Oregon
Tina Kotek, Governor

**Public Utility Commission**
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October 26, 2023

BY EMAIL
Northwest Natural Gas Company
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RE: Advice No. 23-19A

At the public meeting on October 26, 2023, the Commission adopted Staff's recommendation in this matter docketed as UG 486. The Staff Report and a receipted copy of the sheets in your advice filing are attached.

Nolan Moser
Chief Administrative Law Judge
Public Utility Commission of Oregon
(503) 378-3098

**ITEM NO. RA2**

**PUBLIC UTILITY COMMISSION OF OREGON**
**STAFF REPORT**
**SPECIAL PUBLIC MEETING DATE: October 26, 2023**

**REGULAR** __X__ **CONSENT** ____ **EFFECTIVE DATE** __**November 1, 2023**__

**DATE:** October 17, 2023

**TO:** Public Utility Commission

**FROM:** Anna Kim

**THROUGH:** Bryan Conway and Marc Hellman

**SUBJECT:** NORTHWEST NATURAL:
(Docket No. UG 486/Advice No. 23-19A)
Reflects changes in the cost of purchased gas, amortization of deferred gas costs, and the combined changes associated with the annual Purchased Gas Adjustment (PGA) filing.

## STAFF RECOMMENDATION:

Staff recommends that Northwest Natural Gas Company's (NW Natural, NWN, or Company) Advice No. 23-19A, which includes the Company's 2023 Purchased Gas Adjustment (PGA) tariff sheet updates, be approved for service rendered on and after November 1, 2023.

## DISCUSSION:

### Issue

Whether the Public Utility Commission of Oregon (Commission) should approve NW Natural's 2023 annual PGA as reflected in its Advice No. 23-19A.

### Applicable Rule or Law

ORS 757.205 requires public utilities to file all rates, rules, and charges with the Commission. ORS 757.210 provides that the Commission may approve tariff changes if they are fair, just, and reasonable. Filings that make any change in rates, tolls, charges, rules, or regulations must be filed with the Commission at least 30 days before the effective date of the changes.

ORS 757.259(5) states that unless subject to an automatic adjustment clause, amounts deferred under ORS 757.259 shall be allowed in rates only to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates, and upon review of the utility's earnings at the time of application, to amortize the deferral. The Commission may require that amortization of deferred amounts be subject to refund. The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility.

ORS 757.259(6) states that the overall average rate impact of the amortizations authorized under this section in any one year may not exceed three percent of the utility's gross revenues for the preceding calendar year. ORS 757.259(7) allows the Commission to consider an overall average rate impact greater than that specified in subsection (6) for natural gas commodity and pipeline transportation costs incurred by a natural gas utility, if the Commission finds that allowing a higher amortization rate is reasonable under the circumstances.

OAR 860-022-0025 requires that revised tariff filings include statements showing the change in rates, the number of customers affected and resulting change in annual revenue, and the reasons for the tariff revision.

OAR 860-022-0030 requires that tariff filings which result in increased rates include statements showing the number of customers affected, the annual revenue under existing schedules, the annual revenue under proposed schedules, the average monthly bills under existing and proposed schedules, and the reasons supporting the proposed tariff.

The PGA mechanism was originally established by Order No. 89-1046 to minimize the frequency of gas cost-related rate changes and the fluctuation of rate levels pursuant to ORS 757.259(2)(e). Since the mechanism's creation in 1989, the Commission has issued a series of orders concerning PGA filings through open-docket UM 1286.[1] Order No. 18-144 is the most recent of these orders and revises the Commission's procedures and requirements of the Natural Gas Portfolio Development Guidelines in Docket No. UM 1286 by adding language concerning review and approval of long-term hedging instruments in a local distribution company's (LDC) natural gas portfolio. No changes were made to the PGA Filing Guidelines previously established in Order No. 14-238.

[1] Order No. 08-504 established the form of the PGA Mechanism. PGA Guidelines were acknowledged by the Commission in Docket No. UM 1286, Order No. 09-248, on June 23, 2009. The Guidelines in Docket No. UM 1286 have been modified four different times since they were first acknowledged by the Commission, in Order No. 10-197, in Order No. 11-196, in Order No. 14-238, and in Order No. 18-144.

In 2019, the Oregon legislature enacted Senate Bill 98,[2] authorizing portfolio targets for large natural gas utilities for the percentage of natural gas purchased for distribution to Oregon customers that is renewable natural gas (RNG). Under ORS 757.396(2), the Commission is directed to adopt ratemaking mechanisms that allow for the recovery of prudently incurred costs that contribute to the utility meeting the voluntary statutory targets.

Effective July 17, 2020, the Commission adopted OAR 860-150-0300 addressing renewable thermal certificates (RTCs), which states in part:

1. A large natural gas utility may make a filing, consistent with the requirements of OAR 860-022-0070 and other applicable rules of the Commission, seeking to pass through prudently incurred costs associated with the purchase of RNG to meet the annual targets for a large natural gas utility established in ORS 757.396, excluding qualified investments, by means of its purchased gas adjustment mechanism. Such costs may also include the utility's cost of registration for the RTC tracking system described in OAR 860-150-0050, transaction costs for any RTCs acquired in association with the purchase of RNG from another entity, and transaction costs incurred to retire the RTCs associated with gas delivered to retail utility customers.
2. In filings, annual earnings reviews, and quarterly updates associated with the purchased gas adjustment mechanism, a large natural gas utility must clearly identify costs of purchased RNG and the costs associated with RTCs described in section (1) of this rule.

On December 16, 2021, the Department of Environmental Quality (DEQ) adopted the Oregon Climate Protection Program (CPP) rules, which set a cap on greenhouse gas emissions from transportation fuels and natural gas, and are set forth in OAR 340-271-0010 through OAR 340-271-9000.

<u>Analysis</u>

On July 31, 2023, NW Natural submitted Advice No. 23-19, which constitutes its annual PGA filing (Initial 2023 PGA Filing). On September 15, 2023, NW Natural filed a supplement to its initial filing with updated gas costs and tariff sheets, Advice No. 23-19A (Supplemental 2023 PGA Filing). In aggregate, these filings are commonly referred to as the 2023 PGA Filing. The 2023 PGA Filing is comprised of two parts: a forward-looking part for the 2023-2024 Gas Year (Projected Purchased Gas Cost) and a backward-looking part for the 2022-2023 Gas Year (True-Up).

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[2] ORS 757.390 to ORS 757.398.

The Projected Purchased Gas Cost forecasts the costs of natural gas for the upcoming gas year (i.e., November 1, 2023, to October 31, 2024) and results in the new rates set forth in Schedule P.[3] The True-Up of the 2022-2023 Gas Year trues up the costs of natural gas in the previous gas year (November 1, 2022, to October 31, 2023) by comparing the amount collected from customers in that year with the actual costs incurred by the Company in the same year.[4] Any over- or under-collection from customers in the 2022-2023 Gas Year, together with any over- or under-collection from previous years,[5] is either given back (in the case of over-collection) or surcharged (in the case of under-collection) to customers in the upcoming gas year after sharing. The True-Up of the 2022-2023 Gas Year results in the new rates set forth in Schedule 162 and Schedule 164.[6]

*Projected Purchased Gas Cost for the 2023-2024 Gas Year (Rate Schedule P)*
The Projected Purchased Gas Cost comprises two rate components: 1) the commodity component rate; and 2) the capacity or demand component rate. The rates for these components are represented in Table 1 on a $ per therm basis.

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3 Schedule P is titled "Purchased Gas Cost Adjustments."

4 The 2022-2023 Gas Year began November 1, 2022, and concludes October 31, 2023. However, per page 10 of Appendix A to Order No. 14-238 in Docket No. UM 1286 (See: http://apps.puc.state.or.us/orders/2014ords/14-238.pdf), all deferrals to be amortized into rates will be based on June deferral balances plus interest for July-October, and the deferrals that occur after June will be carried forward to the next PGA period.

5 Any over-collection or under-collection from previous years is because actual volumetric sales of natural gas will always be different from forecasted volumetric sales. Since amortizations are intended to be recovered in volumetric forecasted sales, a remaining balance will always be present.

6 Schedule 162 is titled "Temporary (Technical) Adjustments to Rates;" and Schedule 164 is titled "Purchased Gas Cost Adjustment to Rates."

**Table 1: Projected Purchased Gas Cost for 2023-2024[7]**
($/Therm or as noted otherwise)

| Item | | Current Rate 2022-23 Gas Year[8] | Proposed Rate 2023-24 Gas Year | Change |
|---|---|---|---|---|
| Commodity | (A) | $0.50676 | $0.44732 | ($0.05944) |
| Demand | (B) | $0.08571 | $0.10025 | $0.01454 |
| **Total Gas Cost** | **(C = A+B)** | **$0.59247** | **$0.54757** | ($0.04490) |

The commodity component of the Weighted Average Cost of Gas (WACOG) proposed for the 2023-2024 Gas Year is decreasing by 0.05944 per therm, a decrease of 11.7 percent from the previous PGA gas year, as shown in Table 1. Last year, wholesale natural gas prices were predicted to increase significantly. At this point, gas prices are predicted to decline from the last year's prediction.

In 2022, several factors led to increased natural gas prices and elevated price volatility:

- Global market disruption after Russia invaded Ukraine, and Western Countries responded with economic sanctions – Liquefied Natural Gas (LNG) exports from the U.S to Europe surged.
- Surging inflation associated with a healthy job market increased demand for production inputs;
- Storage inventories fell below the five-year average level in 2022 and failed to recover during the 2022 injection season.

Over the course of the last 12 months, the wholesale market price of gas has declined overall.

- Natural gas production increased in 2023, leading to lower prices now than forecast and going forward.
- Prices along the west coast remain relatively high in contrast to gas purchased at AECO.
- The volume of natural gas exports remains high, which may increase gas prices.
- The amount of natural gas in storage is high nationally and available storage space will increase next year with the expansion of Aliso Canyon.
- The recent conflict between Hamas and Israel may also impact the market although it is unclear at the time what effect the conflict will have.

7 Addressed in UG 462 Compliance Filing for Order No. 23-367, workpaper "NWN 2023-24 PGA Rate Development and Dakota City CoS Combined"

8 Please see UG 435 Compliance Filing for Order No. 22-388.

The proposed demand component reflects an increase of approximately $0.01454 per therm, an increase of 16.96 percent from the previous PGA gas year.

*Renewable Natural Gas (RNG), and Oregon DEQ Climate Protection Plan (CPP)*
NWN's filing includes RNG commodity costs of $0, with a net RNG RTC commodity cost in the 2023-24 PGA of $5,359,122 in WACOG, $1,999,311 in Schedule 171 – Transport, and $355,831 in Schedule 171 – Special Contract for a total impact of $7,714,263 for the Company's 2023 PGA.[9] In rates, this amount is offset by the differential in the net cost of RTCs associated with the purchase and sales of RTCs in the 2022-2023 PGA year and what was collected in rates.

*Current Impact of Investment in Hydrogen (H)*
NW Natural reports no immediate impact of H investment herein.

*Sharing Election*
NW Natural again elects 90/10 sharing.[10]

*Filing and Portfolio Guidelines*
NW Natural's 2023 PGA filing meets the PGA Filing Guidelines and the Natural Gas Portfolio Guidelines. NW Natural has demonstrated its adherence to these Guidelines with regard to natural gas supplies and financial hedges. Staff's conclusions are supported by the Company's comprehensive work papers and by review and discussion as part of the quarterly PGA meetings.

Staff reviewed NW Natural's forecasted commodity and demand costs to determine whether the Company complied with the Commission's Natural Gas Portfolio Development Guidelines (Portfolio Guidelines). Accepted "best practices" for the purchase of natural gas supply by a local distribution company (LDC) result in a portfolio that balances the objectives of reliability, cost control, and managing price volatility using diversity, flexibility, and balance in a LDC's gas portfolio. The Portfolio Guidelines implement these "best practices" for Oregon LDCs. The Portfolio Guidelines also require each gas utility to include certain information related to its gas supply portfolio with its annual PGA filing. This information assists the Commission in determining the prudence of the LDC's costs.

NW Natural's portfolio preparation and planning process meets the standards in Section III of the Portfolio Guidelines related to portfolio planning, as do NW Natural's physical gas contracts and financial transactions relating to natural gas pricing. NW Natural has

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9 Addressed in work paper: NWN 2023-2024 PGA RTC Split Model for Sales vs Transport vs SC_September.
10 Addressed in Schedule P, P-5, Section 3.

also demonstrated its adherence to the Portfolio Guidelines with regard to natural gas supplies and financial hedges. In addition, the Company has provided all the information called for in Section IV (Information and Work Papers), and Section V (Supporting Data and Analysis) of the Portfolio Guidelines.

*True-Up of the 2022-2023 Gas Year (Schedule 162)*

**Table 2: True-Up of the 2022-2023 Gas Year [11]**
($/Therm or as noted otherwise)

| Item | | Current Rate[12] | Proposed Rate | Change |
|---|---|---|---|---|
| Commodity Amortization[13] | (D) | $0.05590 | $0.00407 | ($0.05183) |
| Demand Amortization[14] | (E) | $0.00249 | ($0.00379) | ($0.00628) |
| **Total Amortization** | **(F=D+E)** | **$0.05839** | **$0.00028** | ($0.05811) |

Commodity amortization costs are forecasted to decrease with a lower surcharge from the previous year and will decrease the gas commodity amortization price to $0.00407 per therm after accounting for the commodity cost variance sharing between the Company and customers.

For demand amortization, there is currently a surcharge of $0.00249 per therm to customers (except Interruptible customers) which resulted in a slight over-collection. In order to return over-collections from the prior PGA gas year, the Company proposes a rebate of $0.00379 per therm.

*Three Percent Test*
Pursuant to ORS 757.259(6), ORS 757.259(7), and OAR 860-027-0300, the annual average rate impact of the amortizations authorized under the statues may not exceed three percent of the natural gas utility's gross revenues for the preceding calendar year unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances.

11 Addressed in UG 462 Compliance Filing for Order No. 23-367, workpaper "NWN 2023-24 PGA Rate Development and Dakota City CoS Combined"
12 Please see UG 435 Compliance Filing for Order No. 22-388.
13 These figures are for Weighted Average Cost of Gas (WACOG) Deferral only.
14 These figures are for Firm Demand Deferral only.

As shown on Table 3 of this memo, the resulting annual average rate impact from the PGA amortization and 17 other filings[15] on overall rates is a 12.5 percent decrease when compared to the Company's 2022 total gross revenues, which is below the three percent amortization limitation specified in ORS 757.259(6).[16]

The percentage changes in Table 3 include the change in revenues related to the gas commodity portion of the Company's gross revenues for the 2023 PGA gas year based on projected customer usage and differs from the three percent calculation.

**Table 3: Overall Commodity and Related Schedule Revenue and Rate Impact**
($ or as noted otherwise)[17]

| Schedule | Description | Total $ Revenues at Current Rates[18] | Revenue $ Increase / (Decrease)[19] | Change (%)[20] |
|---|---|---|---|---|
| **2** | Residential Sales | $292,528,263 | $260,800,010 | -10.85% |
| **3C** | Small Commercial Firm Sales | $114,287,592 | $96,343,578 | -15.70% |
| **3I** | Small Industrial Firm Sales | $3,660,805 | $3,254,400 | -11.10% |
| **27** | Residential Heating Dry Out | $530,731 | $467,505 | -11.91% |
| **31CFS** | Mid-size Commercial Firm Sales | $13,998,268 | $12,271,039 | -12.34% |
| **31CFT** | Commercial Firm Transportation | $35,783 | $61,222 | 71.09% |
| **31IFS** | Mid-size Industrial Firm Sales | $8,823,356 | $7,770,758 | -11.93% |
| **31IFT** | Industrial Firm Transportation | $6,030 | $9,453 | 56.77% |
| **32CFS** | Large Commercial Firm Sales | $31,906,395 | $28,074,869 | -12.01% |

[15] UG 472/Advice No. 23-05, Intervenor Funding, Schedule 172; Docket No. UG 473/Advice No. 23-06, Oregon Regulatory Fee Schedule 181; UG 474/Advice No. 23-07A, Environmental Costs, Schedule 183; UG 475/Advice No. 23-08, Industrial Demand Side Management (DSM), Schedule 188; UG 476/Advice No. 23-09, Decoupling, Schedule 190; UG 477/Advice No. 23-10, Weather Adjusted Rate Mechanism (WARM), Schedule 195, UG 478/Advice No. 23-11B Oregon Corporate Activity Tax (CAT); UG 479/Advice No. 23-12, Net Curtailment and Entitlement; UG 480/Advice No. 23-13, Residual Account Balances, Geographically Targeted Energy Efficiency, and Gain on Sale of Property, Schedule 178; UG 481/Advice No. 23-14, Residential Rate Mitigation Schedule 166; UG 482/Advice No. 23-15A, RNG Transport allocation, Schedule 171; UG 483/Advice No. 23-16A, COVID-19 Schedule 173; UG 484/Advice No. 23-17B, Transportation Security Administration (TSA) Compliance; UG 487/Advice No. 23-20A, Renewable Natural Gas Automatic Adjustment Clause, Schedule 198; UG 488/Advice No. 23-21, Excess Deferred Income Taxes, Schedule 196; UG 489/Advice No. 23-22, Horizon 1 Start-Up Costs--Schedule 175, Environmental Cost Recovery--Schedule 182, and Pension Balancing Account--Schedule 197.

[16] Addressed in work paper: Rate Development, Tab: Attach C.

[17] Addressed in UG 462 Compliance Filing for Order No. 23-367, workpaper "NWN 2023-24 PGA Rate Development and Dakota City CoS Combined"

[18] See Attachment A of this public meeting memo, column "Total Revenue at Current."

[19] *Id*, see column "Total Change in Revenue."

[20] Here, the percentage change denotes the percentage change in revenues by Rate Schedule.

| Schedule | Description | Total $ Revenues at Current Rates[18] | Revenue $ Increase / (Decrease)[19] | Change (%)[20] |
|---|---|---|---|---|
| **32IFS** | Large Industrial Firm Sales | $12,984,396 | $11,316,058 | -12.85% |
| **32CFT** | Large Commercial Firm Transportation | $50,050 | $46,743 | -6.61% |
| **32IFT** | Large Industrial Firm Transportation | $705,389 | $511,625 | -27.47% |
| **32CIS** | Commercial Interruptible Sales | $15,508,972 | $13,082,237 | -15.65% |
| **32IIS** | Industrial Interruptible Sales | $21,188,642 | $17,834,074 | -15.83% |
| **32CIT** | Large Comm. Interruptible Transport | $53,358 | $36,033 | -32.47% |
| **32IIT** | Large Indus Interruptible Transport | $1,310,177 | $781,624 | -40.34% |
| **33** | High Volume Non-Residential | $0 | $0 | 0.00% |
| **SC** | Special Contracts | $0 | $219,412 | 0.00% |
| **Total** | | **$517,578,208** | **$452,880,640** | **-12.50%** |

Note that Table 3 addresses the aggregate impact of the PGA and associated dockets, while Table 4 addresses only the Company's 2023 PGA.

**Table 4: PGA ONLY Revenue and Bill Impact**
($ or as noted otherwise)

| Schedule | Description | Total $ Revenues at Current Rates[21] | Revenue $ Increase / (Decrease)[22] | Change (%)[23] |
|---|---|---|---|---|
| **2** | Residential Sales | $251,954,574 | ($19,094,233) | -7.58% |
| **3C** | Small Commercial Firm Sales | $107,073,119 | ($8,114,475) | -7.58% |
| **3I** | Small Industrial Firm Sales | $3,106,086 | ($235,393) | -7.58% |
| **27** | Residential Heating Dry Out | $468,185 | ($35,481) | -7.58% |
| **31CFS** | Mid-size Commercial Firm Sales | $13,075,434 | ($990,914) | -7.58% |
| **31CFT** | Commercial Firm Transportation | N/A | N/A | N/A |
| **31IFS** | Mid-size Industrial Firm Sales | $7,514,958 | ($569,517) | -7.58% |
| **31IFT** | Industrial Firm Transportation | N/A | N/A | N/A |
| **32CFS** | Large Commercial Firm Sales | $27,189,599 | ($2,060,548) | -7.58% |
| **32IFS** | Large Industrial Firm Sales | $11,107,318 | ($841,762) | -7.58% |
| **32CFT** | Large Commercial Firm Transportation | N/A | N/A | N/A |

21 See Attachment A of this public meeting memo, column "Total Revenue at Current."
22 Id, see column "Total Change in Revenue."
23 Here, the percentage change denotes the percentage change in revenues by Rate Schedule.

| Schedule | Description | Total $ Revenues at Current Rates[21] | Revenue $ Increase / (Decrease)[22] | Change (%)[23] |
|---|---|---|---|---|
| **32IFT** | Large Industrial Firm Transportation | N/A | N/A | N/A |
| **32CIS** | Commercial Interruptible Sales | $13,030,415 | ($1,454,629) | -11.16% |
| **32IIS** | Industrial Interruptible Sales | $17,825,034 | ($1,989,869) | -11.16% |
| **32CIT** | Large Comm. Interruptible Transport | N/A | N/A | N/A |
| **32IIT** | Large Indus Interruptible Transport | N/A | N/A | N/A |
| **33** | High Volume Non-Residential | N/A | N/A | N/A |
| **SC** | Special Contracts | N/A | N/A | N/A |
| **Overall Commodity Only** | | **$452,344,722** | **($35,386,822)** | **-7.82%** |

Table 4 shows the percentage rate changes when only considering the commodity costs. The overall decrease for these costs is 7.82 percent.

Table 5 below shows residential bill impacts assuming the PGA and other rate changes including the effect of adopting the proposed mitigation rate credit that is addressed in agenda item RA5.

**Table 5**: 2023-2024 **PGA**
Proposed Rate & Bill Increases
Residential Bill Impacts

| | Residential Bill Impacts | | | | | |
|---|---|---|---|---|---|---|
| **Rate Schedule** | **Average Therms** | **Customer Charge $** | **Current Monthly Bill $** | **Proposed Monthly Bill $** | **Change Monthly Bill $** | **% Change Monthly Bill** |
| **January** | | | | | | |
| **2R** | 107 | $8.00 | $161.86 | $146.69 | ($15.17) | -9.37% |
| **Annual / Monthly** | | | | | | |
| **2R** | 56 | $8.00 | $88.46 | $80.53 | ($7.93) | -8.97% |

*Dakota City*
Schedule 198 is Northwest Natural's Renewable Natural Gas Automatic Adjustment Clause, which was adopted in Order No. 22-388. As per that order, values in Schedule 198 may only be updated on November 1 of each year. This year, Schedule 198 is being used to update values of the existing Lexington RNG project in UG 487 and integrate costs of the new Dakota City RNG project in UG 462. In UG 462, Northwest Natural proposes to recover $2.1 million, for the new Dakota City RNG project. In UG 487, Northwest Natural proposes to recover $2.7 million, which includes a forecasted revenue requirement, true-up deferral from last year's forecast and a

sharing deferral associated with the Lexington RNG project. In total, these two projects are expected to increase Oregon revenue by approximately $4.8 million over base rates and result in a recovery of $0.00435 per therm through Schedule 198 for all customer classes and schedules.

*Credits from NW Pipeline*
On August 18, 2017, the Federal Energy Regulatory Commission (FERC) approved a Northwest Pipeline (NW Pipeline) Stipulation and Settlement Agreement in Docket No. RP17-346-000. Section 12.4 of the 2017 Settlement required NW Pipeline to file a Natural Gas Act ("NGA") Section 4 general rate case for rates to become effective not later than January 1, 2023, unless NW Pipeline entered a pre-filing settlement effectively satisfying the NGA Section 4 general rate case filing requirement. From September 2021 through June 2022 NW Pipeline worked with their shippers to resolve issues to avoid filing a full Section 4 general rate case.

On August 26, 2022, Northwest Pipelines filed a stipulation and settlement agreement. As part of this settlement, NW Pipeline would issue credits to shippers of record (2018-2022) to refund monies due to a reduction in the federal corporate income tax rate per the Tax cuts and Jobs Act signed into law on December 22, 2017. During last year's PGA, the stipulation was known but did not get approved until after the PGA was finalized. FERC issued the approval on November 15, 2022. NW Natural had incorporated the estimated benefit of this tax rate reduction effective January 2023 in the last PGA filing.

*Rate Mitigation*
NW Natural implemented the temporary bill credit program for residential customers served under Schedule 2 for the period November 1, 2022, through March 14, 2023, to mitigate the combined bill impact from the rate changes associated with the purchased gas adjustment (PGA) and base rate increases from UG 435.[24] NW Natural deferred a portion of the November 1 rate increase during the winter heating season through these credits. The deferred bill credit monies were amortized from March 15, 2023, through October 31, 2023.[25]

Primarily due to forecasting error, the balancing account for this program was not entirely drawn down and a balance of roughly $6 million remains. NW Natural is requesting to amortize these funds over the 2023-2024 PGA year. This change would replace the current Schedule 166 rate of $0.10137 per therm with a rate of $0.01427 per therm.

[24] The Company's temporary winter bill credit was docketed as UG 459 and approved in Commission Order No. 22-425.
[25] The rate change was approved in Docket No. ADV 1488.

<u>Conclusion</u>

NW Natural's 2023 PGA Filing and other related advice filings reflect a revenue decrease of $64,697,569 or approximately -12.5 percent, effective November 1, 2023, due to gas costs (Purchased Gas Cost Adjustment Provision; Schedule P) and amortization of previous deferrals. This decrease follows a massive increase of 23.7 percent in the last PGA.

The number of customers affected by the changes proposed in this filing is 636,785 residential customers, 61,896 commercial customers, and 668 industrial customers

With all related changes reflective of Table 3, effective November 1, 2023, the monthly bill of a residential customer using an average of 56 therms per month will decrease by $7.93, or 9 percent, from $88.46 to $80.53.

The Company has reviewed this memo and agrees with its contents.

**PROPOSED COMMISSION MOTION:**

Approve NW Natural's Advice No. 23-19A, which includes the Company's 2023 annual PGA tariff sheet updates, for service rendered on and after November 1, 2023.

**Attachment A**: NW Natural Gas 2023 **PGA and Related Dockets**
Incremental Revenue Change by Customer Rate Schedule – (Red) indicates negative numbers.

| Customer Rate Schedule | Description | Gas Costs and Adjustment Schedule Revenues $ at Current Rates | Gas Costs and Adjustment Revenues $ at Proposed Rates | Incremental Change in $ Revenue | % Change by Rate Schedule | % Contributio n to Total Incremental Change |
|---|---|---|---|---|---|---|
| 2 | Residential Sales | $ 292,528,263 | $ 260,800,010 | ($31,728,253) | -10.8% | 49.0% |
| 3C | Small Commercial Firm Sales | $ 114,287,592 | $ 96,343,578 | ($17,944,014) | -15.7% | 27.7% |
| 3I | Small Industrial Firm Sales | $ 3,660,805 | $ 3,254,400 | ($406,405) | -11.1% | 0.6% |
| 27 | Residential Heating Dry Out | $ 530,731 | $ 467,505 | ($63,226) | -11.9% | 0.1% |
| 31CFS | Mid-size Commercial Firm Sales | $ 13,998,268 | $ 12,271,039 | ($1,727,229) | -12.3% | 2.7% |
| 31CFT | Commercial Firm Transportation | $ 35,783 | $ 61,222 | $25,439 | 71.1% | 0.0% |
| 31IFS | Mid-size Industrial Firm Sales | $ 8,823,356 | $ 7,770,758 | ($1,052,598) | -11.9% | 1.6% |
| 31IFT | Industrial Firm Transportation | $ 6,030 | $ 9,453 | $3,423 | 56.8% | 0.0% |
| 32CFS | Large Commercial Firm Sales | $ 31,906,395 | $ 28,074,869 | ($3,831,527) | -12.0% | 5.9% |
| 32IFS | Large Industrial Firm Sales | $ 12,984,396 | $ 11,316,058 | ($1,668,338) | -12.8% | 2.6% |
| 32CFT | Large Comm Firm Transportation | $ 50,050 | $ 46,743 | ($3,308) | -6.6% | 0.0% |
| 32IFT | Large Indus Firm Transportation | $ 705,389 | $ 511,625 | ($193,765) | -27.5% | 0.3% |
| 32CIS | Commercial Interruptible Sales | $ 15,508,972 | $ 13,082,237 | ($2,426,734) | -15.6% | 3.8% |
| 32IIS | Industrial Interruptible Sales | $ 21,188,642 | $ 17,834,074 | ($3,354,568) | -15.8% | 5.2% |
| 32CIT | Large Comm Interruptible Transportation | $ 53,358 | $ 36,033 | ($17,326) | -32.5% | 0.0% |
| 32IIT | Large Indus Interruptible Transportation | $ 1,310,177 | $ 781,624 | ($528,553) | -40.3% | 0.8% |
| 33 | High Volume Non-Residential | $ - | $ - | $0 | N/A | 0.0% |

| Customer Rate Schedule | Description | Gas Costs and Adjustment Schedule Revenues $ at Current Rates | Gas Costs and Adjustment Revenues $ at Proposed Rates | Incremental Change in $ Revenue | % Change by Rate Schedule | % Contribution to Total Incremental Change |
|---|---|---|---|---|---|---|
| SC | Special Contracts | $ - | $ 219,412 | $219,412 | N/A | -0.3% |
| | **Overall** | **$ 517,578,208** | **$ 452,880,640** | **($64,697,569)** | **-13%** | **100%** |

**Attachment B**: NW Natural Gas 2023 **PGA and Related Dockets**
Incremental Revenue Change by Adjustment Schedule – (Red) indicates negative numbers.

| Adjustment Schedule | Description | Gas Cost & Adjustment Schedule Total Revenue at Current Rates | Gas Cost & Adjustment Schedule Total Revenue at Proposed Rates | Total Incremental Change in Revenue | % Change by Rate Schedule | % Contribution to Total Incremental Change |
|---|---|---|---|---|---|---|
| P | PGA Forecast | $452,344,722 | $416,957,900 | ($35,386,822) | -8% | 55% |
| 162 | PGA Gas Cost Differences | $44,898,396 | $415,259 | ($44,483,136) | -99% | 69% |
| 172 | Intervenor Funding | $179,929 | $486,734 | $306,805 | 171% | 0% |
| 180 | TSA Security Directive (O&M) | $2,219,024 | $1,679,831 | ($539,193) | -24% | 1% |
| 181 | Oregon Regulatory Fee | $616,773 | $385,515 | ($231,258) | -37% | 0% |
| 183 | SRRM Adjustment | $7,251,644 | $9,699,797 | $2,448,153 | 34% | -4% |
| 188 | Industrial DSM | $5,395,636 | $6,621,853 | $1,226,216 | 23% | -2% |
| 190 | Decoupling | ($17,503,873) | ($6,153,603) | $11,350,270 | 65% | -18% |
| 195 | WARM | $842,201 | ($2,798,863) | ($3,641,064) | -432% | 6% |
| 196 | Gas Reserves EDIT | ($3,824,206) | $0 | $3,824,206 | -100% | -6% |
| 177 | CAT Deferral & Incremental | $569,981 | $518,776 | ($51,205) | -9% | 0% |
| 168 | Curtailment and Entitlement Revenue | ($153,958) | ($852,223) | ($698,265) | 454% | 1% |
| 178 | Regulatory Rate Adjustment | $63,526 | $31,763 | ($31,763) | -50% | 0% |
| 166 | Residential Rate Mitigation | $14,496,664 | $6,068,479 | ($8,428,185) | -58% | 13% |
| 171 | RNG Transport Allocation | $1,731,777 | ($422,876) | ($2,154,653) | -124% | 3% |
| 173 | COVID Years 2 & 3 | $5,993,947 | $14,501,958 | $8,508,011 | 142% | -13% |
| 189 | TSA Security Directive (Cost of Service) | $708,785 | $915,291 | $206,506 | 29% | 0% |
| 198 | RNG Adj Mechanism | $1,747,239 | $4,825,050 | $3,077,810 | 176% | -5% |
| | **Overall** | **$517,578,208** | **$452,880,640** | **($64,697,569)** | **-13%** | **100%** |

**Attachment C**: NW Natural Gas 2023-2024 **PGA – Three Percent Test**
(Red) indicates negative numbers.

| | **Surcharge $** | **Credit $** |
|---|---|---|
| **Non-Gas Amortizations** | | |
| WARM | | ($2,796,963) |
| Oregon Regulatory Fee | $386,351 | |
| CAT Deferral and Incremental | $517,813 | |
| Net Curtailment and Entitlment | | ($853,066) |
| RNG Transport Allocation | | ($423,484) |
| COVID | $14,503,684 | |
| Rate Mitigation | $6,069,525 | |
| TSA Cost of Service | $912,778 | |
| TSA O&M | $1,680,746 | |
| RNG Special Contracts Allocation | | $96,568 |
| Residual Balances | $27,325 | |
| Total | **$24,098,222** | **($3,976,945)** |

| **Summary** | **$** |
|---|---|
| Net Proposed Amortizations (subject to 3% test) | $20,121,277 |
| Utility Gross Revenues (2021) | $849,278,042 |
| 3% of Utility Gross Revenues | $25,478,341 |
| **Allowed Amortization** | $20,121,277 |
| **Allowed Amortization as % of Gross Revenue** | **2.37%** |

**Attachment D**: 2023-2024 **PGA**
Proposed Rate & Bill Increases by Class of Service - (Red) indicates negative numbers.

| Class of Service | Rate Schedule | Rate Impacts[26] Current Rate $ per Therm | Proposed Rate $ per Therm | Change Rate $ per Therm | % Change Rate per Therm |
|---|---|---|---|---|---|
| **Residential** | | | | | |
| NW Natural | 2R | $1.43686 | $1.29519 | ($0.14167) | -9.86% |
| **Commercial** | | | | | |
| NW Natural | 3C | $1.18666 | $1.08753 | ($0.09913) | -8.35% |
| **Industrial** | | | | | |
| NW Natural | 311SF | $0.82490 | $0.72744 | ($0.09745) | -11.81% |
| **Interruptible** | | | | | |
| NW Natural | 32ISI | $0.66514 | $0.56614 | ($0.09900) | -14.88% |

[26] The residential rates illustrated above do not include pass-through charges included on customer bills that utilities are required to collect and distribute to the appropriate third parties, such as for franchise fees or the Public Purposes Charge.

Proposed Rate & Bill Increases
NW Natural Other Schedules Bill Impacts

| | | Other Schedule Bill Impacts | | | | | |
|---|---|---|---|---|---|---|---|
| **NW Natural** | **Rate Schedule** | **Average Therms /Month** | **Customer Charge $** | **Current Monthly Bill $** | **Proposed Monthly Bill $** | **Change Monthly Bill $** | **% Change Monthly Bill** |
| **January** | | | | | | | |
| Residential | 2R | 107 | $8.00 | $161.86 | $146.69 | ($15.17) | -9.4% |
| Commercial | 3C | 598 | $15.00 | $725.20 | $665.88 | ($59.33) | -8.2% |
| Industrial | 31ISF | 5,776 | $325.00 | $5,089.59 | $4,526.71 | ($562.89) | -11.1% |
| Interruptible | 32ISI | 42,886 | $675.00 | $29,200.16 | $24,954.50 | ($4,245.66) | -14.5% |
| **NW Natural** | **Rate Schedule** | **Annual Therms /Month** | **Customer Charge $** | **Current Monthly Bill $** | **Proposed Monthly Bill $** | **Change Monthly Bill $** | **% Change Monthly Bill** |
| **Annual / Monthly** | | | | | | | |
| Residential | 2R | 56 | $8.00 | $88.46 | $80.53 | ($7.93) | -9.0% |
| Commercial | 3C | 255 | $15.00 | $317.60 | $292.32 | ($25.28) | -8.0% |
| Industrial | 31ISF | 5,776 | $325.00 | $5,089.59 | $4,526.71 | ($562.89) | -11.1% |
| Interruptible | 32ISI | 42,886 | $675.00 | $29,200.16 | $24,954.50 | ($4,245.66) | -14.5% |

## 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, 2023: | | (C) |
| Estimated Annual Sales WACOG per therm (w/ revenue sensitive): | **$0.44732** | (R) |
| Estimated Annual Sales WACOG per therm (w/o revenue sensitive): | **$0.43471** | (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, 2023: | | (C) |
| Estimated Winter Sales WACOG per therm (w/ revenue sensitive): | **$0.49005** | (R) |
| Estimated Winter Sales WACOG per therm (w/o revenue sensitive): | **$0.47624** | (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, 2023: | | (C) |
| Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): | **$0.10025** | (I) |
| Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive): | **$0.09742** | (I) |

(continue to Sheet P-3)



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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, 2023: | | (C) |
| Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive): | **$0.01193** | (I) |
| Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive): | **$0.01159** | (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, 2023: | | (C) |
| Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive): | **$1.48** | (I) |
| Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive): | **$1.44** | (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)

**<u>CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued)</u>:**

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, 2023 through October 31, 2024 are: (C)

(C)

| | |
|---|---|
| November 2023 | $7,751,832 |
| December 2023 | $10,652,646 |
| January 2024 | $10,778,328 |
| February 2024 | $9,705,044 |
| March 2024 | $8,109,098 |
| April 2024 | $6,082,790 |
| May 2024 | $3,774,042 |
| June 2024 | $2,661,181 |
| July 2024 | $2,171,488 |
| August 2024 | $1,852,251 |
| September 2024 | $2,128,570 |
| October 2024 | $4,331,160 |
| ANNUAL TOTAL | $69,998,430 |

(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.

(continue to Sheet P-6)



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## SCHEDULE 150
## MONTHLY INCREMENTAL COST OF GAS
(continued)

B. Compare the AECO, Sumas and Rockies city gate prices derived above and calculate the average of the highest two of those three prices.
C. The city gate price calculated in step B is then adjusted for the Company's revenue-sensitive effects, is converted from million Btus to Therms, and the Oregon Climate Protection Program Compliance Cost is added to the result to derive the Monthly Incremental Cost of Gas.
D. The Oregon Climate Protection Program Compliance Cost is as follows:

**Effective November 1, 2023: $0.00714 per therm** (C) (R)

E. The Company will post the Monthly Incremental Cost of Gas on its website as soon as it is available each month.

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



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## 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, 2023 (C)

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 | | $0.00407 | ($0.00379) | **$0.00028** | (R) |
| 3 CSF | | $0.00407 | ($0.00379) | **$0.00028** | |
| 3 ISF | | $0.00407 | ($0.00379) | **$0.00028** | |
| 27 | | $0.00407 | ($0.00379) | **$0.00028** | |
| 31 CSF | Block 1 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 2 | $0.00407 | ($0.00379) | **$0.00028** | (R) |
| 31 CTF | Block 1 | N/A | N/A | **$0.00000** | |
| | Block 2 | N/A | N/A | **$0.00000** | |
| 31 ISF | Block 1 | $0.00407 | ($0.00379) | **$0.00028** | (R) |
| | Block 2 | $0.00407 | ($0.00379) | **$0.00028** | (R) |
| 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, 2023 (C)

**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 | $0.00407 | ($0.00379) | **$0.00028** | (R) |
| | Block 2 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 3 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 4 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 5 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 6 | $0.00407 | ($0.00379) | **$0.00028** | |
| 32 ISF | Block 1 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 2 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 3 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 4 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 5 | $0.00407 | ($0.00379) | **$0.00028** | |
| | Block 6 | $0.00407 | ($0.00379) | **$0.00028** | (R) |
| 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 | $0.00407 | ($0.00045) | **$0.00362** | (R) |
| | Block 2 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 3 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 4 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 5 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 6 | $0.00407 | ($0.00045) | **$0.00362** | |
| 32 ISI | Block 1 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 2 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 3 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 4 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 5 | $0.00407 | ($0.00045) | **$0.00362** | |
| | Block 6 | $0.00407 | ($0.00045) | **$0.00362** | (R) |
| 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/TF | | N/A | N/A | **$0.00000** | |

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## 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, 2023 (C)

| | | |
|---|---|---|
| Annual Sales WACOG [1] | $0.44732 | (R) |
| Winter Sales WACOG [2] | $0.49005 | (R) |
| Firm Sales Service Pipeline Capacity Component [3] | $0.10025 | (I) |
| Firm Sales Service Pipeline Capacity Component [4] | $1.48 | |
| Interruptible Sales Service Pipeline Capacity Component [5] | $0.01193 | (I) |

[1] Applies to all Sales Service Rate Schedules (per therm) except where Winter Sales WACOG or Monthly Incremental Cost of Gas applies.
[2] Applies to Sales Customers that request Winter Sales WACOG at the September 15 Annual Service Election.
[3] Applies to Rate Schedules 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.

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