SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS

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

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

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

DEFINITIONS:

1. Actual Commodity Cost: The natural gas supply costs for commodity actually paid for the month, including: renewable natural gas supply costs, Financial Transactions, renewable thermal certificates associated with renewable natural gas, transaction costs of acquiring and retiring renewable thermal certificates, registration fees for a Commission-authorized renewable thermal credit tracking system, fuel use, and distribution system lost and unaccounted for natural gas (LUFG) plus Gas Storage Facilities withdrawals, plus or minus the cost of natural gas associated with pipeline imbalances, plus propane costs, plus odorization charges, if applicable, less Net Commodity Off-System Sales Revenues for the month, plus actual Variable Transportation Costs, plus commodity-related reservation charges, plus the costs of Gas Reserves,[1] less all transportation demand charges embedded in commodity costs. (C) (C)
2. Net Commodity Off-System Sales Revenues: Revenues from the sale of natural gas to a party other than the Company's Oregon Sales Service Customers less costs associated with the sales transactions.
3. Variable Transportation Costs: Variable transportation costs, including Pipeline volumetric charges, and other variable costs related to volumes of commodity delivered to Sales Service Customers.
4. Actual Non-Commodity Cost: Actual Non-Commodity gas costs shall be equal to actual Demand Costs, less actual Capacity Release Benefits, plus or minus actual Pipeline refunds or surcharges.
5. Demand Costs: Fixed monthly Pipeline costs and other demand-related natural gas (including renewable natural gas) costs such as capacity reservation charges, plus any transportation demand charges embedded in commodity costs. (C) (C)
6. Capacity Release Benefits: This component includes revenues associated with pipeline capacity releases. The benefits to Customers, through the monthly PGA deferrals, shall be 100% of the capacity release revenues up to the full Pipeline rate, and 80% of the capacity release revenues exceeding amounts reflecting full Pipeline rates. Capacity release revenues shall be quantified on a transaction-by-transaction basis.

(continue to Sheet P-2)

[1] Per the terms of the Stipulation in Docket UM 1520/UG 204.

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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: October 31, 2026: For Residential Schedule 2		(C)
Effective: November 1, 2026: For all other applicable rate schedules		(C)
Estimated Annual Sales WACOG per therm (w/ revenue sensitive):	**$0.36778**	(R)
Estimated Annual Sales WACOG per therm (w/o revenue sensitive):	**$0.35709**	(R)

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

Effective: October 31, 2026: For Residential Schedule 2		(C)
Effective: November 1, 2026: For all other applicable rate schedules		(C)
Estimated Winter Sales WACOG per therm (w/ revenue sensitive):	**$0.40635**	(R)
Estimated Winter Sales WACOG per therm (w/o revenue sensitive):	**$0.39454**	(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: October 31, 2026: For Residential Schedule 2		(C)
Effective: November 1, 2026: For all other applicable rate schedules		(C)
Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive):	**$0.11482**	(I)
Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive):	**$0.11148**	(I)

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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, 2026: For all other applicable rate schedules		(C)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive):	**$0.01366**	(I)
Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive):	**$0.01326**	(I)

12. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.

Effective: November 1, 2026: For all other applicable rate schedules		(C)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive):	**$1.69**	(I)
Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive):	**$1.64**	(I)

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

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

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

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

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

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

(continue to Sheet P-4)

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SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

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

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

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

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

23. Gas Reserves: The volumes of natural gas actually received by the Company through its acquisition of gas reserves through joint venture agreements as authorized by the Commission.[1] For purposes of annual rate filings, the cost of Gas Reserves includes all carrying costs on the rate base investment, amortization, operating expenses, gathering and processing costs, and ad Valorem and severance taxes.[2] The cost of Gas Reserves will be included in Actual Commodity Costs.

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

(continue to Sheet P-5)

[1] See Commission order 11-140 in UM 1520/UG 204.
[2] Except for the seven post-carry wells, which will be priced at $4.725 per dekatherm, pursuant to a Stipulation adopted by the Commission in Order 15-297 in Docket UM 1717.

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, 2026 through October 31, 2027 are: (C)

November	2026	$8,882,961	(C)
December	2026	$12,141,068	
January	2027	$12,197,682	
February	2027	$10,472,315	
March	2027	$9,148,400	
April	2027	$6,554,619	
May	2027	$4,086,916	
June	2027	$2,899,030	
July	2027	$2,266,196	
August	2027	$2,249,971	
September	2027	$2,519,747	
October	2027	$5,003,558	
ANNUAL TOTAL		$78,422,463	(C)

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost, less the cost of renewable natural gas and renewable thermal certificates (including transaction costs and registration fees for a Commission-authorized renewable thermal credit tracking system), 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, storage withdrawals priced at the inventory rate used in the PGA filing and all costs associated with renewable natural gas and renewable thermal certificates. 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.

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PURCHASED GAS COST ADJUSTMENTS
(continued)

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

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

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

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

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