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July 26, 2018

NWN OPUC Advice No. 18-11 / UG 355
(UM 1496)

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: Annual Purchased Gas Cost and Technical Rate Adjustments
UM 1496: Request for Amortization of Certain Deferred Accounts Relating to Gas Costs

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), files herewith revisions to its Tariff, P.U.C. Or. 25[1] ("the Tariff"), stated to become effective with service on and after November 1, 2018, as follows:

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

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

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

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

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

Seventh Revision of Sheet 164-1,
Schedule 164,
"Purchased Gas Cost Adjustments to Rates."

This filing is made in accordance with OAR 860-022-0025, OAR 860-022-0030, and OAR 860-022-0070.

[1] Tariff P.U.C. Or. 25 originated November 1, 2012 with Docket UG 221; OPUC Order No. 12-408 as supplemented by Order No. 12-437, and was filed pursuant to ORS 767.205 and OAR 860-022-0005.

Introduction and Summary

The purpose of this filing is to:

(1) Develop the temporary rate adjustments associated with the amortization of gas cost credit or debit balances in Federal Energy Regulatory Commission (FERC) Account 191, deferred under Docket UM 1496 and proposed to be effective November 1, 2018, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2017; and

(2) Develop the commodity (Weighted Average Cost of Gas "WACOG") and non-commodity ("demand" or "pipeline capacity" charge) purchased gas costs to be effective November 1, 2018.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2017.

The number of customers affected by the changes proposed in this filing is 597,459 residential customers, 61,133 commercial customers, and 691 industrial customers.

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

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

The net effect of this portion of the filing is to decrease the Company's annual revenues by $3,408,953, or about -0.51%. The effect of removing the Account 191 temporary adjustments placed into rates November 1, 2017, is an increase of $15,624,355; and the effect of applying the new Account 191 temporary rate adjustments for the amortization of gas costs deferred under Docket UM 1496 is a decrease of $19,033,308.

The proposed adjustments to customer rates are comprised of the following: (1) a credit of $0.02152 per therm for all sales service customers related to the 191 commodity accounts, and (2) a credit of $0.00595 per therm for all firm sales service customers and a credit of $0.00071 per therm for all interruptible sales service customers related to 191 demand accounts. The net effect of all Account 191 amortizations is a credit of $0.02747 per therm for firm sales service customers and a credit of $0.02223 per therm for interruptible sales service customers.

The Company has developed the adjustments to rates proposed in this filing in accordance with the PGA Filing Guidelines as prescribed by the most recent Commission Order in Docket UM 1286.

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.

II. Purchased Gas Cost Adjustment (PGA)

The net effect of the PGA portion of this filing is to decrease the Company's annual revenues by about $33,803,141, or about -5.1%; the change in commodity cost is a decrease of $32,591,987 and the change in demand cost is a decrease of $1,211,154.

The change in gas costs results in a proposed Annual Sales WACOG of $0.23861 per therm, and a proposed Winter Sales WACOG of $0.28613. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of $0.24552 and a proposed Winter Sales Billing WACOG of $0.29442.

The change in demand costs results in a proposed firm service pipeline capacity charge of $0.10611 per therm, or $1.58 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01263 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of $0.10918 per therm or $1.63 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of $0.01300 per therm.

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

This filing applies the method for calculating the proposed Annual Sales Weighted Average Cost of Gas ("WACOG") that is set forth in a joint party stipulation approved by the Commission in OPUC Order No. 08-504, Docket UM 1286, as modified by the approval of a stipulation affirmed in OPUC Order No. 11-176, Dockets UM 1520/UG 204, and as further prescribed by the PGA Filing Guidelines, Section VI (1)(d) adopted in the most recent Commission Order No. 14-238 in Docket UM 1286.

III. Combined Effect on Customer Bills

The combined effects of this filing is to decrease the Company's annual revenues by about $37,212,094, or about -5.57%; the change in purchased gas costs is a decrease of $33,803,141 and the change in temporary adjustments to rates is a decrease of $3,408,953.

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

Class	**Rate Schedule**	**Average Monthly Bill Change ($)**	**Average Monthly Bill Change (%)**
Residential	Schedule 2	-$3.12	-5.9%
Commercial	Schedule 3	-$14.38	-6.9%
Commercial Firm Sales	Schedule 31	-$145.79	-7.5%
Industrial Firm Sales	Schedule 32	-$979.56	-11.4%
Industrial Interruptible Sales	Schedule 32	-$2,194.89	-13.9%

The monthly bill effects for all other rate classes can be found in the separately provided work papers.

Please note that the monthly bill effects for Rate Schedule 31 and Rate Schedule 32 do not include the effect of changes in the pipeline capacity charge due to the customer option to elect either an MDDV-based capacity charge or a volumetric-based capacity charge. If a customer served under Rate Schedule 32 Industrial Firm Sales Service elected the volumetric pipeline capacity option, the change in the monthly bill effective November 1, 2018 would be a decrease of $1,180.52, or -10.78%.

UM 1286 Natural Gas Portfolio Development Guidelines

In addition to the supporting materials submitted as part of this filing as Exhibit A and Exhibit B, the Company provides Exhibit C which contains the data required by the Natural Gas Portfolio Development Guidelines Sections IV and V as adopted by the Commission in OPUC Order No. 11-196 in Docket UM 1286 ("the OPUC Order"). Some of the information is confidential and highly confidential and is subject to the Modified Protective Order in Docket UM 1286, Order No. 10-337.

Commission Staff's Attachment A through Attachment D, required by Section 5 of the PGA Filing Guidelines, are included in the Company's work papers, and incorporated herein by reference, which will be submitted under separate cover.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after November 1, 2018.

In accordance with ORS 757.205, 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.

Notice to customers will be made in accordance with OAR 860-022-0017.

Please address correspondence on this matter to Kyle Walker at kyle.walker@nwnatural.com with copies to:

eFiling
Rates & Regulatory Affairs
NW Natural
220 NW Second Avenue
Portland, Oregon 97209
Telecopier: (503) 721-2516
Telephone: (503) 226-4211, x3589
eFiling@nwnatural.com

Sincerely,

NW NATURAL

/s/ Gail Hammer

Gail Hammer
Rates & Regulatory Affairs

Attachments: Exhibit A – Purchased Gas Cost Deferral Amortizations
Exhibit B – Purchased Gas Costs
Exhibit C – PGA Portfolio Guidelines Sections IV and V

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

Effective: November 1, 2018:		(T)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.24552**	(R)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.23861**	(R)

8. Estimated Winter Sales WACOG: The Company’s weighted average Commodity Cost of Gas for the five-month period November through March.

Effective: November 1, 2018:		(T)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.29442**	(R)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.28613**	(R)

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

10. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by November 1 – October 31 forecasted Firm Sales Service volumes.

Effective: November 1, 2018:		(T)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.10918**	(R)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.10611**	(R)

(continue to Sheet P-3)

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

11. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by November 1 – October 31 forecasted Interruptible Sales Service volumes.

Effective: November 1, 2018:		(T)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01300**	(R)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01263**	(R)

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, 2018:		(T)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.63**	(R)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.58**	(R)

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

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

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

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

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

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

(continue to Sheet P-4)

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

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

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

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

2. A debit or credit entry shall be made equal to 100% of any monthly difference between actual monthly fixed charge recoveries and Monthly Seasonalized Fixed Charges. The Monthly Seasonalized Fixed Charges for the period November 1, 2018 through October 31, 2019 are: (T)

November	2018	$8,004,201	(C)
December	2018	$11,006,397	
January	2019	$10,996,191	
February	2019	$8,928,533	
March	2019	$7,869,581	
April	2019	$5,866,600	
May	2019	$3,799,111	
June	2019	$2,562,605	
July	2019	$2,014,536	
August	2019	$2,002,335	
September	2019	$2,136,604	
October	2019	$4,571,914	
	TOTAL	$69,758,608	(C)

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. For any given tracker year, if the total activity subject to debit or credit entries that is related to the Gas Reserves transaction exceeds $10 million, amounts beyond $10 million will be recorded at 100%.

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

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

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

(continue to Sheet P-6)

SCHEDULE 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 the Company's Account 191 deferred revenue and gas cost accounts.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 27 Rate Schedule 32
Rate Schedule 3 Rate Schedule 31 Rate Schedule 33

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2018 (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	Total Adjustment	
2		($0.02152)	($0.00595)	**($0.02747)**	(C)
3 CSF		($0.02152)	($0.00595)	**($0.02747)**	
3 ISF		($0.02152)	($0.00595)	**($0.02747)**	
27		($0.02152)	($0.00595)	**($0.02747)**	
31 CSF	Block 1	($0.02152)	($0.00595)	**($0.02747)**	
	Block 2	($0.02152)	($0.00595)	**($0.02747)**	(C)
31 CTF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
31 ISF	Block 1	($0.02152)	($0.00595)	**($0.02747)**	(C)
	Block 2	($0.02152)	($0.00595)	**($0.02747)**	(C)
31 ITF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	

(continue to Sheet 162-2)

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

APPLICATION TO RATE SCHEDULES (continued): Effective: November 1, 2018 (T)

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

Schedule	Block	Account 191 Commodity Adjustment [1]	Account 191 Pipeline Capacity Adjustment	Total Adjustment	
32 CSF	Block 1	($0.02152)	($0.00595)	**($0.02747)**	(C)
	Block 2	($0.02152)	($0.00595)	**($0.02747)**	
	Block 3	($0.02152)	($0.00595)	**($0.02747)**	
	Block 4	($0.02152)	($0.00595)	**($0.02747)**	
	Block 5	($0.02152)	($0.00595)	**($0.02747)**	
	Block 6	($0.02152)	($0.00595)	**($0.02747)**	
32 ISF	Block 1	($0.02152)	($0.00595)	**($0.02747)**	
	Block 2	($0.02152)	($0.00595)	**($0.02747)**	
	Block 3	($0.02152)	($0.00595)	**($0.02747)**	
	Block 4	($0.02152)	($0.00595)	**($0.02747)**	
	Block 5	($0.02152)	($0.00595)	**($0.02747)**	
	Block 6	($0.02152)	($0.00595)	**($0.02747)**	(C)
32 CTF/ITF	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
	Block 3	N/A	N/A	**$0.00000**	
	Block 4	N/A	N/A	**$0.00000**	
	Block 5	N/A	N/A	**$0.00000**	
	Block 6	N/A	N/A	**$0.00000**	
32 CSI	Block 1	($0.02152)	($0.00071)	**($0.02223)**	(C)
	Block 2	($0.02152)	($0.00071)	**($0.02223)**	
	Block 3	($0.02152)	($0.00071)	**($0.02223)**	
	Block 4	($0.02152)	($0.00071)	**($0.02223)**	
	Block 5	($0.02152)	($0.00071)	**($0.02223)**	
	Block 6	($0.02152)	($0.00071)	**($0.02223)**	
32 ISI	Block 1	($0.02152)	($0.00071)	**($0.02223)**	
	Block 2	($0.02152)	($0.00071)	**($0.02223)**	
	Block 3	($0.02152)	($0.00071)	**($0.02223)**	
	Block 4	($0.02152)	($0.00071)	**($0.02223)**	
	Block 5	($0.02152)	($0.00071)	**($0.02223)**	
	Block 6	($0.02152)	($0.00071)	**($0.02223)**	(C)
32 CTI/ITI	Block 1	N/A	N/A	**$0.00000**	
	Block 2	N/A	N/A	**$0.00000**	
	Block 3	N/A	N/A	**$0.00000**	
	Block 4	N/A	N/A	**$0.00000**	
	Block 5	N/A	N/A	**$0.00000**	
	Block 6	N/A	N/A	**$0.00000**	
33 TI		N/A	N/A	**$0.00000**	
33 TF		N/A	N/A	**$0.00000**	

SCHEDULE 164
PURCHASED GAS COST ADJUSTMENT TO RATES

PURPOSE:
To identify the Commodity and Pipeline Capacity Components applicable to the Rate Schedules listed below.

APPLICABLE:
To the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 3 Rate Schedule 27
Rate Schedule 31 Rate Schedule 32

APPLICATION TO RATE SCHEDULES: Effective: November 1, 2018 (T)

Annual Sales WACOG [1]	$0.24552	(R)
Winter Sales WACOG [2]	$0.29442	
Firm Sales Service Pipeline Capacity Component [4]	$0.10918	
Firm Sales Service Pipeline Capacity Component [5]	$1.63	
Interruptible Sales Service Pipeline Capacity Component [6]	$0.01300	(R)

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

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

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

EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations
UM 1496

NWN OPUC Advice No. 18-11 / UG 355

July 26, 2018

NW NATURAL

EXHIBIT A

Supporting Materials

Purchased Gas Cost Deferral Amortizations – UM 1496

NWN OPUC ADVICE NO. 18-11 / UG 355

NW Natural
Rates & Regulatory Affairs
2018-19 PGA - Oregon: August Filing
Summary of TEMPORARY Increments

1			**Current Temporaries**	**WACOG Deferral**	**Demand Deferral - FIRM**	**Demand Deferral - INTERRUPTIBLE**	**Subtotal**
2							
3	Schedule	Block	**A**	**B**	**C**	**D**	**E**
4	2R		($0.01727)	($0.02152)	($0.00595)	$0.00000	($0.02747)
5	3C Sales Firm		$0.03136	($0.02152)	($0.00595)	$0.00000	($0.02747)
6	3I Sales Firm		$0.01614	($0.02152)	($0.00595)	$0.00000	($0.02747)
7	27 Dry Out		($0.01561)	($0.02152)	($0.00595)	$0.00000	($0.02747)
8	31C Sales Firm	Block 1	$0.04321	($0.02152)	($0.00595)	$0.00000	($0.02747)
9		Block 2	$0.04264	($0.02152)	($0.00595)	$0.00000	($0.02747)
10	31C Trans Firm	Block 1	$0.00669	$0.00000	$0.00000	$0.00000	$0.00000
11		Block 2	$0.00613	$0.00000	$0.00000	$0.00000	$0.00000
12	31I Sales Firm	Block 1	$0.01371	($0.02152)	($0.00595)	$0.00000	($0.02747)
13		Block 2	$0.01326	($0.02152)	($0.00595)	$0.00000	($0.02747)
14	31I Trans Firm	Block 1	$0.00560	$0.00000	$0.00000	$0.00000	$0.00000
15		Block 2	$0.00508	$0.00000	$0.00000	$0.00000	$0.00000
16	32C Sales Firm	Block 1	$0.01347	($0.02152)	($0.00595)	$0.00000	($0.02747)
17		Block 2	$0.01279	($0.02152)	($0.00595)	$0.00000	($0.02747)
18		Block 3	$0.01166	($0.02152)	($0.00595)	$0.00000	($0.02747)
19		Block 4	$0.01052	($0.02152)	($0.00595)	$0.00000	($0.02747)
20		Block 5	$0.00955	($0.02152)	($0.00595)	$0.00000	($0.02747)
21		Block 6	$0.00909	($0.02152)	($0.00595)	$0.00000	($0.02747)
22	32I Sales Firm	Block 1	$0.01206	($0.02152)	($0.00595)	$0.00000	($0.02747)
23		Block 2	$0.01160	($0.02152)	($0.00595)	$0.00000	($0.02747)
24		Block 3	$0.01082	($0.02152)	($0.00595)	$0.00000	($0.02747)
25		Block 4	$0.01004	($0.02152)	($0.00595)	$0.00000	($0.02747)
26		Block 5	$0.00930	($0.02152)	($0.00595)	$0.00000	($0.02747)
27		Block 6	$0.00899	($0.02152)	($0.00595)	$0.00000	($0.02747)
28	32 Trans Firm	Block 1	$0.00273	$0.00000	$0.00000	$0.00000	$0.00000
29		Block 2	$0.00232	$0.00000	$0.00000	$0.00000	$0.00000
30		Block 3	$0.00164	$0.00000	$0.00000	$0.00000	$0.00000
31		Block 4	$0.00097	$0.00000	$0.00000	$0.00000	$0.00000
32		Block 5	$0.00056	$0.00000	$0.00000	$0.00000	$0.00000
33		Block 6	$0.00029	$0.00000	$0.00000	$0.00000	$0.00000
34	32C Sales Interr	Block 1	$0.02601	($0.02152)	$0.00000	($0.00071)	($0.02223)
35		Block 2	$0.02562	($0.02152)	$0.00000	($0.00071)	($0.02223)
36		Block 3	$0.02497	($0.02152)	$0.00000	($0.00071)	($0.02223)
37		Block 4	$0.02433	($0.02152)	$0.00000	($0.00071)	($0.02223)
38		Block 5	$0.02394	($0.02152)	$0.00000	($0.00071)	($0.02223)
39		Block 6	$0.02349	($0.02152)	$0.00000	($0.00071)	($0.02223)
40	32I Sales Interr	Block 1	$0.02602	($0.02152)	$0.00000	($0.00071)	($0.02223)
41		Block 2	$0.02563	($0.02152)	$0.00000	($0.00071)	($0.02223)
42		Block 3	$0.02499	($0.02152)	$0.00000	($0.00071)	($0.02223)
43		Block 4	$0.02434	($0.02152)	$0.00000	($0.00071)	($0.02223)
44		Block 5	$0.02396	($0.02152)	$0.00000	($0.00071)	($0.02223)
45		Block 6	$0.02353	($0.02152)	$0.00000	($0.00071)	($0.02223)
46	32 Trans Interr	Block 1	$0.00226	$0.00000	$0.00000	$0.00000	$0.00000
47		Block 2	$0.00192	$0.00000	$0.00000	$0.00000	$0.00000
48		Block 3	$0.00136	$0.00000	$0.00000	$0.00000	$0.00000
49		Block 4	$0.00079	$0.00000	$0.00000	$0.00000	$0.00000
50		Block 5	$0.00045	$0.00000	$0.00000	$0.00000	$0.00000
51		Block 6	$0.00023	$0.00000	$0.00000	$0.00000	$0.00000
52	33		$0.00009	$0.00000	$0.00000	$0.00000	$0.00000

NW Natural
Rates & Regulatory Affairs
2018-19 PGA - Oregon: August Filing
Calculation of Increments Allocated on the EQUAL CENT PER THERM BASIS
ALL VOLUMES IN THERMS

Line	Schedule	Block	Oregon PGA Volumes page, Column F		WACOG Deferral			Demand Deferral - FIRM			Demand Deferral - INTERRUPTIBLE		
1					**WACOG Deferral**			**Demand Deferral - FIRM**			**Demand Deferral - INTERRUPTIBLE**		
2				**Proposed Amount:**	(14,693,762) Temporary Increment			(3,768,531) Temporary Increment			(35,228) Temporary Increment		
3				**Revenue Sensitive Multiplier:**	2.815% add revenue sensitive factor			2.815% add revenue sensitive factor			2.815% add revenue sensitive factor		
4				**Amount to Amortize:**	**(15,119,372)** to all sales			**(3,877,688)** to all firm sales			**(36,248)** to all interruptible sales		
5					**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**	**Multiplier**	**Volumes**	**Increment**
6	Schedule	Block	**A**		**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
7	2R		382,340,529		1.0	382,340,529	($0.02152)	1.0	382,340,529	($0.00595)	0.0	0	$0.00000
8	3C Firm Sales		169,517,330		1.0	169,517,330	($0.02152)	1.0	169,517,330	($0.00595)	0.0	0	$0.00000
9	3I Firm Sales		4,684,198		1.0	4,684,198	($0.02152)	1.0	4,684,198	($0.00595)	0.0	0	$0.00000
10	27 Dry Out		1,072,229		1.0	1,072,229	($0.02152)	1.0	1,072,229	($0.00595)	0.0	0	$0.00000
11	31C Firm Sales	Block 1	13,712,695		1.0	13,712,695	($0.02152)	1.0	13,712,695	($0.00595)	0.0	0	$0.00000
12		Block 2	11,300,457		1.0	11,300,457	($0.02152)	1.0	11,300,457	($0.00595)	0.0	0	$0.00000
13	31C Firm Trans	Block 1	1,495,770		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
14		Block 2	1,912,244		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
15	31I Firm Sales	Block 1	4,480,787		1.0	4,480,787	($0.02152)	1.0	4,480,787	($0.00595)	0.0	0	$0.00000
16		Block 2	9,117,388		1.0	9,117,388	($0.02152)	1.0	9,117,388	($0.00595)	0.0	0	$0.00000
17	31I Firm Trans	Block 1	112,620		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
18		Block 2	337,199		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
19	32C Firm Sales	Block 1	30,908,235		1.0	30,908,235	($0.02152)	1.0	30,908,235	($0.00595)	0.0	0	$0.00000
20		Block 2	8,789,140		1.0	8,789,140	($0.02152)	1.0	8,789,140	($0.00595)	0.0	0	$0.00000
21		Block 3	949,347		1.0	949,347	($0.02152)	1.0	949,347	($0.00595)	0.0	0	$0.00000
22		Block 4	25,135		1.0	25,135	($0.02152)	1.0	25,135	($0.00595)	0.0	0	$0.00000
23		Block 5	0		1.0	0	($0.02152)	1.0	0	($0.00595)	0.0	0	$0.00000
24		Block 6	0		1.0	0	($0.02152)	1.0	0	($0.00595)	0.0	0	$0.00000
25	32I Firm Sales	Block 1	5,602,336		1.0	5,602,336	($0.02152)	1.0	5,602,336	($0.00595)	0.0	0	$0.00000
26		Block 2	6,047,501		1.0	6,047,501	($0.02152)	1.0	6,047,501	($0.00595)	0.0	0	$0.00000
27		Block 3	1,988,054		1.0	1,988,054	($0.02152)	1.0	1,988,054	($0.00595)	0.0	0	$0.00000
28		Block 4	787,826		1.0	787,826	($0.02152)	1.0	787,826	($0.00595)	0.0	0	$0.00000
29		Block 5	0		1.0	0	($0.02152)	1.0	0	($0.00595)	0.0	0	$0.00000
30		Block 6	0		1.0	0	($0.02152)	1.0	0	($0.00595)	0.0	0	$0.00000
31	32 Firm Trans	Block 1	16,505,188		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
32		Block 2	18,272,096		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
33		Block 3	10,705,944		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
34		Block 4	20,210,199		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
35		Block 5	20,401,757		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
36		Block 6	3,247,753		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
37	32C Interr Sales	Block 1	5,440,472		1.0	5,440,472	($0.02152)	0.0	0	$0.00000	1.0	5,440,472	($0.00071)
38		Block 2	7,486,554		1.0	7,486,554	($0.02152)	0.0	0	$0.00000	1.0	7,486,554	($0.00071)
39		Block 3	3,972,506		1.0	3,972,506	($0.02152)	0.0	0	$0.00000	1.0	3,972,506	($0.00071)
40		Block 4	4,854,576		1.0	4,854,576	($0.02152)	0.0	0	$0.00000	1.0	4,854,576	($0.00071)
41		Block 5	65,604		1.0	65,604	($0.02152)	0.0	0	$0.00000	1.0	65,604	($0.00071)
42		Block 6	0		1.0	0	($0.02152)	0.0	0	$0.00000	1.0	0	($0.00071)
43	32I Interr Sales	Block 1	6,350,897		1.0	6,350,897	($0.02152)	0.0	0	$0.00000	1.0	6,350,897	($0.00071)
44		Block 2	7,728,275		1.0	7,728,275	($0.02152)	0.0	0	$0.00000	1.0	7,728,275	($0.00071)
45		Block 3	3,911,705		1.0	3,911,705	($0.02152)	0.0	0	$0.00000	1.0	3,911,705	($0.00071)
46		Block 4	8,709,010		1.0	8,709,010	($0.02152)	0.0	0	$0.00000	1.0	8,709,010	($0.00071)
47		Block 5	2,630,559		1.0	2,630,559	($0.02152)	0.0	0	$0.00000	1.0	2,630,559	($0.00071)
48		Block 6	0		1.0	0	($0.02152)	0.0	0	$0.00000	1.0	0	($0.00071)
49	32 Interr Trans	Block 1	8,589,936		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
50		Block 2	16,089,250		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
51		Block 3	11,585,346		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
52		Block 4	29,563,048		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
53		Block 5	53,552,522		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
54		Block 6	86,265,853		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
55	33		0		0.0	0	$0.00000	0.0	0	$0.00000	0.0	0	$0.00000
56													
57	TOTALS		1,001,320,067			702,473,342	$ (0.02152)		651,323,185	$ (0.00595)		51,150,158	$ (0.00071)
58	**Sources for line 2 above:**												
59	**Inputs page**				Line 33			Line 35			Line 37		
60	**Tariff Schedules**												
61	**Rate Adjustment Schedule**				Sched 162			Sched 162			Sched 162		

NW Natural
Rates and Regulatory Affairs
2018-2019 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/18		
1				
2				
3	Total Billed Gas Sales Revenues	$ 618,450,726		
4	Total Oregon Revenues	$ 621,865,430		
5				
6	Regulatory Commission Fees [1]	n/a	0.300%	Statutory rate
7	City License and Franchise Fees	$ 14,963,448	2.406%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 678,352	0.109%	Line 8 ÷ Line 4
9				
10	Total		**2.815%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).
15 Because the fee changed since our last general rate case, the difference between the previous fee of 0.275%
16 and the new fee of 0.3%, as it affects our base rates, is being captured as a temporary deferral.
17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2018-2019 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Tariff Advice 18-11: PGA Gas Costs and Gas Cost Deferrals

Line		Including Revenue Sensitive Amount
3	**Purchased Gas Cost Adjustment (PGA)**	
5	Commodity Cost Change	($32,591,987)
7	Demand Capacity Cost Change	(1,211,154)
9	**Total Gas Cost Change**	**(33,803,141)**
11	**Temporary Increments**	
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	15,624,355
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(19,033,308)
19	**Net Temporary Rate Adjustment**	**(3,408,953)**
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($37,212,094)**
25	2017 Oregon Earnings Test Normalized Total Revenues	$668,336,000
27	Effect of this filing, as a percentage change (line 21 ÷ line 25)	-5.57%

NW Natural
Rates & Regulatory Affairs
2018-2019 PGA Filing - August Filing
Summary of Deferred Accounts Included in the PGA

	Account	Balance 6/30/2018	Jul-Oct Estimated Activity	Jul-Oct Interest	Estimated Balance 10/31/2018	Interest Rate During Amortization	Estimated Interest During Amortization	Total Estimated Amount for (Refund) or Collection	Amounts Excluded from PGA Filing	Amounts Included in PGA Filing
	A	B	C	D	E	F1	F2	G	H	I
					E = sum B thru D	2.92%		G = E + F2		Excl. Rev Sens
43	**Gas Cost Deferrals and Amortizations**									
44	191401 AMORTIZE OREGON WACOG	(475,903)	908,197	(793)	431,502					
45	191400 WACOG - ACCRUE OREGON	(14,515,461)	0	(380,012)	(14,895,473)					
46	Subtotal	(14,991,363)	908,197	(380,805)	(14,463,971)	2.92%	(229,791)	(14,693,762)		**(14,693,762)**
47										
48	191411 AMORTIZE DEMAND OREGON	(1,456,893)	1,607,896	(6,394)	144,609					
49	191410 DEMAND - ACCRUE OREGON	(380,261)	0	(9,955)	(390,216)					
50	191417 DEMAND - ACCRUE COOS BAY	174,676	0	0	174,676					
51	191450 OREGON DEMAND ACCRUE VOLUME	(3,579,628)	0	(93,714)	(3,673,342)					
52	Subtotal	(5,242,106)	1,607,896	(110,063)	(3,744,273)	2.92%	(59,486)	(3,803,759)		**(3,803,759)**
53										

Company: Northwest Natural Gas Company
State: Oregon
Description: Core Market Commodity gas cost deferral
Account Number: 191400
Docket UM 1496
Last deferral reauthorization was approved in Order 17-397

Narrative: Deferral of customer's share of the difference between actual core commodity cost incurred and the Annual Sales WACOG embedded in customer rates. For the Nov 2017 - Oct 2018 PGA year, the deferral election was 90%.

1	Debit (Credit)									
2			Commodity	Storage	Hedge					
3	Month/Year	Note	Deferral	Adjustment	Adjustment	Interest	Interest Rate	Transfer	Activity	Balance
4	(a)	(b)	(c)	(d)	(e)	(f1)	(f2)	(g)	(h)	(i)
5										
6	Beginning Bal									
133	Jun-17		405,864.95	(1,427.06)	10.80	(43,619.59)	7.778%		360,829	(6,571,082.25)
134	Jul-17		(230,489.69)	(1,219.12)	0.00	(43,342.49)	7.778%		(275,051)	(6,846,133.55)
135	Aug-17		815,392.78	(1,070.96)	0.00	(41,735.27)	7.778%		772,587	(6,073,547.00)
136	Sep-17		(386,669.61)	(1,336.49)	910.30	(40,621.22)	7.778%		(427,717)	(6,501,264.02)
137	Oct-17		(2,060,662.59)	(2,796.77)	(238.60)	(48,827.13)	7.778%		(2,112,525)	(8,613,789.11)
138	Nov-17	1	(161,023.75)	(24,818.42)	8,799.00	(12,698.87)	7.778%	6,743,112.06	6,553,370	(2,060,419.10)
139	Dec-17		(966,340.01)	(38,724.30)	(32,151.00)	(16,716.39)	7.778%		(1,053,932)	(3,114,350.79)
140	Jan-18		(1,200,403.59)	(31,882.61)	(33,107.00)	(24,287.11)	7.778%		(1,289,680)	(4,404,031.11)
141	Feb-18		(2,337,041.62)	(31,436.90)	(2,853.00)	(36,230.55)	7.778%		(2,407,562)	(6,811,593.18)
142	Mar-18		(2,924,008.07)	(27,470.45)	3,967.00	(53,702.87)	7.778%		(3,001,214)	(9,812,807.56)
143	Apr-18		(2,962,519.55)	(18,470.70)	(30,590.00)	(73,363.38)	7.778%		(3,084,944)	(12,897,751.20)
144	May-18		(859,748.34)	(9,407.43)	(19,480.00)	(86,478.84)	7.778%		(975,115)	(13,872,865.81)
145	Jun-18	2	(542,893.90)	(7,996.05)	0.00	(91,704.64)	7.778%	(0.30)	(642,595)	(14,515,460.70)
146	Jul-18					(94,084.38)	7.778%		(94,084)	(14,609,545.08)
147	Aug-18					(94,694.20)	7.778%		(94,694)	(14,704,239.28)
148	Sep-18					(95,307.98)	7.778%		(95,308)	(14,799,547.26)
149	Oct-18					(95,925.73)	7.778%		(95,926)	(14,895,472.99)
150										

151 **History truncated for ease of viewing**

152

153 **NOTES:**

154 **1** -Transferred June balance plus July-October interest on June balance to account 191401 for amortization.

155 **2** -Transfer represents true-up of balance to the general ledger.

Company: Northwest Natural Gas Company
State: Oregon
Description: Amortization of Oregon WACOG Deferral
Account Number: 191401
Dockets UM 1496 and UG 334
Amortization of 2016-17 deferral approved in Order No. 17-415

1 Debit (Credit)

Line	Month/Year	Note	Amortization	Transfers	Interest	Interest rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
6								
7	Beginning Balance							
144	Jun-17		398,199.38		(311.93)	2.20%	397,887.45	28,643.17
145	Jul-17		300,985.19		328.42	2.20%	301,313.61	329,956.78
146	Aug-17		256,002.32		839.59	2.20%	256,841.91	586,798.69
147	Sep-17		285,070.47		1,337.11	2.20%	286,407.58	873,206.27
148	Oct-17		451,844.21		2,015.07	2.20%	453,859.28	1,327,065.55
149	Nov-17		377,595.68		2,779.08	2.20%	380,374.76	1,707,440.31
150	Nov-17	**1**	238,843.57	(6,743,112.06)	(13,136.99)	2.38%	(6,517,405.48)	(4,809,965.17)
151	Dec-17		782,465.67		(8,763.82)	2.38%	773,701.85	(4,036,263.32)
152	Jan-18		948,702.48		(7,064.46)	2.38%	941,638.02	(3,094,625.30)
153	Feb-18		714,101.20		(5,429.52)	2.38%	708,671.68	(2,385,953.63)
154	Mar-18		771,688.75		(3,966.88)	2.38%	767,721.87	(1,618,231.76)
155	Apr-18		580,351.83		(2,633.98)	2.38%	577,717.85	(1,040,513.91)
156	May-18		337,202.92		(1,729.29)	2.38%	335,473.63	(705,040.28)
157	Jun-18	**2**	230,307.63	0.01	(1,169.94)	2.38%	229,137.70	(475,902.59)
158	Jul-18	*forecast*	*173,843.95*		(771.48)	2.38%	173,072.47	(302,830.12)
159	Aug-18	*forecast*	*173,512.42*		(428.55)	2.38%	173,083.87	(129,746.25)
160	Sep-18	*forecast*	*184,429.04*		(74.44)	2.38%	184,354.60	54,608.35
161	Oct-18	*forecast*	*376,411.97*		481.58	2.38%	376,893.55	431,501.90

163 **History truncated for ease of viewing**

165 **NOTES:**
166 **1** - Transferred in authorized balance from accounts 191400 and 191405.
167 **2** - Transfer represents a true-up to the general ledger.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Core Market Demand cost deferral
Account Number:	191410
	Docket UM 1496
	Last deferral reauthorization was approved in Order 17-397
Narrative:	Deferral of 100% of the difference between actual demand cost incurred and the demand cost embedded in customer rates.

1	Debit (Credit)							
2			Demand					
3	Month/Year	Note	Deferral	Transfer	Interest	Interest Rate	Activity	Balance
4	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
5								
6	Beginning Bal							
133	Jun-17		(59,805.29)		2,307.55	7.778%	(57,497.74)	328,417.29
134	Jul-17		50,310.48		2,291.74	7.778%	52,602.22	381,019.51
135	Aug-17		45,479.60		2,617.03	7.778%	48,096.63	429,116.14
136	Sep-17		51,674.83		2,948.86	7.778%	54,623.69	483,739.83
137	Oct-17		14,061.80		3,181.01	7.778%	17,242.81	500,982.64
138	Nov-17	**1**	84,238.73	(337,015.20)	1,335.79	7.778%	(251,440.68)	249,541.96
139	Dec-17		(604,612.34)		(342.00)	7.778%	(604,954.34)	(355,412.38)
140	Jan-18		5,653.08		(2,285.34)	7.778%	3,367.74	(352,044.64)
141	Feb-18		47,076.21		(2,129.27)	7.778%	44,946.94	(307,097.69)
142	Mar-18		(568.26)		(1,992.35)	7.778%	(2,560.61)	(309,658.30)
143	Apr-18		(11,204.15)		(2,043.41)	7.778%	(13,247.56)	(322,905.86)
144	May-18		311,167.47		(1,084.53)	7.778%	310,082.94	(12,822.92)
145	Jun-18	**2**	(366,168.02)	(0.21)	(1,269.80)	7.778%	(367,438.03)	(380,260.95)
146	Jul-18				(2,464.72)	7.778%	(2,464.72)	(382,725.67)
147	Aug-18				(2,480.70)	7.778%	(2,480.70)	(385,206.37)
148	Sep-18				(2,496.78)	7.778%	(2,496.78)	(387,703.15)
149	Oct-18				(2,512.96)	7.778%	(2,512.96)	(390,216.11)
150								

151 **History truncated for ease of viewing**

152

153 **NOTES**

154 **1** -Transferred June balance plus July-October interest on June balance to account 191411 for amortization.

155 **2** -Transfer represents true-up to gerneral ledger.

Company:	Northwest Natural Gas Company
State:	Oregon
Description:	Amortization of Oregon Demand Deferral
Account Number:	191411
	Dockets UM 1496 and UG 334
	Amortization of 2016-17 deferral approved in Order No. 17-415

1 Debit (Credit)

Row	Month/Year	Note	Amortization	Transfers	Interest	Interest Rate	Activity	Balance
5	(a)	(b)	(c)	(d)	(e1)	(e2)	(f)	(g)
7	Beginning Balance							
144	Jun-17		(366,341.19)		827.78	2.20%	(365,513.41)	269,171.85
145	Jul-17		(271,847.95)		244.29	2.20%	(271,603.66)	(2,431.81)
146	Aug-17		(226,081.55)		(211.70)	2.20%	(226,293.25)	(228,725.06)
147	Sep-17		(253,329.02)		(651.55)	2.20%	(253,980.57)	(482,705.63)
148	Oct-17		(413,392.22)		(1,263.90)	2.20%	(414,656.12)	(897,361.75)
149	Nov-17	old rates	(389,749.23)		(2,002.43)	2.20%	(391,751.66)	(1,289,113.41)
150	Nov-17	new rates **(1)**	406,267.49	(8,666,375.60)	(16,785.43)	2.38%	(8,276,893.54)	(9,566,006.96)
151	Dec-17		1,474,502.36		(17,510.37)	2.38%	1,456,991.99	(8,109,014.97)
152	Jan-18		1,804,585.95		(14,293.33)	2.38%	1,790,292.62	(6,318,722.35)
153	Feb-18		1,342,223.34		(11,201.09)	2.38%	1,331,022.25	(4,987,700.10)
154	Mar-18		1,454,274.77		(8,450.12)	2.38%	1,445,824.65	(3,541,875.44)
155	Apr-18		1,083,277.72		(5,950.47)	2.38%	1,077,327.25	(2,464,548.20)
156	May-18		611,785.35		(4,281.33)	2.38%	607,504.02	(1,857,044.18)
157	Jun-18	**2**	403,434.48	(0.20)	(3,283.07)	2.38%	400,151.21	(1,456,892.96)
158	Jul-18	*forecast*	*298,700.53*		(2,593.29)	2.38%	296,107.24	(1,160,785.72)
159	Aug-18	*forecast*	*298,199.69*		(2,006.51)	2.38%	296,193.18	(864,592.54)
160	Sep-18	*forecast*	*320,611.14*		(1,396.84)	2.38%	319,214.30	(545,378.24)
161	Oct-18	*forecast*	*690,384.77*		(397.04)	2.38%	689,987.73	144,609.49

163 **History truncated for ease of viewing**

165 **<u>NOTES:</u>**

166 **1** - Transferred in authorized balances from accounts 191410, 191450, and 191417.

167 **2** - Transfer represents a true-up to the general ledger.

Company: Northwest Natural Gas Company
State: Oregon
Description: Coos County Demand
Account Number: 191417
Docket UM 1179 Order 04-702

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

1 Debit (Credit)

	Month/Year	Note	Deferral	Adjustment	Transfer	Interest	Activity	Balance
5	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
6	Beginning Bal							
133	Jun-17		23,783.00	(4,586.06)			19,196.94	244,677.89
134	Jul-17		23,783.00	(3,703.86)			20,079.14	264,757.03
135	Aug-17		23,783.00	(3,785.49)			19,997.51	284,754.54
136	Sep-17		23,783.18	(3,564.99)			20,218.19	304,972.73
137	Oct-17		23,783.00	(4,742.05)			19,040.95	324,013.68
138	Nov-17	**1**	23,783.00	(5,892.30)	(244,677.89)		(226,787.19)	97,226.49
139	Dec-17		23,783.00	(8,278.65)			15,504.35	112,730.84
140	Jan-18		23,783.00	(8,897.40)			14,885.60	127,616.44
141	Feb-18		16,991.00	(6,948.51)			10,042.49	137,658.93
142	Mar-18		16,991.00	(8,818.14)			8,172.86	145,831.79
143	Apr-18		16,991.00	(8,864.47)			8,126.53	153,958.32
144	May-18		16,991.00	(7,525.02)			9,465.98	163,424.30
145	Jun-18		16,991.00	(5,739.59)			11,251.41	174,675.71
146	Jul-18						0.00	174,675.71
147	Aug-18						0.00	174,675.71
148	Sep-18						0.00	174,675.71
149	Oct-18						0.00	174,675.71

151 **History truncated for ease of viewing**

153 **NOTES**

154 **1** - June balance transferred to account 191411 for amortization.

Company: Northwest Natural Gas Company
State: Oregon
Description: Seasonalized Demand Collection Deferral
Account Number: 191450
Docket UM 1496
Last deferral reauthorization was approved in Order 17-397

Narrative: Deferral of 100% of the difference between actual demand costs collected and the seasonalized imbedded demand costs embedded in customer rates.

1 Debit (Credit)

	Month/Year	Note	Demand Deferral	Interest	Interest Rate	Transfer	Activity	Balance
4	(a)	(b)	(d)	(e)	(f)	(g)	(i)	(j)
5								
6	Beginning Bal							
133	Jun-17		87,645.12	(58,319.67)	7.778%		29,325.45	(9,012,132.60)
134	Jul-17		80,425.65	(58,152.99)	7.778%		22,272.66	(8,989,859.94)
135	Aug-17		322,377.30	(57,224.50)	7.778%		265,152.80	(8,724,707.14)
136	Sep-17		72,264.24	(56,316.45)	7.778%		15,947.79	(8,708,759.36)
137	Oct-17		(613,434.01)	(58,435.31)	7.778%		(671,869.32)	(9,380,628.68)
138	Nov-17	**1**	(310,750.65)	(1,866.30)	7.778%	9,248,068.70	8,935,451.75	(445,176.92)
139	Dec-17		(1,199,738.07)	(6,773.64)	7.778%		(1,206,511.71)	(1,651,688.63)
140	Jan-18		710,279.42	(8,403.80)	7.778%		701,875.62	(949,813.01)
141	Feb-18		(1,430,829.82)	(10,793.45)	7.778%		(1,441,623.27)	(2,391,436.28)
142	Mar-18		(1,361,964.00)	(19,914.39)	7.778%		(1,381,878.39)	(3,773,314.67)
143	Apr-18		(579,845.74)	(26,336.55)	7.778%		(606,182.29)	(4,379,496.97)
144	May-18		767,684.94	(25,898.50)	7.778%		741,786.44	(3,637,710.52)
145	Jun-18	**2**	81,397.24	(23,314.63)	7.778%	(0.01)	58,082.60	(3,579,627.92)
146	Jul-18			(23,201.95)	7.778%		(23,201.95)	(3,602,829.87)
147	Aug-18			(23,352.34)	7.778%		(23,352.34)	(3,626,182.21)
148	Sep-18			(23,503.70)	7.778%		(23,503.70)	(3,649,685.91)
149	Oct-18			(23,656.05)	7.778%		(23,656.05)	(3,673,341.96)

151 **History truncated for ease of viewing**

153 **NOTES**

154 **1** -Transferred June balance plus July-October interest on June balance to account 191411 for amortization.
155 **2** -Transfer represents true-up to general ledger.

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 18-11 / UG 355

July 26, 2018

NW NATURAL

EXHIBIT B

Supporting Materials

Purchased Gas Cost

NWN OPUC ADVICE NO. 18-11 / UG 355

NW Natural
2018-2019 PGA - SYSTEM: August Filing
Summary of Total Commodity Cost
ALL VOLUMES IN THERMS

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**		$15,701,597	$17,070,194	$18,451,301	$15,591,294	$16,212,921	$8,365,471	$5,618,179	$3,791,460	$3,202,973	$3,175,579	$3,311,115	$7,049,249	$117,541,333
6	tab commodity cost from supply, column cd, lines 93-104 plus gen input line 80; and														
7	tab commodity cost from gas reserve, column q, lines 59-70														
8	**Volumetric Pipeline Chgs**		$82,366	$90,383	$95,619	$82,914	$92,148	$66,003	$44,657	$31,762	$26,114	$25,962	$27,188	$52,681	$717,797
9	tab commodity cost from vol pipe, column e, line 78-89														
10	**Commodity Cost from Storage**		$3,591,190	$13,013,211	$11,581,510	$7,508,298	$1,639,012	$110,473	$85,535	$290,137	$299,807	$299,807	$290,137	$299,807	$39,008,924
11	tab Commodity Cost from Storage, column k, line 61-72														
12	**Commodity Cost from Gas Reserves**		$2,440,931	$2,477,398	$2,410,848	$2,206,909	$2,340,196	$2,262,094	$2,314,514	$2,206,436	$2,200,514	$2,168,405	$2,091,449	$2,108,511	$27,228,206
13	tab Commodity Cost from Gas Reserve, column p, line 59-70														
14	**Total Commodity Cost**		$21,816,085	$32,651,186	$32,539,278	$25,389,415	$20,284,277	$10,804,041	$8,062,885	$6,319,795	$5,729,407	$5,669,753	$5,719,889	$9,510,249	$184,496,261
15															
16	**VOLUMES**														
17	Commodity Volumes at Receipt Points		77,972,536	78,916,075	84,504,538	74,199,626	83,514,622	67,736,526	44,855,304	30,237,594	24,086,816	23,925,316	25,355,836	52,443,136	667,747,925
18	Pipeline Fuel Use		1,842,102	1,929,755	2,075,502	1,770,454	1,971,269	1,713,107	1,106,570	727,380	564,927	560,715	600,064	1,304,460	16,166,304
19	Gas Arriving at City Gate		76,130,434	76,986,320	82,429,036	72,429,172	81,543,353	66,023,419	43,748,734	29,510,214	23,521,889	23,364,601	24,755,773	51,138,676	651,581,621
20															
21	Storage Gas Withdrawals		12,270,780	44,408,822	39,525,472	26,863,467	6,895,791	398,367	314,030	879,900	909,230	909,230	879,900	909,230	135,164,221
22	Pipeline Fuel Use for Off-site Storage		0	0	0	44,595	72,363	0	0	0	0	0	0	0	116,958
23	Storage Gas Deliveries at City Gate		12,270,780	44,408,822	39,525,472	26,818,872	6,823,428	398,367	314,030	879,900	909,230	909,230	879,900	909,230	135,047,262
24															
25	Total Gas At City Gate (Storage and Commodity)		88,401,214	121,395,142	121,954,508	99,248,044	88,366,781	66,421,786	44,062,764	30,390,114	24,431,119	24,273,831	25,635,673	52,047,906	786,628,883
26															
27	Unaccounted for Gas		556,970	563,232	603,051	529,892	596,571	483,027	320,066	215,897	172,086	170,935	181,113	374,131	4,766,971
28															
29	Load Served		87,844,244	120,831,910	121,351,457	98,718,152	87,770,210	65,938,759	43,742,699	30,174,218	24,259,033	24,102,896	25,454,560	51,673,776	781,861,912

Line	WACOG Calculations	(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	**Gas Reserves Supply:**													
31	Total cost (line 12 above)	$2,440,931	$2,477,398	$2,410,848	$2,206,909	$2,340,196	$2,262,094	$2,314,514	$2,206,436	$2,200,514	$2,168,405	$2,091,449	$2,108,511	$27,228,206
32	Load served by gas reserves	3,205,453	3,253,991	3,158,060	2,802,586	3,057,810	2,925,208	2,980,556	2,838,750	2,902,190	2,856,640	2,728,169	2,773,965	35,483,378
33														
34	**Total Load Served**													
35	Oregon	79,005,879	108,331,537	108,678,490	88,565,771	78,779,355	59,336,873	39,500,340	27,338,319	21,821,366	21,697,200	22,910,530	46,507,683	702,473,342
36	Washington	8,838,365	12,500,372	12,672,967	10,152,382	8,990,855	6,601,886	4,242,359	2,835,899	2,437,666	2,405,696	2,544,030	5,166,093	79,388,570
37	Total (same as line 25 +/- rounding)	87,844,244	120,831,910	121,351,457	98,718,152	87,770,210	65,938,759	43,742,699	30,174,218	24,259,033	24,102,896	25,454,560	51,673,776	781,861,912
38														
39	**Washington WACOG Calculation**													
40														
41	**Hedged Rockies supply excluding Gas Reserves**													
42	Hedged Rockies supply volumes	16,308,600	16,852,220	16,852,220	12,453,840	13,022,170	3,706,500	1,532,020	1,482,600	1,532,020	1,532,020	1,482,600	3,830,050	90,586,860
43	Hedged Rockies supply cost	$4,788,300	$4,947,910	$4,947,910	$3,564,540	$3,660,015	$660,375	$292,020	$282,600	$292,020	$292,020	$282,600	$707,963	$24,718,273
44	Hedged Rockies supply price per therm	$0.29361	$0.29361	$0.29361	$0.28622	$0.28106	$0.17817	$0.19061	$0.19061	$0.19061	$0.19061	$0.19061	$0.18484	$0.27287
45														
46	Load served by gas reserves	3,205,453	3,253,991	3,158,060	2,802,586	3,057,810	2,925,208	2,980,556	2,838,750	2,902,190	2,856,640	2,728,169	2,773,965	35,483,378
47	Gas Reserves cost	$2,440,931	$2,477,398	$2,410,848	$2,206,909	$2,340,196	$2,262,094	$2,314,514	$2,206,436	$2,200,514	$2,168,405	$2,091,449	$2,108,511	$27,228,206
48	Gas Reserves price per therm	$0.76149	$0.76134	$0.76340	$0.78745	$0.76532	$0.77331	$0.77654	$0.77726	$0.75823	$0.75908	$0.76661	$0.76011	$0.76735
49														
50	Washington percentage of total load (line 36 ÷ line 37)	10.1%	10.3%	10.4%	10.3%	10.2%	10.0%	9.7%	9.4%	10.0%	10.0%	10.0%	10.0%	10.2%
51														
52	Total System Commodity Cost (line 14 above)	$21,816,085	$32,651,186	$32,539,278	$25,389,415	$20,284,277	$10,804,041	$8,062,885	$6,319,795	$5,729,407	$5,669,753	$5,719,889	$9,510,249	$184,496,261
53	Less: Commodity Cost of Rockies Hedged Supplies (from line 43)	$4,788,300	$4,947,910	$4,947,910	$3,564,540	$3,660,015	$660,375	$292,020	$282,600	$292,020	$292,020	$282,600	$707,963	$24,718,273
54	Less: Commodity Cost of Gas Reserves (from line 12)	$2,440,931	$2,477,398	$2,410,848	$2,206,909	$2,340,196	$2,262,094	$2,314,514	$2,206,436	$2,200,514	$2,168,405	$2,091,449	$2,108,511	$27,228,206
55	Less: Cost of Index Adder for Gas Reserves Allocated to Baseload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
56	Total System Commodity Cost excluding Rockies hedged & Gas Reserves	$14,586,853	$25,225,878	$25,180,520	$19,617,966	$14,284,066	$7,881,572	$5,456,351	$3,830,759	$3,236,874	$3,209,328	$3,345,840	$6,693,775	$132,549,782
57														
58	Total System Load Served (from line 29)	87,844,244	120,831,910	121,351,457	98,718,152	87,770,210	65,938,759	43,742,699	30,174,218	24,259,033	24,102,896	25,454,560	51,673,776	781,861,912
59	Less: load from Rockies hedged supplies (from line 42)	16,308,600	16,852,220	16,852,220	12,453,840	13,022,170	3,706,500	1,532,020	1,482,600	1,532,020	1,532,020	1,482,600	3,830,050	90,586,860
60	Less: load served by gas reserves (from line 32)	3,205,453	3,253,991	3,158,060	2,802,586	3,057,810	2,925,208	2,980,556	2,838,750	2,902,190	2,856,640	2,728,169	2,773,965	35,483,378
61	Total System load excluding Rockies hedged & Gas Reserves	68,330,190	100,725,699	101,341,177	83,461,726	71,690,230	59,307,051	39,230,123	25,852,868	19,824,823	19,714,236	21,243,791	45,069,761	655,791,674
62														
63	System price excluding Rockies hedged & Gas Reserves (line 56 ÷ line 61)	$0.21348	$0.25044	$0.24847	$0.23505	$0.19925	$0.13289	$0.13909	$0.14818	$0.16327	$0.16279	$0.15750	$0.14852	$0.20212
64														
65	**Washington allocation of Rockies hedged supply**													
66	Rockies hedged supply needed for Washington (line 50 * (line 42 + line 46)	1,970,919	2,070,940	2,081,069	1,571,412	1,640,158	663,171	437,720	406,207	443,421	438,866	421,077	660,402	12,805,362
67	Cost of Rockies hedged supply allocated to Washington (line 66 * line 44)	$578,682	$608,049	$611,023	$449,770	$460,983	$118,157	$83,434	$77,427	$84,520	$83,652	$80,261	$122,069	$3,358,026
68														
69	**Washington portfolio**													
70	Volumes													
71	Total Washington load	8,838,365	12,500,372	12,672,967	10,152,382	8,990,855	6,601,886	4,242,359	2,835,899	2,437,666	2,405,696	2,544,030	5,166,093	79,388,570
72	Washington load met by Rockies hedged supply	1,970,919	2,070,940	2,081,069	1,571,412	1,640,158	663,171	437,720	406,207	443,421	438,866	421,077	660,402	12,805,362
73	Remaining Washington load	6,867,446	10,429,432	10,591,898	8,580,970	7,350,697	5,938,715	3,804,639	2,429,692	1,994,245	1,966,830	2,122,953	4,505,691	66,583,208
74														
75	Cost													
76	Cost of Rockies hedged supply allocated to Washington (line 67)	$578,682	$608,049	$611,023	$449,770	$460,983	$118,157	$83,434	$77,427	$84,520	$83,652	$80,261	$122,069	$3,358,026
77	Cost of remaining Washington load (line 73 * line 63)	$1,466,062	$2,611,947	$2,631,769	$2,016,957	$1,464,626	$789,196	$529,187	$360,032	$325,600	$320,180	$334,365	$669,185	$13,519,107
78	Total cost of Washington portfolio	$2,044,744	$3,219,996	$3,242,792	$2,466,726	$1,925,609	$907,353	$612,621	$437,459	$410,121	$403,832	$414,627	$791,254	$16,877,134
79														
80	**Washington Sales WACOG** (line 78 ÷ line 71)	$0.23135	$0.25759	$0.25588	$0.24297	$0.21417	$0.13744	$0.14441	$0.15426	$0.16824	$0.16787	$0.16298	$0.15316	$0.21259
81														
82	**WASHINGTON BILLING WACOG**	$0.24193	$0.26937	$0.26758	$0.25408	$0.22396	$0.14372	$0.15101	$0.16131	$0.17593	$0.17554	$0.17043	$0.16016	$0.22231
83														
84	**Oregon WACOG Calculation**													
85														
86	Total system commodity cost	$21,816,085	$32,651,186	$32,539,278	$25,389,415	$20,284,277	$10,804,041	$8,062,885	$6,319,795	$5,729,407	$5,669,753	$5,719,889	$9,510,249	$184,496,261
87	Commodity cost allocated to Washington portfolio	$2,044,744	$3,219,996	$3,242,792	$2,466,726	$1,925,609	$907,353	$612,621	$437,459	$410,121	$403,832	$414,627	$791,254	$16,877,134
88	Total commodity cost for Oregon	$19,771,341	$29,431,190	$29,296,487	$22,922,688	$18,358,668	$9,896,688	$7,450,264	$5,882,336	$5,319,286	$5,265,920	$5,305,262	$8,718,995	$167,619,127
89														
90	**Oregon Sales WACOG (line 88 ÷ line 35)**	$0.25025	$0.27168	$0.26957	$0.25882	$0.23304	$0.16679	$0.18861	$0.21517	$0.24377	$0.24270	$0.23156	$0.18747	$0.23861
91														
92	**OREGON BILLING WACOG**	$0.25750	$0.27955	$0.27738	$0.26632	$0.23979	$0.17162	$0.19407	$0.22140	$0.25083	$0.24973	$0.23827	$0.19290	$0.24552

NW Natural
2018-2019 PGA - SYSTEM: August Filing
Summary of Total Demand Charges

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			30	31	31	28	31	30	31	30	31	31	30	31	365
4	**Transport charges by transporter:**														
5															
6	Northwest Pipeline		$4,190,973	$4,330,672	$4,330,672	$3,911,576	$4,330,672	$4,095,947	$4,232,479	$4,095,947	$4,232,479	$4,232,479	$4,095,947	$4,232,479	$50,312,323
7															
8	Alberta: NOVA		623,609	623,609	623,609	623,609	623,609	623,609	623,609	623,609	623,609	623,609	623,609	623,609	7,483,305
9															
10	Alberta: Foothills		300,101	300,101	300,101	300,101	300,101	267,865	267,865	267,865	267,865	267,865	267,865	300,101	3,407,800
11															
12	Alberta: GTN		484,979	501,145	501,145	452,647	501,145	408,140	421,745	408,140	421,745	421,745	408,140	501,145	5,431,862
13															
14	BC: Southern Crossing		612,390	631,603	631,603	573,964	631,603	612,390	631,603	612,390	631,603	631,603	612,390	631,603	7,444,745
15															
16	BC: Spectra (Westcoast)		313,700	323,390	323,390	294,320	323,390	313,700	323,390	313,700	323,390	323,390	313,700	323,390	3,812,850
17															
18	KB Pipeline		18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	18,688	224,258
19															
20	Total System Demand		$6,544,441	$6,729,209	$6,729,209	$6,174,906	$6,729,209	$6,340,339	$6,519,379	$6,340,339	$6,519,379	$6,519,379	$6,340,339	$6,631,016	$78,117,143

NW Natural

2018-2019 PGA - SYSTEM: August Filing

Derivation of Oregon per therm Non-Commodity Charges

ALL VOLUMES IN THERMS

Oregon Derivation of Demand Increments

Line				
1			Without	WITH
2			Revenue Sensitive	Revenue Sensitive
3	(a)	(b)	(c)	(d)
4	System Demand		$78,117,143	
5	Oregon Allocation Factor 1/		89.30%	
6	Oregon Demand		$69,758,608	
7				
8	Oregon Firm Sales Forecasted Normal Volumes		651,323,185	
9	Oregon Interruptible Sales Forecasted Normal Volumes		51,150,158	
10				
11				
12	Proposed Firm Demand Per Therm 2/		$0.10611	$0.10918
13	Proposed Interruptible Demand 2/		$0.01263	$0.01300
14	Proposed MDDV Demand Charge		$1.58	$1.63
15				
16	Current Firm Demand Per Therm		$0.11588	$0.11921
17	Current Interruptible Demand		$0.01379	$0.01419
18	Current MDDV Demand Charge		$1.72	$1.77
19				
20	Percent Change in Firm Demand		-8.43%	
21				
22				
23	1/Allocation Factor: 2018-19 PGA forecast firm sales volumes:			
24		Washington	Oregon	System
25	Firm Sales	78,031,973	651,323,185	729,355,158
26		10.70%	89.30%	100.00%
27				
28	2/Calculation of Proposed Demand Rates:			
29				
30	Demand change factor		0.916	
31				
32	Firm Demand (line 16 * line 30)		$0.10611	$69,112,710
33	Interruptible Demand (line 17 * line 30)		$0.01263	$645,898
34				$69,758,608
35				$0

NW Natural

2018-2019 PGA - SYSTEM: August Filing

Calculation of Winter WACOG

Prices are per therm

1	Forecast price for AECO gas:			
2				
3		AECO/NIT		
4				
5	November	$0.14120		
6	December	$0.15590		
7	January	$0.16231		
8	February	$0.16010		
9	March	$0.14605		
10	April	$0.10684		
11	May	$0.10494		
12	June	$0.10711		
13	July	$0.11119		
14	August	$0.11080		
15	September	$0.11050		
16	October	$0.11520		
17				
18				
19	Average price, November-March		$0.15311	average lines 5-9
20				
21	Annual average price, November-October		$0.12768	average lines 5-16
22				
23	Ratio of winter to annual		1.19917	line 19 ÷ line 21
24				
25			Without Rev	WITH Rev
26			Sensitive	Sensitive
OR	Oregon Annual WACOG		$0.23861	$0.24552
OR	Oregon Winter WACOG		$0.28613	$0.29442
			line 23 * $0.23861	
WA	Washington Annual WACOG		$0.21259	$0.22231
WA	Washington Winter WACOG		$0.25493	$0.26659
			line 23 * $0.21259	

NW Natural
2018-2019 PGA - OREGON: August Filing
Derivation of Oregon Seasonalized Fixed Charges

(a)	(b)	Normalized Residential Volumes (c)	Normalized Commercial Volumes (d)	Firm Industrial Volumes (e)	Interruptible Volumes (f)	Total (g)	Firm Demand Increment Eff. 11/01/18 (h)	Interr. Demand Increment Eff. 11/01/18 (i)	Seasonalized Fixed Charges (j)
November	2018	45,951,584	26,287,038	2,710,880	4,056,376	79,005,879	$0.10611	$0.01263	$8,004,201
December	2018	64,232,609	35,804,985	3,065,341	5,228,602	108,331,537	$0.10611	$0.01263	$11,006,397
January	2019	63,689,736	35,616,830	3,640,317	5,731,607	108,678,490	$0.10611	$0.01263	$10,996,191
February	2019	51,214,458	29,023,971	3,307,365	5,019,977	88,565,771	$0.10611	$0.01263	$8,928,533
March	2019	44,567,550	25,959,252	3,013,221	5,239,332	78,779,355	$0.10611	$0.01263	$7,869,581
April	2019	32,338,596	19,724,557	2,677,090	4,596,629	59,336,873	$0.10611	$0.01263	$5,866,600
May	2019	19,319,216	13,516,829	2,467,598	4,196,698	39,500,340	$0.10611	$0.01263	$3,799,111
June	2019	11,685,959	9,847,924	2,185,597	3,618,839	27,338,319	$0.10611	$0.01263	$2,562,605
July	2019	8,438,240	7,936,789	2,226,944	3,219,394	21,821,366	$0.10611	$0.01263	$2,014,536
August	2019	8,400,334	7,894,235	2,193,658	3,208,973	21,697,200	$0.10611	$0.01263	$2,002,335
September	2019	9,305,663	8,050,214	2,404,751	3,149,902	22,910,530	$0.10611	$0.01263	$2,136,604
October	2019	24,268,814	15,539,714	2,815,327	3,883,828	46,507,683	$0.10611	$0.01263	$4,571,914
		383,412,758	235,202,338	32,708,089	51,150,158	702,473,342			$69,758,608

	Encana Gas Reserves Deal		Projected November 2018	Projected December 2018	Projected January 2019	Projected February 2019	Projected March 2019	Projected April 2019	Projected May 2019	Projected June 2019	Projected July 2019	Projected August 2019	Projected September 2019	Projected October 2019	Projected PGA Totals
1	**Therms Delivered (000s)**														
2	**Total Therms**		3,105.49	3,152.18	3,057.22	2,712.75	2,959.78	2,831.78	2,885.36	2,747.82	2,809.60	2,765.19	2,640.83	2,684.77	34,352.79
3	**Rate per Therm (Depletion Rate)**		0.47273	0.47273	0.47273	0.47273	0.47273	0.47273	0.47273	0.47273	0.47273	0.47273	0.47273	0.47273	0.47273
4	**Delivery Value**		1,468.06	1,490.13	1,445.24	1,282.40	1,399.18	1,338.67	1,364.00	1,298.98	1,328.18	1,307.19	1,248.40	1,269.17	16,239.63
5															0.4727
6	**Opex / Severance / Ad Valorem**														
7	**Operating Cost**		469.74	481.11	469.07	454.08	479.19	486.16	520.31	489.26	456.27	454.44	449.16	451.04	5,659.84
8	**Severance and Ad Valorem Taxes**		82.15	96.64	97.41	82.75	75.85	57.68	57.81	56.04	62.53	61.84	58.22	59.70	848.63
9	**Total**		551.89	577.74	566.49	536.83	555.03	543.84	578.13	545.31	518.81	516.28	507.38	510.74	6,508.47
10															0.1895
11	**Average Rate Base**		47,618.23	46,497.36	45,414.91	44,452.27	43,403.71	42,399.67	41,376.99	40,402.16	39,405.83	38,424.95	37,487.34	36,534.43	
12															
13	**Carrying Cost**														
14	**Equity**	**9.5000%**	188.49	184.05	179.77	175.96	171.81	167.83	163.78	159.93	155.98	152.10	148.39	144.62	
15	**Equity % of Cap Struct**	**50.0000%**													
16	**Equity Pretax**	**39.4589%**	237.22	227.45	220.73	218.74	214.53	213.50	207.76	202.74	195.51	190.16	185.88	180.08	
17	**Debt**	**6.0560%**	120.16	117.33	114.60	112.17	109.52	106.99	104.41	101.95	99.43	96.96	94.59	92.19	
18	**Total Carrying Cost**		357.38	344.78	335.33	330.91	324.05	320.49	312.17	304.69	294.95	287.12	280.47	272.27	3,764.59
19															0.1096
20	**Total Cost**		2,377.33	2,412.65	2,347.06	2,150.14	2,278.26	2,203.00	2,254.30	2,148.98	2,141.94	2,110.59	2,036.25	2,052.19	26,512.69
21	**Total Volume**		3,105.49	3,152.18	3,057.22	2,712.75	2,959.78	2,831.78	2,885.36	2,747.82	2,809.60	2,765.19	2,640.83	2,684.77	34,352.79
22	**Total Rate Per Therm**		0.766	0.765	0.768	0.793	0.770	0.778	0.781	0.782	0.762	0.763	0.771	0.764	0.772

Non-Carry Wells Gas Reserves Deal		Projected November 2018	Projected December 2018	Projected January 2019	Projected February 2019	Projected March 2019	Projected April 2019	Projected May 2019	Projected June 2019	Projected July 2019	Projected August 2019	Projected September 2019	Projected October 2019	Projected PGA Totals
Therms Delivered (000s)														
Total Therms		137.58	140.00	137.90	122.73	133.91	127.76	130.17	124.24	126.65	124.97	119.36	121.75	1,547.03
Rate per Therm (Depletion Rate)		0.5953	0.5953	0.5953	0.5953	0.5953	0.5953	0.5953	0.5953	0.5953	0.5953	0.5953	0.5953	0.5953
Delivery Value		81.90	83.34	82.10	73.06	79.72	76.06	77.49	73.97	75.40	74.40	71.06	72.48	920.99
														0.5953
Opex / Severance / Ad Valorem														
Operating Cost		16.81	17.18	16.88	16.22	16.84	16.93	18.02	17.08	16.30	16.23	15.99	16.09	200.57
Severance and Ad Valorem Taxes		3.64	4.29	4.39	3.74	3.43	2.60	2.61	2.53	2.82	2.79	2.63	2.71	38.20
Total		20.44	21.47	21.27	19.96	20.27	19.53	20.63	19.61	19.12	19.03	18.62	18.80	238.77
														0.1543
Average Rate Base		3,098.09	3,035.11	2,972.96	2,917.46	2,857.06	2,799.36	2,740.60	2,684.43	2,627.21	2,570.73	2,516.70	2,461.63	
Carrying Cost														
Equity	**9.5000%**	12.26	12.01	11.77	11.55	11.31	11.08	10.85	10.63	10.40	10.18	9.96	9.74	
Equity % of Cap Struct	**50.0000%**													
Equity Pretax	**39.4589%**	16.67	16.33	15.99	15.69	15.37	15.06	14.74	14.44	14.13	13.83	13.54	13.24	
Debt	**6.0560%**	7.82	7.66	7.50	7.36	7.21	7.06	6.92	6.77	6.63	6.49	6.35	6.21	
Total Carrying Cost		24.48	23.99	23.50	23.06	22.58	22.12	21.66	21.21	20.76	20.32	19.89	19.45	263.02
														0.1700
Total Cost		126.83	128.80	126.87	116.08	122.57	117.71	119.79	114.80	115.28	113.74	109.57	110.74	1,422.78
Total Volume		137.58	140.00	137.90	122.73	133.91	127.76	130.17	124.24	126.65	124.97	119.36	121.75	1,547.03
Total Rate Per Therm [1]		0.922	0.920	0.920	0.946	0.915	0.921	0.920	0.924	0.910	0.910	0.918	0.910	0.920

[1] The actual price included in WACOG is $0.4725/Th. per Order No. 15-297

NW Natural
Rates & Regulatory Affairs
2018-19 PGA - Oregon: August Filing
Attachment C: 3% Test

Line		Surcharge	Credit	
1		**Surcharge**	**Credit**	
2	**2018-2019 PGA Gas Cost True-Up**		(19,033,308)	
3				
4	**Non-Gas Cost Amortizations**			
5	WARM	1,158,308		
	Residual Deferral	-		
6	Intervenor Funding	215,512		
7	Oregon Regulatory Fee	250,404		
8	Industrial DSM	6,187,089		
9	Decoupling	7,730,779		
10	Subtotal	15,542,092	(19,033,308)	
11				
12	Total	(3,491,216)		
13				
14	**Total Proposed Amortization**			(3,491,216)
15	Less:			
16	Intervenor Funding[1]			(215,512)
17	Industrial DSM[1]			(6,187,089)
18	Decoupling[1]			(7,730,779)
19				
20	**Net Proposed Amortizations (subject to the 3% test)**			(17,624,596)
21				
22	**Utility Gross Revenues (2017)** [2]			678,370,976
23				
24	**3% of Utility Gross Revenues**			20,351,129
25				
26	**Allowed Amortization**			(17,624,596)
27				
28	**Allowed Amortization as % of Gross Revenues**			-2.6%
29				
30	Notes:			
31	[1] Amortizations of the deferral are not subject to the 3% test pursuant to ORS 757.259 as they are			
32	automatic adjustment clauses.			
33	[2] Unadjusted general revenues as shown in the most recent Results of Operations.			

NW Natural
Rates & Regulatory Affairs
2018-19 PGA - Oregon: August Filing
Effects on Average Bill by Rate Schedule [1]

Advice 18-11
See note [9]

ALL VOLUMES IN THERMS

Line	Schedule	Block	Oregon PGA Normalized Volumes page, Column D	Therms in Block	Normal Therms Monthly Average use	Minimum Monthly Charge	11/1/2017 Billing Rates	11/1/2017 Current Average Bill	Proposed 11/1/2018 PGA Rates	Proposed 11/1/2018 PGA Average Bill	Proposed 11/1/2018 PGA % Bill Change
5								F=D+(C * E)		W = D+(C * V)	X = (W- F)/F
6	Schedule	Block	A	B	C	D	E	F	V	W	X
7	2R		382,340,529	N/A	53	$8.00	$0.83850	$52.44	$0.77958	$49.32	-5.9%
8	3C Firm Sales		169,517,330	N/A	244	$15.00	$0.79685	$209.43	$0.73793	$195.05	-6.9%
9	3I Firm Sales		4,684,198	N/A	1,100	$15.00	$0.77033	$862.36	$0.71141	$797.55	-7.5%
10	27 Dry Out		1,072,229	N/A	46	$6.00	$0.73387	$39.76	$0.67495	$37.05	-6.8%
11	31C Firm Sales	Block 1	13,712,695	2,000	2,982	$325.00	$0.54893	**$1,943.28**	$0.50004	**$1,797.49**	-7.5%
12		Block 2	11,300,457	all additional			$0.52996		$0.48107		
13	31C Firm Trans	Block 1	1,495,770	2,000	1,731	$575.00	$0.18791	**$900.27**	$0.18791	**$900.27**	0.0%
14		Block 2	1,912,244	all additional			$0.17183		$0.17183		
15	31I Firm Sales	Block 1	4,480,787	2,000	5,371	$325.00	$0.47445	**$2,816.91**	$0.42556	**$2,554.32**	-9.3%
16		Block 2	9,117,388	all additional			$0.45773		$0.40884		
17	31I Firm Trans	Block 1	112,620	2,000	7,497	$575.00	$0.16963	**$1,757.12**	$0.16963	**$1,757.12**	0.0%
18		Block 2	337,199	all additional			$0.15333		$0.15333		
19	32C Firm Sales	Block 1	30,908,235	10,000	7,196	$675.00	$0.40410	**$3,582.90**	$0.35521	**$3,231.09**	-9.8%
20		Block 2	8,789,140	20,000			$0.38859		$0.33970		
21		Block 3	949,347	20,000			$0.36280		$0.31391		
22		Block 4	25,135	100,000			$0.33696		$0.28807		
23		Block 5	0	600,000			$0.32119		$0.27230		
24		Block 6	0	all additional			$0.31083		$0.26194		
25	32I Firm Sales	Block 1	5,602,336	10,000	20,036	$675.00	$0.40145	**$8,567.11**	$0.35256	**$7,587.55**	-11.4%
26		Block 2	6,047,501	20,000			$0.38637		$0.33748		
27		Block 3	1,988,054	20,000			$0.36119		$0.31230		
28		Block 4	787,826	100,000			$0.33605		$0.28716		
29		Block 5	0	600,000			$0.32066		$0.27177		
30		Block 6	0	all additional			$0.31065		$0.26176		
31	32 Firm Trans	Block 1	16,505,188	10,000	42,064	$925.00	$0.09971	**$4,338.61**	$0.09971	**$4,338.61**	0.0%
32		Block 2	18,272,096	20,000			$0.08473		$0.08473		
33		Block 3	10,705,944	20,000			$0.05984		$0.05984		
34		Block 4	20,210,199	100,000			$0.03492		$0.03492		
35		Block 5	20,401,757	600,000			$0.01995		$0.01995		
36		Block 6	3,247,753	all additional			$0.01002		$0.01002		
37	32C Interr Sales	Block 1	5,440,472	10,000	32,387	$675.00	$0.41842	**$13,818.48**	$0.36018	**$11,932.26**	-13.6%
38		Block 2	7,486,554	20,000			$0.40295		$0.34471		
39		Block 3	3,972,506	20,000			$0.37716		$0.31892		
40		Block 4	4,854,576	100,000			$0.35139		$0.29315		
41		Block 5	65,604	600,000			$0.33590		$0.27766		
42		Block 6	0	all additional			$0.32544		$0.26720		
43	32I Interr Sales	Block 1	6,350,897	10,000	37,687	$675.00	$0.41821	**$15,811.36**	$0.35997	**$13,616.47**	-13.9%
44		Block 2	7,728,275	20,000			$0.40279		$0.34455		
45		Block 3	3,911,705	20,000			$0.37706		$0.31882		
46		Block 4	8,709,010	100,000			$0.35132		$0.29308		
47		Block 5	2,630,559	600,000			$0.33588		$0.27764		
48		Block 6	0	all additional			$0.32544		$0.26720		
49	32 Interr Trans	Block 1	8,589,936	10,000	206,472	$925.00	$0.10042	**$9,491.89**	$0.10042	**$9,491.89**	0.0%
50		Block 2	16,089,250	20,000			$0.08536		$0.08536		
51		Block 3	11,585,346	20,000			$0.06027		$0.06027		
52		Block 4	29,563,048	100,000			$0.03515		$0.03515		
53		Block 5	53,552,522	600,000			$0.02010		$0.02010		
54		Block 6	86,265,853	all additional			$0.01007		$0.01007		
55	33		0	N/A	0	$38,000	$0.00575	$38,000.00	$0.00575	$38,000.00	0.0%
56											
57	**Totals**		1,001,320,067								

58
59 [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.
60 [2] Tariff Advice Notice 18-04: Non-Gas Cost Deferral Amortizations - Intervenor Funding
61 [3] Tariff Advice Notice 18-05: Non-Gas Cost Deferral Amortizations - Residual Account
62 [4] Tariff Advice Notice 18-06: Non-Gas Cost Deferral Amortizations - Oregon PUC Fee
63 [5] Tariff Advice Notice 18-07: Non-Gas Cost Deferral Amortizations - SRRM
64 [6] Tariff Advice Notice 18-08: Non-Gas Cost Deferral Amortizations - Industrial DSM
65 [7] Tariff Advice Notice 18-09: Non-Gas Cost Deferral Amortizations - Decoupling
66 [8] Tariff Advice Notice 18-10: Non-Gas Cost Deferral Amortizations - WARM
67 [9] Tariff Advice Notice 18-11: PGA

NW Natural
Rates and Regulatory Affairs
2018-2019 PGA Filing - OREGON
Basis for Revenue Related Costs

Line		Twelve Months Ended 06/30/18		
1				
2				
3	Total Billed Gas Sales Revenues	$ 618,450,726		
4	Total Oregon Revenues	$ 621,865,430		
5				
6	Regulatory Commission Fees [1]	n/a	0.300%	Statutory rate
7	City License and Franchise Fees	$ 14,963,448	2.406%	Line 7 ÷ Line 4
8	Net Uncollectible Expense [2]	$ 678,352	0.109%	Line 8 ÷ Line 4
9				
10	Total		**2.815%**	Sum lines 8-9
11				
12				

13 **Note:**
14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).
15 Because the fee changed since our last general rate case, the difference between the previous fee of 0.275%
16 and the new fee of 0.3%, as it affects our base rates, is being captured as a temporary deferral.
17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2018-2019 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Tariff Advice 18-11: PGA Gas Costs and Gas Cost Deferrals

Line		Including Revenue Sensitive Amount
1		
2		
3	**Purchased Gas Cost Adjustment (PGA)**	
4		
5	Commodity Cost Change	($32,591,987)
6		
7	Demand Capacity Cost Change	(1,211,154)
8		
9	**Total Gas Cost Change**	**(33,803,141)**
10		
11	**Temporary Increments**	
12		
13	Removal of Current Temporary Increments	
14	Amortization of 191.xxx Account Gas Costs	15,624,355
15		
16	Addition of Proposed Temporary Increments	
17	Amortization of 191.xxx Account Gas Costs	(19,033,308)
18		
19	**Net Temporary Rate Adjustment**	**(3,408,953)**
20		
21	**TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES**	**($37,212,094)**
22		
23		
24		
25	2017 Oregon Earnings Test Normalized Total Revenues	$668,336,000
26		
27	Effect of this filing, as a percentage change (line 21 ÷ line 25)	-5.57%

EXHIBIT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 18-11

July 26, 2018

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
IV	General Information and Forecasting		
1	General Information		
a)	Definitions of all major terms and acronyms in the data and information provided.	4	
b)	Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.	6	
c)	All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.	7	
2	Workpapers		
a)	PGA Summary Sheet	8	
b)	Gas Supply Portfolio and Related Transportation		
1	Summary of portfolio planning	10	
2	LDC sales system demand forecasting	11	
3	Natural gas price forecasts	11	
4	Physical resources for the portfolio	12	CONFIDENTIAL
	Supporting Tables	26-29	
5	Financial resources for the portfolio (derivatives and other financial arrangements).	24	
6	Storage resources.	24	
7	Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation.	30	
8	Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.	30	
9	Summary of portfolio documentation provided	30	
V.1	**Physical Gas Supply**		HIGHLY CONFIDENTIAL
a)	For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:	31	
1	Pricing for the resource, including the commodity price and, if relevant, reservation charges.	31	
2	For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process.	31	
3	Brief explanation of each contract's role within the portfolio.	31	
b)	For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:	33	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
1	An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility.	33	
2	Any contract provisions that materially deviate from the standard NAESB contract.	34	
V.2	**Hedging**		
	The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.	35	**HIGHLY CONFIDENTIAL**
V.3	**Load Forecasting**		
a)	Customer count and revenue by month and class.	36	
b)	Historical (five years) and forecasted (one year ahead) sales system physical peak demand.	37	
c)	Historical (five years), and forecasted (one year ahead) sales system physical annual demand.	37	
d)	Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following,	37	
1	Annual for each customer class	37	
2	Annual and monthly baseload.	38	
3	Annual and monthly non-baseload.	38	
4	Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.	39	
V.4	**Market Information**		
	General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.	40	
V.5	**Data Interpretation**		
	If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.	44	
V.6	**Credit Worthiness Standards**		
	A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.	45	
	NW Natural Gas Supply Risk Management Policies	46	**CONFIDENTIAL**
V.7	**Storage**		
	Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.	72	
a)	Type of storage (e.g., depleted field, salt dome).	72	
b)	Location of each storage facility.	72	

GUIDELINE REFERENCE	DATA REQUIREMENT	Page No.	STATUS
c)	Total level of storage in terms of deliverability and capacity held during the gas year.	72	
d)	Historical (five years) gas supply delivered to storage, both annual total and by month.	72	
e)	Historical (five years) gas supply withdrawn from storage, both annual total and by month.	72	
f)	An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.	74	
g)	Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.	74	
h)	For LDCs that own and operate storage:		
a.	The date and results of the last engineering study for that storage.	91	CONFIDENTIAL
b.	A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.	107	
V.8	**Attestation as to Consistency**	108	

Section IV. General Information and Forecasting

1. General Information

a) Definitions of all major terms and acronyms in the data and information provided.

AECO	The industry acronym used for Alberta sourced natural gas supply. It originally comes from Alberta Energy Company which was incorporated in 1973 by the Alberta government (fully divested in 1993).
Base Load gas (contract)	Purchase agreements in which NW Natural has to take a set amount of gas each day from a supplier for the term of the agreement. Usually involves paying for any gas not taken unless excused by reason of Force Majeure.
Base Rate	The portion of rates that does not change outside of a general rate case, except as allowed through a Commission approved base rate adjustment.
Base Rate Adjustment	A permanent adjustment to rates approved by the Commission outside of a general rate case process.
Btu	British thermal unit. 100,000 Btus is equivalent to one therm.
CGPR	Canadian Gas Price Reporter. This is the industry publication in Canada that is put out by Canadian Enerdata Ltd and is the exclusive source of Canadian natural gas storage and price forecasts and publishes first of month Canadian indices used in baseload purchase pricing
Collar	Financial hedges that set ceiling and floor values on the price of gas purchases.
Commodity Component	The Tariff term used to refer to the cost of gas component of a customer's billing rate, and which will equal either (a) the Annual Sales WACOG, (b) the Winter Sales WACOG, or (c) the Monthly Incremental Cost of Gas.
Dth	Dekatherm. A unit of measure equal to 10 therms or one million Btu.
Demand [Charge]	The term used to refer to Pipeline Capacity related costs.
Derivative products	Financial transactions related to gas supply, including but not limited to hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.
EIA	U.S. Energy Information Administration
FERC	Federal Energy Regulatory Commission
Financial swaps	Transactions that involve an exchange of cash flows with a counterparty.

Financially hedged	Purchases that have associated financial swaps such that the price of the gas is fixed for a pre-determined period of time.
FOM	First of Month
Fuel-in-Kind (KIG)	The published fuel rate calculated based on the amount of fuel used on each pipeline to run the compressors and other equipment to move gas across their pipes. Fuel is taken in kind from all receipt shippers by reducing each shippers daily volumes in accordance to the pipelines estimated fuel requirements.
GMR-NWP Rockies	Inside FERC's Gas Market Report, a publication put out by Platts (a McGraw-Hill subsidiary) that is the source used for price forecasts and indices that used to set US baseload and some daily purchase prices.
IRP	Integrated Resource Plan
MDDV	Maximum Daily Delivery Volume
NWP	Northwest Pipeline
Off-system storage	Storage facilities located outside NW Natural’s service territory.
On-system storage	Storage facilities located inside NW Natural’s service territory.
PGA	Purchased Gas Adjustment
Peak day	The day in which volumes distributed or sold by NW Natural are at a maximum. May be theoretical (the “design day”) or actual.
Pipeline Capacity	The quantity (volume) of natural gas available on the interstate pipeline for the transportation of gas supplies to the Company's distribution system. Pipeline Capacity related costs are often referred to as "Demand".
Recallable gas supply/capacity	Refers to arrangements that allow NW Natural to use the upstream pipeline capacity and gas supplies held by third parties.
Revenue Sensitive	The amount by which rates are adjusted to reflect the effects of revenue related costs, such as uncollectible expense, regulatory fees, and city license and franchise fees
Swing gas (contract)	Purchase agreements in which NW Natural has the right, but not the obligation, to take gas from a supplier on any given day.
Technical Rate Adjustments	Also referred to as Temporary Rate Adjustments.
Therm	A unit of heating value equivalent to 100,000 Btus. The amount of heat energy in approximately 100 cubic feet of Natural Gas.
Total Commodity Cost	The combined costs for all purchased gas supplies, excluding transportation costs.

Total Gas Cost	The combined costs of all purchased gas supplies and associated transportation costs.
Transportation Cost	The combined costs for all pipeline related demand, capacity or reservation charges
Transportation Resources	The various upstream pipeline capacity agreements held by the company.
Upstream pipeline	Those pipelines that collect natural gas from the areas where it is produced in the British Columbia, Alberta and the U.S. Rocky Mountain supply regions and transport that gas to NW Natural's service territory.
Upstream pipeline capacity	Refers to the rights that NW Natural has obtained to transport gas on upstream pipelines.
WACOG	The Company's weighted average commodity cost of gas (excluding transportation cost), also referred to as Annual Sales WACOG.
Winter Sales WACOG	The Company's winter period weighted average commodity cost of gas (excluding transportation cost).

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

The administration of President Trump has created many uncertainties in the natural gas industry, including the potential renegotiation of NAFTA, encouragement of LNG exports, the imposition of a variety of import tariffs, the appointment of four new FERC commissioners, and the rollback of certain EPA policies. These items could encompass the two-thirds of our gas supplies that are purchased in western Canada and imported into the United States, the steel pipeline used by the industry, etc., but so far none have directly impacted the Oregon portfolio.

The Tax Cuts and Jobs Act approved by Congress on December 22, 2017 will result in lower costs for U.S. pipelines, which for the Company means Northwest Pipeline and GTN rates will be affected at some point in the future.

- For Northwest Pipeline, this change was anticipated in the 2016 rate settlement negotiations, which specified capturing the income tax differential and rolling it back to customers at the time of the next rate case (no later than 2023).
- For GTN, a change in income tax rates was not anticipated at the time of the 2015 rate case negotiations, though its 13% rate reduction effective 1/1/2016 will be augmented by a further 7% rate reduction on 1/1/2020 if GTN does not refile its rates. GTN is required under the 2015 settlement to refile its rates no later than 2021 for a 1/1/2022 effective date.

The WUTC issued a Policy Statement on Natural Gas Hedging Practices in March 2017. Per the time line in that Policy Statement, for the 2018-19 PGA year, the Company has started to employ new analytical techniques that have the effect of creating a more dynamic environment for the development and execution of gas acquisition and financial hedging strategies.

c) All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.

And

Attestation of verification of consistency

In accordance with the PGA Portfolio Guidelines at Section IV(1)(c), the Company acknowledges that all forecasts of demand, weather, etc., upon which the gas supply portfolio for this PGA filing is based, uses the methodology and data sources that are consistent with the Company's working draft of its 2018 IRP as well as its most recent Oregon rate case (UG 344) filed December 2017.

The forecast does differ from the most recently acknowledged 2016 IRP. The 2016 IRP used a bottom-up approach to build the demand forecast by customer class and load center using the SENDOUT® model. The 2017 rate case approach applied a linear regression to estimate the relationship between customer use by specific rate schedule and heating degree days (HDDs). After testing the efficacy of both models, the Company decided to use the HDD-based model for its normalized weather forecast. The Company still employs SENDOUT® and other modeling approaches for its peak demand forecast. For a full description of the HDD-based forecast, pleases reference UG 344/NW Natural/200, McVay/10-11.

Note, however, that the supply portfolio for this PGA is based on a demand side management (DSM) savings forecast that has been updated since the 2017 rate case filing. This DSM forecast will be consistent with the forecast used in the 2018 IRP.

2. Workpapers

a) PGA Summary

	Amount	Location in Company Filing (cite)
1) Change in Annual Revenues		
(Per OAR 860-022-0017(3)(a))		
A) Dollars *(To .1 million)*	($33,806,371)	Refer to workpaper "PGA filing Summary Effects"
B) Percent *(To .1 percent)*	-5.06%	"
2) Annual Revenues Calculation *(Whole Dollars)*		
A) PGA Cost Change *(Commodity & Transportation)*	(33,803,141)	Refer to workpaper "PGA filing Summary Effects"
B) Remove Last Year's Temporary Increment Total	(2,400,975)	"
C) Add New Temporary Increment	2,397,745	"
D) Other Additions or Subtractions (*Break out & List each below -- Attach additional sheet if necessary*)		
1) Net Safety Programs	0	Refer to workpaper "PGA filing Summary Effects"
2) Mist Recall	0	"
3) Schedule 182	0	
4)	0	
5)	0	
6)	0	
E) Total Proposed Change	(33,806,371)	"
3) Residential Bill Effects Summary		
A) Residential Schedule 2 Rate Impacts		
1) Current Billing Rate per Therm	$0.83850	Refer to workpaper '2018-2019 Rate Development'
2) Proposed Billing Rate per Therm	$0.77706	"
3) Rate Change Per Therm	($0.06144)	"
4) Percent Change per Therm *(to .1%)*	-7.3%	"
B) Average Residential Bill Impact (forecasted weather-normalized annual)		
1) Average Residential Monthly Use	53.0	Refer to workpaper '2018-2019 Rate Development'
2) Customer Charge	$8.00	"
3) Current Average Monthly Bill	$52.44	"
4) Proposed Average Monthly Bill	$49.18	"
5) Change in Average Monthly Bill	($3.26)	"
6) Percent change in Average Monthly Bill *(to .1%)*	-6.2%	"
C) Average January Residential Bill Impact		
1) Average January Residential Use *(forecasted weather-normalized)*	105.3	18-19 PGA Load Forecast
2) Customer Charge	$8.00	N/A
3) Current Average January Bill	$96.29	N/A
4) Proposed Average January Bill	$89.82	N/A
5) Change in Average January Bill	($6.47)	N/A
6) Percent change in Average January Bill (*to .1%)*	-6.7%	N/A

	Amount	Location in Company Filing (cite)
4) Breakdown of Costs		
A) Embedded in Rates (System Costs)		
1) Total Commodity Cost	$204,855,030	17-18 PGA Filing
a) Total Demand Cost (assoc. w/ supply)		
b) Total Peaking Cost (assoc. w/ supply)		
c) Total Reservation Cost (assoc. w/ supply)		
d) Total Volumetric Cost (assoc. w/ supply)	$1,051,169	17-18 PGA Filing
e) Total Storage Cost (assoc. w/ supply)	$42,651,069	17-18 PGA Filing
f) Other	$29,262,347	17-18 PGA Filing
2) Total Transportation Cost *(Pipeline related)*	$79,266,586	17-18 PGA Filing
a) Total Upstream Canadian Toll	$0	
i.Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
b) Total Domestic Cost	$0	
i. Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	$0	
5) Total Gas Costs	$284,121,616	
B) Projected For New Rates (System Costs)		
1) Total Commodity Cost	$184,496,261	Exhibit B, Page 1
a) Total Demand Cost (assoc. w/ supply)		
b) Total Peaking Cost (assoc. w/ supply)		
c) Total Reservation Cost (assoc. w/ supply)		
d) Total Vaporization Cost (assoc. w/ supply)		
e) Total Volumetric Cost (assoc. w/ supply)	$717,797	Exhibit B, Page 1
f) Total Storage Cost (assoc. w/ supply)	$39,008,924	Exhibit B, Page 1
g) Other (A&G Benchmark Savings)	$27,228,206	Exhibit B, Page 1
2) Total Transportation Cost *(Pipeline related)*	$78,117,143	Exhibit B, Page 3
a) Total Upstream Canadian Toll	$0	
i.Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
b) Total Domestic Cost	$0	
i. Total Demand, Capacity, or Reservation Cost	$0	
ii. Total Volumetric Cost	$0	
3) Total Storage Costs	$0	
4) Capacity Release Credits	$0	
5) Total Gas Costs	$262,613,404	

	Amount	Location in Company Filing (cite)
5) WACOG *(Weighted Average Cost of Gas)*		
A) Embedded in Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.29186	N/A
b. Without revenue sensitive	$0.28370	N/A
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.11921	N/A
b. Without revenue sensitive	$0.11588	N/A

B) Proposed for New Rates		
1) WACOG *(Commodity Only)*		
a. With revenue sensitive	$0.24552	Exhibit B, Page 2 and Page 5
b. Without revenue sensitive	$0.23861	"
2) WACOG (Non-Commodity)		
a. With revenue sensitive	$0.10918	Exhibit B, Page 4
b. Without revenue sensitive	$0.10611	"
6) Therms Sold	702,473,342	Exhibit B, Page 2
7) Purchasing / Hedging Strategies *Prepare 1-2 page summary of gas cost situation to include resources, purchasing strategy, hedging, and pipeline issues. Within the summary include:*		
A) Resources embedded in current rates and an explanation of proposed resources.		
1) Firm Pipeline Capacity		
a) Year-round supply contracts	N/A	Exhibit A, IV.2.b 1-7
b) Winter-only contracts	N/A	"
c) Reliance on Spot Gas/Other Short Term Contracts	N/A	"
d) Other - e.g. Supply area storage	N/A	"
2) Market Area Storage		
a) Underground-owned	N/A	"
b) Underground- contracted	N/A	"
c) LNG-owned	N/A	"
d) LNG-contracted	N/A	"
3) Other Resources		
a) Recallable Supply	N/A	"
b) City gate Deliveries	N/A	"
c) Owned-Production	N/A	"
d) Propane/Air	N/A	"

b) Gas Supply Portfolio and Related Transportation

1. Summary of portfolio planning

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers at a reasonable cost.

To ensure adequate reliability, NW Natural 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 and use of on-system underground and LNG storage.

Upstream pipeline capacity has been contracted with the following objectives in mind:

(1) Diversify capacity sources so that disruptions in any one supply region, such as from a pipeline rupture, well freeze-offs, etc., have a minimal impact on NW Natural;
(2) Obtain upstream capacity along the path from NW Natural’s service territory to points generally recognized for their liquidity, such as AECO/NIT, to maximize buying opportunities and minimize price volatility; and,
(3) Find ways to minimize the cost of upstream capacity such as through optimization activities or committing to capacity only on a winter season basis if possible.

Upstream gas supply contracts have been negotiated with the following objectives in mind:

(1) Use a diverse group of reliable suppliers as established by their asset positions, past performance and other factors;
(2) Try to match our year-round customer requirements to baseload (take-or-pay) year-round supply contracts to obtain the most favorable pricing and simplify administration;
(3) Use winter only (Nov-Mar) and bullet (single month) term contracts to match our rise in requirements during the heating season and shoulder months;
(4) Reduce spot purchase requirements during the winter due to the likely correlation of high requirements with high spot prices;
(5) Take advantage of favorable pricing opportunities to use supply-basin storage if and when possible;
(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.

One item that would have been found in the above list years ago was an objective to use a variety of multi-year contract durations to avoid having to re-contract all physical gas supplies every year. In recent years, however, with the surge in supplies represented by shale gas and more efficient drilling techniques, the Company gradually has eliminated its reliance on multi-year physical term contracts by replacing them as they expired with 1-year or shorter term purchases.

2. LDC sales system demand forecasting

The Company's methodology for forecasting annual sales and firm peak day requirements is described in its Integrated Resource Plan (IRP), of which the latest is the 2018 draft IRP filed in July 2018 that is currently under review by the OPUC and the WUTC. Also applicable here is the load forecast methodology previously established for the PGA process.

While the demand forecast reflects "normal" weather, the Company still plans for the possibility of extreme cold weather during the upcoming heating season. From a gas supply portfolio standpoint, the biggest impact of the two different load forecasts is in the dispatch of storage resources. That is, to handle the possibility of an cold winter, storage withdrawals are restrained in the resource dispatch during the early months of the winter in order to maintain maximum storage deliverability into early February, which historically has been the latest time period for extreme cold weather events to occur. This restraint around storage withdrawals is done in the PGA forecast even though it assumes normal weather for the upcoming winter, when such restraints would not be necessary. In this way the Company addresses the need to maintain reliability of service to firm customers should extreme cold weather arise during the coming winter, while at the same time complying with the PGA load forecast requirements.

3. Natural gas price forecasts

NW Natural relies on forecasts prepared by the US Energy Information Administration (EIA), the IHS Markit consulting firm, as well as NYMEX and Intercontinental Exchange (ICE) futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NW Natural by way of trade publications, consultant visits, oil/gas company presentations and other governmental sources. These provide opportunities to test assumptions and explore alternate viewpoints.

An analysis performed in past years by NW Natural suggested that current prices are strongly correlated to the futures market, that is, a dip in current prices will drop future prices for the upcoming PGA year, and vice versa. Therefore, a low current price period is more opportune to perform gas price hedging for the PGA year than a high priced period. This methodology will be revisited in the future in order to ensure it is still appropriate.

4. Physical resources for the portfolio

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

There are three changes to note regarding the physical supply portfolio as compared to last year's PGA filing:

(1) The Company's draft IRP load forecast performed in early 2018 identified a small resource need of approximately 10,000 Dth/day to meet the 2018-19 design peak day of approximately 1 million Dth/day. The Company's analysis led to the acquisition of a citygate delivery call option to fill this gap. Documentation regarding that decision process is provided on the following page.

Confidential Subject to Modified Protective Order 10-337

CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

[redacted]

(2) The Company extended the termination date of its existing T-South capacity contract on the Westcoast Energy pipeline system in British Columbia from October 31, 2018 to October 31, 2021. The analysis that led to this decision is provided in the following documents, on pages 15-21.

Confidential Subject to Modified Protective Order 10-337

[redacted]

[redacted]

T-South Contract Economic Analysis - June 2017

CONFIDENTIAL

[redacted]

[redacted]

T-South Contract Economic Analysis - June 2017

CONFIDENTIAL

[redacted]

[redacted]

CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

[redacted]

[redacted]

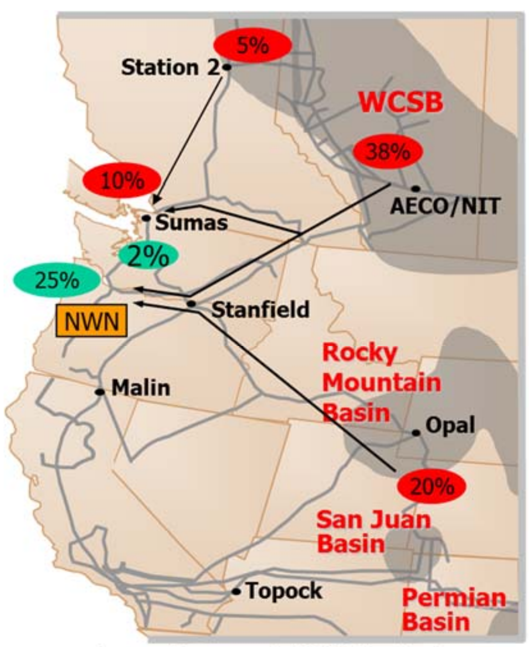
(3) Renewable natural gas from the City of Portland's waste water treatment plant is expected to enter the Company's system during the upcoming PGA year, likely in the second quarter of 2019. The volumes are small (less than 2,000 Dth/day) and the pricing will be comparable to the other source of gas delivered directly into the Company's distribution system, that being the native gas produced from the Mist field.

Other physical resource items that do not represent changes but merit mention are:

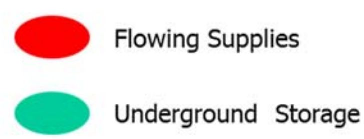
(i) There were more opportunities to use segmented capacity as a resource during the 2017/18 winter, and its reliable performance justifies its continued inclusion in the Company's resource portfolio;
(ii) A previously identified trend of rising heat content on the interstate pipeline system has not reversed, which means slightly higher deliverabilities from the Portland LNG and Newport LNG plants, along with slightly more working gas capacity for utility customers at Mist, continue to be maintained in the portfolio;
(iii) The removal of frozen carbon dioxide from the Newport LNG plant, and an ongoing engineering evaluation of the Portland LNG plant, continue to restrict the working gas capacities of those two plants; and
(iv) The Company continues to participate in an expansion of the T-South pipeline system in British Columbia, which will allow more purchases at Station 2 in lieu of Sumas and potentially Alberta and the Rockies. Since this expansion will not be in service until at least November 1, 2020, that capacity has no impact on this or the next PGA filing.

The Company's portfolio continues to reflect the gas reserves purchased under the agreement with Encana approved by the OPUC in 2011 with Encana. That agreement was amended in March 2014 and seven new gas wells were drilled with the successor company Jonah Energy LLC. This PGA continues to reflect the approved regulatory treatment for both sets of reserves. As a reminder, the seven Jonah Energy wells have an approved regulatory treatment that is different from the reserves obtained under the original program with Encana, but all of the gas reserve volumes essentially function as a financial tool, i.e., they displace an identical volume of financial derivatives that the Company otherwise would have executed. For the purposes of this filing, the Encana and Jonah Energy gas reserve volumes have no impact on the company's physical supply portfolio.

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



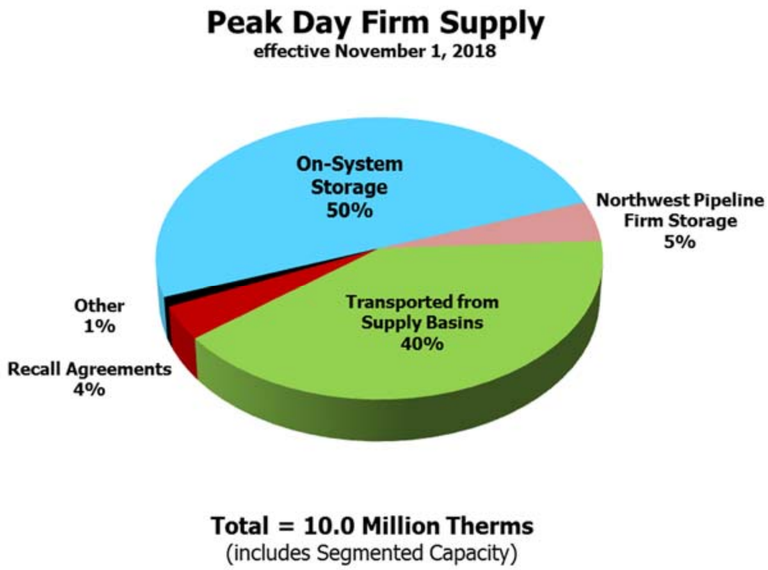
Assumes that storage is 100% full on Nov 1.



BC (Stn 2)	19,000 Dth
BC (Sumas)	41,000
Alberta	150,000
Rockies	80,000
Jackson Prairie	10,000
Mist Storage	100,000
Portland LNG	0
Newport LNG	0
Total	400,000 Dth

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

Should its "design" peak day occur during the upcoming heating season, all physical resources would be used in the following proportions (607,000 therms/day of segmented capacity is included):

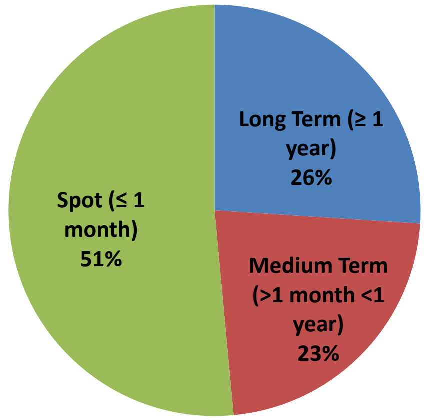


Regarding physical supply purchasing, NW Natural will have baseload contracts with suppliers amounting to at least 500,000 therms per day of firm deliveries on a daily basis throughout the upcoming November 2018 through October 2019 period. This reflects the relatively stable daily component of NWN's demand, i.e., water heater and other non-space heating loads that are not seasonal in nature. This has been reduced slightly from last year to ensure we are not over-committed during the summer months.

Outside the non-heating season (June through September), additional baseload amounts are contracted to reflect likely heating demand. Rather than selecting a set amount for the entire heating season (November through March) as in past years, more variation in baseload quantities by month is being used this year to better reflect the ranges of heating loads that are likely to occur over the course of the heating season. The total baseload amount will range up to 2.5 million therms per day in December. The details by month are provided at the bottom of Table 1.

With slightly over 3.4 million therms per day of firm upstream pipeline capacity to its service territory, and potentially over 4.0 million therms per day if segmented capacity is included, this means substantial capacity is available for spot purchases (one month and shorter duration) as and when needed. During the 2017 calendar year, just over half of the Company's purchases were made on the spot market as shown below, and no significant changes are expected for the coming year.

Supply Diversity by Contract Duration
January 2017 to December 2017



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

NW Natural “swaps” monthly index prices for fixed prices through the use of standard financial hedge instruments in order to increase price stability across the year. Volumes in storage, including any supply-basin storage arrangements, provide another form of hedging. That is, while the gas for storage injection is purchased on the spot market, its pricing is known to a very large extent in advance of the PGA filing and so can be reflected in the PGA rates. In addition, gas reserves provide a financial hedge for Oregon customers in a different form.

NW Natural currently estimates that it will financially hedge the prices of approximately 53% of its expected annual sales requirements for the upcoming PGA year commencing November 1, 2018, a slight increase from last year. Gas reserves are expected to account for another 5% of hedge volumes, a slight decrease from last year reflecting the natural depletion of the resource. Storage gas, which again is gas purchased on the spot market, will account for another 17%, a slight decrease from last year due to the expiration of an Alberta storage contract. Local Mist gas production adds another 1%, a slight decrease from last year due to the natural depletion of the native gas. The remaining 24% of our annual purchase volumes, when combined with our purchases for storage, means about 41% of NW Natural's total volumes will be purchased on an unhedged basis.

Financial hedging targets are set by an executive level oversight committee within the Company - the Gas Acquisition Strategy & Policies (GASP) Committee - and are reviewed on a monthly basis to determine if changes should be made in response to market conditions or other factors as the year progresses.

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

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

6. Storage resources

NWN relies on four storage facilities to balance its supply portfolio and meet customer requirements. Mist, Portland LNG (also known as Gasco) and Newport LNG are owned and operated by the company. NWN contracts with Northwest Pipeline for service at the Jackson Prairie underground facility in Washington state.

Storage provides the following benefits to customers:

a. Avoids the need to subscribe to year-round interstate pipeline capacity to meet winter season loads. This benefit applies to the storage located on NW Natural's system, and partially applies to Jackson Prairie storage, which is eligible for a Northwest Pipeline transportation service that is less expensive than normal year-round firm service. This benefit does not apply to storage located in the supply basins such as Alberta.

b. Allows more gas purchasing during the non-heating season, when prices are typically lower, instead of heating season periods when prices typically peak. Supply-basin storage is pursued when this potential benefit is sufficient to offset the cost of the storage service.
c. Provides diversity of supply and gas movement to and through NWN's service territory, improving overall reliability.
d. Helps balance daily demand with supplies, reducing the potential for imbalance penalties with upstream pipelines.
e. Provides flexibility to take advantage of daily, monthly and seasonal variations in gas pricing, either directly by NW Natural or through its third party optimization arrangement.

Additional benefits attributable to Mist have been created through the development of an interstate storage service starting back in 2001. For example, rather than large "lumpy" resource additions requiring years of preparation, the "pre-build" of interstate storage service provides the ability to time and size incremental Mist capacity to a degree not achievable through typical resource development. Also, revisions to the customer load forecast have meant that previously planned storage additions for the utility could be deferred with multiple benefits to customers, e.g., rate base additions are deferred while revenue sharing from the interstate storage service continues.

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

Supporting information to IV.2.b.4

Table 1

NW Natural
Firm Off-System Gas Supply Contracts
for the 2018/2019 Tracker Year

Supply Location	Duration	Baseload Qty (Dth/day)	Swing Qty (Dth/day)	Contract Termination Date
British Columbia:				
IGI	Nov-Oct	5,000		10/31/2019
ConocoPhillips (Canada)	Nov-Oct	5,000		10/31/2019
ConocoPhillips (Canada)	Nov-Mar	10,000		3/31/2019
TD Energy	Nov-Mar	10,000		3/31/2019
BP Canada Energy Group	Nov-Mar	5,000		3/31/2019
BP Canada Energy Group	Nov-Mar	5,000		3/31/2019
Alberta:				
J. Aron	Nov-Oct	10,000		10/31/2019
Suncor Energy	Nov-Oct	5,000		10/31/2019
J. Aron	Nov-Mar	5,000		3/31/2019
Shell Energy NA	Nov-Mar	10,000		3/31/2019
Suncor Energy	Nov-Mar	10,000		3/31/2019
BP Canada Energy Group ULC	Nov-Mar	5,000		3/31/2019
MacQuarie Canada	Nov-Mar	5,000		3/31/2019
MacQuarie Canada	Nov-Feb	5,000		2/28/2019
MacQuarie Canada	Dec-Feb	5,000		2/28/2019
TD Energy	Dec-Feb	5,000		2/28/2019
Shell Energy NA	Dec-Jan	10,000		1/31/2019
Castleton Merchant Trading	Dec-Jan	10,000		1/31/2019
TD Energy	Dec-Jan	5,000		1/31/2019
ConocoPhillips (Canada)	Dec-Jan	5,000		1/31/2019
Pending	Dec-Jan	20,000		1/31/2019
Pending	Nov	17,500		11/30/2018
Pending	Dec	15,000		12/31/2018
Pending	Jan	10,000		1/31/2019
Pending	Apr	65,000		4/30/2019
Pending	May	32,500		5/31/2019
Pending	Oct	40,000		10/31/2019
Rockies:				
Ultra Resources	Nov-Oct	10,000		10/31/2019
MacQuarie Energy	Nov-Oct	5,000		10/31/2019
ConocoPhilips Company	Nov-Oct	5,000		10/31/2019
Concord Engery	Nov-Oct	5,000		10/31/2019
CIMA Energy LTD	Nov-Mar	10,000		3/31/2019
Citadel Energy Marketing	Nov-Mar	5,000		3/31/2019
Castleton Merchant Trading	Nov-Mar	5,000		3/31/2019
MacQuarie Energy	Nov-Mar	5,000		3/31/2019
Ultra Resources	Nov-Mar	5,000		3/31/2019
ConocoPhilips Company	Nov-Mar	5,000		3/31/2019
J. Aron	Nov-Mar		10,000	3/31/2019
J. Aron	Apr-Oct		10,000	10/31/2019
Pending	Nov	7,500		11/30/2018
Pending	Dec-Jan	5,000		1/31/2019
Pending	Dec-Feb	5,000		2/28/2019
Pending	Feb	5,000		2/28/2019

Month	Baseload Qty (Dth/day)	Baseload+Swing (Dth/day)
Nov-18	180,000	190,000
Dec-18	240,000	250,000
Jan-19	235,000	245,000
Feb-19	175,000	185,000
Mar-19	150,000	160,000
Apr-19	115,000	125,000
May-19	82,500	92,500
Jun-19	50,000	60,000
Jul-19	50,000	60,000
Aug-19	50,000	60,000
Sep-19	50,000	60,000
Oct-19	90,000	100,000

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

Supporting information to IV.2.b.4

Table 2

NW Natural
Firm Transportation Capacity
for the 2018/2019 Tracker Year

Pipeline and Contract	Contract Demand (Dth/day)	Termination Date
Northwest Pipeline:		
Sales Conversion (#100005)	214,889	10/31/2031
1993 Expansion (#100058)	35,155	9/30/2044
1995 Expansion (#100138)	102,000	10/31/2025
Occidental cap. acq. (#139153)	1,046	10/31/2030
Occidental cap. acq. (#139154)	4,000	10/31/2030
International Paper cap. acq. (#138065)	4,147	10/31/2030
March Point cap. acq. (#136455)	12,000	12/31/2046
Total NWP Capacity	373,237	
less recallable release to -		
Portland General Electric	(30,000)	10/31/2020
Net NWP Capacity	343,237	
TransCanada - GTN:		
Sales Conversion (#00180)	3,616	10/31/2023
1993 Expansion (#00164)	46,549	10/31/2023
1995 Rationalization (#11030)	56,000	10/31/2021
Total GTN Capacity	106,165	
TransCanada - Foothills:		
1993 Expansion	47,727	10/31/2019
1995 Rationalization	57,417	10/31/2019
Engage Capacity Acquisition	3,708	10/31/2019
2004 Capacity Acquisition	48,669	10/31/2019
Total Foothills Capacity	157,521	
TransCanada - NOVA:		
1993 Expansion	48,135	10/31/2020
1995 Rationalization	57,909	10/31/2020
Engage Capacity Acquisition	3,739	10/31/2020
2004 Capacity Acquisition	49,138	10/31/2020
Total NOVA Capacity	158,921	
T-South Capacity (through Tenaska)	19,000	10/31/2021
Southern Crossing Pipeline	48,000	10/31/2020

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contract, which is through a contract with Tenaska with no renewal rights.
2. The Southern Crossing contract is denominated in volumetric units, hence the Dth units shown are an approximation.
3. The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
4. Segmented capacity has not been included in this table.
5. T-South capacity does not include the new T-South Expansion contract of approximately 25,000 Dth/day, which will begin no earlier than November 1, 2020.

Supporting information IV.2.b4

Table 3

NW Natural
Firm Storage Resources
for the 2018/2019 Tracker Year

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)	Termination Date
Jackson Prairie:			
SGS-2F	46,030	1,120,288	10/31/2025
TF-2 (primary firm portion)	23,038	839,046	10/31/2025
TF-2 (primary firm portion)	9,467	281,242	10/31/2025
TF-1	13,525	n/a	10/31/2031
Firm On-System Storage Plants:			
Mist (reserved for core)	305,000	11,382,120	n/a
Portland LNG Plant	131,880	503,782	n/a
Newport LNG Plant	65,280	979,200	n/a
Total On-System Storage	502,160	12,865,102	
Total Firm Storage Resource	548,190	13,985,390	

Notes:

1. The SGS-2F and TF-2 contracts have a unilateral annual evergreen provision (continuation at NW Natural's sole option), while the TF-1 contract requires mutual consent with Northwest Pipeline to continue after the indicated termination date.
2. The TF-2 contracts also contain additional "subordinated" firm service of 9,586 Dth/day on the first agreement listed above and 3,939 Dth/day on the second agreement. The subordinated service is NOT included in NW Natural's peak day planning.
3. On-system storage peak deliverability is based on design criteria, for example, Mist is at least 50% full.
4. Mist numbers pertain to the portion reserved for core utility service per the Company's Integrated Resource Plan. Additional capacity and deliverability at Mist have been contracted under varying terms to Interstate/Intrastate storage customers.
5. The Dth numbers for Mist, Newport LNG and Portland LNG are approximate in that they are converted from Mcf volumes, and so depend on the heat content of the stored gas. The current heat content used for Mist is 1080 Btu/cf. The current heat content used for Newport is 1088 Btu/cf and Portland LNG is 1099 Btu/cf.
6. Newport LNG tank de-rated to 90% of the tank capacity pending CO2 removal project.
7. Due to an ongoing Engineering analysis of the Portland LNG tank, liquifaction will be limited to 76% of the tank's capacity.
8. NW Natural has no supply-basin storage contract for the coming year.

Supporting information IV.2.b4

Table 4

NW Natural
Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2018/2019 Tracker Year

Type	Max. Daily Rate (Dth/day)	Max. Availability (days)	Termination Date
Recall Agreements:			
PGE	30,000	30	10/31/2020
International Paper	8,000	40	Upon 1-year notice
Georgia Pacific-Halsey mill	1,000	15	Upon 1-year notice
Total Recall Resource	39,000		
Citygate Deliveries:			
Citygate Delivery	10,000	5	2/28/2019
Mist Production:			
Enerfin Resources	≈1,000	n/a	Life of the wells

Notes:
1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas 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 is to buy gas from existing wells through the life of those wells.
3. Citygate delivery is a call option during the heating season.

Table 5

NW Natural
Peak Day Resource Summary
for the 2018/2019 Tracker Year

Resource Type	Max. Daily Rate (Dth/day)
Net Deliverability over Upstream Pipeline Capacity	343,237
Off-System Storage (Jackson Prairie only)	46,030
On-System Storage (Mist, Portland LNG and Newport LNG)	502,160
Recallable Capacity and Supply Agreements	39,000
Citygate Deliveries	10,000
Nominal Mist Production Gas	1,000
Segmented Capacity (not primary firm)	60,700
Total Peak Day Resources	1,002,127

Notes:
1. Per draft 2018 IRP filed in July 2018, Segmented Capacity currently is included as a firm resource until 11/1/2021.

7. Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation

Forecasted DSM figures reflect new, additional savings for the gas year, and not the cumulative results of measures installed over time.

	2018/2019
Forecast Annual Demand (therms)	781,861,912
Forecast Peak Demand (therms) - Normal	4,229,210
Forecast Peak Demand (therms) - Design	9,947,760
Forecast DSM Annual (therms)	11,403,263
Forecast DSM Peak (therms) - Design Peak	74,750
Forecast Annual Demand with Forecast DSM	781,861,912
Forecast Peak Demand with Forecast DSM - Normal	4,229,210
Forecast Peak Demand with Forecast DSM - Design	9,947,760

8. Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.

Gas supply incentive mechanisms can lead to alternate uses of the resource portfolio, such as additional movements of gas in and out of storage, but the effects “net out” over the course of a year and so do not change the forecasted annual and peak demand used to develop the PGA portfolio.

9. Summary of portfolio documentation provided

See Index.

Section V.1 - Physical Gas Supply

a) For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:

1. Pricing for the resource, including the commodity price and, if relevant, reservation charges.

See Tables 1-4 below.

2. For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process

See Tables 1-4 below.

3. Brief explanation of each contract's role within the portfolio.

See Tables 1-4 below. **[START HIGHLY CONFIDENTIAL]**

TABLE 1

Northwest Natural Gas Company HIGHLY CONFIDENTIAL
PGA Filing Guidelines SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2018 - October 31, 2019
Physical Natural Gas term contracts

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

Rocky Mountain Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dths	Swing Volume/Day in Dths	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
MacQuarie Energy, LLC (1)	11/1/2018	10/31/2019	[redacted]	IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	18-AL-8
CIMA Energy LTD (2)	11/1/2018	3/31/2019		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	18-AL-11
Citadel Energy Marketing, LLC (3)	11/1/2018	3/31/2019		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	18-AL-13
CIMA Energy LTD (4)	11/1/2018	3/31/2019		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	18-AL-14
ConocoPhillips Company (5)	11/1/2018	3/31/2019		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	18-AL-22
ConocoPhillips Company (6)	11/1/2018	10/31/2019		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	18-AL-23
Concord Energy, LLC (7)	11/1/2018	10/31/2019		IFGMR-NWP Rockies FOM	5,000				Opal	18-AL-24
Castleton Commodities Merchant Trading (8	11/1/2018	3/31/2019		IFGMR-NWP Rockies FOM	5,000				Rocky Mountain Pool	18-AL-28
Ultra Resources (10)	11/1/2018	11/1/2019		IFGMR-NWP Rockies FOM	5,000				Opal	18-MM-18
Ultra Resources (11)	11/1/2018	11/1/2019		IFGMR-NWP Rockies FOM	5,000				Opal	18-MM-27
MacQuarie Energy, LLC (12)	11/1/2018	4/1/2019		IFGMR-NWP Rockies FOM	5,000				Opal	18-MM-20
Ultra Resources (13)	11/1/2018	4/1/2019		IFGMR-NWP Rockies FOM	5,000				Opal	18-MM-25
PENDING:										
November 2018-October 2019 - 5,000 Dth (Rocky Mtn Pool)										
J. Aron & Company (9)	11/1/2018	3/31/2019	[redacted]	IFGMR-NWP Rockies FOM		up to 10,000	NW Natural Call Option			
J. Aron & Company (9)	4/1/2019	10/31/2019		IFGMR-NWP Rockies FOM		up to 10,000	J. Aron Put Option			

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Rocky Mountain Pool	5	[redacted]	Price
(2) Rocky Mountain Pool	5		Price
(3) Rocky Mountain Pool	4		Price
(4) Rocky Mountain Pool	4		Price
(5) Rocky Mountain Pool	4		Price
(6) Rocky Mountain Pool	6		Price
(7) Opal	4		Price
(8) Rocky Mountain Pool	5		Price
(9) Rocky Mountain Pool	4		Price
(10) Opal	4		Price
(11) Opal	4		Price
(12) Opal	4		Price
(13) Opal	3		Price

TABLE 2

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2018 - October 31, 2019
Physical Natural Gas term contracts

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

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Swing Reservation Fee cents/Dth/day	Contractual Conditions	Default Receipt Pt. Purchase Location	Internal Reference No.
ConocoPhillips Canada Marketing & Trading (1)	11/1/2018	3/31/2019	[redacted]	IFGMR-NWP Canadian Border FOM	10,000				Huntingdon	18-AL-10
BP Canada Energy Group (2)	11/1/2018	3/31/2019	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	18-AL-17
TD Energy Trading, Inc. (3)	11/1/2018	3/31/2019	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	18-AL-18
BP Canada Energy Group (4)	11/1/2018	3/31/2019	[redacted]	IFGMR-NWP Canadian Border FOM	5,000				Huntingdon	18-AL-31

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1) Huntingdon	5	[redacted]	Price
(2) Huntingdon	3	[redacted]	Price
(3) Huntingdon	3	[redacted]	Price
(4) Huntingdon	5	[redacted]	Price

TABLE 3

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2018 - October 31, 2019
Physical Natural Gas term contracts

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

Huntingdon, BC Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Default Receipt Pt. Purchase Location	Internal Reference No.
J. Aron & Company (1)	11/1/2018	10/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	17-SJ-3
ConocoPhillips Canada Marketing & Trading (2)	11/1/2018	10/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	17-MM-40
TD Energy Trading, Inc. (3)	11/1/2018	3/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000	Station 2	18-MM-24

Transactions for new PGA year

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

TABLE 4

Northwest Natural Gas Company
PGA Filing Guidelines

HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337

November 1, 2018 - October 31, 2019
Physical Natural Gas term contracts

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

Aeco-NIT Supply contracts

Supplier	Term Start	Term End	Commodity Price	Published Index	Baseload Volume/Day in Dth's	Swing Volume/Day in Dth's	Contractual Conditions	Internal Reference No.
J. Aron & Company (1)	11/1/2018	3/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-4
Shell Energy North America (2)	11/1/2018	3/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-5
J. Aron & Company (3)	11/1/2018	10/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-12
BP Canada Energy Group ULC (4)	11/1/2018	3/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-20
Shell Energy North America (5)	11/1/2018	3/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-21
MacQuarie Energy Canada Ltd. (6)	11/1/2018	3/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-26
TD Energy Trading (7)	12/1/2018	1/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-34
ConocoPhillips Canada Marketing (8)	12/1/2018	1/31/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-AL-35
Suncor (9)	11/1/2018	11/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-MM-21
Suncor (10)	11/1/2018	4/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-MM-23
Suncor (11)	11/1/2018	4/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-MM-31
TD Energy Trading (12)	12/1/2018	3/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-MM-39
J. Aron & Company (13)	11/1/2018	11/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-MM-33
MacQuarie Energy Canada Ltd. (14)	11/1/2018	3/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-MM-35
MacQuarie Energy Canada Ltd. (15)	12/1/2018	3/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	5,000			18-MM-38
Shell Energy North America (16)	12/1/2018	2/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000			18-MM-40
Castleton Commodities Canada (17)	12/1/2018	2/1/2019	[redacted]	CGPR AECO FOM (7A) $US/Dth	10,000			18-MM-41

PENDING:

Bullet (One Month) Baseload:
November 2018- 17,500 Dth (fixed price physical)
December 2018- 15,000 Dth (fixed price physical)
January 2019- 10,000 Dth (fixed price physical)
April 2019- 65,000 Dth (Index-CGPR (7A) $US/Dth)
May 2019- 32,500 Dth (Index-CGPR (7A) $US/Dth)
October 2019- 40,000 Dth (Index-CGPR (7A) $US/Dth)

Transactions for new PGA year

Bidding Process Information	# of Bidders	Range of bids.	Winning Bid Criteria
(1)	4	[redacted]	Price
(2)	4	[redacted]	Price
(3)	5	[redacted]	Price
(4)	5	[redacted]	Price
(5)	5	[redacted]	Price
(6)	5	[redacted]	Price
(7)	4	[redacted]	Price
(8)	4	[redacted]	Price
(9)	3	[redacted]	Price
(10)	4	[redacted]	Price
(11)	4	[redacted]	Price
(12)	5	[redacted]	Price
(13)	4	[redacted]	Price
(14)	4	[redacted]	Price
(15)	4	[redacted]	Price
(16)	3	[redacted]	Price
(17)	3	[redacted]	Price
(18)	4	[redacted]	Price
(19)	4	[redacted]	Price

[END HIGHLY CONFIDENTIAL]

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

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

1. The purchasing of baseload and spot supplies for the 2018-2019 PGA follows the Gas Acquisition Plan as prepared by the Gas Supply department and overseen by the company's Gas Acquisition Strategy and Policies (GASP) Committee. GASP members include the company's CFO and other senior company management.

2. In our gas purchasing for 2018-2019, we continue to strive for a diversity of supply on a regional basis and among approved counterparties, as listed in the company's Gas Supply Risk Management Policies. The advantage of regional diversity is the opportunity to manage purchases to capture the lowest cost while avoiding over-reliance on any one trading point or counterparty.

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

   a. One year and greater baseload (take or pay) contract volumes are meant to meet the low end of sales requirements while avoiding the potential for excess supply that might have to be sold at a loss when sales volumes are low. Pricing is comparable to shorter term contracts and the administrative needs are a bit simpler.

   b. Shorter term contracts are aligned to meet the forecasted demand increase during the heating season and are divided between baseload and a small amount of winter call option ("swing") contracts. This helps minimize the exposure to purchasing large volumes of high priced spot gas during cold weather events.

   c. A small amount of April – October summer put option contracts are sold to offset the cost of the winter call option contracts and, in this filing, result in no net payment of any reservation charges on the call options. The volume of the put option contracts is kept to a minimum to avoid over supply during the summer months when added to the term volumes.

   d. Spot purchases are used to fill in requirements on a very short-term basis, from one day up to one month, throughout the PGA year. One month spot purchases are negotiated to capture the best monthly index pricing using either the publication *Inside FERC's Gas Market Report* for Rockies and Sumas purchases, or the publication *Canadian Gas Price Reporter* for Canadian purchases in Alberta or at Station 2 in British Columbia. Daily spot purchasing utilizes either a daily index (e.g., Rocky Mountain or Sumas daily indices published in *Gas Daily*) or a fixed price in U.S. dollars as negotiated directly with the suppliers. The electronic trading platform Intercontinental Exchange (ICE) provides real-time pricing for Rocky Mountain, Sumas, Station 2 and Alberta supplies as a reference tool for such price negotiations.

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

None for the vast bulk of the company's purchases made in the Rockies, British Columbia and Alberta.
A small percentage (less than 1%) of the company's purchases is sourced from the Mist field. This is native gas that continues to be locally produced there. These purchases do not rely on a NAESB contract but instead on a custom-written contract that dates back to 1995. As an example, gas quality and measurement is a relatively simple matter in the NAESB contract because the gas already has to conform to the tariff provisions of one or more applicable interstate pipelines, but it requires a lot more attention for Mist production gas because there are no transporting interstate pipelines over which the gas is delivered to the company. In addition, this contract contains an option that allows the Company, in its sole discretion, to buy out the remaining gas in a production reservoir in order to convert it into a storage reservoir.

At some point during the 2018-2019 PGA year, the City of Portland is expected to commence producing renewable natural gas (RNG) that will be purchased to some extent by the Company. This gas purchase contract has not been completed yet, but it is expected to be a NAESB contract that also references a separate interconnection agreement containing additional requirements pertaining to gas quality, monitoring, and sampling.

Section V.2 - Hedging

The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.

2018-2019 FINANCIAL HARD HEDGES (counterparty does not own option)

Trade type	Contract	Counterparty	Pricing Point	Trade quantity	Total quantity	Cost per Dth	Total Cost
Financial Swap	100102	[redacted]	AECO	5,000	1,070,000	[redacted]	[redacted]
Financial Swap	100109	[redacted]	AECO	2,500	535,000	[redacted]	[redacted]
Financial Swap	100100	[redacted]	AECO	7,500	225,000	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100100	[redacted]	Rockies	7,500	232,500	[redacted]	[redacted]
Financial Swap	100107	[redacted]	Rockies	10,000	280,000	[redacted]	[redacted]
Financial Swap	100104	[redacted]	AECO	2,500	2,740,000	[redacted]	[redacted]
Financial Swap	100101	[redacted]	AECO	2,500	225,000	[redacted]	[redacted]
Financial Swap	100101	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]
Financial Swap	100111	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	AECO	5,000	310,000	[redacted]	[redacted]
Financial Swap	100104	[redacted]	AECO	5,000	310,000	[redacted]	[redacted]
Financial Swap	100107	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100107	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100101	[redacted]	Rockies	7,500	225,000	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	AECO	2,500	155,000	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100100	[redacted]	AECO	7,500	225,000	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100108	[redacted]	AECO	2,500	155,000	[redacted]	[redacted]
Financial Swap	100107	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]
Financial Swap	100112	[redacted]	Rockies	2,500	230,000	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Rockies	2,500	230,000	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	AECO	2,500	230,000	[redacted]	[redacted]
Financial Swap	100111	[redacted]	Rockies	2,500	230,000	[redacted]	[redacted]
Financial Swap	100107	[redacted]	Sumas	2,500	230,000	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100111	[redacted]	Rockies	2,500	230,000	[redacted]	[redacted]
Financial Swap	100111	[redacted]	Rockies	2,500	230,000	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Sumas	2,500	230,000	[redacted]	[redacted]
Financial Swap	100102	[redacted]	AECO	2,500	225,000	[redacted]	[redacted]
Financial Swap	100107	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100107	[redacted]	Rockies	2,500	535,000	[redacted]	[redacted]
Financial Swap	100107	[redacted]	AECO	10,000	620,000	[redacted]	[redacted]
Financial Swap	100102	[redacted]	Rockies	2,500	912,500	[redacted]	[redacted]
Financial Swap	100108	[redacted]	AECO	2,500	912,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	AECO	2,500	1,827,500	[redacted]	[redacted]
Financial Swap	100104	[redacted]	AECO	2,500	2,740,000	[redacted]	[redacted]
Financial Swap	100109	[redacted]	Sumas	2,500	377,500	[redacted]	[redacted]
Financial Swap	100106	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]
Financial Swap	100101	[redacted]	Rockies	7,500	232,500	[redacted]	[redacted]
Financial Swap	100109	[redacted]	AECO	2,500	377,500	[redacted]	[redacted]
Financial Swap	100101	[redacted]	Rockies	2,500	377,500	[redacted]	[redacted]

Section V.3 - Load Forecasting

a. Customer count and revenue by month and class.

	Customer Cnt Jul-17	Revenue Jul-17	Customer Cnt Aug-17	Revenue Aug-17	Customer Cnt Sep-17	Revenue Sep-17
Total	**730,654**	$ 27,225,075.80	**730,324**	$ 24,870,651.98	**730,824**	$ 26,544,801.70
Oregon	650,088	24,490,796.61	649,583	22,443,070.97	649,912	24,012,088.07
Washington	80,566	2,734,279.19	80,741	2,427,581.01	80,912	2,532,713.63
Total Residential	662,245	14,144,117.31	662,030	12,659,746.29	662,555	13,642,619.38
Total Commercial	67,226	8,624,672.25	67,107	7,755,802.36	67,078	8,259,619.56
Total Industrial	661	1,532,876.90	668	1,515,711.98	670	1,695,510.93
Total Interruptible	130	1,381,965.92	128	1,377,081.54	130	1,390,844.79
Total Transportation - Commercial Firm	170	218,258.61	170	217,221.21	170	233,532.00
Total Transportation - Industrial Firm	123	647,334.71	122	652,706.14	122	645,626.23
Total Transportation - Interruptible	99	675,850.10	99	692,382.46	99	677,048.81
Unbilled Revenue		(454,430.71)		(34,768.23)		2,537,129.62
Agency Fees						
Net Balancing/Overrun		71.00		-		-
Total Gas Operating Revenue		**$ 26,770,716.09**		**$ 24,835,883.75**		**$ 29,081,931.32**

	Customer Cnt Oct-17	Revenue Oct-17	Customer Cnt Nov-17	Revenue Nov-17	Customer Cnt Dec-17	Revenue Dec-17
Total	**732,460**	$38,240,638.63	**735,271**	$ 59,885,200.07	**737,873**	$ 92,177,907.97
Oregon	651,289	34,611,996.32	653,752	53,993,464.26	656,031	83,163,089.44
Washington	81,171	3,628,642.31	81,519	5,891,735.81	81,842	9,014,818.53
Total Residential	663,982	21,573,707.88	666,475	36,937,934.68	668,803	58,924,844.22
Total Commercial	67,291	11,152,092.80	67,605	17,216,235.83	67,881	27,093,248.95
Total Industrial	667	2,004,941.63	665	2,018,560.60	667	2,109,249.37
Total Interruptible	130	1,787,440.85	131	2,008,197.60	129	2,231,085.39
Total Transportation - Commercial Firm	170	297,431.76	170	333,798.81	169	397,961.36
Total Transportation - Industrial Firm	122	702,817.26	126	722,902.53	126	758,692.26
Total Transportation - Interruptible	98	722,206.45	99	647,570.02	98	662,826.42
Unbilled Revenue		14,572,405.89		17,470,281.64		16,202,055.26
Agency Fees						
Net Balancing/Overrun		-		-		-
Total Gas Operating Revenue		**$52,813,044.52**		**$ 77,355,481.71**		**$ 108,379,963.23**

	Customer Cnt Jan-18	Revenue Jan-18	Customer Cnt Feb-18	Revenue Feb-18	Customer Cnt Mar-18	Revenue Mar-18
Total	**739,947**	$ 111,380,546.52	**740,832**	$ 88,656,968.84	**741,920**	$ 86,722,892.36
Oregon	657,776	99,953,476.06	658,466	80,222,142.65	659,339	77,475,762.75
Washington	82,171	11,427,070.46	82,366	8,434,826.19	82,581	9,247,129.61
Total Residential	670,691	71,328,081.33	671,597	56,634,290.64	672,570	54,059,698.61
Total Commercial	68,070	33,831,964.73	68,044	26,150,425.15	68,152	26,655,079.10
Total Industrial	664	2,265,051.97	667	2,036,886.07	677	2,085,806.87
Total Interruptible	130	2,197,956.09	131	2,138,845.67	130	2,179,739.28
Total Transportation - Commercial Firm	169	363,473.82	170	361,587.28	170	350,166.33
Total Transportation - Industrial Firm	125	738,623.95	125	714,001.92	124	716,101.70
Total Transportation - Interruptible	98	655,394.63	98	620,932.11	97	676,300.47
Unbilled Revenue		(14,454,428.81)		(974,405.40)		(9,507,263.68)
Agency Fees						
Net Balancing/Overrun		985.00		1,923.00		-
Total Gas Operating Revenue		**$ 96,927,102.71**		**$ 87,684,486.44**		**$ 77,215,628.68**

	Customer Cnt Apr-18	Revenue Apr-18	Customer Cnt May-18	Revenue May-18	Customer Cnt Jun-18	Revenue Jun-18
Total	**742,558**	$ 67,985,285.80	**742,852**	$ 43,641,038.17	**742,667**	$ 20,446,950.57
Oregon	659,793	61,009,147.60	659,966	39,496,051.74	659,633	17,361,066.27
Washington	82,765	6,976,138.20	82,886	4,144,986.43	83,034	3,085,884.30
Total Residential	673,195	42,005,637.91	673,620	25,656,782.33	673,479	11,084,029.35
Total Commercial	68,169	20,710,621.64	68,037	13,430,660.64	67,990	6,234,480.37
Total Industrial	676	1,896,780.53	677	1,598,360.52	681	1,042,865.89
Total Interruptible	130	1,729,521.25	129	1,390,414.88	128	587,050.93
Total Transportation - Commercial Firm	168	304,356.94	168	247,490.18	169	229,145.03
Total Transportation - Industrial Firm	124	690,603.78	124	666,424.34	124	645,040.06
Total Transportation - Interruptible	96	647,763.75	97	650,905.28	96	624,338.94
Unbilled Revenue		(10,678,403.44)		(11,448,550.61)		(2,461,744.69)
Agency Fees						
Net Balancing/Overrun		407,150.00		(203,575.00)		12,019.00
Total Gas Operating Revenue		**$ 57,714,032.36**		**$ 31,988,912.56**		**$ 17,997,224.88**

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

	2018/2019 Forecasted	2017/2018	2016/2017	2015/2016	2014/2015	2013/2014
System peak demand (therms)	9,947,760	9,751,743	9,777,033	9,452,960	9,369,764	9,320,242

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

Gas Year	Forecasted 2018/2019	2017/2018	2016/2017	2015/2016	2014/2015	2013/2014
Annual Demand (therms)	781,861,912	728,507,577	814,067,230	757,005,313	747,790,904	746,847,556

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

1. Annual for each customer class

Gas Year	Forecasted 2018/2019	2017/2018	2016/2017	2015/2016	2014/2015	2013/2014
Residential (therms)	435,558,160	425,937,713	455,301,805	365,156,667	340,361,989	416,389,181
Commercial (therms)	257,979,154	254,850,710	269,622,885	224,829,519	216,426,531	254,877,091
Industrial Firm (therms)	35,817,844	35,388,739	35,071,414	32,871,710	32,273,813	34,838,443
Industrial Interruptible (therms)	52,506,755	52,905,669	54,169,492	52,979,815	58,789,923	62,513,367

2. Annual and monthly baseload.

Gas Year	Forecasted 2018-2019	2017/2018	2016/2017	2015/2016	2014/2015	2013/2014
November	26,189,278	23,614,500	27,268,028	22,351,644	22,999,936	22,397,233
December	27,071,943	23,641,081	28,187,051	22,916,079	24,282,715	23,202,872
January	27,233,210	23,661,617	28,354,961	22,938,449	24,362,006	23,196,614
February	25,213,380	23,676,660	26,251,933	21,874,421	22,159,174	20,943,260
March	27,353,836	23,692,533	28,480,556	22,968,882	23,866,828	23,202,391
April	26,656,257	23,699,551	27,754,243	22,440,684	22,869,798	22,513,500
May	27,325,047	23,708,824	28,450,580	22,997,543	23,238,337	23,254,362
June	26,569,021	23,713,005	27,663,414	22,470,443	22,332,108	22,556,453
July	23,888,418	23,710,088	24,872,395	23,023,353	23,019,887	23,314,587
August	23,825,426	23,708,249	24,806,808	23,050,124	23,015,123	23,324,427
September	23,197,126	23,717,107	24,152,629	22,527,362	22,737,568	22,537,805
October	27,099,442	23,742,626	28,215,683	23,100,640	23,881,459	23,359,078
Annual	311,622,383	284,285,840	324,458,279	272,659,625	278,764,939	273,802,581

3. Annual and monthly non-baseload

Gas Year	Forecasted 2018/2019	2017/2018	2016/2017	2015/2016	2014/2015	2013/2014
November	61,654,966	57,380,740	64,194,567	64,242,976	62,486,370	62,248,709
December	93,759,967	93,647,405	97,621,991	98,795,855	96,475,524	95,405,022
January	94,118,247	88,933,839	97,995,029	92,054,676	90,486,111	91,382,451
February	73,504,772	67,127,899	76,532,474	74,851,835	71,804,677	72,204,387
March	60,416,374	54,005,602	62,904,957	59,855,292	58,202,117	58,522,284
April	39,282,502	32,492,116	40,900,570	40,203,184	38,491,513	38,745,792
May	16,417,652	16,233,535	17,093,904	18,600,362	17,127,632	17,039,845
June	3,605,196	4,731,141	3,753,696	4,336,063	3,488,689	4,181,989
July	370,615	889,329	385,881	304,475	25,201	707,612
August	277,470	593,417	288,899	0	-	769,863
September	2,257,433	3,450,139	2,350,418	2,211,685	2,291,298	3,220,573
October	24,574,334	24,736,573	25,586,564	28,889,285	28,146,833	28,616,445
Annual	470,239,529	444,221,737	489,608,951	484,345,688	469,025,965	473,044,975

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

NW Natural
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V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:
4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update

2018/2019	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	4,977,360	1,362,842	329,151	1,098,836	258,470	6,367,367	969,000	50,602,590	13,298,733	8,579,895	87,844,244
December	6,685,663	1,728,940	410,274	1,402,872	351,433	7,876,788	1,193,661	71,968,627	17,064,713	12,148,939	120,831,910
January	6,608,295	1,733,614	412,973	1,437,437	359,023	8,019,291	1,196,938	72,247,519	17,022,423	12,313,944	121,351,457
February	5,282,908	1,454,392	295,247	1,189,884	285,958	6,416,168	984,357	58,654,282	14,288,533	9,866,423	98,718,152
March	4,942,226	1,538,145	385,755	1,025,867	236,843	6,619,420	1,065,468	49,674,649	13,527,824	8,754,012	87,770,210
April	4,269,475	1,276,038	348,293	725,932	155,907	5,457,455	922,735	35,646,527	10,690,418	6,445,979	65,938,759
May	2,982,382	857,932	255,156	543,264	98,090	3,820,004	690,694	23,525,589	6,825,318	4,144,269	43,742,699
June	2,107,593	613,999	177,950	427,027	71,834	2,856,658	522,777	15,678,458	4,953,856	2,764,065	30,174,218
July	1,582,060	536,144	143,778	371,253	67,168	2,191,427	460,627	12,671,020	3,865,057	2,370,498	24,259,033
August	1,702,830	526,005	135,427	365,356	67,261	2,210,459	456,230	12,509,816	3,791,077	2,338,434	24,102,896
September	1,798,278	549,400	142,544	371,184	68,553	2,241,117	449,505	13,013,814	4,344,688	2,475,477	25,454,560
October	3,316,301	896,168	230,067	625,642	135,260	4,164,198	701,041	28,243,884	8,330,382	5,030,832	51,673,776
Annual	46,255,370	13,073,620	3,266,614	9,584,552	2,155,802	58,240,353	9,613,032	444,436,777	118,003,022	77,232,768	781,861,912

2017/2018	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	3,970,205	1,071,820	285,583	720,861	187,892	4,623,955	815,203	38,381,270	8,492,989	6,140,858	64,690,636
December	6,325,218	1,529,262	399,894	1,139,531	258,557	7,114,047	1,140,776	64,911,614	13,624,189	10,169,077	106,612,165
January	7,086,049	1,782,845	442,123	1,481,840	317,137	8,766,492	1,281,132	77,372,860	18,409,078	13,180,336	130,119,891
February	5,308,633	1,523,786	373,916	1,087,294	250,844	6,774,777	1,139,429	58,422,175	13,132,447	9,458,179	97,471,478
March	5,820,566	1,601,378	435,381	1,126,418	219,380	7,406,613	1,177,108	62,004,567	15,295,122	10,513,034	105,599,567
April	4,411,399	1,324,036	351,968	848,997	144,820	5,851,181	1,019,180	45,566,847	11,932,297	7,709,931	79,160,656
May	2,477,463	912,501	287,615	539,671	67,513	4,133,757	683,569	24,595,559	7,748,997	4,231,320	45,677,964
June	1,976,734	575,877	166,901	400,513	71,006	2,679,291	490,318	14,704,996	4,646,276	2,732,234	28,444,147
July	1,614,014	546,973	146,682	378,751	64,403	2,235,690	469,931	12,926,949	3,943,123	2,272,901	24,599,417
August	1,724,534	532,710	137,153	370,012	65,087	2,238,633	462,045	12,669,262	3,839,397	2,262,835	24,301,667
September	1,922,905	587,476	152,422	396,908	71,919	2,396,435	480,658	13,915,721	4,645,792	2,597,010	27,167,246
October	3,112,415	841,072	215,922	587,177	126,482	3,908,183	657,941	26,507,450	7,818,230	4,704,327	48,479,198
Annual	45,750,135	12,829,736	3,395,561	9,077,973	1,845,040	58,129,052	9,817,288	451,979,269	113,527,936	75,972,041	782,324,032

2016/2017	Albany	Astoria	Coos Bay	The Dalles (OR)	The Dalles (WA)	Eugene	Newport	Portland	Salem	Vancouver	Total
November	3,003,230	866,732	244,968	577,151	138,181	3,710,737	662,395	29,583,502	7,379,381	4,592,272	50,758,549
December	6,057,420	1,587,331	425,823	1,071,584	321,684	6,465,606	1,342,518	64,675,278	12,434,157	9,483,114	103,864,513
January	8,917,184	2,243,860	561,692	1,816,082	433,633	9,767,406	1,610,061	100,280,072	21,394,925	16,404,941	163,429,856
February	6,378,898	1,783,591	417,441	1,575,289	311,503	7,956,474	1,166,305	77,162,935	17,771,326	12,361,070	126,884,830
March	5,274,286	1,554,099	408,833	1,115,885	217,752	6,598,937	1,119,451	58,462,872	14,551,440	9,638,087	98,941,642
April	4,075,561	1,250,351	330,786	782,657	157,473	5,165,565	958,829	42,782,622	10,904,867	6,945,582	73,354,293
May	2,930,675	963,140	280,474	592,666	89,307	4,245,719	733,482	30,962,201	8,642,168	5,020,020	54,459,853
June	1,782,610	748,878	229,441	370,336	59,280	3,017,799	626,326	18,324,272	5,327,166	3,142,214	33,628,323
July	1,340,199	571,201	180,700	331,753	50,467	2,374,096	575,659	13,438,280	4,113,787	2,352,950	25,329,093
August	1,238,820	517,215	168,535	308,341	42,815	2,103,505	501,714	11,242,027	3,498,148	1,988,179	21,609,300
September	1,344,073	539,378	162,512	316,946	49,841	2,243,515	550,930	12,502,063	3,985,898	2,108,252	23,803,407
October	2,470,061	656,707	205,683	467,806	107,107	3,065,124	647,252	21,379,126	5,631,688	3,373,020	38,003,574
Annual	44,813,016	13,282,482	3,616,888	9,326,496	1,979,042	56,714,482	10,494,923	480,795,249	115,634,950	77,409,702	814,067,230

2015/2016	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver	Total
November	3,074,744	846,306	494,121	3,799,048	702,449	30,577,070	6,134,192	4,402,104	50,030,034
December	5,810,458	1,586,640	1,118,426	7,180,600	1,151,546	65,454,108	13,991,455	10,431,152	106,724,386
January	6,859,044	1,746,878	1,379,298	8,245,535	1,345,348	77,006,101	16,857,523	12,573,721	126,013,448
February	4,560,345	1,326,755	979,876	6,136,769	869,227	50,609,904	12,137,199	8,326,569	84,946,643
March	4,210,415	1,209,540	832,358	5,426,045	898,389	44,305,807	10,493,399	7,082,115	74,458,068
April	2,860,334	982,126	608,204	4,626,706	708,780	31,109,796	8,853,355	5,222,831	54,972,131
May	1,966,950	704,500	365,481	3,282,636	582,555	19,755,223	5,517,571	3,190,935	35,365,850
June	1,589,927	652,322	324,374	2,863,446	541,081	16,487,323	4,364,444	2,761,428	29,584,345
July	1,276,440	569,474	315,360	2,512,049	512,910	13,549,814	4,137,273	2,348,586	23,327,828
August	1,094,713	490,165	309,016	2,301,093	484,354	11,915,029	3,596,497	2,087,015	23,050,124
September	1,290,982	519,961	308,947	2,343,325	535,853	13,080,874	3,890,952	2,248,661	24,739,046
October	2,058,103	655,682	400,183	2,906,804	633,634	20,461,984	5,354,997	3,227,248	51,989,926
Annual	36,652,454	11,290,349	7,435,643	51,624,055	8,966,126	394,313,032	95,328,857	63,902,363	685,201,829

2014/2015	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver	Total
November	3,490,958	869,406	739,467	4,017,243	761,672	33,112,773	6,228,375	4,808,471	54,028,365
December	5,847,679	1,367,602	1,245,731	6,776,032	921,294	59,955,127	13,259,278	9,648,654	99,021,398
January	6,351,751	1,511,674	1,385,617	7,384,910	1,127,141	65,692,741	14,491,558	10,585,680	108,531,072
February	4,503,610	1,122,974	1,087,328	5,805,289	768,470	47,086,091	11,421,381	7,829,682	79,624,824
March	4,158,320	1,121,188	913,284	5,503,855	806,489	38,235,877	9,848,434	6,201,912	66,789,358
April	3,717,325	981,132	727,827	4,717,038	774,036	32,236,045	8,249,792	5,074,817	56,478,012
May	2,664,122	782,272	580,411	3,898,397	634,775	23,625,974	6,697,473	3,789,305	42,672,730
June	1,840,466	647,219	429,546	2,824,482	551,338	15,117,689	4,430,159	2,542,401	28,383,298
July	1,432,574	550,017	382,927	2,328,798	491,887	11,488,733	3,356,047	1,895,492	21,926,476
August	1,479,412	496,116	392,405	2,151,660	453,438	10,679,209	3,115,291	1,785,762	20,553,293
September	1,731,118	511,828	426,199	2,268,709	504,023	12,315,742	3,477,020	2,079,370	23,314,009
October	2,061,765	577,540	473,559	2,809,490	492,610	15,383,719	4,344,711	2,494,906	28,638,300
Annual	39,279,100	10,538,968	8,784,299	50,485,903	8,287,172	364,929,719	88,919,520	58,736,452	629,961,134

2013/2014	Albany	Astoria	The Dalles (OR)	Eugene	Newport/LC	Portland	Salem	Vancouver	Total
November	3,004,316	923,615	752,502	4,951,166	773,173	35,213,397	8,421,835	5,303,793	59,343,797
December	7,773,336	1,773,068	1,371,882	8,478,833	1,393,910	73,290,876	15,193,898	11,654,376	120,930,179
January	7,314,992	1,764,673	1,520,332	9,839,902	1,249,414	77,670,980	19,041,102	12,893,003	131,294,398
February	6,676,619	1,663,860	1,442,076	7,936,329	1,120,325	72,081,981	15,896,859	11,761,142	118,579,191
March	4,458,858	1,237,372	1,159,727	5,962,629	864,287	51,903,144	12,484,347	8,469,900	86,540,264
April	3,776,291	1,049,610	784,535	5,052,348	779,630	36,250,554	9,500,909	5,960,021	63,153,898
May	2,855,731	770,344	612,151	3,922,913	584,808	24,906,632	6,850,569	4,016,235	44,519,383
June	1,904,412	586,081	470,687	3,016,935	517,593	16,685,126	4,754,490	2,725,858	30,661,182
July	1,597,377	562,799	415,682	2,491,542	502,615	13,198,442	3,914,695	2,234,904	24,918,056
August	1,511,671	530,842	380,067	2,240,954	468,602	10,815,694	3,171,714	1,812,836	20,932,379
September	1,637,412	510,399	390,868	2,220,473	483,630	11,242,660	3,430,400	1,899,175	21,815,016
October	1,980,952	517,141	420,442	2,571,228	459,522	13,984,555	3,967,612	2,228,583	26,130,034
Annual	44,491,967	11,889,804	9,720,950	58,685,251	9,197,509	437,244,041	106,628,429	70,959,826	748,817,777

Section V.4 - Market Information

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

Deregulation from the late 1970s to early 1990s was a response to perceived natural gas shortages. In the new unregulated environment, prices dropped due to competition, increased efficiencies, technological improvements, and the discovery of more natural gas.

In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were tightening and that demand growth would be dependent on bringing additional supplies to North America in the form of LNG imports. Catastrophic hurricanes (Katrina, Rita, et al) in 2005 interrupted natural gas supplies from the Gulf of Mexico and prices spiked again. Gas prices soared in the spring and summer of 2008 on the tails of predicted supply shortfalls. At that time, Henry Hub prices peaked at $13.31/Dth. Within months, the onset of a global economic recession reduced demand while the advent of horizontal drilling into shale formations unleashed a surge of production. Prices soon tumbled (Figure 1). Historical indexed prices into the Pacific Northwest at NW Natural's major supply points reflected national trends (Figure 2).

Figure 1

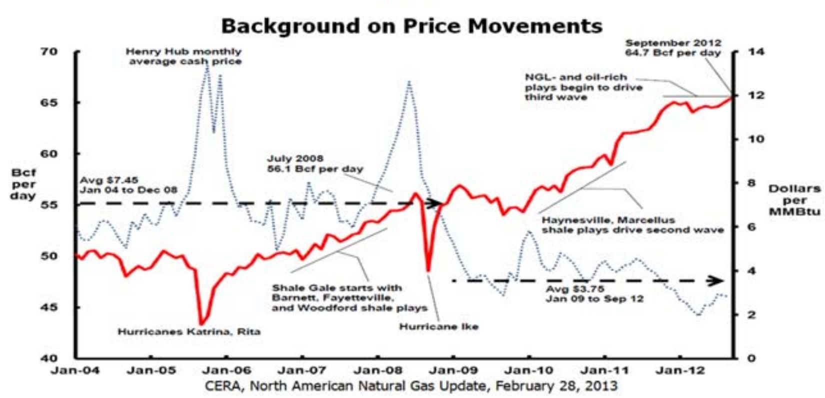
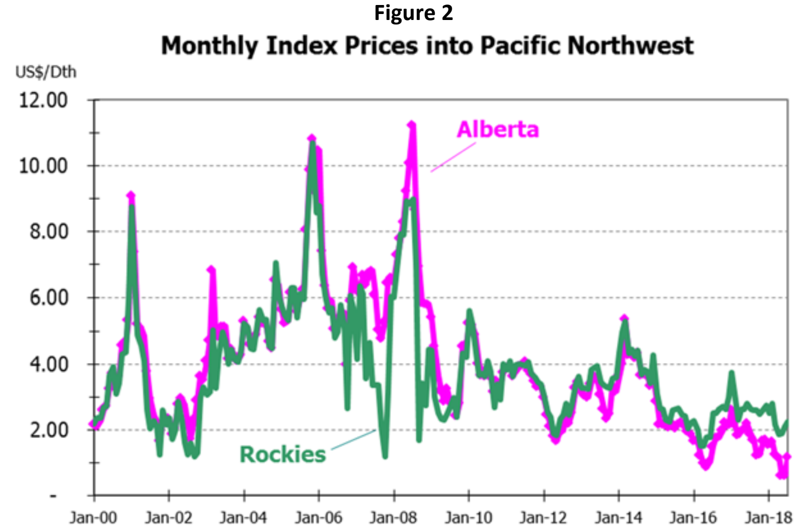
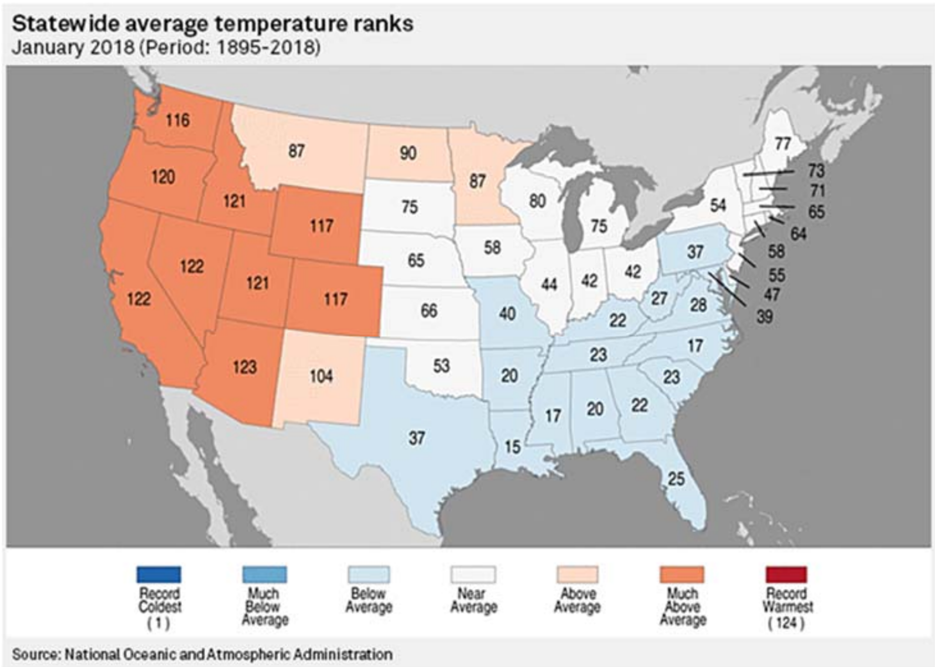


Figure 2



As mentioned, production began ramping up in 2008 with the surge in shale drilling innovations. Prices fell dramatically, and as shown in Figure 2, initially bottomed out in spring 2012. Prices then rose and fell again, aided primarily by the weather. First there was the so-called "Polar Vortex" that swept the eastern half of the country in 2013/14 and again in 2014/15, then the exceedingly warm El Niño winter of 2015/2016. The recent winter of 2017/18 was mixed with a relatively mild December coupled with a cold January in the eastern and southern US (Figure 3).

Figure 3



The US Energy Information Administration's (EIA) June 2018 Short-Term Energy Outlook has a baseline price forecast with upper and lower confidence intervals as shown in Figure 4. These prices are for the Henry Hub, which is in Louisiana, and prices are generally lower in the Pacific Northwest though the correlations are far from exact. EIA, as well as the "futures market" represented by the NYMEX curve, indicate an expectation for prices over the next year to be generally flat with the usual seasonal variations. The large skew to the upside represented by the upper confidence intervals is mostly a function of current relatively low storage levels that may not recover in time for the coming heating season (Figure 5).

Figure 4

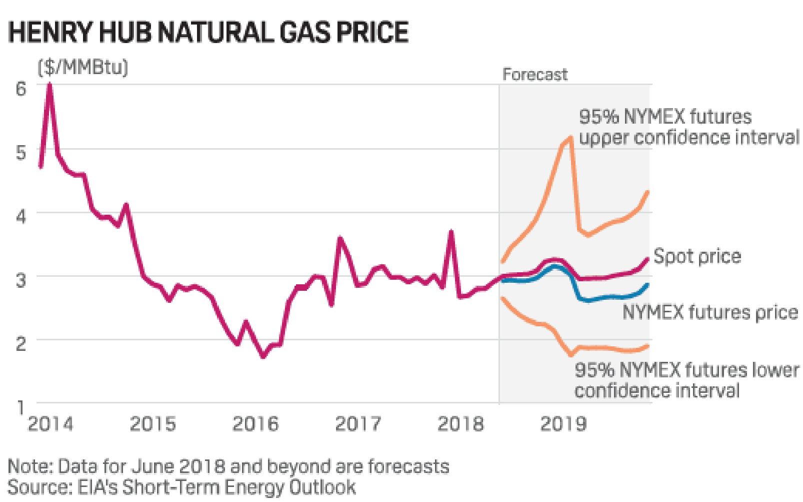
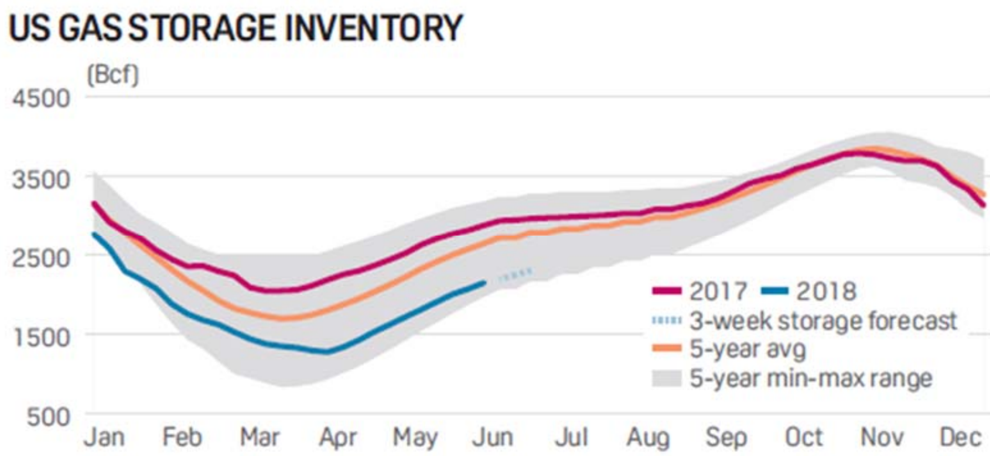
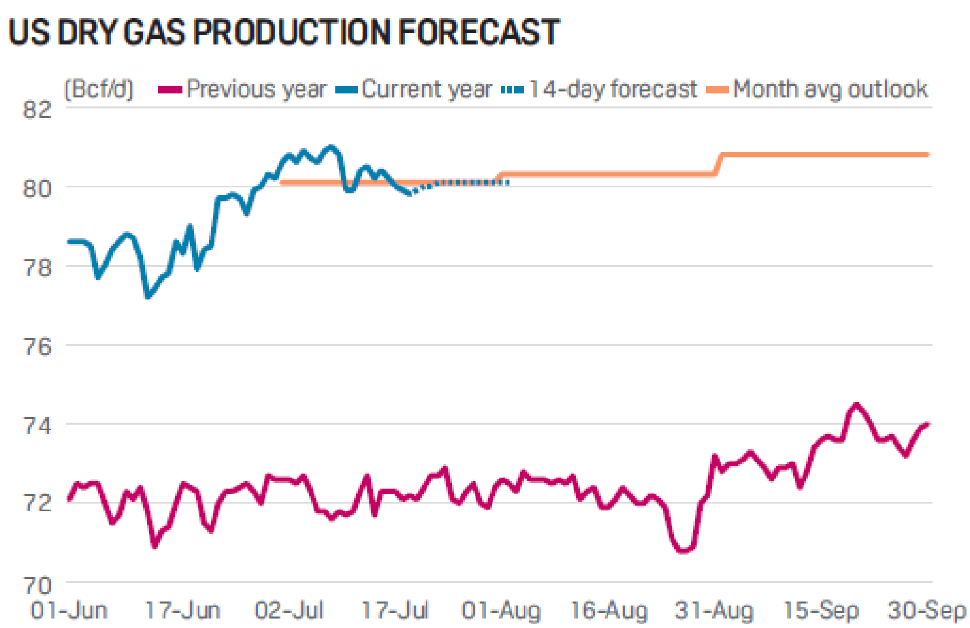


Figure 5



Besides weather and storage, the other two major factors affecting the price outlook are gas production levels that continue to grow, which is balanced by surging export demand. Regarding gas production, the outlook is for continued year-over-year growth (Figure 6).

Figure 6



Gas export demand, meanwhile, can be divided into two categories: exports via pipeline to Mexico, and exports to the world in the form of liquefied natural gas (LNG) shipments. Regarding pipeline flows to Mexico, the outlook is for steady growth (Figure 7), while LNG exports are not expected to grow again until more LNG liquefaction capacity comes on-line towards the end of 2019 (Figure 8).

Figure 7

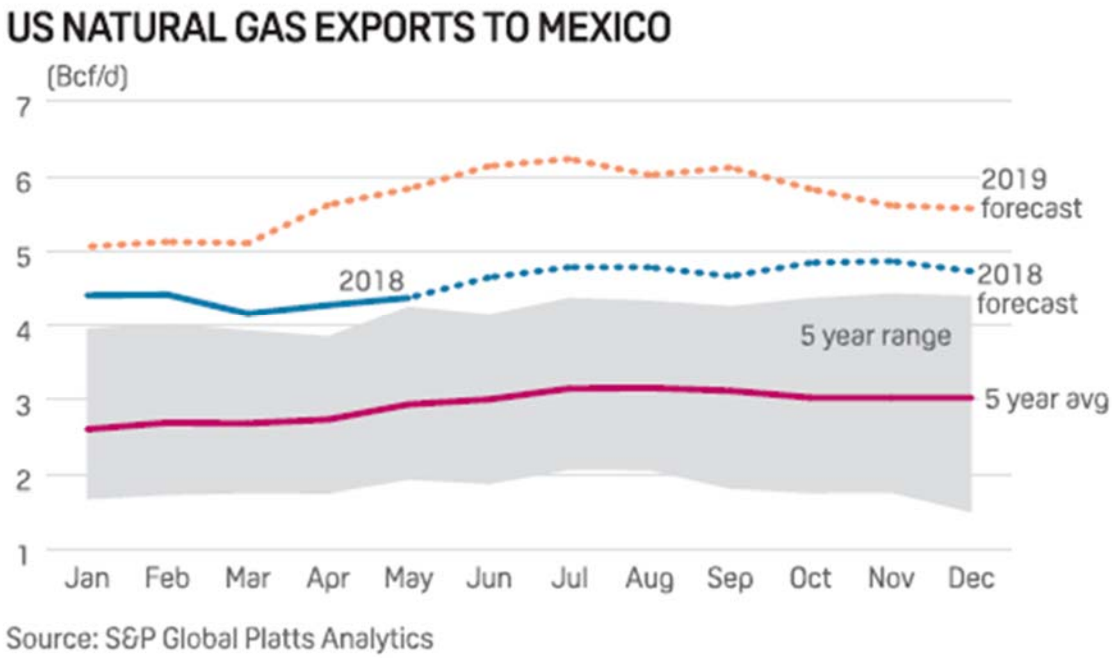
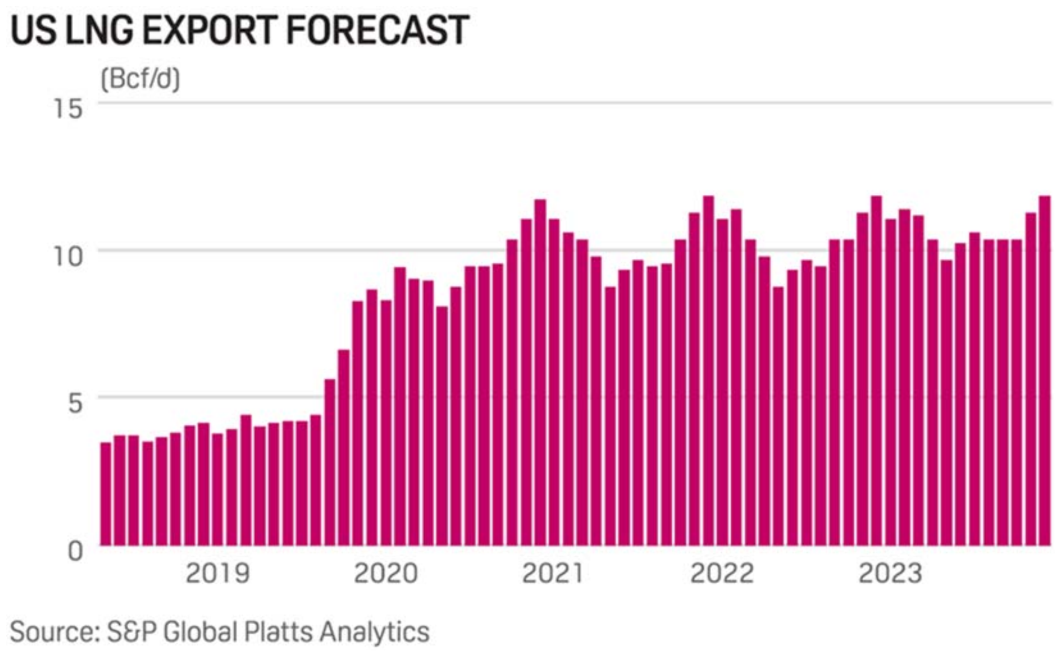


Figure 8



Regarding liquidity at our major supply points in the Rockies and western Canada (AECO, Sumas and Station 2), it is likely to continue to be very strong for the next couple of years. That is, Rockies and western Canadian gas that typically flowed to mid-Continent and East Coast markets will continue to be displaced by the growth in gas supplies from eastern shale plays such as Marcellus. Rockies gas may be pulled in greater volumes to the southern tier of states as gas in those areas is increasingly exported via pipeline or LNG cargoes. It is likely, though, that demand growth in the Pacific Northwest - some combination of power generation, industrial loads and perhaps regional LNG exports - eventually will catch up with available supplies, spurring a strong price response. The magnitude of the price response will depend on the ability of gas producers to tap more supplies from western Canada (primarily BC shales) and the Rockies. All of these factors are much longer term in nature and will not affect the upcoming PGA year, where storage positions, the weather, and pipeline operations (maintenance activities, etc.) will continue, as they have in the past, to be the dominant factors influencing near-term prices.

Section V.5 - Data Interpretation

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

See Exhibit C, IV.2.b

Section V.6 - Credit Worthiness Standards

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

IV. Credit Risk Management

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

	Procedure	Responsible Office
1	Analyzes the counterparty's profile to determine credit risk tolerances.	Mid Office
2	Sets counterparty credit limits in accordance with company policy (see Exhibit "E" of the Gas Supply Risk Management Policies).	Mid Office
3	Monitors credit exposure and coordinates with the Front Office to mitigate risk.	Mid Office
4	If the credit exposure amount exceeds the counterparty credit limit, verifies the limit violation.	Mid Office
5	Notifies Front Office Executive of limit violations in physical transactions, and Mid Office Executive of limit violations in financial transactions.	Mid Office
6	Determines any appropriate action in response to physical transaction violations.	Front Office Executive
7	Communicates instructions for dealing with physical transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Front Office Executive
8	Determines any appropriate action in response to financial transaction violations that are not already addressed in the Derivatives Policy.	Mid Office Executive
9	Communicates instructions for dealing with financial transaction violations to Front Office and submits copies of the instructions to the Mid Office.	Mid Office Executive
10	Calculates and analyzes various credit risk metrics to better understand the current and potential risks in the portfolio.	Mid Office
11	Calculates and records appropriate credit reserves on a monthly basis.	Mid Office
12	Reviews credit limits at least twice a year, and additionally as needed, to assess whether changes should be made.	Mid Office
13	Monitors news articles, bankruptcy filings, legal actions, etc. on a daily basis for all established counterparties.	Front Office Mid Office

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures
Effective March 28, 2005; Last updated January 5, 2015

NW NATURAL

Gas Supply Risk Management Policies

Index No. 110

September 26, 2017

Original Date of Approval: March 29, 2005

[redacted]

[redacted]

CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

[redacted]

[redacted]

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CONFIDENTIAL SUBJECT TO
MODIFIED PROTECTIVE ORDER 10-337

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CONFIDENTIAL SUBJECT TO
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MODIFIED PROTECTIVE ORDER 10-337

[redacted]

Section V.7 - Storage

Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.

a) Type of storage (e.g. depleted field, salt dome).
See Table 1 below.

b) Location of each storage facility.
See Table 1 below.

c) Total level of storage in terms of deliverability and capacity held during the gas year.
See Table 1 below.

TABLE 1

Facility	Max. Daily Rate (Dth/day)	Max. Seasonal Level (Dth)
Jackson Prairie - aquifer - Chehalis, WA	46,030	1,120,288
Mist (share allocated to Utility) - depleted field - Mist, OR	305,000	11,382,120
Portland LNG - LNG Plant - Portland, OR	131,880	503,782
Newport LNG - LNG Plant - Newport, OR	65,280	979,200

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

See Table 2 below.

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

See Table 2 below.

TABLE 2

Northwest Natural Gas Company
PGA Portfolio Guidelines
2018-2019 Oregon PGA

NORTHWEST NATURAL GAS COMPANY
All Sites Therms Summary

	BEGINNING BALANCE			ISSUES (Withdrawals)		LIQUEFIED	INJECTIONS (Deliveries)			ENDING BALANCE	
MONTH	THERMS	AMOUNT	RATE	THERMS	AMOUNT	THERMS	AMOUNT	RATE	THERMS	AMOUNT	RATE
Jan-13	150,229,068	$ 62,862,077.99	0.41844	14,677,497	$ 5,405,016.60	5,093,510	$ 1,831,966.73	0.35967	140,645,081	$ 59,289,028.12	0.42155
Feb	140,645,081	$ 59,289,028.12	0.42155	13,800,354	$ 5,335,663.36	1,262,630	$ 409,713.41	0.32449	128,107,357	$ 54,363,078.17	0.42436
Mar	128,107,357	$ 54,363,078.17	0.42436	3,567,521	$ 1,115,677.83	5,501,939	$ 1,964,738.34	0.35710	130,041,775	$ 55,212,138.68	0.42457
Apr	130,041,775	$ 55,212,138.68	0.42457	21,459,008	$ 8,365,699.38	4,538,540	$ 1,807,682.82	0.39830	113,121,307	$ 48,654,122.12	0.43011
May	113,121,307	$ 48,654,122.12	0.43011	4,818,397	$ 1,845,435.83	8,574,316	$ 2,707,134.37	0.31573	116,877,226	$ 49,515,820.66	0.42366
Jun	116,877,226	$ 49,515,820.66	0.42366	175,511	$ 91,369.64	8,915,841	$ 3,055,934.87	0.34275	125,524,403	$ 52,469,340.89	0.41800
Jul	125,524,403	$ 52,469,340.89	0.41800	565,039	$ 240,884.14	15,007,288	$ 4,532,440.74	0.30202	139,966,652	$ 56,760,897.49	0.40553
Aug	139,966,651	$ 56,760,897.49	0.40553	274,464	$ 135,425.37	17,596,859	$ 4,711,223.75	0.26773	157,289,046	$ 61,336,695.87	0.38996
Sep	157,289,046	$ 61,336,695.87	0.38996	285,901	$ 140,062.88	10,388,350	$ 2,723,301.45	0.26215	167,391,495	$ 63,919,934.44	0.38186
Oct	167,391,495	$ 63,919,934.44	0.38186	4,070,753	$ 1,272,892.19	10,841,958	$ 4,013,141.26	0.37015	174,162,700	$ 66,660,183.51	0.38275
Nov	174,162,700	$ 66,660,183.51	0.38275	7,315,178	$ 2,342,207.60	12,577,745	$ 4,710,632.15	0.37452	179,425,267	$ 69,028,608.06	0.38472
Dec	179,425,267	$ 69,028,608.06	0.38472	46,561,323	$ 17,032,482.39	6,732,330	$ 3,374,222.26	0.50120	139,596,274	$ 55,370,347.93	0.39665
TOTAL 2013 ACTIVITY				117,570,946	$ 43,322,817.21	107,031,306	$ 35,842,132.15				
Jan-14	139,596,274	$ 55,370,347.93	0.39665	30,835,168	$ 11,843,590.19	1,760,410	$ 767,548.02	0.43601	110,521,516	$ 44,294,305.76	0.40078
Feb	110,521,516	$ 44,294,305.76	0.40078	29,228,201	$ 12,337,686.61	2,109,060	$ 1,410,671.47	0.66886	83,402,375	$ 33,367,290.62	0.40008
Mar	83,402,375	$ 33,367,290.62	0.40008	4,103,948	$ 1,427,892.69	5,235,359	$ 2,778,669.67	0.53075	84,533,786	$ 34,718,067.60	0.41070
Apr	84,533,786	$ 34,718,067.60	0.41070	2,620,950	$ 1,039,548.32	7,343,259	$ 3,410,003.35	0.46437	89,256,095	$ 37,088,522.63	0.41553
May	89,256,095	$ 37,088,522.63	0.41553	179,202	$ 87,337.55	15,343,377	$ 6,883,358.12	0.44862	104,420,270	$ 43,884,543.20	0.42027
Jun	104,420,270	$ 43,884,543.20	0.42027	409,025	$ 200,391.58	15,898,061	$ 7,384,324.83	0.46448	119,909,306	$ 51,068,476.45	0.42589
Jul	119,909,306	$51,068,476.45	0.42589	150,183	$ 70,223.64	25,904,013	$ 10,835,078.53	0.41828	145,663,136	$61,833,331.34	0.42450
Aug	145,663,136	$61,833,331.34	0.42450	12,428	$ 5,479.26	25,531,734	$ 10,129,576.35	0.39674	171,182,442	$71,957,428.43	0.42036
Sep	171,182,442	$71,957,428.43	0.42036	62,586	$ 30,087.78	17,516,192	$ 7,008,362.97	0.40011	188,636,048	$78,935,703.62	0.41846
Oct	188,636,048	$78,935,703.62	0.41846	1,483,225	$ 756,854.52	10,968,256	$ 4,113,318.43	0.37502	198,121,080	$82,292,167.52	0.41536
Nov	198,121,080	$82,292,167.52	0.41536	13,322,697	$ 5,892,179.83	4,433,490	$ 1,873,768.24	0.42264	189,231,873	$78,273,755.94	0.41364
Dec	189,231,873	$78,273,755.94	0.41364	13,750,118	$ 5,897,877.99	2,358,363	$ 663,443.82	0.28132	177,840,118	$73,039,321.77	0.41070
TOTAL 2014 ACTIVITY				96,157,731	$ 39,589,149.96	134,401,574	$ 57,258,123.80				
Jan-15	177,840,117	$ 73,039,321.77	0.41070	14,245,904	$ 6,012,586.29	888,310	$ 262,325.07	0.29531	164,482,523	$ 67,289,060.55	0.40910
Feb	164,482,523	$ 67,289,060.55	0.40910	7,292,629	$ 3,141,852.01	6,012,346	$ 1,426,726.22	0.23730	163,202,240	$ 65,573,934.76	0.40180
Mar	163,202,240	$ 65,573,934.76	0.40180	1,830,436	$ 805,376.16	4,745,680	$ 1,098,192.39	0.23141	166,117,484	$ 65,866,750.99	0.39651
Apr	166,117,484	$ 65,866,750.99	0.39651	4,171,954	$ 1,638,956.58	5,066,936	$ 1,154,126.03	0.22778	167,012,466	$ 65,381,920.44	0.39148
May	167,012,466	$ 65,381,920.44	0.39148	113,933	$ 49,743.72	7,893,979	$ 2,109,511.88	0.26723	174,792,512	$ 67,441,688.60	0.38584
Jun	174,792,512	$ 67,441,688.60	0.38584	294,416	$ 129,698.39	8,657,668	$ 2,004,911.84	0.23158	183,155,764	$ 69,316,902.05	0.37846
Jul	183,155,764	$ 69,316,902.05	0.37846	299,408	$ 131,777.68	5,312,087	$ 1,249,966.44	0.23531	188,168,443	$ 70,435,090.81	0.37432
Aug	188,168,443	$ 70,435,090.81	0.37432	265,134	$ 116,504.21	10,284,977	$ 2,520,779.67	0.24509	198,188,286	$ 72,839,366.27	0.36753
Sep	198,188,286	$ 72,839,366.27	0.36753	292,458	$ 128,767.66	4,899,483	$ 1,221,204.70	0.24925	202,795,311	$ 73,931,803.31	0.36456
Oct	202,795,311	$ 73,931,803.31	0.36456	2,277,409	$ 813,221.62	2,847,073	$ 670,156.87	0.23538	203,364,975	$ 73,788,738.56	0.36284
Nov	203,364,975	$ 73,788,738.56	0.36284	10,693,933	$ 4,130,133.60	1,901,500	$ 384,080.18	0.20199	194,572,542	$ 70,042,685.14	0.35998
Dec	194,572,542	$ 70,042,685.14	0.35998	15,224,286	$ 5,264,682.89	-	$ -	-	179,348,256	$ 64,778,002.25	0.36119
TOTAL 2015 ACTIVITY				57,001,900	22,363,301	58,510,039	14,101,981				
Jan-16	179,348,259	$ 64,778,002.22	0.36119	14,375,950	$ 4,938,031.01	418,320	$ 87,922.80	0.20983	165,390,629	$ 59,927,894.01	0.36234
Feb	165,390,629	$ 59,927,894.01	0.36234	7,364,928	$ 2,243,437.76	-	$ -	-	158,025,701	$ 57,684,456.24	0.36503
Mar	158,025,701	$ 57,684,456.24	0.36503	2,222,649	$ 959,777.96	1,763,451	$ 191,087.31	0.10836	157,566,503	$ 56,915,765.59	0.36122
Apr	157,566,503	$ 56,915,765.59	0.36122	1,057,389	$ 358,801.37	4,694,562	$ 438,244.89	0.09278	161,203,676	$ 56,995,209.11	0.35354
May	161,203,676	$ 56,995,209.11	0.35354	278,494	$ 122,520.76	3,596,484	$ 422,136.36	0.11737	164,521,666	$ 57,294,824.71	0.34823
Jun	164,521,666	$ 57,294,824.71	0.34823	435,454	$ 189,445.52	3,366,849	$ 568,276.71	0.16879	167,453,061	$ 57,673,655.90	0.34440
Jul	167,453,061	$ 57,673,655.90	0.34442	269,411	$ 118,504.52	5,608,504	$ 1,122,283.87	0.20010	172,792,154	$ 58,677,435.25	0.33958
Aug	172,792,154	$ 58,677,435.25	0.33958	205,324	$ 91,088.63	5,982,972	$ 1,151,367.95	0.19244	178,569,802	$ 59,737,714.57	0.33453
Sep	178,569,802	$ 59,737,714.57	0.33453	197,222	$ 86,897.34	4,882,475	$ 1,187,474.19	0.24321	183,255,055	$ 60,838,291.42	0.33199
Oct	183,255,055	$ 60,838,291.42	0.33199	1,056,059	$ 313,511.00	1,880,810	$ 483,228.96	0.25693	184,079,806	$ 61,008,009.38	0.33142
Nov	184,079,806	$ 61,008,009.38	0.33142	2,445,979	$ 519,391.23	2,651,577	$ 550,271.16	0.20753	184,285,404	$ 61,038,889.31	0.33122
Dec	184,285,404	$ 61,038,889.31	0.33122	41,956,760	$ 13,229,908.36	3,321,350	$ 1,094,211.31	0.32945	145,649,994	$ 48,903,192.26	0.33576
TOTAL 2016 ACTIVITY				71,865,619	23,171,315	38,167,354	7,296,506				
Jan-17	145,649,994	$ 48,903,192.26	0.33576	34,412,044	$ 10,618,258.84	970,160	$ 301,841.76	0.31113	112,208,110	$ 38,586,775.18	0.34389
Feb	112,208,110	$ 38,586,775.18	0.34389	6,091,545	$ 1,334,519.38	1,156,690	$ 285,920.63	0.24719	107,273,255	$ 37,538,176.43	0.34993
Mar	107,273,255	$ 37,538,176.43	0.34993	2,529,712	$ 508,063.47	12,163,490	$ 2,795,959.60	0.22986	116,907,033	$ 39,826,072.56	0.34066
Apr	116,907,033	$ 39,826,072.56	0.34066	392,914	$ 128,470.77	4,116,895	$ 1,016,838.56	0.24699	120,631,014	$ 40,714,440.35	0.33751
May	120,631,014	$ 40,714,440.35	0.33751	255,999	$ 107,906.02	16,616,184	$ 4,183,845.45	0.25179	136,991,199	$ 44,790,379.78	0.32696
Jun	136,991,199	$ 44,790,379.78	0.32696	457,220	$ 201,460.40	9,984,353	$ 2,235,016.36	0.22385	146,518,332	$ 46,823,935.74	0.31958
Jul	146,518,332	$ 46,823,935.74	0.31958	280,665	$ 116,409.53	5,263,399	$ 1,143,959.51	0.21734	151,501,066	$ 47,851,485.72	0.31585
Aug	151,501,066	$ 47,851,485.72	0.31585	240,705	$ 102,876.07	6,510,945	$ 1,364,411.81	0.20956	157,771,306	$ 49,113,021.46	0.31129
Sep	157,771,306	$ 49,113,021.46	0.31129	61,212	$ 24,079.69	10,010,999	$ 1,417,611.84	0.14161	167,721,093	$ 50,506,553.61	0.30113
Oct	167,721,093	$ 50,506,553.61	0.30113	538,330	$ 129,207.72	8,164,995	$ 1,621,771.04	0.19862	175,347,758	$ 51,999,116.93	0.29655
Nov	175,347,758	$ 51,999,116.93	0.29655	912,972	$ 214,393.42	7,698,320	$ 1,807,623.80	0.23481	182,133,106	$ 53,592,347.31	0.29425
Dec	182,133,106	$ 53,592,347.31	0.29425	36,600,387	$ 10,781,710.23	38,884	$ 9,173.94	0.23593	145,571,603	$ 42,819,811.03	0.29415
TOTAL 2017 ACTIVITY				82,773,705	24,267,356	82,695,314	18,183,974				
Jan-18	145,571,603	$ 42,819,811.03	0.29415	10,975,019	$ 2,913,022.18	-	$ -	-	134,596,584	$ 39,906,788.85	0.29649
Feb	134,596,584	$ 39,906,788.85	0.29649	12,967,334	$ 3,641,271.92	-	$ -	-	121,629,250	$ 36,265,516.93	0.29816
Mar	121,629,250	$ 36,265,516.93	0.29816	3,885,930	$ 892,033.44	2,989,082	$ 546,352.00	0.18278	120,732,402	$ 35,919,835.49	0.29752
Apr	120,732,402	$ 35,919,835.49	0.29752	3,803,091	$ 956,966.49	178,867	$ 32,225.00	0.18016	117,108,178	$ 34,995,094.00	0.29883
May	117,108,178	$ 34,995,094.00	0.29883	126,554	$ 39,609.08	3,770,591	$ 438,837.66	0.11638	120,752,215	$ 35,394,322.58	0.29312
Jun	120,752,215	$ 35,394,322.58	0.29312	449,287	$ 115,798.86	9,323,597	$ 1,587,585.23	0.17028	129,626,525	$ 36,866,108.95	0.28440
TOTAL 2018 ACTIVITY				32,207,215	8,558,702	16,262,137	2,605,000				

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

The price of gas placed into storage, classed as working inventory, will be the average cost of gas defined as the average commodity cost of gas delivered to the city gate (utilizing unhedged discretionary sources first: i.e., spot gas first, then swing, and base load term supplies last. If storage injections exceed unhedged gas purchases, then average cost of hedged gas would be used to value the remainder of the storage injections.) This price would represent commodity cost, transportation cost, and fuel-in-kind (FIK) at either the NWN city gas (internal storage) or at the external storage site.

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

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

* Direct associated costs, such as liquefaction fees, fuel-in-kind and actual material costs incurred can be added to the base cost when determined significant.

* Injections into virtual storage sites are valued using specific commodity deals plus added costs for fuel and to maintain specific contract terms for each site. In addition, the price will include the virtual storage reservation fees.

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

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

See below for the Rate Schedule SGS-2F Service Agreement.[1]

[1] The Use of the storage facilities also requires the use of transportation service agreements controlled by the tariffs of the applicable upstream pipelines as and when needed to inject gas into and withdraw gas from each of these facilities.

Rate Schedule SGS-2F Service Agreement

Contract No. 100502

THIS SERVICE AGREEMENT (Agreement) by and between Northwest Pipeline LLC (Transporter) and Northwest Natural Gas Company (Shipper) is made and entered into on September 26, 2017 and restates the Service Agreement made and entered into on January 21, 2008.

WHEREAS:

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

B. Significant events and previous amendments of this Agreement include:

1. Transporter and Shipper agree to amend the Primary Term End Date on Exhibit A from October 31, 2004, to October 31, 2025. This amendment is being executed in conjunction with 1) contract extensions and pressure increases on Agreement Nos. 100005, 139153 and 139154, 2) contract extensions on Agreement Nos. 100138, 100308, 100310, 138065 and 140964 and 3) realignment of MDDOs on Agreement No. 136455.

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

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

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

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

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

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

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

7. Exhibit / Addendum to Service Agreement Incorporation. Exhibit A is attached hereto and incorporated as part of this Agreement. If any other Exhibits apply, as noted on Exhibit A to this Agreement, then such Exhibits also are attached hereto and incorporated as part of this Agreement. If an Addendum to Service Agreement has been generated pursuant to Sections 11.5 or 22.12 of the GT&C of the Tariff, it also is attached hereto and incorporated as part of this Agreement.

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

9. Superseded Agreements. When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s): Restated Firm Service Agreement dated January 21, 2008, but the following Amendments and/or Addendum to Service Agreement which have been executed but are not yet effective are not superseded and are added to and become an Amendment and/or Addendum to this agreement: None

IN WITNESS WHEREOF, Transporter and Shipper have executed this Agreement as of the date first set forth above.

Northwest Natural Gas Company	Northwest Pipeline LLC
By: /S/	By: /S/
Name: RANDOLPH S. FRIEDMAN	Name: LYNN DAHLBERG
Title: SENIOR DIRECTOR, GAS SUPPLY	Title: DIRECTOR, MARKETING SERVICES

EXHIBIT A
Dated and Effective September 26, 2017
to the
Rate Schedule SGS-2F Service Agreement
(Contract No. 100502)
between Northwest Pipeline LLC
and Northwest Natural Gas Company
SERVICE DETAILS

1. Customer Category: Pre-Expansion Shipper
2. Storage Demand: 46,030 Dth per day
3. Storage Capacity: 1,120,288 Dth
4. Recourse or Discounted Recourse Storage Rates:
    a. Demand Charge (per Dth of Storage Demand):
       Maximum Base Tariff Rate
    b. Capacity Demand Charge (per Dth of Storage Capacity):
       Maximum Base Tariff Rate
    c. Rate Discount Conditions Consistent with Section 3.2 of Rate Schedule SGS-2F:
       Not Applicable
5. Service Term:
    a. Primary Term Begin Date: November 01, 1998
    b. Primary Term End Date: October 31, 2025
    c. Evergreen Provisions: Yes, grandfathered unilateral evergreen under Section 15.3 of Rate Schedule SGS-2F
6. Regulatory Authorization: 18 CFR 284.223
7. Additional Exhibits:

   Exhibit B No

   Exhibit D No

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm

1. AVAILABILITY

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

2. APPLICABILITY AND CHARACTER OF SERVICE

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

2.2 Storage Components. Firm storage service consists of Transporter’s injection storage and withdrawal of Shipper’s gas.

2.3 Character of Service. Storage gas service rendered to Shipper under this Rate Schedule, up to Shipper's Storage Demand and Storage Capacity and subject to the limitations of this Rate Schedule and the executed Service Agreement, shall be firm and shall not be subject to curtailment or interruption except as expressly provided in this Rate Schedule and in the General Terms and Conditions. Storage gas service rendered to Shipper under this Rate Schedule in excess of Shipper’s Storage Demand and Storage Capacity is not firm.

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

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

3. MONTHLY RATE

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

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

(a) The demand charge will be the sum of the daily product of Shipper's Storage Demand and the Demand Charge rate stated on Sheet No. 7 of this Tariff that applies to the customer category identified in the Service Agreement.

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

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

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

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

3. MONTHLY RATE (Continued)

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

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

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

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

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

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

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

3. MONTHLY RATE (Continued)

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

4. MINIMUM MONTHLY BILL

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

5. FUEL GAS REIMBURSEMENT

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

6. STORAGE DEMAND

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

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

7. STORAGE CAPACITY

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

8. DEFINITIONS

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

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

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

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

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

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

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

8. DEFINITIONS (Continued)

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

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

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

9. WITHDRAWALS OF STORAGE GAS

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

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

9. WITHDRAWALS OF STORAGE GAS (Continued)

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

10. INJECTIONS OF WORKING GAS FOR SHIPPER'S ACCOUNT

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

11. RESERVED FOR FUTURE USE

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

12. LIMITATIONS ON INJECTIONS AND WITHDRAWALS FROM STORAGE

Shipper may Nominate gas to be injected into or withdrawn from storage for Shipper's account at any time during the year. In no event shall the balance of gas stored in Shipper's account exceed Shipper's Storage Capacity as defined under Section 6 of this Rate Schedule. Transporter will schedule available injection capacity consistent with the priority of service provisions and curtailment policy in Section 12 of the General Terms and Conditions.

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

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

Shipper may nominate to withdraw quantities in excess of Shipper's Storage Demand on a best-efforts basis; provided, however, that the total quantity withdrawn may not exceed the level of Shipper's Available Working Gas. Transporter may make such excess withdrawal, consistent with the priority of service provisions contained in Section 12 of the General Terms and Conditions.

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

14. TRANSFER OF WORKING GAS INVENTORY

Shippers that are subject to this Rate Schedule may agree to transfer their respective Jackson Prairie Working Gas Inventories to any capacity holder in the Jackson Prairie Storage facility under Rate Schedules SGS-2F, SGS-2I, and PAL. Participating Shippers must notify Transporter's Marketing Services personnel of their intent to transfer such inventory, in writing, prior to the beginning of the gas day in which such transfer will occur. Transfers of Working Gas Inventory may not result in any Shipper taking title to quantities that exceed such Shipper's contractual rights.

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

Transfers from a SGS-2F to SGS-2I, PAL contracts will be scheduled pursuant to the priority of service provisions and curtailment policy in Section 12 of the General Terms and Conditions.

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

15. EVERGREEN PROVISION

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

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

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

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

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

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

15. EVERGREEN PROVISION (Continued)

(a) The established rollover period will be:

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

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

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

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

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

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

15.3 Grandfathered Unilateral Evergreen Provision. If Shipper's Service Agreement contains a grandfathered unilateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

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

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

15. EVERGREEN PROVISION (Continued)

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

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

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

16. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, are applicable to this Rate Schedule and are hereby made a part hereof.

h) For LDC's that own and operate storage:

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

See Attachment 1 to V.7.h to this Exhibit C dated July 2018, identified as Confidential and subject to Modified Protective Order No. 10-337.

Confidential Subject to Modified Protective Order 10-337

[redacted]

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Confidential Subject to
Modified Protective Order 10-337

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Modified Protective Order 10-337

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Confidential Subject to
Modified Protective Order 10-337

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[redacted]

[redacted]

[redacted]

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

There have been no significant changes in physical or operational parameters of the storage facility since completion of the July 2017 study.

Section V.8 - Attestation as to Consistency

See IV.1.c

CERTIFICATE OF SERVICE

I hereby certify that on July 26, 2018, I have served foregoing unredacted version of the Confidential and Highly Confidential portions of NW Natural's OPUC Advice 18-11 / UG 355 Exhibit C, subject to Modified Protective Order 10-337, via US Mail in Docket UM 1286.

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DATED July 26, 2018, Portland, OR.

*/s/ Erica Lee-Pella*___________

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