of NG. Similar caution should be exercised when using NEMS to assess the broader economic impacts of energy policy initiatives, *e.g.*, carbon cap-and-trade programs.

Climate-change proposals currently before Congress [3] depend heavily on predictions of the response of natural-gas supply and prices to carbon-permit prices. The actual capability of the NG supply network both here and abroad will be a critical factor in how economies adjust to such climate-change policies. Overestimating the supply capabilities of this network (as EIA has done over the past decade) could lead to underestimating the costs of carbon regulations.

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Exhibit: B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW Natural

SUPPORTING MATERIALS

TO

COMBINED EFFECTS,
COMMODITY AND NON-COMMODITY COSTS, AND
TEMPORARY AND PERMANENT ADJUSTMENTS EFFECTS

Purchased Gas Cost and Technical Adjustments to Rates

NWN Advice No. OPUC 07-7

August 31, 2007

NW Natural

Exhibit B
Supporting Materials

NWN Advice No. OPUC 07-7

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Summary of Temporary Increments 15

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August 31, 2007

NW Natural
Rates & Regulatory Affairs
2007-2008 PGA Filing - Oregon
Calculation of Proposed Rates - SUMMARY

		11/1/2006 Billing Rates	Net change WACOG	Net change Demand [1]	Proposed Rates PGA Only [1]	Net change Permanent Increments	Net change Temporary Increments	Elasticity Adjustment	**Proposed 11/1/2007 Rates [1]**
					D=A+B+C				**H=D+E+F+G**
Schedule	Block	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
1R		1.40893	(0.02223)	(0.00824)	1.37846	0.00089	(0.04982)	(0.00413)	1.32540
1C		1.37653	(0.02223)	(0.00824)	1.34606	0.00083	(0.06096)	(0.00156)	1.28437
2R		1.34052	(0.02223)	(0.00824)	1.31005	0.00079	(0.04915)	(0.00413)	1.25756
3C Firm Sales		1.24436	(0.02223)	(0.00824)	1.21389	0.00061	(0.05967)	(0.00156)	1.15327
Intentionally blank									
3I Firm Sales		1.21826	(0.02223)	(0.00824)	1.18779	0.00057	(0.05771)	0.00000	1.13065
Intentionally blank									
19	1st mantle	22.93	(0.43)	(0.16)	22.34	0.00	(1.04)	(0.08)	21.22
19	add'l mtls	22.32	(0.43)	(0.16)	21.73	0.00	(1.04)	(0.08)	20.61
31C Firm Sales	Block 1	0.94879	(0.02223)		0.92656	0.00033	(0.05807)	(0.00156)	0.86726
	Block 2	0.93239	(0.02223)		0.91016	0.00031	(0.05790)	(0.00156)	0.85101
31C Firm Trans	Block 1	0.18282	0.00000		0.18282	0.00033	(0.00342)	(0.00156)	0.17817
	Block 2	0.16642	0.00000		0.16642	0.00031	(0.00325)	(0.00156)	0.16192
31C Interr Sales	Block 1	0.95003	(0.02223)		0.92780	0.00033	(0.05725)	(0.00156)	0.86932
	Block 2	0.93363	(0.02223)		0.91140	0.00031	(0.05708)	(0.00156)	0.85307
31I Firm Sales	Block 1	0.93608	(0.02223)		0.91385	0.00028	(0.05624)	0.00000	0.85789
	Block 2	0.91968	(0.02223)		0.89745	0.00025	(0.05608)	0.00000	0.84162
31I Firm Trans	Block 1	0.17011	0.00000		0.17011	0.00028	(0.00159)	0.00000	0.16880
	Block 2	0.15371	0.00000		0.15371	0.00025	(0.00143)	0.00000	0.15253
31I Interr Sales	Block 1	0.93732	(0.02223)		0.91509	0.00028	(0.05542)	0.00000	0.85995
	Block 2	0.92092	(0.02223)		0.89869	0.00025	(0.05526)	0.00000	0.84368
32C Firm Sales	Block 1	0.86737	(0.02223)		0.84514	0.00015	(0.05563)	0.00000	0.78966
	Block 2	0.85215	(0.02223)		0.82992	0.00013	(0.05550)	0.00000	0.77455
	Block 3	0.82681	(0.02223)		0.80458	0.00010	(0.05523)	0.00000	0.74945
	Block 4	0.80146	(0.02223)		0.77923	0.00006	(0.05498)	0.00000	0.72431
	Block 5	0.78626	(0.02223)		0.76403	0.00002	(0.05484)	0.00000	0.70921
	Block 6	0.77612	(0.02223)		0.75389	0.00002	(0.05474)	0.00000	0.69917
32I Firm Sales	Block 1	0.86737	(0.02223)		0.84514	0.00015	(0.05557)	0.00000	0.78972
	Block 2	0.85215	(0.02223)		0.82992	0.00013	(0.05544)	0.00000	0.77461
	Block 3	0.82681	(0.02223)		0.80458	0.00010	(0.05517)	0.00000	0.74951
	Block 4	0.80146	(0.02223)		0.77923	0.00006	(0.05492)	0.00000	0.72437
	Block 5	0.78626	(0.02223)		0.76403	0.00002	(0.05478)	0.00000	0.70927
	Block 6	0.77612	(0.02223)		0.75389	0.00002	(0.05468)	0.00000	0.69923
32 Firm Trans	Block 1	0.10140	0.00000		0.10140	0.00015	(0.00092)	0.00000	0.10063
	Block 2	0.08618	0.00000		0.08618	0.00013	(0.00079)	0.00000	0.08552
	Block 3	0.06084	0.00000		0.06084	0.00010	(0.00052)	0.00000	0.06042
	Block 4	0.03549	0.00000		0.03549	0.00006	(0.00027)	0.00000	0.03528
	Block 5	0.02029	0.00000		0.02029	0.00002	(0.00013)	0.00000	0.02018
	Block 6	0.01015	0.00000		0.01015	0.00002	(0.00003)	0.00000	0.01014
32 Interr Sales	Block 1	0.86861	(0.02223)		0.84638	0.00015	(0.05475)	0.00000	0.79178
	Block 2	0.85339	(0.02223)		0.83116	0.00013	(0.05462)	0.00000	0.77667
	Block 3	0.82805	(0.02223)		0.80582	0.00010	(0.05435)	0.00000	0.75157
	Block 4	0.80270	(0.02223)		0.78047	0.00006	(0.05410)	0.00000	0.72643
	Block 5	0.78750	(0.02223)		0.76527	0.00002	(0.05396)	0.00000	0.71133
	Block 6	0.77736	(0.02223)		0.75513	0.00002	(0.05386)	0.00000	0.70129
32 Interr Trans	Block 1	0.10140	0.00000		0.10140	0.00015	(0.00092)	0.00000	0.10063
	Block 2	0.08618	0.00000		0.08618	0.00013	(0.00079)	0.00000	0.08552
	Block 3	0.06084	0.00000		0.06084	0.00010	(0.00052)	0.00000	0.06042
	Block 4	0.03549	0.00000		0.03549	0.00006	(0.00027)	0.00000	0.03528
	Block 5	0.02029	0.00000		0.02029	0.00002	(0.00013)	0.00000	0.02018
	Block 6	0.01015	0.00000		0.01015	0.00002	(0.00003)	0.00000	0.01014
54		1.31800	(0.02223)	(0.00824)	1.28753	0.00072	(0.05874)	0.00000	1.22951
33		0.00549	0.00000	0.00000	0.00549	0.00001	(0.00005)	0.00000	0.00545

Sources:

Direct Inputs	06-07 PGA							
Rates in detail		Col F - Col B	Column G+H-C-D		Col K - Col J	Col M - Col L	Column O	

[1] For convenience of presentation, demand charges for Rate Schedules 31 and 32 are omitted

NW Natural
Rates & Regulatory Affairs
2007-2008 PGA Filing - Oregon
PGA Effects on Average Bill by Rate Schedule

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

Row	Schedule	Block	Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	11/1/2006 Billing Rates	11/1/2006 Current Average Bill	Proposed 11/1/2007 PGA Only Rates	Proposed 11/1/2007 PGA Only Average Bill	Proposed 11/1/2007 PGA Only % Bill Change	Proposed 11/1/2007 Temp & Base Rates	Proposed 11/1/2007 Temp & Base Average Bill	Proposed 11/1/2007 Temp & Base % Bill Change	Proposed 11/1/2007 Total Rates	Proposed 11/1/2007 Total Average Bill	Proposed 11/1/2007 Total % Bill Change
5								F=D+(C * E)		H=D+(C * G)	I =(H - F)/F		K=D+(C * J)	L =(K - F)/F		K=D+(C * M)	O =(N - F)/F
6	Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
7	1R		738,740	N/A	17.0	5.00	1.40893	28.95	1.37846	28.43	-1.8%	1.35587	28.05	-3.1%	1.32540	27.53	-4.9%
8	1C		69,478	N/A	32.0	5.00	1.37653	49.05	1.34606	48.07	-2.0%	1.31484	47.07	-4.0%	1.28437	46.10	-6.0%
9	2R		349,180,219	N/A	56.0	6.00	1.34052	81.07	1.31005	79.36	-2.1%	1.28803	78.13	-3.6%	1.25756	76.42	-5.7%
10	3C Firm Sales		150,214,247	N/A	231.0	8.00	1.24436	295.45	1.21389	288.41	-2.4%	1.18374	281.44	-4.7%	1.15327	274.41	-7.1%
11	Intentionally blank																
12	3I Firm Sales		4,452,443	N/A	1,359.0	8.00	1.21826	1,663.62	1.18779	1,622.21	-2.5%	1.16112	1,585.96	-4.7%	1.13065	1,544.55	-7.2%
13	Intentionally blank																
14	19	1st mantle	26,476	N/A	116.0	22.04	22.93	22.93	22.34	22.34	-2.6%	21.81	21.81	-4.9%	21.22	21.22	-7.5%
15	19	add'l mtls	0	N/A	0.0	21.43	22.32	22.32	21.73	21.73	-2.6%	21.20	21.20	-5.0%	20.61	20.61	-7.7%
16	31C Firm Sales	Block 1	25,260,012	2,000	4,291.0	325.00	0.94879	2,222.58	0.92656	2,178.12		0.88949	2,103.98		0.86726	2,059.52	
17		Block 2	37,514,863	all additional			0.93239	2,136.11	0.91016	2,085.18		0.87324	2,000.59		0.85101	1,949.66	
18		Total						**4,358.69**		**4,263.30**	-2.2%		**4,104.57**	-5.8%		**4,009.18**	-8.0%
19	31C Firm Trans	Block 1	0	2,000	0.0	325.00	0.18282	325.00	0.18282	325.00		0.17817	325.00		0.17817	325.00	
20		Block 2	0	all additional			0.16642		0.16642			0.16192			0.16192		
21		Total						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
22	31C Interr Sales	Block 1	24,218	2,000	0.0	325.00	0.95003	325.00	0.92780	325.00		0.89155	325.00		0.86932	325.00	
23		Block 2	62,749	all additional			0.93363		0.91140			0.87530			0.85307		
24		Total						**325.00**		**325.00**	0.0%		**325.00**	0.0%		**325.00**	0.0%
25	31I Firm Sales	Block 1	6,121,113	2,000	7,483.0	325.00	0.93608	2,197.16	0.91385	2,152.70		0.88012	2,085.24		0.85789	2,040.78	
26		Block 2	18,752,037	all additional			0.91968	5,042.61	0.89745	4,920.72		0.86385	4,736.49		0.84162	4,614.60	
27		Total						**7,239.77**		**7,073.42**	-2.3%		**6,821.73**	-5.8%		**6,655.38**	-8.1%
28	31I Firm Trans	Block 1	52,053	2,000	10,847.0	325.00	0.17011	665.22	0.17011	665.22		0.16880	662.60		0.16880	662.60	
29		Block 2	338,435	all additional			0.15371	1,359.87	0.15371	1,359.87		0.15253	1,349.43		0.15253	1,349.43	
30		Total						**2,025.09**		**2,025.09**	0.0%		**2,012.03**	-0.6%		**2,012.03**	-0.6%
31	31I Interr Sales	Block 1	364,285	2,000	6,942.0	325.00	0.93732	2,199.64	0.91509	2,155.18		0.88218	2,089.36		0.85995	2,044.90	
32		Block 2	1,218,399	all additional			0.92092	4,551.19	0.89869	4,441.33		0.86591	4,279.33		0.84368	4,169.47	
33		Total						**6,750.83**		**6,596.51**	-2.3%		**6,368.69**	-5.7%		**6,214.37**	-7.9%
27	32C Firm Sales	Block 1	4,362,476	10,000	23,219.0	675.00	0.86737	9,348.70	0.84514	9,126.40		0.81189	8,793.90		0.78966	8,571.60	
28		Block 2	5,217,416	20,000			0.85215	11,264.57	0.82992	10,970.71		0.79678	10,532.63		0.77455	10,238.78	
29		Block 3	1,533,406	20,000			0.82681		0.80458			0.77168			0.74945		
30		Block 4	588,989	100,000			0.80146		0.77923			0.74654			0.72431		
31		Block 5	0	600,000			0.78626		0.76403			0.73144			0.70921		
32		Block 6	0	all additional			0.77612		0.75389			0.72140			0.69917		
33		Total						**20,613.27**		**20,097.11**	-2.5%		**19,326.53**	-6.2%		**18,810.38**	-8.7%
34	32I Firm Sales	Block 1	5,173,377	10,000	39,992.0	675.00	0.86737	9,348.70	0.84514	9,126.40		0.81195	8,794.50		0.78972	8,572.20	
35		Block 2	7,849,163	20,000			0.85215	17,043.00	0.82992	16,598.40		0.79684	15,936.80		0.77461	15,492.20	
36		Block 3	3,725,142	20,000			0.82681	8,261.49	0.80458	8,039.36		0.77174	7,711.23		0.74951	7,489.10	
37		Block 4	5,709,579	100,000			0.80146		0.77923			0.74660			0.72437		
38		Block 5	577,883	600,000			0.78626		0.76403			0.73150			0.70927		
39		Block 6	0	all additional			0.77612		0.75389			0.72146			0.69923		
40		Total						**34,653.19**		**33,764.16**	-2.6%		**32,442.53**	-6.4%		**31,553.50**	-8.9%
41	32 Firm Trans	Block 1	4,350,187	10,000	87,217.0	675.00	0.10140	1,689.00	0.10140	1,689.00		0.10063	1,681.30		0.10063	1,681.30	
42		Block 2	7,273,834	20,000			0.08618	1,723.60	0.08618	1,723.60		0.08552	1,710.40		0.08552	1,710.40	
43		Block 3	4,842,493	20,000			0.06084	1,216.80	0.06084	1,216.80		0.06042	1,208.40		0.06042	1,208.40	
44		Block 4	11,950,946	100,000			0.03549	1,320.83	0.03549	1,320.83		0.03528	1,313.02		0.03528	1,313.02	
45		Block 5	14,478,740	600,000			0.02029		0.02029			0.02018			0.02018		
46		Block 6	14,543	all additional			0.01015		0.01015			0.01014			0.01014		
47		Total						**5,950.23**		**5,950.23**	0.0%		**5,913.12**	-0.6%		**5,913.12**	-0.6%
48	32 Interr Sales	Block 1	16,505,951	10,000	45,154.0	675.00	0.86861	9,361.10	0.84638	9,138.80		0.81401	8,815.10		0.79178	8,592.80	
49		Block 2	23,517,823	20,000			0.85339	17,067.80	0.83116	16,623.20		0.79890	15,978.00		0.77667	15,533.40	
50		Block 3	12,749,089	20,000			0.82805	12,548.27	0.80582	12,211.40		0.77380	11,726.17		0.75157	11,389.29	
51		Block 4	20,468,411	100,000			0.80270		0.78047			0.74866			0.72643		
52		Block 5	9,662,278	600,000			0.78750		0.76527			0.73356			0.71133		
53		Block 6	0	all additional			0.77736		0.75513			0.72352			0.70129		
54		Total						**38,977.17**		**37,973.40**	-2.6%		**36,519.27**	-6.3%		**35,515.49**	-8.9%
55	32 Interr Trans	Block 1	5,757,246	10,000	294,470.0	675.00	0.10140	1,689.00	0.10140	1,689.00		0.10063	1,681.30		0.10063	1,681.30	
56		Block 2	10,476,487	20,000			0.08618	1,723.60	0.08618	1,723.60		0.08552	1,710.40		0.08552	1,710.40	
57		Block 3	7,884,762	20,000			0.06084	1,216.80	0.06084	1,216.80		0.06042	1,208.40		0.06042	1,208.40	
58		Block 4	25,434,579	100,000			0.03549	3,549.00	0.03549	3,549.00		0.03528	3,528.00		0.03528	3,528.00	
59		Block 5	52,120,670	600,000			0.02029	2,931.30	0.02029	2,931.30		0.02018	2,915.40		0.02018	2,915.40	
60		Block 6	82,075,249	all additional			0.01015		0.01015			0.01014			0.01014		
61		Total						**11,109.70**		**11,109.70**	0.0%		**11,043.50**	-0.6%		**11,043.50**	-0.6%
62	54		0	N/A	0.0	N/A	1.31800	N/A	1.28753	N/A	N/A	1.25998	N/A	N/A	1.22951	N/A	N/A
63	33		0	N/A	0.0	38,000.00	0.00549	38,000.00	0.00549	38,000.00	0.0%	0.00545	38,000.00	0.0%	0.00545	38,000.00	0.0%
64																	
65	**Totals**		938,690,486														
66			0														

67

68 **Sources:**

69 Direct Inputs — per Tariff — per Tariff

70

71 Rates in summary — Column A — Column D — Cols A+E+F+G — Column H

72

73 [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
2007-2008 PGA Filing - Oregon
PGA Effects on Revenue

		Amount	Reference
1		**Amount**	**Reference**
2	**Purchased Gas Cost Adjustment (PGA)**		
3			
4	Gas Cost Change	($14,401,246)	NWN 2007-08 PGA gas cost file.xls
5			
6	Capacity Cost Change	(4,830,273)	NWN 2007-08 PGA gas cost file.xls
7			
8	**Total PGA Change**	(19,231,519)	
9			
10	**Temporary Rate Adjustments**		
11			
12	Proposed Temporary Increments	(35,500,751)	NWN 2007-08 Oregon PGA rate development file
13			
14	Removal of Current Temporary Increments	3,064,959	2006-2007 PGA filing
15			
16	**Total Net Temporary Rate Adjustment**	(38,565,710)	
17			
18	**Base Rate Adjustments**		
19			
20	Proposed Safety Program Costs	5,013,000	NWN/A Page ____ of ____
21			
22	Removal of Current Safety Program Costs	(4,591,000)	2006-2007 PGA filing
23			
24	Coos Bay Adjustment	(134,214)	Coos Bay workpaper
25			
26	Removal of Current Coos Bay Adjustment	123,563	2006-2007 PGA filing
27			
28	Price Elasticity Adjustment	(1,731,067)	NWN 2007-08 Oregon PGA rate development file
29			
30	**Total Net Base Rate Adjustment**	(1,319,718)	
31			
32			
33	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($59,116,947)**	
34			
35			
36			
37	2006 Oregon Earnings Test Normalized Total Revenues	$912,138,000	
38			
39	Affect of this filing, as a percentage change (line 31÷ line 35)	-6.48%	

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

Line		Twelve Months Ended 06/30/07		
1				
2				
3	Total Billed Gas Sales Revenues	894,784,907		
4	Total Oregon Revenues	920,881,457		
5				
6	Regulatory Commission Fees [1]	2,302,204	0.250%	Statutory rate
7	City License and Franchise Fees	21,382,205	2.322%	Line 7 ÷ Line 4
8	Net Uncollectible Expense	2,025,953	0.220%	Line 8 ÷ Line 4
9				
10	Total	25,710,362	**2.792%**	Sum lines 8-9
11				
12				
13	**Note:**			
14	[1] Dollar figure is set at statutory level of 0.25% times Total Oregon Revenues (line 4)			
15				
16				
17				

NW Natural
2007-2008 PGA - SYSTEM
Summary of Total Commodity Cost

SYSTEM COSTS

1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
2			November	December	January	February	March	April	May	June	July	August	September	October	TOTAL
3			1	2	3	4	5	6	7	8	9	10	11	12	
4	**COSTS**														
5	Commodity Cost from Supply		$58,436,721	$71,997,903	$56,594,547	$47,283,816	$54,006,035	$45,612,602	$33,114,746	$23,643,191	$21,664,032	$21,622,168	$23,263,098	$40,291,495	$497,530,352
6	tab commodity cost from supply, column ao, lines 93-105														
7	Volumetric Pipeline Chgs		$295,665	$372,676	$270,502	$237,849	$257,852	$209,396	$154,768	$112,390	$102,853	$102,138	$109,094	$181,850	$2,407,033
8	tab commodity cost from vol pipe, column e, line 78-90														
9	Commodity Cost from Storage		$296,453	$11,535,256	$23,216,592	$19,491,444	$7,467,590	$347,295	$145,655	$140,957	$145,655	$145,655	$140,957	$145,655	$63,219,164
10	tab Commodity Cost from Storage, column h, line 61-73														
11	Total Commodity Cost		$59,028,839	$83,905,835	$80,081,641	$67,013,109	$61,731,477	$46,169,293	$33,415,169	$23,896,538	$21,912,540	$21,869,961	$23,513,149	$40,619,000	$563,156,549
12															
13	**VOLUMES**														
14	Pipeline Commodity at Receipt Points		88,683,722	101,250,074	77,972,309	65,072,560	74,317,719	63,921,105	46,373,501	32,683,722	29,478,758	29,265,442	31,609,416	55,201,210	695,829,538
15	Pipeline Fuel Use		2,599,076	2,966,042	2,287,030	1,926,102	2,180,425	1,986,007	1,478,191	1,112,204	1,069,861	1,064,816	1,092,864	1,735,696	21,498,314
16	Pipeline Gas Arriving at City Gate		86,084,646	98,284,032	75,685,279	63,146,458	72,137,294	61,935,098	44,895,310	31,571,518	28,408,897	28,200,626	30,516,552	53,465,514	674,331,224
17	Storage Gas Deliveries		510,970	21,108,465	42,130,847	35,670,563	13,860,137	609,376	217,000	210,000	217,000	217,000	210,000	217,000	115,178,358
18	Total Gas At Citygate (Storage and Pipeline)		86,595,616	119,392,497	117,816,126	98,817,021	85,997,431	62,544,474	45,112,310	31,781,518	28,625,897	28,417,626	30,726,552	53,682,514	789,509,582
19															
20	Unaccounted for Gas		477,688	545,380	419,979	350,400	400,291	343,679	249,125	175,193	157,642	156,485	169,337	296,678	3,741,877
21															
22	Load Served		86,117,928	118,847,117	117,396,147	98,466,621	85,597,139	62,200,795	44,863,185	31,606,325	28,468,255	28,261,141	30,557,215	53,385,836	785,767,705
23															0
24	**Annual Sales WACOG**		$0.68544	$0.70600	$0.68215	$0.68057	$0.72119	$0.74226	$0.74482	$0.75607	$0.76972	$0.77385	$0.76948	$0.76086	$0.71670
25															
OR	**OREGON Sales WACOG with Revenue Sensitive**		$0.70513	$0.72628	$0.70174	$0.70012	$0.74190	$0.76358	$0.76621	$0.77779	$0.79183	$0.79608	$0.79158	$0.78271	$0.73728
WA	**WASHINGTON Sales WACOG with Revenue Sensitive**		$0.71618	$0.73766	$0.71274	$0.71109	$0.75353	$0.77555	$0.77822	$0.78998	$0.80424	$0.80855	$0.80399	$0.79498	$0.74884

NW Natural
2007-2008 PGA - SYSTEM
Summary of Total Demand Charges

SYSTEM COSTS

(a)	(b)	(c) November	(d) December	(e) January	(f) February	(g) March	(h) April	(i) May	(j) June	(k) July	(l) August	(m) September	(n) October	(o) TOTAL
		30	31	31	29	31	30	31	30	31	31	30	31	366
Transport charges by transporter:														
Northwest Pipeline		$3,976,718	$4,109,273	$4,109,273	$3,711,603	$4,109,273	$3,976,718	$4,109,273	$3,976,718	$4,109,273	$3,976,718	$3,976,718	$4,109,273	$48,250,831
GTN		688,389	711,335	711,335	642,497	711,335	579,333	598,644	579,333	598,644	579,333	579,333	711,335	7,690,846
TCPL BC		355,475	355,475	355,475	355,475	355,475	318,136	318,136	318,136	318,136	318,136	318,136	355,475	4,041,666
NOVA		664,565	664,565	664,565	664,565	664,565	664,565	664,565	664,565	664,565	664,565	664,565	664,565	7,974,780
Terasen (Southern Crossing)		588,371	607,983	607,983	549,146	607,983	588,371	607,983	588,371	607,986	588,371	588,371	607,983	7,138,902
Spectra (Westcoast)		751,167	753,682	753,682	746,137	753,682	751,167	753,682	751,167	753,682	751,167	751,167	753,682	9,024,064
KB Pipeline		18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	224,256
Total System Demand		$7,043,373	$7,221,001	$7,221,001	$6,688,111	$7,221,001	$6,896,978	$7,070,971	$6,896,978	$7,070,974	$6,896,978	$6,896,978	$7,221,001	$84,345,345

Detail in file "NOVA ANG Monthly Summary for Tracker 2007-8.xls"

NW Natural
2007-2008 PGA - OREGON
Derivation of Oregon per therm Non-Commodity Charges

Oregon Derivation of Demand Increments

Line				
1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$84,345,345	
5	Oregon Allocation Factor 1/		90.41%	
6	Oregon Demand		$76,256,626	
7				
8	Oregon Firm Sales Normal Volumes		627,127,552	
9	Oregon Interruptible Sales Normal Volumes		84,573,655	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.11968	$0.12312
13	Proposed Interruptible Demand 2/		$0.01424	$0.01465
14	Proposed MDDV Demand Charge		$1.78	$1.83
15				
16	Current Firm Demand Per Therm		$0.12736	$0.13136
17	Current Interruptible Demand		$0.01515	$0.01562
18	Current MDDV Demand Charge		$1.90	$1.96
19				
20	Percent Change in Firm Demand		-6.42%	
21				
22				
23	1/Allocation Factor: Actual 12 months ended 06/30/07 firm sales volumes:			
24		Washington	Oregon	System
25	Residential	42,790,894	347,997,386	390,788,279
26	Commercial	20,440,701	226,017,442	246,458,143
27	Industrial	3,211,106	52,360,737	55,571,842
28	Total	66,442,701	626,375,564	692,818,265
29		9.59%	90.41%	100.00%
30				
31	2/Calculation of Proposed Demand Rates:			
32				
33	Demand change factor		0.940	
34				
35	Firm Demand (line 8 * line 35)		$0.11968	$75,052,631
36	Interruptible Demand (line 9 * line 36)		$0.01424	$1,203,995
37				$76,256,626
38				$0

NW Natural
2007-2008 PGA - SYSTEM
Calculation of Winter WACOG

Line				
1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.69239		
6	December	$0.76795		
7	January	$0.79384		
8	February	$0.79560		
9	March	$0.78379		
10	April	$0.71888		
11	May	$0.71209		
12	June	$0.72067		
13	July	$0.73075		
14	August	$0.73808		
15	September	$0.74306		
16	October	$0.75470		
17				
18				
19	Average price, November-March		$0.76671	average lines 5-9
20				
21	Annual average price, November-October		$0.74598	average lines 5-16
22				
23	Ratio of winter to annual		1.02779	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.71670	$0.73728
OR	Oregon Winter WACOG		$0.73662	$0.75778
			line 23 * 0.7167	
WA	Washington Annual WACOG		$0.71670	$0.74884
WA	Washington Winter WACOG		$0.73662	$0.76965
			line 23 * 0.7167	

NW Natural
2007-2008 PGA - OREGON
Derivation of Oregon Seasonalized Fixed Charges

1			Normalized	Normalized	Firm	Interruptible			Firm Demand	Interr. Demand		Seasonalized
2			Residential	Commercial	Industrial	Industrial			Increment	Increment		Fixed
3			Volumes	Volumes	Volumes	Volumes	Total		Eff. 11/01/07	Eff. 11/01/07		Charges
4	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
5												
6	November	2007										$6,341,766
7												
8	December	2007	59,902,645	34,850,521	5,226,489	7,595,750	107,575,405		$0.11968	$0.01424		$12,073,358
9	January	2008	58,141,399	33,817,633	5,801,852	8,575,538	106,336,421		$0.11968	$0.01424		$11,821,776
10	February	2008	48,037,926	28,309,538	5,219,336	7,769,581	89,336,382		$0.11968	$0.01424		$9,872,251
11	March	2008	40,395,177	24,597,015	4,733,614	7,801,663	77,527,468		$0.11968	$0.01424		$8,455,621
12	April	2008	27,413,236	17,777,945	4,115,115	6,993,380	56,299,676		$0.11968	$0.01424		$6,000,379
13	May	2008	17,581,761	12,819,961	3,765,256	6,449,912	40,616,890		$0.11968	$0.01424		$4,180,822
14	June	2008	10,407,856	9,021,136	3,323,913	5,882,154	28,635,059		$0.11968	$0.01424		$2,806,743
15	July	2008	7,669,489	7,729,087	3,763,281	6,829,243	25,991,100		$0.11968	$0.01424		$2,390,466
16	August	2008	7,562,658	7,670,750	3,780,184	6,753,696	25,767,287		$0.11968	$0.01424		$2,371,647
17	September	2008	8,922,424	8,231,762	4,155,690	6,330,893	27,640,769		$0.11968	$0.01424		$2,640,437
18	October	2008	22,269,103	15,085,987	4,035,932	6,722,250	48,113,272		$0.11968	$0.01424		$5,049,248
19	November	2008	41,615,286	24,936,520	4,440,077	6,869,595	77,861,478		$0.11968	$0.01424		$8,593,868
20												
21												
22			349,918,959	224,847,854	52,360,738	84,573,655	711,701,207					$76,256,616

TF0305 0320003P1582nd Sub Thirty-Second Rev Sheet No. 5
TF04 Thirty-First Revised Sheet No. 5
TF05Laren M. Gertsch, Director
TF06042607 051607

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

Rate Schedule and Type of Rate	Base Tariff Rate Minimum	Base Tariff Rate Maximum	ACA(2)	Currently Effective Tariff Rate(3) Minimum	Currently Effective Tariff Rate(3) Maximum
Rate Schedule TF-1 (4)(5)					
Reservation					
(Large Customer)					
System-Wide	.00000	.37984	-	.00000	.37984
15 Year Evergreen Exp.	.00000	.38101	-	.00000	.38101
25 Year Evergreen Exp.	.00000	.36445	-	.00000	.36445
Volumetric					
(Large Customer)					
System-Wide	.00756	.03000	.00160	.00916	.03160
15 Year Evergreen Exp.	.00369	.00369	.00160	.00529	.00529
25 Year Evergreen Exp.	.00369	.00369	.00160	.00529	.00529
(Small Customer) (6)	.00756	.67209	.00160	.00916	.67369
Scheduled Overrun	.00756	.40984	.00160	.00916	.41144
Rate Schedule TF-2 (4)(5)					
Reservation	.00000	.37984	-	.00000	.37984
Volumetric	.00756	.03000	-	.00756	.03000
Scheduled Daily Overrun	.00756	.40984	-	.00756	.40984
Annual Overrun	.00756	.40984	-	.00756	.40984
Rate Schedule TI-1					
Volumetric (7)	.00756	.40984	.00160	.00916	.41144
Scheduled Overrun	.00756	.40984	.00160	.00916	.41144
Rate Schedule TFL-1 (4)(5)					
Parachute Lateral (9)					
Reservation	.00000	.07377	-	.00000	.07377
Volumetric	.00000	.00000	.00160	.00160	.00160
Scheduled Overrun	.00000	.07377	.00160	.00160	.07537
Rate Schedule TIL-1					
Parachute Lateral (9)					
Volumetric	.00000	.07377	.00160	.00160	.07537
Scheduled Overrun	.00000	.07377	.00160	.00160	.07537

TF0307 160003P128Sub Sixteenth Revised Sheet No. 7
TF04 Fifteenth Revised Sheet No. 7
TF05Laren M. Gertsch, Director
TF06042707 030107

STATEMENT OF RATES (Continued)

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

(Dollars per Dth)

Rate Schedule and Type of Rate	Currently Effective Tariff Rate (1) Minimum	Maximum
Rate Schedule SGS-2F (2) (3)		
Demand Charge		
Pre-Expansion Shipper	0.00000	0.01551
Interim Best-Efforts Withdrawal Charge		
Expansion Shipper	0.00000	0.01634
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2007 Phase	0.00000	0.00253
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.01551
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00056
Expansion Shipper - 2007 Phase	0.00000	0.00253
Rate Schedule SGS-2I		
Volumetric	0.00000	0.00113

Footnotes

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

TF0308 0170003P126Sub Seventeenth Revised Sheet No. 8
TF04 Sixteenth Revised Sheet No. 8
TF05Laren M. Gertsch, Director
TF06041007033007RP06-416-000 010107
TF071861272

STATEMENT OF RATES (Continued)

Effective Rates Applicable to Rate Schedule LS-1

(Dollars per Dth)

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

Footnotes

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

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

NW Natural
Rates & Regulatory Affairs
2007-2008 PGA Filing - Oregon
Elasticity Adjustment

Line	Schedule	Block	Elasticity Volumes	Monthly Service Charge	Customers	Current 2006-2007 Billing Rate	Proposed 2007-2008 Billing Rate Before Elasticity	Current 2006-2007 Revenue	Proposed 2007-2008 Revenue	Proposed 2007-2008 WACOG	Proposed 2007-2008 Demand	Proposed 2007-2008 Temporaries	Proposed 2007-2008 Margin Rate	Proposed 2007-2008 Margin
								F=(D*A)+(B*C*12)	G=(E*A)+(B*C*12)				K = E - H - I - J	L = K * A
1	Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L
2	1R		743,853.5	$5.00	3,682	$1.40893	$1.32953	$1,268,958	$1,209,896	$0.73728	$0.12312	($0.04531)	$0.51444	$382,668
3	1C		68,074.7	$5.00	182	$1.37653	$1.28593	$104,627	$98,459	$0.73728	$0.12312	($0.06142)	$0.48695	$33,149
4	2R		351,570,628.8	$6.00	516,536	$1.34052	$1.26169	$508,478,051	$480,763,739	$0.73728	$0.12312	($0.04465)	$0.44594	$156,779,406
5	3C Firm Sales		147,185,048.6	$8.00	54,214	$1.24436	$1.15483	$188,355,731	$175,178,254	$0.73728	$0.12312	($0.06014)	$0.35457	$52,187,403
6	Intentionally blank													
7	3I Firm Sales													
8	Intentionally blank													
9	19	1st mantle												
10	19	add'l mtls												
11	31C Firm Sales	Block 1	24,749,790.0	$325.00	1,219	$0.94879	$0.99194	$28,236,453	$29,304,407	$0.73728	$0.12312	($0.05856)	$0.19010	$4,704,935
12		Block 2	36,757,107.8			$0.93239	$0.97569	$34,271,960	$35,863,543	$0.73728	$0.12312	($0.05839)	$0.17368	$6,383,974
13	31C Firm Trans	Block 1	0.0	$325.00	0	$0.18282	$0.17973	$0	$0	$0.00000	$0.00000	($0.01037)	$0.19010	$0
14		Block 2	0.0			$0.16642	$0.16348	$0	$0	$0.00000	$0.00000	($0.01020)	$0.17368	$0
15	31C Interr Sales	Block 1	23,728.9	$325.00	0	$0.95003	$0.88553	$22,543	$21,013	$0.73728	$0.01465	($0.05650)	$0.19010	$4,511
16		Block 2	56,533.3			$0.93363	$0.86928	$52,781	$49,143	$0.73728	$0.01465	($0.05633)	$0.17368	$9,819
17			561,154,766		575,833			$760,791,104	$722,488,454					$220,485,865
18														
19	**Calculation of Class Prices and Margins:**					06-07 Class Price	07-08 Class Price	06-07 Class Revenues	07-08 Class Revenues				Class Margin Rate	Class Margin
20						Column F ÷ A	Column G ÷ A						Column L ÷ A	
21	**Residential (Line 2 + Line 4)**		352,314,482		520,218	**$1.44685**	**$1.36802**	509,747,009	481,973,635				**$0.44608**	157,162,074
22	**Commercial (Line 17 - Line 21)**		208,840,283		55,615	**$1.20209**	**$1.15167**	251,044,095	240,514,819				**$0.30322**	63,323,791
23			561,154,766		575,833			760,791,104	722,488,454					220,485,865
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	Column N		
29	Volumes page		Column G		Column H									
30	PGA Effects page			Column D										
31														

32 **ELASTICITY CALCULATION:**

Line		Residential Current	Residential Proposed	Commercial Current	Commercial Proposed
34	Elasticity volumes		352,314,482		208,840,283
35					
36	Class prices (Columns D & E, lines 21, 22)	$1.44685	$1.36802	$1.20209	$1.15167
37					
38	Change in class prices		($0.07883)		($0.05042)
39					
40	Percentage change in class prices		-5.4%		-4.2%
41					
42	Volume change due to elasticity (Residential @ 0.172, Commercial @ 0.11)		-0.9%		-0.5%
43					
44	Volume change due to elasticity in therms (line 42 x line 34)		(3,170,830)		(1,044,201)
45					
46	Margin rate per therm (Columns K & L, lines 21, 22)		$0.44608		$0.30322
47					
48	**Margin Shortfall (line 44 x Line 46)**		**($1,414,444)**		**($316,623)**
49					
50	**Rate Change Due to Elasticity Effects (line 48 ÷ line 34)**		**($0.00401)**		**($0.00152)**
51					
52	**Rate Change Due to Elasticity Effects with revenue sensitive added**		**($0.00413)**		**($0.00156)**

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Summary of PERMANENT Increments

Row	Schedule	Block	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
5							E=A+B+C+D						K=sum F thru J	L= K - E
6	Schedule	Block	A	B	C	D	E	F	G	H	I	J	K	L
7	1R		0.00363	0.00167	0.00396	(0.00026)	0.00900	0.00241	0.00125	0.00164	0.00488	(0.00029)	0.00989	0.00089
8	1C		0.00357	0.00159	0.00376	(0.00025)	0.00867	0.00241	0.00119	0.00155	0.00462	(0.00027)	0.00950	0.00083
9	2R		0.00346	0.00145	0.00343	(0.00023)	0.00811	0.00241	0.00109	0.00142	0.00423	(0.00025)	0.00890	0.00079
10	3C Firm Sales		0.00325	0.00115	0.00273	(0.00018)	0.00695	0.00241	0.00086	0.00113	0.00336	(0.00020)	0.00756	0.00061
11	Intentionally blank													
12	3I Firm Sales		0.00316	0.00104	0.00247	(0.00016)	0.00651	0.00241	0.00078	0.00102	0.00305	(0.00018)	0.00708	0.00057
13	Intentionally blank													
14	19	1st mantle	0.05	0.00	0.00	0.00	0.05	0.05	0.00	0.00	0.00	0.00	0.05	0.00
15	19	add'l mtls	0.05	0.00	0.00	0.00	0.05	0.05	0.00	0.00	0.00	0.00	0.05	0.00
16	31C Firm Sales	Block 1	0.00285	0.00062	0.00146	(0.00010)	0.00483	0.00241	0.00046	0.00060	0.00180	(0.00011)	0.00516	0.00033
17		Block 2	0.00281	0.00056	0.00134	(0.00009)	0.00462	0.00241	0.00042	0.00055	0.00165	(0.00010)	0.00493	0.00031
18	31C Firm Trans	Block 1	0.00285	0.00062	0.00146	(0.00010)	0.00483	0.00241	0.00046	0.00060	0.00180	(0.00011)	0.00516	0.00033
19		Block 2	0.00281	0.00056	0.00134	(0.00009)	0.00462	0.00241	0.00042	0.00055	0.00165	(0.00010)	0.00493	0.00031
20	31C Interr Sales	Block 1	0.00285	0.00062	0.00146	(0.00010)	0.00483	0.00241	0.00046	0.00060	0.00180	(0.00011)	0.00516	0.00033
21		Block 2	0.00281	0.00056	0.00134	(0.00009)	0.00462	0.00241	0.00042	0.00055	0.00165	(0.00010)	0.00493	0.00031
22	31I Firm Sales	Block 1	0.00041	0.00056	0.00132	(0.00009)	0.00220	0.00000	0.00041	0.00054	0.00162	(0.00009)	0.00248	0.00028
23		Block 2	0.00037	0.00050	0.00119	(0.00008)	0.00198	0.00000	0.00037	0.00049	0.00146	(0.00009)	0.00223	0.00025
24	31I Firm Trans	Block 1	0.00041	0.00056	0.00132	(0.00009)	0.00220	0.00000	0.00041	0.00054	0.00162	(0.00009)	0.00248	0.00028
25		Block 2	0.00037	0.00050	0.00119	(0.00008)	0.00198	0.00000	0.00037	0.00049	0.00146	(0.00009)	0.00223	0.00025
26	31I Interr Sales	Block 1	0.00041	0.00056	0.00132	(0.00009)	0.00220	0.00000	0.00041	0.00054	0.00162	(0.00009)	0.00248	0.00028
27		Block 2	0.00037	0.00050	0.00119	(0.00008)	0.00198	0.00000	0.00037	0.00049	0.00146	(0.00009)	0.00223	0.00025
28	32C Firm Sales	Block 1	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00000	0.00025	0.00032	0.00096	(0.00006)	0.00147	0.00015
29		Block 2	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00000	0.00021	0.00027	0.00082	(0.00005)	0.00125	0.00013
30		Block 3	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00000	0.00015	0.00019	0.00058	(0.00003)	0.00089	0.00010
31		Block 4	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00000	0.00009	0.00011	0.00034	(0.00002)	0.00052	0.00006
32		Block 5	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00000	0.00005	0.00006	0.00019	(0.00001)	0.00029	0.00002
33		Block 6	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00000	0.00002	0.00003	0.00010	(0.00001)	0.00014	0.00002
34	32I Firm Sales	Block 1	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00000	0.00025	0.00032	0.00096	(0.00006)	0.00147	0.00015
35		Block 2	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00000	0.00021	0.00027	0.00082	(0.00005)	0.00125	0.00013
36		Block 3	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00000	0.00015	0.00019	0.00058	(0.00003)	0.00089	0.00010
37		Block 4	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00000	0.00009	0.00011	0.00034	(0.00002)	0.00052	0.00006
38		Block 5	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00000	0.00005	0.00006	0.00019	(0.00001)	0.00029	0.00002
39		Block 6	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00000	0.00002	0.00003	0.00010	(0.00001)	0.00014	0.00002
40	32 Firm Trans	Block 1	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00000	0.00025	0.00032	0.00096	(0.00006)	0.00147	0.00015
41		Block 2	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00000	0.00021	0.00027	0.00082	(0.00005)	0.00125	0.00013
42		Block 3	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00000	0.00015	0.00019	0.00058	(0.00003)	0.00089	0.00010
43		Block 4	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00000	0.00009	0.00011	0.00034	(0.00002)	0.00052	0.00006
44		Block 5	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00000	0.00005	0.00006	0.00019	(0.00001)	0.00029	0.00002
45		Block 6	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00000	0.00002	0.00003	0.00010	(0.00001)	0.00014	0.00002
46	32 Interr Sales	Block 1	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00000	0.00025	0.00032	0.00096	(0.00006)	0.00147	0.00015
47		Block 2	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00000	0.00021	0.00027	0.00082	(0.00005)	0.00125	0.00013
48		Block 3	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00000	0.00015	0.00019	0.00058	(0.00003)	0.00089	0.00010
49		Block 4	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00000	0.00009	0.00011	0.00034	(0.00002)	0.00052	0.00006
50		Block 5	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00000	0.00005	0.00006	0.00019	(0.00001)	0.00029	0.00002
51		Block 6	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00000	0.00002	0.00003	0.00010	(0.00001)	0.00014	0.00002
52	32 Interr Trans	Block 1	0.00025	0.00033	0.00079	(0.00005)	0.00132	0.00000	0.00025	0.00032	0.00096	(0.00006)	0.00147	0.00015
53		Block 2	0.00021	0.00028	0.00067	(0.00004)	0.00112	0.00000	0.00021	0.00027	0.00082	(0.00005)	0.00125	0.00013
54		Block 3	0.00015	0.00020	0.00047	(0.00003)	0.00079	0.00000	0.00015	0.00019	0.00058	(0.00003)	0.00089	0.00010
55		Block 4	0.00009	0.00012	0.00027	(0.00002)	0.00046	0.00000	0.00009	0.00011	0.00034	(0.00002)	0.00052	0.00006
56		Block 5	0.00005	0.00007	0.00016	(0.00001)	0.00027	0.00000	0.00005	0.00006	0.00019	(0.00001)	0.00029	0.00002
57		Block 6	0.00002	0.00003	0.00008	(0.00001)	0.00012	0.00000	0.00002	0.00003	0.00010	(0.00001)	0.00014	0.00002
58	54		0.00341	0.00138	0.00326	(0.00022)	0.00783	0.00241	0.00103	0.00134	0.00400	(0.00023)	0.00855	0.00072
59	33		0.00001	0.00002	0.00004	0.00000	0.00007	0.00000	0.00001	0.00002	0.00005	0.00000	0.00008	0.00001

Sources:

Direct Inputs	06-07 PGA	06-07 PGA	06-07 PGA	06-07 PGA						
Equal ¢ per therm					Column AE					
Equal % of margin						Column Q	Column T	Column W	Column Z	

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Summary of TEMPORARY Increments

Schedule	Block	REMOVE Current Temporaries	ADD WACOG Deferral	ADD Demand Deferral FIRM	ADD Demand Deferral INTERR	ADD Residential Decoupling	ADD Commercial Decoupling	ADD DSM & Weatherization	ADD Intervenor Funding - CUB	ADD Coos Bay	ADD Storage Inventory Adjustment	ADD Intervenor Funding - NWIGU	ADD IMP Refund	ADD Oregon Tax Kicker	Total Current Temps N=sum B thru M	Net Effect of Temps O = N - A
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1R		0.00451	(0.04934)	(0.00224)	0.00000	0.00767	0.00000	(0.00009)	0.00017	(0.00007)	0.00348	0.00000	(0.00224)	(0.00265)	(0.04531)	(0.04982)
1C		(0.00046)	(0.04934)	(0.00224)	0.00000	0.00000	(0.00853)	(0.00009)	0.00000	(0.00007)	0.00348	0.00000	(0.00212)	(0.00251)	(0.06142)	(0.06096)
2R		0.00450	(0.04934)	(0.00224)	0.00000	0.00767	0.00000	(0.00009)	0.00017	(0.00006)	0.00348	0.00000	(0.00194)	(0.00230)	(0.04465)	(0.04915)
3C Sales Firm		(0.00047)	(0.04934)	(0.00224)	0.00000	0.00000	(0.00853)	(0.00009)	0.00000	(0.00005)	0.00348	0.00000	(0.00154)	(0.00183)	(0.06014)	(0.05967)
Intentionally blank																
3I Sales Firm		0.00648	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00004)	0.00348	0.00006	(0.00140)	(0.00166)	(0.05123)	(0.05771)
Intentionally blank																
19	1st mantle	0.13	(0.94)	(0.04)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	(0.91)	(1.04)
19	add'l mtls	0.13	(0.94)	(0.04)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	(0.91)	(1.04)
31C Sales Firm	Block 1	(0.00049)	(0.04934)	(0.00224)	0.00000	0.00000	(0.00853)	(0.00009)	0.00000	(0.00003)	0.00348	0.00000	(0.00083)	(0.00098)	(0.05856)	(0.05807)
	Block 2	(0.00049)	(0.04934)	(0.00224)	0.00000	0.00000	(0.00853)	(0.00009)	0.00000	(0.00002)	0.00348	0.00000	(0.00075)	(0.00090)	(0.05839)	(0.05790)
31C Trans Firm	Block 1	(0.00695)	0.00000	0.00000	0.00000	0.00000	(0.00853)	0.00000	0.00000	(0.00003)	0.00000	0.00000	(0.00083)	(0.00098)	(0.01037)	(0.00342)
	Block 2	(0.00695)	0.00000	0.00000	0.00000	0.00000	(0.00853)	0.00000	0.00000	(0.00002)	0.00000	0.00000	(0.00075)	(0.00090)	(0.01020)	(0.00325)
31C Sales Interr	Block 1	0.00075	(0.04934)	0.00000	(0.00027)	0.00000	(0.00853)	0.00000	0.00000	(0.00003)	0.00348	0.00000	(0.00083)	(0.00098)	(0.05650)	(0.05725)
	Block 2	0.00075	(0.04934)	0.00000	(0.00027)	0.00000	(0.00853)	0.00000	0.00000	(0.00002)	0.00348	0.00000	(0.00075)	(0.00090)	(0.05633)	(0.05708)
31I Sales Firm	Block 1	0.00647	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00002)	0.00348	0.00006	(0.00074)	(0.00088)	(0.04977)	(0.05624)
	Block 2	0.00647	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00002)	0.00348	0.00006	(0.00067)	(0.00079)	(0.04961)	(0.05608)
31I Trans Firm	Block 1	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00002)	0.00000	0.00006	(0.00074)	(0.00088)	(0.00158)	(0.00159)
	Block 2	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00002)	0.00000	0.00006	(0.00067)	(0.00079)	(0.00142)	(0.00143)
31I Sales Interr	Block 1	0.00771	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	(0.00002)	0.00348	0.00006	(0.00074)	(0.00088)	(0.04771)	(0.05542)
	Block 2	0.00771	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	(0.00002)	0.00348	0.00006	(0.00067)	(0.00079)	(0.04755)	(0.05526)
32C Sales Firm	Block 1	0.00647	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00001)	0.00348	0.00000	(0.00044)	(0.00052)	(0.04916)	(0.05563)
	Block 2	0.00647	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00001)	0.00348	0.00000	(0.00038)	(0.00045)	(0.04903)	(0.05550)
	Block 3	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00001)	0.00348	0.00000	(0.00026)	(0.00031)	(0.04877)	(0.05523)
	Block 4	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	0.00000	0.00348	0.00000	(0.00015)	(0.00018)	(0.04852)	(0.05498)
	Block 5	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	0.00000	0.00348	0.00000	(0.00009)	(0.00010)	(0.04838)	(0.05484)
	Block 6	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	0.00000	0.00348	0.00000	(0.00004)	(0.00005)	(0.04828)	(0.05474)
32I Sales Firm	Block 1	0.00647	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00001)	0.00348	0.00006	(0.00044)	(0.00052)	(0.04910)	(0.05557)
	Block 2	0.00647	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00001)	0.00348	0.00006	(0.00038)	(0.00045)	(0.04897)	(0.05544)
	Block 3	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00001)	0.00348	0.00006	(0.00026)	(0.00031)	(0.04871)	(0.05517)
	Block 4	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	0.00000	0.00348	0.00006	(0.00015)	(0.00018)	(0.04846)	(0.05492)
	Block 5	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	0.00000	0.00348	0.00006	(0.00009)	(0.00010)	(0.04832)	(0.05478)
	Block 6	0.00646	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	0.00000	0.00348	0.00006	(0.00004)	(0.00005)	(0.04822)	(0.05468)
32 Trans Firm	Block 1	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00000	0.00006	(0.00044)	(0.00052)	(0.00091)	(0.00092)
	Block 2	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00000	0.00006	(0.00038)	(0.00045)	(0.00078)	(0.00079)
	Block 3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00000	0.00006	(0.00026)	(0.00031)	(0.00052)	(0.00052)
	Block 4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00015)	(0.00018)	(0.00027)	(0.00027)
	Block 5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00009)	(0.00010)	(0.00013)	(0.00013)
	Block 6	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00004)	(0.00005)	(0.00003)	(0.00003)
32 Sales Interr	Block 1	0.00771	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00348	0.00006	(0.00044)	(0.00052)	(0.04704)	(0.05475)
	Block 2	0.00771	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00348	0.00006	(0.00038)	(0.00045)	(0.04691)	(0.05462)
	Block 3	0.00770	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00348	0.00006	(0.00026)	(0.00031)	(0.04665)	(0.05435)
	Block 4	0.00770	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00348	0.00006	(0.00015)	(0.00018)	(0.04640)	(0.05410)
	Block 5	0.00770	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00348	0.00006	(0.00009)	(0.00010)	(0.04626)	(0.05396)
	Block 6	0.00770	(0.04934)	0.00000	(0.00027)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00348	0.00006	(0.00004)	(0.00005)	(0.04616)	(0.05386)
32 Trans Interr	Block 1	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00000	0.00006	(0.00044)	(0.00052)	(0.00091)	(0.00092)
	Block 2	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00000	0.00006	(0.00038)	(0.00045)	(0.00078)	(0.00079)
	Block 3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00001)	0.00000	0.00006	(0.00026)	(0.00031)	(0.00052)	(0.00052)
	Block 4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00015)	(0.00018)	(0.00027)	(0.00027)
	Block 5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00009)	(0.00010)	(0.00013)	(0.00013)
	Block 6	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00006	(0.00004)	(0.00005)	(0.00003)	(0.00003)
54		0.00649	(0.04934)	(0.00224)	0.00000	0.00000	0.00000	(0.00009)	0.00000	(0.00006)	0.00348	0.00000	(0.00183)	(0.00217)	(0.05225)	(0.05874)
33		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	(0.00002)	(0.00003)	(0.00005)	(0.00005)

Sources:

Direct Inputs	06-07 PGA												
Equal ¢ per therm		Column D	Column G	Column J	Column M	Column P	Column S	Column V		Column Y	Column AB		
Equal % of margin									Column H			Column K	Column N

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	$341
2	Activity Ended September 30, 2003	3,510	442
3	Activity Ended September 30, 2004	3,094	401
4	Activity Ended September 30, 2005	6,000	803
5	Activity Ended September 30, 2006	(695)	(96)
6	Activity Ended September 30, 2007	430	66
7	Total Bare Steel Program	$15,004	$1,958
Geohazard Program			
8	Activity Ended September 30, 2002	$1,714	$219
9	Activity Ended September 30, 2003	555	70
10	Activity Ended September 30, 2004	139	18
11	Activity Ended September 30, 2005	206	28
12	Activity Ended September 30, 2006	2,863	394
13	Activity Ended September 30, 2007	254	39
14	Total Geohazard Program	$5,731	$767
Integrity Management Program			
15	Activity Ended September 30, 2005	$3,476	$465
16	Activity Ended September 30, 2006	8,978	1,235
17	Activity Ended September 30, 2007	3,821	588
18	Total Integrity Management Program	$16,275	$2,288
GRAND TOTAL ALL PROGRAMS		$37,010	$5,013

Reflects Actuals through June 30, 2007

NW Natural
Rates and Regulatory Affairs
2007-2008 PGA Filing - Oregon
Estimated Revenue Effects for the 12 Months Beginning November 1, 2007

Line No.	Item	Total Increment Amounts	Limit For Increment Amounts
1	Commodity and Demand Deferrals	($36,540,002)	
2	Temporary Increments	1,039,251	
3	Total	($35,500,751)	
4	2006 Utility Revenues		$1,000,187,047
5	@ 3% threshold		3.0%
6	Threshold for Annual Effect of Proposed Change in Amortization		$30,005,611

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