INTERMOUNTAIN®
GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

August 14, 2023

Ms. Jan Noriyuki
Commission Secretary
Idaho Public Utilities Commission
P.O. Box 83720
Boise, ID 83720-0074

RE: Case No. INT-G-23-04

Dear Ms. Noriyuki:

Attached for consideration by this Commission is an electronic submission of Intermountain Gas Company's Purchased Gas Cost Adjustment Filing with prices proposed to be effective on October 1, 2023.

If you should have any questions regarding the attached, please don't hesitate to contact me at (208) 377-6015.

Sincerely,

Lori A. Blattner
Director, Regulatory Affairs
Intermountain Gas Company

Enclosure

cc: Mark Chiles
Preston Carter

INTERMOUNTAIN GAS COMPANY

CASE NO. INT-G-23-04

APPLICATION,

EXHIBITS,

AND

WORKPAPERS

In the Matter of the Application of INTERMOUNTAIN GAS COMPANY
For Authority to Decrease its Prices on October 1, 2023

(October 1, 2023 Purchased Gas Cost Adjustment Filing)

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

In the Matter of the Application of INTERMOUNTAIN GAS COMPANY for Authority to Change its Prices	**Case No. INT-G-23-04** **APPLICATION**

Intermountain Gas Company ("Intermountain" or "Company"), a subsidiary of MDU Resources Group, Inc. with general offices located at 555 South Cole Road, Boise, Idaho, pursuant to the Rules of Procedure of the Idaho Public Utilities Commission ("Commission"), requests authority, pursuant to Idaho Code Sections 61-307 and 61-622, to place into effect October 1, 2023 new rate schedules which will decrease its annualized revenues by approximately $86.9 million. Because of changes in Intermountain's gas related costs, as described more fully in this Application, Intermountain's earnings will not be impacted as a result of the proposed changes in prices and revenues. Exhibit No. 1 is a summary of the overall price changes by class of customer and is attached and incorporated by reference. Intermountain's current rate schedules showing proposed changes are attached as Exhibit No. 2 and incorporated by reference. The resulting proposed rate schedules are attached as Exhibit No. 3 and incorporated by reference.

Please address communications regarding this Application to:

Lori A. Blattner
Director – Regulatory Affairs
Intermountain Gas Company
Post Office Box 7608
Boise, Idaho 83707
Lori.Blattner@intgas.com

and

Preston N. Carter
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In support of this Application, Intermountain alleges and states as follows:

I.

Intermountain is a gas utility, subject to the jurisdiction of the Commission, engaged in the sale of and distribution of natural gas within the State of Idaho under authority of Commission Certificate No. 219, issued December 2, 1955, as amended and supplemented by Order No. 6564, dated October 3, 1962.

Intermountain provides natural gas service to the following Idaho communities and counties and adjoining areas:

Ada County - Boise, Eagle, Garden City, Kuna, Meridian, and Star;
Bannock County - Arimo, Chubbuck, Inkom, Lava Hot Springs, McCammon, and Pocatello;
Bear Lake County - Georgetown, and Montpelier;
Bingham County - Aberdeen, Basalt, Blackfoot, Firth, Fort Hall, Moreland/Riverside, and Shelley;
Blaine County - Bellevue, Hailey, Ketchum, and Sun Valley;
Bonneville County - Ammon, Idaho Falls, Iona, and Ucon;
Canyon County - Caldwell, Greenleaf, Middleton, Nampa, Parma, and Wilder;
Caribou County - Bancroft, Grace, and Soda Springs;
Cassia County - Burley, Declo, Malta, and Raft River;
Elmore County - Glenns Ferry, Hammett, and Mountain Home;
Fremont County - Parker and St. Anthony;
Gem County - Emmett;
Gooding County - Gooding and Wendell;
Jefferson County - Lewisville, Menan, Rigby, and Ririe;
Jerome County - Jerome;
Lincoln County - Shoshone;
Madison County - Rexburg and Sugar City;
Minidoka County - Heyburn, Paul, and Rupert;
Owyhee County - Bruneau and Homedale;
Payette County - Fruitland, New Plymouth, and Payette;
Power County - American Falls;
Twin Falls County - Buhl, Filer, Hansen, Kimberly, Murtaugh, and Twin Falls;
Washington County - Weiser.

Intermountain's properties in these locations consist of transmission pipelines, liquefied natural gas storage facilities, compressor stations, distribution mains, services, meters and regulators, and general plant and equipment.

II.

With this Application, Intermountain seeks to pass through to each of its customer classes changes in gas related costs resulting from: 1) costs billed to Intermountain from firm transportation providers including Northwest Pipeline LLC ("Northwest" or "Northwest Pipeline"), 2) a decrease in Intermountain's Weighted Average Cost of Gas ("WACOG"), 3) interest expense on short-term debt borrowed to pay for the unprecedented gas costs incurred during the 2022-2023 heating season, 4) an updated customer allocation of gas related costs pursuant to the Company's Purchased Gas Cost Adjustment ("PGA") provision, 5) the inclusion of temporary surcharges and credits for one year relating to natural gas purchases and interstate transportation costs from Intermountain's deferred gas cost accounts, 6) benefits resulting from Intermountain's management of its storage and firm capacity rights on various pipeline systems, 7) benefits associated with the sale of liquefied natural gas from the Company's Nampa, Idaho facility, 8) the recovery of deferred in-person customer payment fees, and 9) the recovery of over-refunded Residential Energy Efficiency funds. Intermountain also seeks to eliminate the temporary surcharges and credits included in its current prices during the past 12 months, pursuant to Case No. INT-G-22-04. If approved, these changes would result in a price increase to T-3 customers and a price decrease to all other customer classes.

These price changes are applicable to service rendered under rate schedules affected by and subject to Intermountain's PGA, initially approved by this Commission in Order No. 26109, Case No. INT-G-95-1, and additionally approved through subsequent proceedings.

III.

The Commission approved the current temporary and transportation prices in Order No. 35538, Case No. INT-G-22-04. Prices related to the cost of gas were approved in Order No. 35673, Case No. INT-G-22-08.

IV.

Intermountain's proposed prices incorporate all changes in costs relating to the Company's firm interstate transportation capacity including, but not limited to, any price changes or projected cost adjustments implemented by the Company's pipeline suppliers which have occurred since Intermountain's PGA filing in Case No. INT-G-22-04. Exhibit No. 4, which contains pertinent excerpts from applicable pipeline tariffs, is attached and incorporated by reference.

The current filing includes an increase in Intermountain's firm transportation cost on the upstream pipeline facilities of NOVA Gas Transmission Ltd. ("NOVA"), Foothills Pipe Lines Ltd. ("Foothills"), and Gas Transmission Northwest LLC ("GTN"). Intermountain has held more firm transportation receipt capacity at Stanfield on Northwest Pipeline than it had firm transportation delivery capacity at Stanfield on GTN. This mismatch meant Intermountain was unable to take full advantage of the more economically priced natural gas out of the Aeco supply basin in the Province of Alberta. In late 2020, Intermountain was informed by TC Energy (the parent company of NOVA, Foothills, and GTN) that they would be conducting an open season for a pipeline expansion on NOVA, Foothills and GTN for firm transportation service from Aeco to Malin, OR. Intermountain was awarded 79,000 MMBtu per day of firm transportation on GTN and the related upstream pipelines of Foothills and NOVA with an expected in-service date of November 1, 2023. The open season award left Intermountain 21,000 MMBtu per day short of their requested participation level. With the assistance of IGI Resources, Intermountain was able to acquire an additional 21,000 per day through a permanent release of firm transportation capacity from two producers. This 21,000 per day permanent release was on all three pipelines (NOVA, Foothills and GTN) and the start date of such capacity is April 1, 2024. The Company is confident (based on current longer term futures gas prices) that the increase in transportation costs will be more than offset by access to the significantly lower priced gas supplies out of the Aeco supply basin. The total firm transportation cost increase resulting from these changes is approximately $18.9 million.

In addition to the changes described above, Northwest Pipeline has decreased its transportation rates since the last PGA, while Foothills and NOVA have increased their rates. The net price increase resulting from these changes and the changes above is $17,458,630 and is included on Exhibit No. 5, Lines 3-6. Exhibit No. 5 is attached and incorporated by reference.

V.

Intermountain continues to contract a variety of natural gas storage assets on Northwest Pipeline's system as well as with Dominion Energy Questar Pipeline, LLC ("Dominion"). In addition to providing operational reliability, these storage contracts can provide significant price stability to customers.

Furthermore, Intermountain continues to effectively manage its natural gas storage assets at Northwest's Jackson Prairie and Dominion's Clay Basin storage facilities. Supporting documents to Line 20 of Exhibit No. 5 show Intermountain's management of these storage assets resulted in $2.3 million in savings for customers.

Since the last PGA, Northwest Pipeline has increased rates for some aspects of its storage services while decreasing rates for other aspects. As seen on Exhibit No. 5, Lines 7 through 20, the total increase to Intermountain's prices resulting from these changes is $399,204.

VI.

The WACOG reflected in Intermountain's proposed prices is $0.30455 per therm, as shown on Exhibit No. 5, Line 22, Col. (f). This compares to $0.52808 per therm currently included in the Company's tariffs. This represents a decrease of approximately $98.5 million as seen on Exhibit No. 5, Line 22, Col. (h).

As the market approached the winter of November 2022 to March 2023, a number of factors contributed to the unprecedented rise in the regional commodity gas cost throughout the Western U.S. last winter. November 2022 started off very cold versus normal and the colder than normal weather continued into December. As a result, many utilities in the Pacific Northwest initially held back on withdrawing any gas from storage in order to protect such storage balances should there be a continued cold period or a new cold snap later in the winter, which in turn put a higher demand on non-storage gas and a rise in prices. Certain well freeze offs also occurred in the Rocky Mountain region further exacerbating the price increases.

The combination of all these events, and the commensurate run up in natural gas prices, prompted the Company to file an Interim PGA (Case No. INT-G-22-08) to increase its WACOG from $0.39216 to $0.52808, an overall increase of 17.12% to customer prices. Increasing the WACOG to match current market conditions helped to keep deferrals lower by sending accurate price signals to customers. Since that time there has been a substantial decrease in natural gas prices. That pricing decrease together with the Company's hedging program has resulted in the significant WACOG decrease proposed in this year's filing.

To help offset some of the volatility in the market, the proposed WACOG includes benefits to Intermountain's customers generated by the Company's management of its significant natural gas storage assets. Because gas added to storage is procured during the summer season when prices are traditionally lower than during the winter, the cost of Intermountain's storage gas is normally less than what could be obtained on the open market in winter months. Additionally, in an effort to further stabilize the prices paid by our customers during the upcoming winter period, Intermountain has entered into various fixed price agreements to lock-in the price for portions of its underground storage and other winter "flowing" supplies thus stabilizing a portion of the supply price and insulating it from the significant volatility seen in the futures market.

Intermountain believes that the WACOG proposed in this Application, subject to the effect of actual supply and demand and based on current market conditions, provides today's most reasonable forecast of gas costs for the 2023 - 2024 PGA period. Intermountain will employ, in addition to those fixed price agreements already in place, cost effective price arrangements to further secure the price of flowing gas embedded within this Application when, and if, those pricing opportunities materialize in the marketplace.

Intermountain believes that timely natural gas price signals enhance its customers' ability to make informed and appropriate energy use decisions. The Company is committed to alert customers to any significant impending price changes before their winter natural gas usage occurs. By employing the Company's Energy Efficiency programs, customer mailings, the Company's website, and various media resources, Intermountain will continue to educate its customers regarding the wise and efficient use of natural gas, billing options available to help manage their energy budget, and any pending natural gas price changes.

VII.

Pursuant to the Commission's Order in Case No. INT-G-22-04, Intermountain included temporary credits in its October 1, 2022 prices for the principal reason of passing back to its customers deferred gas cost benefits. Line 27 of Exhibit No. 5 reflects the elimination of these temporary credits.

In summary, Exhibit No. 5 outlines the price changes in 1) Intermountain's base rate gas costs as previously described, 2) its rate class allocation, and 3) net adjustments to temporary surcharges or credits flowing through to Intermountain's customers.

VIII.

Under the Company's PGA tariff, Intermountain's proposed prices will be adjusted for updated customer class sales volumes and purchased gas cost allocations. Intermountain's proposed prices include a gas transportation cost adjustment pursuant to these PGA provisions, as outlined on Exhibit No. 6, Line 25. The price impact of this adjustment is included on Exhibit No. 5, Line 28. The Gas Transportation Cost resulting from the adjustment plus the annual difference in demand charges from Exhibit No. 5, Lines 1 – 20, Col. (h) is shown on Exhibit No. 6, Line 29. Exhibit No. 6 is attached and incorporated by reference.

IX.

Intermountain proposes to pass through to its customers the benefits that will be generated from the management of its transportation capacity, totaling $5.74 million as outlined on Exhibit No. 8. These benefits include credits generated through releases of a portion of Intermountain's firm capacity rights on Northwest Pipeline as well as credits generated from releases of Intermountain's upstream pipeline capacity. Intermountain proposes to pass back these credit amounts via the per therm credits, as detailed on Exhibit No. 8 and included on Exhibit No. 7, Line

1. Exhibit Nos. 7 and 8 are attached and incorporated by reference.

X.

Intermountain proposes to allocate deferred gas costs from its Account No. 191 balance to its customers through temporary price adjustments to be effective during the 12-month period from October 1, 2023 to September 30, 2024, as follows:

1) Intermountain has deferred fixed gas costs in its Account No. 191. The credit amount shown on Exhibit No. 9, Line 7, Col. (b) of $21.3 million is attributable to a true-up of the collection of interstate pipeline capacity costs, a federal income tax refund from Northwest Pipeline, the true-up of expense issues previously ruled on by this Commission, and mitigating capacity release credits generated from the incremental release of Intermountain's pipeline capacity. Intermountain proposes to true-up these balances via the per therm credits, as detailed on Exhibit No. 9 and included on Exhibit No. 7, Line 2. Exhibit No. 9 is attached and incorporated by reference.

2) Intermountain has also deferred in its Account No. 191 a variable gas cost debit of $24.2 million, as shown on Exhibit No. 10, Line 2, Col. (b). This deferred debit is attributable to Intermountain's variable gas costs since October 1, 2022.

Additionally, the Company proposes to collect the interest expense on short-term debt it borrowed to pay for the extraordinary natural gas costs incurred during the 2022-2023 heating season that the Company would not have otherwise borrowed. As an example of the unprecedented nature of these costs, the commodity costs incurred in December 2022 and January 2023 were so large that they equal approximately 99% of the entire 2023-2024 forecasted commodity costs included in this filing. As a direct consequence of these unprecedented costs, on December 27, 2022, the Company filed an Interim PGA, Case No. INT-G-22-08, to significantly increase the WACOG. Although raising the WACOG helped the Company collect additional money from customers to pay for the increased gas costs, the collection occurred over a period of months. To bridge the gap between the payment of gas costs and collection, on December 28, 2022, Intermountain filed Case No. INT-G-22-09 to request authority to issue up to $150 million of short-term debt to cover natural gas costs that would be payable in January and February of 2023. This short-term debt was critical since Intermountain did not have sufficient cash to pay for these unexpected and extremely high gas costs.

Between January and June 2023, the Company incurred approximately $3 million of short-term interest expense and estimates that it will incur an additional $768,049 between July and September on the balance of short-term debt currently outstanding. The Company is proposing to offset this amount of expense by the total interest accumulated on PGA deferral balances between January and September 2023 as well as the interest income earned on the Company's money market account between January and April 2023 which held the Company's net cash balance related to the short-term borrowings during this time period. In total, the estimated short-term interest expense through September 30, 2023, which the Company is proposing to collect, is approximately $3.2 million as shown on Exhibit No. 10, Line 3, Col. (b). Additionally, the Company proposes to true-up the July-September estimate and defer any additional short-term interest expense, net of the interest accumulated on PGA deferral balances, incurred through January 19, 2024 which is the maturity date of the short-term debt.

The sum of the variable gas costs since October 1, 2022 and the short-term interest expense is $27,430,825 as shown on Exhibit No. 10, Line 4, Col. (b). Intermountain proposes to collect this balance via a per therm debit, as shown on Exhibit No. 10, Line 6, Col. (b) and included on Exhibit No. 7, Line 3.

3) Finally, Intermountain has deferred in its Account No. 191 deferred gas costs related to Lost and Unaccounted for Gas as shown on Exhibit No. 10, Lines 7 through 28, Col. (b). This deferral results in a per therm decrease to Intermountain's customers, as illustrated on Exhibit No. 10. This per therm decrease is included on Exhibit No. 7, Line 3. Exhibit No. 10 is attached and incorporated by reference.

XI.

Pursuant to Commission Order No. 32793, Case No. INT-G-13-02, Intermountain has deferred in its Account No. 191 gas cost credits associated with sales of liquefied natural gas at its Nampa, Idaho facility. Intermountain proposes to pass back this $1.4 million sales credit as outlined on Exhibit No. 11, Line 7 and shown on Exhibit No. 7, Line 4. Exhibit No. 11 is attached and incorporated by reference.

XII.

In Commission Order No. 34099, Case No. INT-G-18-01, the Company was directed to defer and later collect through the PGA the fees associated with in-person customer payments at third party vendors. This authorization was extended in Order No. 35047, Case No. INT-G-21-02. Finally, Order No. 35836, Case No. INT-G-22-07, authorized the Company to collect in-person payment fees through base rates going forward, with the fees deferred from October 1, 2022 through February 1, 2023 to be collected in this PGA filing. Exhibit No. 12 summarizes the customer class surcharges associated with these deferred costs which are included on Exhibit No. 7, Line 5. Exhibit No. 12 is attached and incorporated by reference.

XIII.

In Commission Order No. 35539, Case No. INT-G-22-05, the Commission approved the credit of $4.85 million in over-collected Energy Efficiency Residential Funds to be passed back to residential customers in the PGA. By September 30, 2023, the Company estimates that it will have over-refunded Residential Energy Efficiency Funds by $686,777 as shown on Exhibit No. 13. The Company proposes to collect this balance as shown on Exhibit No. 13, Line 5 and on Exhibit No. 7, Line 6. Exhibit No. 13 is attached and incorporated by reference.

XIV.

As outlined on Exhibit No. 2, Page 1, Lines 21 through 29, the T-3 and T-4 tariffs include the following adjustments: a) the removal of existing temporary price changes, and b) the inclusion of proposed temporary price changes from Exhibit No. 7. The net change from these aforementioned adjustments results in a rate increase for the Company's T-3 customers and a rate decrease for T-4 customers.

XV.

The proposed price changes herein requested among the classes of service of Intermountain reflect a just, fair, and equitable pass-through of changes in gas related costs to Intermountain's customers.

XVI.

This Application has been brought to the attention of Intermountain's customers through a Customer Notice and by a Press Release sent to daily and weekly newspapers, and major radio and television stations in Intermountain's service area. The Press Release and Customer Notice are attached and incorporated by reference. Copies of this Application, its Exhibits, and Workpapers have been provided to those parties regularly intervening in Intermountain's rate proceedings.

XVII.

Intermountain requests that this matter be handled under modified procedure pursuant to Rules 201-204 of the Commission's Rules of Procedure. Intermountain stands ready for immediate consideration of this matter.

XIII.

Intermountain respectfully petitions the Idaho Public Utilities Commission as follows:

a. That the proposed rate schedules submitted as Exhibit No. 3 be approved without suspension and made effective as of October 1, 2023 in the manner shown on Exhibit No. 3;

b. That the filing requirement for the Deferred Gas Cost Balance, LNG Sales Cost Benefit Analysis, and Weighted Average Cost of Gas reports be maintained at quarterly frequency;

c. That this Application be heard and acted upon without hearing under modified procedure; and

d. For such other relief as this Commission may determine proper.

DATED: August 14, 2023.

INTERMOUNTAIN GAS COMPANY	GIVENS PURSLEY LLP
By ______________________	By ______________________
Lori A. Blattner	Preston N. Carter
Director – Regulatory Affairs	Attorney for Intermountain Gas Company

CERTIFICATE OF SERVICE

I certify that on August 14, 2023, a true and correct copy of the foregoing Case No. INT-G-23-04 was served upon the following parties via the manner indicated below:

Ed Finklea Alliance of Western Energy Consumers 545 Grandview Drive Ashland, OR 97520 efinklea@awec.solutions	**Electronic Mail**
Michael Hale J. R. Simplot Company 1099 W. Front St. Boise, ID 83702 michael.hale@simplot.com	**Electronic Mail**

*/s/Jacob Betterbed*____________________________________

Jacob Betterbed – Regulatory Analyst

EXHIBIT NO. 1

CASE NO. INT-G-23-04

INTERMOUNTAIN GAS COMPANY

SUMMARY OF PRICE CHANGES

(2 pages)

INTERMOUNTAIN GAS COMPANY
Analysis of Annualized Price Change by Class of Service
Normalized Volumes for Twelve Months Ended December 31, 2022

Line No.	Description	Annual Therms/Contract Demand	Average Prices Effective per Case No. INT-G-22-07 Commission Order No. 35836 Revenue	$/Therm	Proposed Adjustments Effective 10/1/2023 Revenue	$/Therm	Proposed Average Prices Effective 10/1/2023 Revenue	$/Therm	Percent Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Gas Sales:**								
2	RS Residential	285,332,326	$ 275,031,829	$ 0.96390	$ (52,940,560)	$ (0.18554)	$ 222,091,269	$ 0.77836	-19.25%
3	GS-1 General Service	140,493,766	125,965,306	0.89659	(30,674,004)	(0.21833)	95,291,302	0.67826	-24.35%
4	LV-1 Large Volume	14,763,102	10,301,250	0.69777	(3,190,602)	(0.21612)	7,110,648	0.48165	-30.97%
5	**Total Gas Sales**	440,589,194	411,298,385	0.93352	(86,805,166)	(0.19702)	324,493,219	0.73650	-21.11%
6	**Transportation:**								
7	T-3 Transportation (Volumetric)	44,289,741	527,048	0.01190	22,588	0.00051	549,636	0.01241	4.29%
8	T-4 Transportation (Volumetric)	340,008,634	4,148,105	0.01220	-	-	4,148,105	0.01220	0.00%
9	T-4 Demand Charge	17,962,920 [(1)]	5,394,624	0.30032	(80,115)	(0.00446)	5,314,509	0.29586	-1.49%
10	**Total Transportation**	384,298,375	10,069,777	0.02620	(57,527)	(0.00015)	10,012,250	0.02605	-0.57%
11	**Total**	824,887,569	$ 421,368,162	$ 0.51082	$ (86,862,693)	$ (0.10530)	$ 334,505,469	$ 0.40552	-20.61%

[(1)] Non-additive demand charge determinants

INTERMOUNTAIN GAS COMPANY
ANALYSIS OF INT-G-23-04 PRICE CHANGE

Line No.	Description	Amount	Total
	(a)	(b)	(c)
1	**Deferrals:**		
2	INT-G-22-04 Temporaries Reversed		$ (1,957,026) [1]
3	Add INT-G-23-04 Temporaries:		
4	Fixed Deferred Gas Costs	$ (27,023,889) [2]	
5	Variable Deferred Gas Costs	27,430,825 [3]	
6	Lost and Unaccounted For Gas Costs	(419,549) [4]	
7	LNG Sales Credit	(1,423,100) [5]	
8	In-Person Payment Fees Deferral	32,461 [6]	
9	Residential Energy Efficiency Funds	686,777 [7]	
10	Total Temporaries Added		(716,475)
11	**Total Deferrals**		$ (2,673,501)
12	**Base Rate Price Change:**		
13	Fixed Cost Changes:		
14	NWP TF-1 Reservation (Full Rate)	$ (1,616,442) [8]	
15	NWP TF-1 Reservation (Discounted)	(533,930) [9]	
16	Upstream Capacity (Full Rate)	19,059,870 [10]	
17	Upstream Capacity (Discounted)	549,132 [11]	
18	SGS-2F and LS-2F	399,204 [12]	
19	Other Storage Facility	- [13]	
20	Total Fixed Cost Change	17,857,834	
21	Changes in WACOG	(98,484,903) [14]	
22	Reallocation of Fixed Costs	(3,559,548) [15]	
23	**Total Base Rate Price Changes**		(84,186,617)
24	**Total Annual Price Change**		$ (86,860,118)
25	Annual Price Change per Exhibit No. 1, Page 1		$ (86,862,693) [16]
26	Difference Due to Rounding		$ 2,575

(1) Temporary prices from INT-G-22-04 times Exhibit No. 1, Page 1, Lines 2 - 4, 7 and 9, Column (b)
(2) See Exhibit No. 8, Line 3, Column (b), plus Exhibit No. 9, Line 7, Column (b)
(3) See Exhibit No. 10, Line 4, Column (b)
(4) See Exhibit No. 10, Line 12 plus Line 20, Column (b)
(5) See Exhibit No. 11, Line 5, Column (b)
(6) See Exhibit No. 12, Line 4, Column (b)
(7) See Exhibit No. 13, Line 3, Column (b)
(8) See Exhibit No. 5, Line 3, Column (h)
(9) See Exhibit No. 5, Line 4, Column (h)
(10) See Exhibit No. 5, Line 5, Column (h)
(11) See Exhibit No. 5, Line 6, Column (h)
(12) See Exhibit No. 5, sum of Lines 9 - 19, Column (h)
(13) See Exhibit No. 5, Line 20, Column (h)
(14) See Exhibit No. 5, Line 22, Column (h)
(15) See Exhibit No. 5, Line 28, Columns (i) - (k), times Line 24, Columns (i) - (k)
(16) See Exhibit No. 1, Page 1, Line 11, Column (e)

EXHIBIT NO. 2

CASE NO. INT-G-23-04

INTERMOUNTAIN GAS COMPANY

CURRENT TARIFFS

Showing Proposed Price Changes

(10 pages)

INTERMOUNTAIN GAS COMPANY
Comparison of Proposed October 1, 2023 Prices
To Currently Approved Prices

Line No.	Rate Class	Currently Approved Prices	Proposed Adjustment	Proposed October 1, 2023 Prices
	(a)	(b)	(c)	(d)
1	**RS**	$ 0.83980	$ (0.18554)	$ 0.65426
2	**GS-1**			
3	Block 1	0.87448	(0.21833)	0.65615
4	Block 2	0.85301	(0.21833)	0.63468
5	Block 3	0.83228	(0.21833)	0.61395
6	Block 4	0.76959	(0.21833)	0.55126
7	CNG Fuel			
8	Block 1	0.82908	(0.21833)	0.61075
9	Block 2	0.76639	(0.21833)	0.54806
10	**IS-R** (1)	0.84206	(0.20585)	0.63621
11	**IS-C** (2)			
12	Block 1	0.87128	(0.21833)	0.65295
13	Block 2	0.84981	(0.21833)	0.63148
14	Block 3	0.82908	(0.21833)	0.61075
15	Block 4	0.76639	(0.21833)	0.54806
16	**LV-1**			
17	Demand Charge	0.32000	-	0.32000
18	Block 1	0.67765	(0.21612)	0.46153
19	Block 2	0.65952	(0.21612)	0.44340
20	Block 3	0.65500	(0.21612)	0.43888
21	**T-3**			
22	Block 1	0.03612	0.00051 (3)	0.03663
23	Block 2	0.01422	0.00051 (3)	0.01473
24	Block 3	0.00472	0.00051 (3)	0.00523
25	**T-4**			
26	Demand Charge	0.30032	(0.00446) (4)	0.29586
27	Block 1	0.02172	-	0.02172
28	Block 2	0.00768	-	0.00768
29	Block 3	0.00236	-	0.00236

(1) The IS-R price is based on the RS price and receives the same PGA adjustments, except for the the Residential Energy Efficiency Funds rate adjustment

(2) The IS-C price is based on the GS-1 price and receives the same PGA adjustments

(3) Remove INT-G-22-04 temporary, ($0.00082), and add temporary from Exhibit No. 7 Line 7, Column (e)

(4) Remove INT-G-22-04 temporary, ($0.01968), and add temporary from Exhibit No. 7 Line 7, Column (f)

INTERMOUNTAIN GAS COMPANY
Summary of Proposed Tariff Components and Line Break Pricing

Line No.	Description	RS	GS-1	LV-1	T-3	T-4
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Cost of Gas:**					
2	Temporary Purchased Gas Cost Adjustment [1]	$ (0.00078)	$ (0.00377)	$ 0.03253	$ (0.00031)	$ (0.02414)
3	Weighted Average Cost of Gas [2]	0.30455	0.30455	0.30455	-	-
4	Gas Transportation Cost [3]	0.20184	0.18332	0.09445	-	-
5	**Total Proposed Cost of Gas**	$ 0.50561	$ 0.48410	$ 0.43153	$ (0.00031)	$ (0.02414)
6	**Distribution Cost:** [4]					
7	Block 1	$ 0.13301	$ 0.16885	$ 0.03000	$ 0.03694	$ 0.02172
8	Block 2		0.14738	0.01187	0.01504	0.00768
9	Block 3		0.12665	0.00735	0.00554	0.00236
10	Block 4		0.06396			
11	Demand Charge			0.32000		0.32000
12	Energy Efficiency Charge	0.01564 [5]	0.00320 [6]			
13	**Proposed Prices:**					
14	Block 1	$ 0.65426	$ 0.65615	$ 0.46153	$ 0.03663	$ 0.02172
15	Block 2		0.63468	0.44340	0.01473	0.00768
16	Block 3		0.61395	0.43888	0.00523	0.00236
17	Block 4		0.55126			
18	Demand Charge			0.32000		0.29586
19	Line Break Pricing [7]	$ 0.50639				

(1) See Exhibit No. 7, Line 7, Columns (b) - (f)
(2) See Exhibit No. 5, Line 22, Column (f)
(3) See Exhibit No. 6, Line 29, Columns (e) - (g)
(4) See Case No. INT-G-22-07
(5) See Case No. INT-G-22-05
(6) See Case No. INT-G-20-04
(7) Sum of Lines 3 and 4, Column (b)

I.P.U.C. Gas Tariff Rate Schedules ~~Twelfth~~ Thirteenth Revised	Sheet No. 1 (Page 1 of 1)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved **Effective**
~~**August 8, 2023**~~ ~~**July 1, 2023**~~
~~**Per ON 35877**~~
Jan Noriyuki Secretary

Rate Schedule RS
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge: $8.00 per bill

Per Therm Charge: $~~0.83980~~0.65426*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($~~0.00057~~0.00078)
	2) Weighted average cost of gas	$~~0.52808~~0.30455
	3) Gas transportation cost	$~~0.16364~~0.20184
Distribution Cost:		$0.13301
EE Charge:		$0.01564

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

ENERGY EFFICIENCY CHARGE ADJUSTMENT:

This tariff is subject to an adjustment for costs related to the Company's Energy Efficiency program as provided for in Rate Schedule EEC-RS. The Energy Efficiency Charge is separately stated on customer bills.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

I.P.U.C. Gas Tariff Rate Schedules Sixty-~~Seventh~~ Eighth Revised	Sheet No. 3 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved ~~August 8, 2023~~ Effective ~~July 1, 2023~~
~~Per ON 35877~~
Jan Noriyuki Secretary

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be allowed at the Company's discretion.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$15.00 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	$~~0.87448~~0.65615*
	Block Two:	Next	1,800 therms per bill @	$~~0.85301~~0.63468*
	Block Three:	Next	8,000 therms per bill @	$~~0.83228~~0.61395*
	Block Four:	Over	10,000 therms per bill @	$~~0.76959~~0.55126*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	~~$0.01445~~($0.00377)
	2) Weighted average cost of gas	$~~0.52808~~0.30455
	3) Gas transportation cost	$~~0.15990~~0.18332

Distribution Cost:	Block One:	First	200 therms per bill @	$0.16885
	Block Two:	Next	1,800 therms per bill @	$0.14738
	Block Three:	Next	8,000 therms per bill @	$0.12665
	Block Four:	Over	10,000 therms per bill @	$0.06396
EE Charge:				$0.00320

I.P.U.C. Gas Tariff Rate Schedules Sixty-~~Seventh~~ Eighth Revised	Sheet No. 3 (Page 2 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~August 8, 2023~~ ~~July 1, 2023~~
~~Per ON 35877~~
Jan Noriyuki Secretary

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge:	$15.00 per bill		
Per Therm Charge:	Block One:	First 10,000 therms per bill @	$~~0.82908~~0.61075*
	Block Two:	Over 10,000 therms per bill @	$~~0.76639~~0.54806*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	~~$0.01445~~($0.00377)
	2) Weighted average cost of gas	$~~0.52808~~0.30455
	3) Gas transportation cost	$~~0.15990~~0.18332
Distribution Cost:	Block One: First 10,000 therms per bill @	$0.12665
	Block Two: Over 10,000 therms per bill @	$0.06396

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

ENERGY EFFICIENCY CHARGE ADJUSTMENT:

This tariff is subject to an adjustment for costs related to the Company's Energy Efficiency program as provided for in Rate Schedule EEC-GS. The Energy Efficiency Charge is not applicable to gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines. The Energy Efficiency Charge is separately stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

I.P.U.C. Gas Tariff Rate Schedules Twenty-~~Third~~Fourth Revised	Sheet No. 4 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved ~~August 8, 2023~~ Effective ~~July 1, 2023~~
~~Per ON 35877~~
Jan Noriyuki Secretary

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge: $8.00 per bill

Per Therm Charge: $~~0.84206~~0.63621*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	~~$0.01733~~($0.00319)
	2) Weighted average cost of gas	$~~0.52808~~0.30455
	3) Gas transportation cost	$~~0.16364~~0.20184
Distribution Cost:		$0.13301

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

I.P.U.C. Gas Tariff Rate Schedules Twenty-~~Second~~ Third Revised	Sheet No. 5 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~August 8, 2023~~ ~~July 1, 2023~~
~~Per ON 35877~~
Jan Noriyuki Secretary

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$12.50 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	$~~0.87128~~0.65295*
	Block Two:	Next	1,800 therms per bill @	$~~0.84981~~0.63148*
	Block Three:	Next	8,000 therms per bill @	$~~0.82908~~0.61075*
	Block Four:	Over	10,000 therms per bill @	$~~0. 76639~~0.54806*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	~~$0.01445~~($0.00377)
	2) Weighted average cost of gas	$~~0.52808~~0.30455
	3) Gas transportation cost	$~~0.15990~~0.18332

Distribution Charge:	Block One:	First	200 therms per bill @	$0.16885
	Block Two:	Next	1,800 therms per bill @	$0.14738
	Block Three:	Next	8,000 therms per bill @	$0.12665
	Block Four:	Over	10,000 therms per bill @	$0.06396

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Customer Charge: $150.00 per bill

Demand Charge: $0.32000 per MDFQ therm

Per Therm Charge:	Block One:	First	35,000 therms per bill @	$~~0.67765~~0.46153*
	Block Two:	Next	35,000 therms per bill @	$~~0.65952~~0.44340*
	Block Three:	Over	70,000 therms per bill @	$~~0.65500~~0.43888*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	$~~0.03247~~0.03253
	2) Weighted average cost of gas	$~~0.52808~~0.30455
	3) Gas transportation cost	$~~0.08710~~0.09445

Distribution Cost:	Block One:	First	35,000 therms per bill @	$0.03000
	Block Two:	Next	35,000 therms per bill @	$0.01187
	Block Three:	Over	70,000 therms per bill @	$0.00735

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ), which will be stated in and in effect throughout the term of the service contract.

3. The monthly Demand Charge will be equal to the MDFQ times the Demand Charge rate. Demand Charge relief will be afforded to those LV-1 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

I.P.U.C. Gas Tariff Rate Schedules Twenty-~~Third~~Fourth Revised	Sheet No. 8 (Page 1 of 1)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved Effective
~~August 8, 2023~~ ~~July 1, 2023~~
~~Per ON 35877~~
Jan Noriyuki Secretary

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Customer Charge:	$300.00 per bill		
Per Therm Charge:	Block One:	First	100,000 therms transported @ $~~0.03612~~0.03663*
	Block Two:	Next	50,000 therms transported @ $~~0.01422~~0.01473*
	Block Three:	Over	150,000 therms transported @ $~~0.00472~~0.00523*

*Includes temporary purchased gas cost adjustment of ($0.000~~82~~31)

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill based on annual usage of 200,000 therms. The deficit usage below 200,000 therms shall be billed at the T-3 Block 1 rate.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this Rate Schedule.

3. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

4. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.

5. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company's distribution system.

I.P.U.C. Gas Tariff Rate Schedules Twenty-~~Second~~ Third Revised	Sheet No. 9 (Page 1 of 2)
Name of Utility	**Intermountain Gas Company**

IDAHO PUBLIC UTILITIES COMMISSION
Approved ~~August 8, 2023~~ Effective ~~July 1, 2023~~
~~Per ON 35877~~
Jan Noriyuki Secretary

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year.

MONTHLY RATE:

Customer Charge:	$150.00 per bill		
Demand Charge:	$~~0.30032~~ 0.29586 per MDFQ therm*		
Per Therm Charge:	Block One:	First	250,000 therms transported @ $0.02172
	Block Two:	Next	500,000 therms transported @ $0.00768
	Block Three:	Over	750,000 therms transported @ $0.00236

*Includes temporary purchased gas cost adjustment of ($0.~~01968~~02414)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. This service does not include the cost of the customer's gas supply of the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this Rate Schedule.

3. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

4. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ), which will be stated in and in effect throughout the term of the service contract.

5. The monthly Demand Charge will be equal to the MDFQ times the Demand Charge rate. Demand Charge relief will be afforded to those T-4 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

EXHIBIT NO. 3

CASE NO. INT-G-23-04

INTERMOUNTAIN GAS COMPANY

PROPOSED TARIFFS

(8 pages)

Rate Schedule RS
RESIDENTIAL SERVICE

APPLICABILITY:

Applicable to any customer using natural gas for residential purposes.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge: $8.00 per bill

Per Therm Charge: $0.65426*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00078)
	2) Weighted average cost of gas	$0.30455
	3) Gas transportation cost	$0.20184
Distribution Cost:		$0.13301
EE Charge:		$0.01564

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

ENERGY EFFICIENCY CHARGE ADJUSTMENT:

This tariff is subject to an adjustment for costs related to the Company's Energy Efficiency program as provided for in Rate Schedule EEC-RS. The Energy Efficiency Charge is separately stated on customer bills.

SERVICE CONDITIONS:

All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

Rate Schedule GS-1
GENERAL SERVICE

APPLICABILITY:

Applicable to customers whose requirements for natural gas do not exceed 2,000 therms per day, at any point on the Company's distribution system. Requirements in excess of 2,000 therms per day may be allowed at the Company's discretion.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$15.00 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	$0.65615*
	Block Two:	Next	1,800 therms per bill @	$0.63468*
	Block Three:	Next	8,000 therms per bill @	$0.61395*
	Block Four:	Over	10,000 therms per bill @	$0.55126*

***I**ncludes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment			($0.00377)
	2) Weighted average cost of gas			$0.30455
	3) Gas transportation cost			$0.18332
Distribution Cost:	Block One:	First	200 therms per bill @	$0.16885
	Block Two:	Next	1,800 therms per bill @	$0.14738
	Block Three:	Next	8,000 therms per bill @	$0.12665
	Block Four:	Over	10,000 therms per bill @	$0.06396
EE Charge:				$0.00320

Rate Schedule GS-1
GENERAL SERVICE
(Continued)

For separately metered deliveries of gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines.

Customer Charge:	$15.00 per bill		
Per Therm Charge:	Block One:	First 10,000 therms per bill @	$0.61075*
	Block Two:	Over 10,000 therms per bill @	$0.54806*
*Includes the following:			
Cost of Gas:	1) Temporary purchased gas cost adjustment		($0.00377)
	2) Weighted average cost of gas		$0.30455
	3) Gas transportation cost		$0.18332
Distribution Cost:	Block One:	First 10,000 therms per bill @	$0.12665
	Block Two:	Over 10,000 therms per bill @	$0.06396

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

ENERGY EFFICIENCY CHARGE ADJUSTMENT:

This tariff is subject to an adjustment for costs related to the Company's Energy Efficiency program as provided for in Rate Schedule EEC-GS. The Energy Efficiency Charge is not applicable to gas utilized solely as Compressed Natural Gas Fuel in vehicular internal combustion engines. The Energy Efficiency Charge is separately stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this rate schedule is a part.

Rate Schedule IS-R
RESIDENTIAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any residential customer otherwise eligible to receive service under Rate Schedule RS who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-R and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$8.00 per bill
Per Therm Charge:	$0.63621*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00319)
	2) Weighted average cost of gas	$0.30455
	3) Gas transportation cost	$0.20184
Distribution Cost:		$0.13301

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

Rate Schedule IS-C
SMALL COMMERICAL INTERRUPTIBLE SNOWMELT SERVICE

APPLICABILITY:

Applicable to any customer otherwise eligible to receive gas service under Rate Schedule GS-1 who has added natural gas snowmelt equipment after 6/1/2010. The intended use of the snowmelt equipment is to melt snow and/or ice on sidewalks, driveways or any other similar appurtenances. Any and all such applications meeting the above criteria will be subject to service under Rate Schedule IS-C and will be separately and individually metered. All service hereunder is interruptible at the sole discretion of the Company.

FACILITY REIMBURSEMENT CHARGE:

All new interruptible Snowmelt service customers are required to pay for the cost of the Snowmelt meter set and other related facility and equipment costs, prior to the installation of the meter set. Any request to alter the physical location of the meter set and related facilities from Company's initial design may be granted provided, however, the Company can reasonably accommodate said relocation and Customer agrees to pay all related costs.

RATE:

Monthly minimum charge is the Customer Charge.

Customer Charge:	$12.50 per bill			
Per Therm Charge:	Block One:	First	200 therms per bill @	$0.65295*
	Block Two:	Next	1,800 therms per bill @	$0.63148*
	Block Three:	Next	8,000 therms per bill @	$0.61075*
	Block Four:	Over	10,000 therms per bill @	$0.54806*

*Includes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	($0.00377)
	2) Weighted average cost of gas	$0.30455
	3) Gas transportation cost	$0.18332

Distribution Charge:	Block One:	First	200 therms per bill @	$0.16885
	Block Two:	Next	1,800 therms per bill @	$0.14738
	Block Three:	Next	8,000 therms per bill @	$0.12665
	Block Four:	Over	10,000 therms per bill @	$0.06396

Rate Schedule LV-1
LARGE VOLUME FIRM SALES SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any existing customer receiving service under the Company's rate schedule LV-1 or any customer not previously served under this schedule whose usage does not exceed 500,000 therms annually, upon execution of a one-year minimum written service contract for firm sales service in excess of 200,000 therms per year.

MONTHLY RATE:

Customer Charge:	$150.00 per bill			
Demand Charge:	$0.32000 per MDFQ therm			
Per Therm Charge:	Block One:	First	35,000 therms per bill @	$0.46153*
	Block Two:	Next	35,000 therms per bill @	$0.44340*
	Block Three:	Over	70,000 therms per bill @	$0.43888*

***I**ncludes the following:

Cost of Gas:	1) Temporary purchased gas cost adjustment	$0.03253
	2) Weighted average cost of gas	$0.30455
	3) Gas transportation cost	$0.09445

Distribution Cost:	Block One:	First	35,000 therms per bill @	$0.03000
	Block Two:	Next	35,000 therms per bill @	$0.01187
	Block Three:	Over	70,000 therms per bill @	$0.00735

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ), which will be stated in and in effect throughout the term of the service contract.

3. The monthly Demand Charge will be equal to the MDFQ times the Demand Charge rate. Demand Charge relief will be afforded to those LV-1 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

Rate Schedule T-3
INTERRUPTIBLE DISTRIBUTION TRANSPORTATION SERVICE

AVAILABILITY:

Available at any point on the Company's distribution system to any customer upon execution of a one year minimum written service contract.

MONTHLY RATE:

Customer Charge: $300.00 per bill

Per Therm Charge:	Block One:	First	100,000 therms transported @ $0.03663*
	Block Two:	Next	50,000 therms transported @ $0.01473*
	Block Three:	Over	150,000 therms transported @ $0.00523*

*Includes temporary purchased gas cost adjustment of ($0.00031)

ANNUAL MINIMUM BILL:

The customer shall be subject to the payment of an annual minimum bill based on annual usage of 200,000 therms. The deficit usage below 200,000 therms shall be billed at the T-3 Block 1 rate.

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA. This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. This service does not include the cost of the customer's gas supply or the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this Rate Schedule.

3. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

4. The Company, in its sole discretion, shall determine whether or not it has adequate capacity to accommodate transportation of the customer's gas supply on the Company's distribution system.

5. If requested by the Company, the customer expressly agrees to immediately curtail or interrupt its operations during periods of capacity constraints on the Company's distribution system.

Rate Schedule T-4
FIRM DISTRIBUTION ONLY TRANSPORTATION SERVICE

AVAILABILITY:

Available at any mutually agreeable delivery point on the Company's distribution system to any customer upon execution of a one year minimum written service contract for firm distribution transportation service in excess of 200,000 therms per year**.**

MONTHLY RATE:

Customer Charge: $150.00 per bill

Demand Charge: $0.29586 per MDFQ therm*

Per Therm Charge:	Block One:	First	250,000 therms transported @ $0.02172
	Block Two:	Next	500,000 therms transported @ $0.00768
	Block Three:	Over	750,000 therms transported @ $0.00236

*Includes temporary purchased gas cost adjustment of ($0.02414)

PURCHASED GAS COST ADJUSTMENT:

This tariff is subject to an adjustment for the cost of purchased gas as provided for in Rate Schedule PGA**.** This adjustment is incorporated into the calculation of the Cost of Gas stated on customer bills.

SERVICE CONDITIONS:

1. All natural gas service hereunder is subject to the General Service Provisions of the Company's Tariff, of which this Rate Schedule is a part.

2. This service does not include the cost of the customer's gas supply of the interstate pipeline capacity. The customer is responsible for procuring its own supply of natural gas and transportation to Intermountain's distribution system under this Rate Schedule.

3. The customer understands and agrees that the Company is not responsible to deliver gas supplies to the customer which have not been nominated, scheduled, and delivered by the interstate pipeline to the designated city gate.

4. The customer shall negotiate with the Company, a mutually agreeable Maximum Daily Firm Quantity (MDFQ), which will be stated in and in effect throughout the term of the service contract.

5. The monthly Demand Charge will be equal to the MDFQ times the Demand Charge rate. Demand Charge relief will be afforded to those T-4 customers when circumstances impacted by force majeure events prevent the Company from delivering natural gas to the customer's meter.

EXHIBIT NO. 4

CASE NO. INT-G-23-04

INTERMOUNTAIN GAS COMPANY

PERTINENT EXCERPTS PERTAINING TO INTERSTATE PIPELINES AND RELATED FACILITIES

(28 pages)

NORTHWEST PIPELINE LLC

(6 pages)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

Northwest Pipeline LLC
Docket No. RP22-1155-001

Issued: December 21, 2022

On November 30, 2022, Northwest Pipeline LLC filed tariff records[1] to implement the rates provided in the Stipulation and Agreement (Settlement) filed in Docket No. RP22-1155-000, which was approved by the Commission on November 15, 2022.[2] Specifically, the tariff records place the Settlement rates into effect. Pursuant to authority delegated to the Director, Division of Pipeline Regulation, under 18 C.F.R. § 375.307, the tariff records are accepted, effective January 1, 2023, as requested.

The filing was publicly noticed. No protests or adverse comments were filed. Pursuant to Rule 214 of the Commission's regulations (18 C.F.R. § 385.214), notices of intervention, timely-filed motions to intervene, and any unopposed motions to intervene out-of-time filed before the issuance date of this order are granted.

This action shall not be construed as a waiver of the requirements of section 7 of the Natural Gas Act, as amended; nor shall it be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in the applicant's tariff; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicant.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Issued by: Marsha K. Palazzi, Director, Division of Pipeline Regulation

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[1] *See* Appendix.

[2] *Northwest Pipeline LLC.*, 181 FERC ¶ 61,118 (2022).

Document Accession #: 20221130-5273 Filed Date: 11/30/2022

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

Rate Schedule and Type of Rate	Base Tariff Rate (1),(3) Minimum	Maximum
Rate Schedule TF-1 (4)(5)		
Reservation		
(Large Customer)		
System-Wide	.00000	.37250
25 Year Evergreen Exp.	.00000	.27082
Volumetric (2)		
(Large Customer)		
System-Wide	.00935	.00935
25 Year Evergreen Exp.	.00935	.00935
(Small Customer) (6)	.00935	.66230
Scheduled Overrun (2)	.00935	.38185
Rate Schedule TF-2 (4)(5)		
Reservation	.00000	.37250
Volumetric	.00935	.00935
Scheduled Daily Overrun	.00935	.38185
Annual Overrun	.00935	.38185
Rate Schedule TI-1 (2)		
Volumetric (7)	.00935	.38185
Rate Schedule TFL-1 (4)(5)		
Reservation	-	-
Volumetric (2)	-	-
Scheduled Overrun (2)	-	-
Rate Schedule TIL-1 (2)		
Volumetric	-	-

Document Accession #: 20221130-5273 Filed Date: 11/30/2022

STATEMENT OF RATES (Continued)

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

(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate (1) Minimum	Base Tariff Rate (1) Maximum
Rate Schedule SGS-2F (2) (3) (4) (5)		
Demand Charge		
Pre-Expansion Shipper	0.00000	0.02220
Expansion Shipper	0.00000	0.03393
Capacity Demand Charge		
Pre-Expansion Shipper	0.00000	0.00081
Expansion Shipper	0.00000	0.00291
Volumetric Bid Rates		
Withdrawal Charge		
Pre-Expansion Shipper	0.00000	0.02220
Expansion Shipper	0.00000	0.03393
Storage Charge		
Pre-Expansion Shipper	0.00000	0.00081
Expansion Shipper	0.00000	0.00291
Rate Schedule SGS-2I		
Volumetric	0.00000	0.00240

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

Document Accession #: 20221130-5273 Filed Date: 11/30/2022

STATEMENT OF RATES (Continued)

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

(Dollars per Dth)

Rate Schedule and Type of Rate	Base Tariff Rate (1) Minimum	Maximum
Rate Schedule LS-2F (3)		
Demand Charge (2)	0.00000	0.03136
Capacity Demand Charge (2)	0.00000	0.00401
Volumetric Bid Rates		
Vaporization Demand-Related Charge (2)	0.00000	0.03136
Storage Capacity Charge (2)	0.00000	0.00401
Liquefaction	0.58646	0.58646
Vaporization	0.07272	0.07272
Rate Schedule LS-2I		
Volumetric	0.00000	0.00802
Liquefaction	0.58646	0.58646
Vaporization	0.07272	0.07272

Footnotes

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

(2) Rates are daily rates computed on the basis of 365 days per year.

(3) Rates are also applicable to capacity release service except for short-term capacity release transactions for 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, which are not subject to the stated Maximum Base Tariff Rate. (Section 22 of the General Terms and Conditions describes how bids for capacity release will be evaluated.) The Vaporization Demand-Related Charge and Storage Capacity Charge are applicable to Replacement Shippers bidding for capacity released on a one-part volumetric bid basis.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

Northwest Pipeline LLC
Docket No. RP23-479-000

Issued: March 23, 2023

On February 28, 2023, Northwest Pipeline LLC filed a tariff record[1] to reflect its revised fuel reimbursement factors, pursuant to sections 14.12 and 14.20 of the General Terms and Conditions of its tariff. Pursuant to authority delegated to the Director, Division of Pipeline Regulation, under 18 C.F.R. § 375.307, the tariff record is accepted, effective April 1, 2023, as requested.

The filing was publicly noticed. No protests or adverse comments were filed. Pursuant to Rule 214 of the Commission's regulations (18 C.F.R. § 385.214), notices of intervention, timely-filed motions to intervene, and any unopposed motions to intervene out-of-time filed before the issuance date of this order are granted.

This action shall not be construed as a waiver of the requirements of section 7 of the Natural Gas Act, as amended; nor shall it be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in the applicant's tariff; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicant.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Issued by: Marsha K. Palazzi, Director, Division of Pipeline Regulation

[1] Northwest Pipeline LLC, Fifth Revised Volume No. 1, Sheet No. 14, Fuel Use Factors (32.0.0).

STATEMENT OF FUEL USE REQUIREMENTS FACTORS
FOR REIMBURSEMENT OF FUEL USE

Applicable to Transportation Service Rendered Under
Rate Schedules Contained in this Tariff, Fifth Revised Volume No. 1

The rates set forth on Sheet Nos. 5, 6, 7, 8 and 8-A are exclusive of fuel use requirements. Shipper shall reimburse Transporter in-kind for its fuel use requirements in accordance with Section 14 of the General Terms and Conditions contained herein.

The fuel use reimbursement furnished by Shippers shall be as follows for the applicable Rate Schedules included in this Tariff:

Rate Schedules TF-1, TF-2, TI-1, and DEX-1	1.06%
Rate Schedule TF-1 - Evergreen Expansion	
Incremental Surcharge (1)	0.50%
Rate Schedule TFL-1	-
Rate Schedule TIL-1	-
Rate Schedules SGS-2F and SGS-2I	0.49%
Rate Schedules LS-2F, LS-3F and LS-2I	
Liquefaction	2.08%
Vaporization	0.09%
Rate Schedule LD-4I	
Liquefaction	2.08%

The fuel use factors set forth above shall be calculated and adjusted as explained in Section 14 of the General Terms and Conditions. Fuel reimbursement quantities to be supplied by Shippers to Transporter shall be determined by applying the factors set forth above to the quantity of gas nominated for receipt by Transporter from Shipper for transportation, Jackson Prairie injection, Plymouth liquefaction, Plymouth vaporization, or for deferred exchange, as applicable.

Footnote

(1) In addition to the Rate Schedule TF-1 fuel use requirements factor, the Evergreen Expansion Incremental Surcharge will apply to the quantity of gas nominated for receipt at the Sumas, SIPI or Pacific Pool receipt points under Evergreen Expansion service agreements.

NOVA GAS TRANSMISSION LTD.

(4 pages)

Canada Energy Regulator Régie de l'énergie du Canada

ORDER TG-003-2023

IN THE MATTER OF the *Canadian Energy Regulator Act* (**CER Act**); and

IN THE MATTER OF an application filed by NOVA Gas Transmission Ltd. (**NGTL**) with the Canada Energy Regulator (**CER**) pursuant to section 226 and paragraph 229(1)(b) of the CER Act, filed under File OF-Tolls-Group1-N081-2023-01 01.

BEFORE the Commission of the CER on 29 May 2023.

WHEREAS on 29 May 2014, the National Energy Board (**NEB**) issued the MH-001-2013 Decision, approving NGTL's methodology for calculating abandonment surcharges;

AND WHEREAS on 18 April 2018, the NEB issued a Letter Decision, approving NGTL's Abandonment Cost Estimate of $2,535,332,000 (2016 dollars);

AND WHEREAS on 25 March 2020, the Commission issued Order TG-001-2020, approving NGTL's rate design (**Rate Design**);

AND WHEREAS on 17 August 2020, the Commission issued Order TG-009-2020, approving NGTL's 2020-2024 Toll Settlement (**Settlement**);

AND WHEREAS on 13 December 2022, the Commission issued Order TGI-002-2022, approving NGTL's interim tolls and abandonment surcharges effective 1 January 2023;

AND WHEREAS on 21 April 2023, NGTL filed an application (**Application**) requesting an order for approval of final 2023 rates, tolls and charges (**Final 2023 Tolls**) and final 2023 abandonment surcharges (**Final 2023 Abandonment Surcharges**);

AND WHEREAS the Commission is satisfied with the consultation conducted and is not aware of any outstanding concerns with the Application from shippers and participants of NGTL's Tolls, Tariffs, Facilities and Procedures Committee or other interested parties;

AND WHEREAS the Commission finds the Final 2023 Tolls are just, reasonable and not unjustly discriminatory and have been calculated in accordance with the Settlement and Rate Design, and the Final 2023 Abandonment Surcharges have been calculated in accordance with the NEB MH-001-2013 and 18 April 2018 Decisions respecting abandonment costs and surcharges;

…/2

IT IS ORDERED pursuant to section 226 and paragraph 229(1)(b) of the CER Act that:

1. The interim tolls approved through Order TGI-002-2022 for the period 1 January 2023 to 31 May 2023 are approved as final;
2. The applied-for final 2023 tolls for the period 1 June 2023 to 31 December 2023, as contained in Attachment G to the Application, are approved as final;
3. The interim abandonment surcharges approved through Order TGI-002-2022, and as contained in Attachment H to the Application, are approved as final for the period 1 January 2023 to 31 December 2023.

THE COMMISSION OF THE CANADA ENERGY REGULATOR

Signed by

Ramona Sladic
Secretary of the Commission

NOVA Gas Transmission Ltd.

Attachment 2
Delivery Point Rates
Page 1 of 11

Final June-December 2023 Rates

DELIVERY POINT RATES

Group 1 Delivery Point Number	Group 1 Delivery Point Name	FT-D Demand Rate Price Point "Z" ($/GJ/mo)	IT-D Rate ($/GJ/d)
2000	ALBERTA-B.C. BORDER	6.61	0.2391
31111	ALLIANCE CLAIRMONT INTERCONNECT APN	5.95	0.2151
31110	ALLIANCE EDSON INTERCONNECT APN	5.95	0.2151
31112	ALLIANCE SHELL CREEK INTERCONNECT APGC	5.95	0.2151
1958	EMPRESS BORDER	5.95	0.2151
3886	GORDONDALE BORDER	5.95	0.2151
6404	MCNEILL BORDER	5.95	0.2151

Group 2 Delivery Point Number	Group 2 Delivery Point Name	FT-D Demand Rate Price Point "Z" ($/GJ/mo)	IT-D Rate ($/GJ/d)	Subject to ATCO Pipelines Franchise Fees[1]
31000	A.T. PLASTICS SALES APN	8.37	0.3028	Yes
31001	ADM AGRI INDUSTRIES SALES APN	8.37	0.3028	Yes
3880	AECO INTERCONNECTION	8.37	0.3028	
31003	AGRIUM CARSELAND SALES APS	8.37	0.3028	
31002	AGRIUM FT. SASK SALES APN	8.37	0.3028	Yes
31004	AGRIUM REDWATER SALES APN	8.37	0.3028	
31005	AINSWORTH SALES APGP	8.37	0.3028	
31006	AIR LIQUIDE SALES APN	8.37	0.3028	
6126	AITKEN CREEK SOUTH SALES [2]	10.73	0.3805	
3820	AITKEN CREEK INTERCONNECT [2]	10.73	0.3805	
3214	AKUINU RIVER WEST SALES	8.37	0.3028	
31007	ALBERTA ENVIROFUELS SALES APN	8.37	0.3028	Yes [3]
31008	ALBERTA HOSPITAL SALES APN	8.37	0.3028	Yes
3868	ALBERTA-MONTANA BORDER	8.37	0.3028	
3297	ALDER FLATS SOUTH NO 2 SALES	8.37	0.3028	
3059	ALLISON CREEK SALES	8.37	0.3028	
6132	ALTARES SALES [2]	10.73	0.3805	
6133	ALTARES SOUTH SALES [2]	10.73	0.3805	
31009	ALTASTEEL SALES APN	8.37	0.3028	Yes [3]
6145	ANDERSON LAKE SALES	8.37	0.3028	
31012	APL JASPER SALES APN	8.37	0.3028	Yes
3488	ARDLEY SALES	8.37	0.3028	
3237	ASPEN SALES	8.37	0.3028	
3662	ATUSIS CREEK EAST SALES	8.37	0.3028	
3216	AURORA NO 2 SALES	8.37	0.3028	
3135	AURORA SALES	8.37	0.3028	
3288	BANTRY SALES	8.37	0.3028	
3423	BASHAW WEST SALES	8.37	0.3028	
6158	BASSET LAKE WEST SALES	8.37	0.3028	
31013	BAYMAG SALES APS	8.37	0.3028	
6112	BAY TREE SALES	8.37	0.3028	
31014	BEAR CREEK COGEN SALES APGP	8.37	0.3028	
3299	BEAR RIVER WEST SALES	8.37	0.3028	
3068	BEAVER HILLS SALES	8.37	0.3028	
3268	BENBOW SOUTH SALES	8.37	0.3028	
3933	BIG EDDY INTERCONNECTION	8.37	0.3028	

Final June-December 2023 Rates

TABLE OF RATES, TOLLS AND CHARGES

Service	Rates, Tolls and Charges		
1. Rate Schedule FT-R	Refer to Attachment “1” for applicable FT-R Demand Rate per month based on a three-year term (Price Point “B”) & Surcharge for each Receipt Point		
	Average Firm Service Receipt Price (AFSRP)		$283.02 / 10^3m^3 / month
2. Rate Schedule FT-RN	Refer to Attachment “1” for applicable FT-RN Demand Rate per month & Surcharge for each Receipt Point		
3. Rate Schedule FT-D [1]	Refer to Attachment “2” for applicable FT-D Demand Rate per month based on a one-year term (Price Point “Z”) & Surcharge for each Group 1 or Group 2 Delivery Point		
	Average FT-D Demand Rate for Group 1 Delivery Points		$6.19 / GJ / month
	FT-D Demand Rate for Group 2 Delivery Points		$8.37 / GJ / month
	FT-D Demand Rate for Group 3 Delivery Points		$10.05 / GJ / month
4. Rate Schedule STFT	STFT Bid Price = Minimum of 100% of the applicable FT-D Demand Rate based on a one-year term (Price Point “Z”) for each Group 1 Delivery Point		
5. Rate Schedule FT-DW	FT-DW Bid Price = Minimum of 125% of the applicable FT-D Demand Rate based on a three-year term (Price Point “Y”) for each Group 1 Delivery Point		
6. Rate Schedule FT-P [1]	Refer to Attachment “3” for applicable FT-P Demand Rate per month		
7. Rate Schedule IT-R	Refer to Attachment “1” for applicable IT-R Rate for each Receipt Point		
8. Rate Schedule IT-D [1]	Refer to Attachment “2” for applicable IT-D Rate for each Delivery Point		
9. Rate Schedule FCS	The FCS Charge is determined in accordance with Attachment “1” to the applicable Schedule of Service		
10. Rate Schedule PT	Schedule No.	PT Rate	PT Gas Rate
	9021-01000-0	$1,138 / day	3.1 / 10^3m^3 / day
	9021-01000-1	$4,896 / day	11.0 / 10^3m^3 / day
	9022-01000-0	$1,690 / day	3.6 / 10^3m^3 / day
	9022-01001-0	$3,071 / day	11.0 / 10^3m^3 / day
	9022-01002-0	$3,997 / day	14.6 / 10^3m^3 / day
11. Rate Schedule OS	Schedule No.		Charge
	2022993541 / 2022956310		$127.71 / 10^3m^3 / month
	2022017998		$666 / month
	2003004522		Applicable IT-R and IT-D Rate
	2011476052 / 2011476054		$0.2753 / GJ subject to $717,000 Minimum Annual Charge
	2017887638 / 2011476092 2016721799 / 2016759254		$0.095 / GJ and $1,000 / month
	2021735873 / 2019305573		$7.54 / GJ / month and Applicable IT-D Rate on Over-Run
12. Rate Schedule CO_2	Tier	1 / 2 / 3	
	CO_2 Rate (/ 10^3m^3)	$625.19 / $494.89 / $324.51	
13. Monthly Abandonment Surcharge [2]		$6.94 /$10^3m^3$ /month	$0.18 /GJ /month
14. Daily Abandonment Surcharge [3]		$0.23 /$10^3m^3$ /day	$0.0060 /GJ /day
15. Federal Fuel Charge [4]	Marketable Natural Gas [5]		$0.1239 / m^3

1. Service under Rate Schedules FT-D, FT-P and IT-D for delivery stations identified in Attachment 2, and Rate Schedule OS No. 2011476092, are subject to the ATCO Pipelines Franchise Fees pursuant to paragraph 15.13 of the General Terms and Conditions.
2. Monthly Abandonment Surcharge applicable to Rate Schedules FT-R, FT-D, FT-P, FT-RN, FT-DW, and STFT, and the following Schedules OS: 2022993541, 2022956310, 2022017998, 2021735873, 2019305573.
3. Daily Abandonment Surcharge applicable to Rate Schedules IT-R, IT-D, the following Rate Schedules OS: 2003004522, 2011476052, 2011476054, 2017887638, 2011476092, 2016721799, 2016759254, and if applicable Over-Run Gas.
4. Collected on all deliveries of gas within Alberta pursuant to any Rate Schedule unless NGTL has received a valid exemption certificate pursuant to the Greenhouse Gas Pollution Pricing Act.
5. See FCN12 Canada Revenue Agency Administrative Position regarding Marketable Natural Gas under Part 1 of the Greenhouse Gas Pollution Pricing Act.

FOOTHILLS PIPE LINES LTD.

(3 pages)

TC Energy

450 – 1 Street SW
Calgary, Alberta T2P 5H1

Tel: (403) 920-2603
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Email: bernard_pelletier@tcenergy.com

November 4, 2022

Canada Energy Regulator
Suite 210, 517 Tenth Avenue SW
Calgary, Alberta T2R 0A8

Filed Electronically

Attention: Ms. Ramona Sladic, Secretary of the Commission

Dear Ms. Sladic:

Re: Foothills Pipe Lines Ltd. (Foothills)
Statement of Rates and Charges effective January 1, 2023

Foothills encloses for filing with the Commission pursuant to section 229(1)(a) of the *Canadian Energy Regulator Act* rates and charges for transportation service on Foothills Zones 6, 7, 8 and 9 to be effective January 1, 2023 (Effective 2023 Rates).

The following attachments are included with this letter:

- Attachment 1 consists of supporting Schedules A through G
- Attachments 2 and 3 are black-lined and clean copies, respectively, of the Table of Effective Rates for 2023

The rates and charges are based on the methodology approved in Order TG-8-2004, as amended by Order TG-03-2007.

The filing also includes the Foothills Abandonment Surcharges effective January 1, 2023, which are included in the Table of Effective Rates for 2023. The supporting information on the Abandonment Surcharge calculations are provided in the attached Schedule G.

Foothills met with customers and interested parties on October 27, 2022 and presented the preliminary 2023 revenue requirement, preliminary Effective 2023 Rates and preliminary Abandonment Surcharges. Based on this consultation, Foothills is not aware of any objections to its proposal for establishing the Effective 2023 Rates.

Foothills understands that any party that is opposed to the rates and charges will advise the Commission accordingly.

Foothills will notify its customers and interested parties of this filing and post a copy of it on TC Energy's Foothills System website at: http://www.tccustomerexpress.com/934.html

Communication regarding this filing should be directed to:

Andrew Pittet
Regulatory Project Manager
Tolls and Tariffs, Canadian Natural Gas Pipelines

Foothills Pipe Lines Ltd.
450 – 1 Street SW
Calgary, Alberta T2P 5H1

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Email: ashley_mitchell@tcenergy.com

Yours truly,
Foothills Pipe Lines Ltd.

Original signed by

Bernard Pelletier
Director, Regulatory Tolls and Tariffs
Canadian Natural Gas Pipelines

Attachments

cc: Foothills Firm Customers
Interruptible Customers and Interested Parties

TABLE OF EFFECTIVE RATES

1. Rate Schedule FT, Firm Transportation Service

	Demand Rate ($/GJ/Km/Month)
Zone 6	0.0059841968
Zone 7	0.0019358505
Zone 8*	0.0152423554
Zone 9	0.0156366328

2. Rate Schedule OT, Overrun Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 6	0.0002164148
Zone 7	0.0000700088

3. Rate Schedule IT, Interruptible Transportation Service

	Commodity Rate ($/GJ/Km)
Zone 8	0.0005512304
Zone 9	0.0005654892

4. Monthly Abandonment Surcharge**

All Zones	0.0919386987 ($/GJ/Month)

5. Daily Abandonment Surcharge***

All Zones	0.0030226421($/GJ/Day)

* For Zone 8, Customers Haul Distance shall be 170.7 km.

**Monthly Abandonment Surcharge applicable to Rate Schedule Firm Transportation Service, and Short Term Firm Transportation Service for all zones.

***Daily Abandonment Surcharge applicable to Rate Schedule Overrun Transportation Service for Zone 6 & 7, Interruptible Transportation Service for Zone 8 & 9, and Small General Service for Zone 9.

GAS TRANSMISSION NORTHWEST LLC

(6 pages)

Document Accession #: 20211118-3098 Filed Date: 11/18/2021

177 FERC ¶ 61,110
FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

November 18, 2021

In Reply Refer To:
Gas Transmission Northwest LLC
Docket No. RP15-904-003

Gas Transmission Northwest LLC
Wright & Talisman P.C.
1200 G Street NW
Suite 600
Washington, DC 20005

Attention: Joseph S. Koury, Attorney

Dear Mr. Koury:

1. On September 29, 2021, Gas Transmission Northwest LLC (GTN) filed a stipulation and agreement (Settlement) pursuant to Rule 207 of the Commission's Rules of Practice and Procedure.[1] The Settlement is submitted in lieu of a Natural Gas Act (NGA) section 4 general rate case filing and fulfills GTN's obligation, established in earlier proceedings, to submit rates to be effective no later than April 1, 2022.[2] GTN believes that the Settlement is supported or unopposed by all of its shippers and other interested parties. As discussed below, we approve the Settlement as proposed to be effective January 1, 2022**.**

2. Previously, the Commission approved a settlement filed by GTN on June 30, 2015 (2015 Settlement)[3] and an amendment to that 2015 Settlement on November 30, 2018.[4]

---

[1] 18 C.F.R. § 385.207(a)(5) (2020).

[2] *Gas Transmission Northwest LLC*, 151 FERC ¶ 61,280 (2015); *Gas Transmission Northwest LLC*, 165 FERC ¶ 61,195 (2018) (approving 2018 settlement amending an earlier settlement); *Gas Transmission Northwest LLC*, 175 FERC ¶ 61,250 (2021) (extending deadline for rate filing under earlier settlements).

[3] *Gas Transmission Northwest LLC*, 151 FERC ¶ 61,280 (2015).

[4] *Gas Transmission Northwest LLC*, 165 FERC ¶ 61,195 (2018).

On June 4, 2021, GTN filed a motion to extend GTN's obligation to file an NGA section 4 rate case until April 1, 2022. The Commission approved the extension of time on June 28, 2021.[5]

3. This Settlement resolves issues regarding GTN's rates and rate filing obligations. The Settlement maintains existing tariff recourse rates and establishes depreciation rates and a carbon tax regulatory asset. It also provides for the establishment of income tax allowance and accumulated deferred income tax in the future. In addition, it establishes that after December 31, 2023, GTN will report to settling parties the expenses, capital expenditures and amounts recovered relating to dithiazine contamination and remediation.

4. GTN states that the Settlement establishes a rate case moratorium through December 31, 2023 and a comeback provision to file for rates to become effective no later than April 1, 2024, accounting for any Commission-imposed suspension period. GTN further states that the standard of review for modifications by the Commission to the terms of the Settlement "shall be the most stringent standard permissible under applicable law."[6]

5. Public notice of the filing was issued on October 1, 2021. Interventions and protests were due as provided in section 154.210 of the Commission's regulations.[7] Pursuant to Rule 214,[8] all timely filed motions to intervene are granted. The Canadian Association of Petroleum Producers intervened, supporting the Settlement. No protests or adverse comments were filed.

6. The Settlement appears to provide that the standard of review applicable to modifications to the Settlement proposed by third parties and the Commission acting *sua sponte* "shall be the most stringent standard permissible under applicable law."[9] Although we do not decide in this order what standard of review applies to the Settlement or any component of it, we clarify the framework that would apply if the Commission were required to determine the standard of review in a later challenge to the Settlement by a third party or the Commission acting *sua sponte*.

[5] *Gas Transmission Northwest LLC*, 175 FERC ¶ 61,250 (2021).

[6] Settlement at article V and article XIII.

[7] 18 C.F.R. § 154.210 (2020).

[8] 18 C.F.R. § 385.214 (2020).

[9] Settlement at article V and article XIII.

7. The *Mobile-Sierra* "public interest" presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitute contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption. In *New England Power Generators Association v. FERC*,[10] however, the Court of Appeals for the D.C. Circuit determined that the Commission is legally authorized to impose a more rigorous application of the statutory "just and reasonable" standard of review on future changes to agreements that fall within the second category described above.

8. We find that the uncontested Settlement appears to be fair and reasonable and in the public interest. The Settlement is supported or not opposed by all parties to the proceeding and establishes a rate moratorium. Therefore, we approve the Settlement as proposed to be effective January 1, 2022. The Commission's approval of the Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

By direction of the Commission. Commissioner Danly is concurring with a separate statement attached.

Kimberly D. Bose,
Secretary.

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[10] *New England Power Generators Ass'n v. FERC*, 707 F.3d 364, 370-371 (D.C. Cir. 2013).

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Gas Transmission Northwest LLC   Docket No. RP15-904-003

(Issued November 18, 2021)

DANLY, Commissioner, *concurring*:

I agree with the Commission's decision to approve Gas Transmission Northwest LLC's Amended and Restated Stipulation and Agreement of Settlement (Settlement).[1] As I stated in my dissent in *Kinetica Deepwater Express, LLC*, I suggest to anyone participating in the natural gas industry that it might be prudent to be clearer in your settlement agreements as to whether you are actually a party to that agreement.[2] Though I understand that defining "Settling Parties" as parties that "either support or do not oppose"[3] the Settlement is common in the industry, situations will almost certainly arise in which an entity's status as party or non-party to a settlement will be dispositive. This will be even more important should the issue be presented to a body less indifferent to fundamentals of contract law than this Commission.

For these reasons, I respectfully concur.

____
James P. Danly
Commissioner

[1] *Gas Transmission Nw. LLC*, 177 FERC ¶ 61,110 (2021).

[2] *Kinetica Deepwater Express, LLC*, 175 FERC ¶ 61,048 (2021) (Danly, Comm'r, concurring in part and dissenting in part at P 10 n.12).

[3] Settlement at Art. III(A) and App. A.

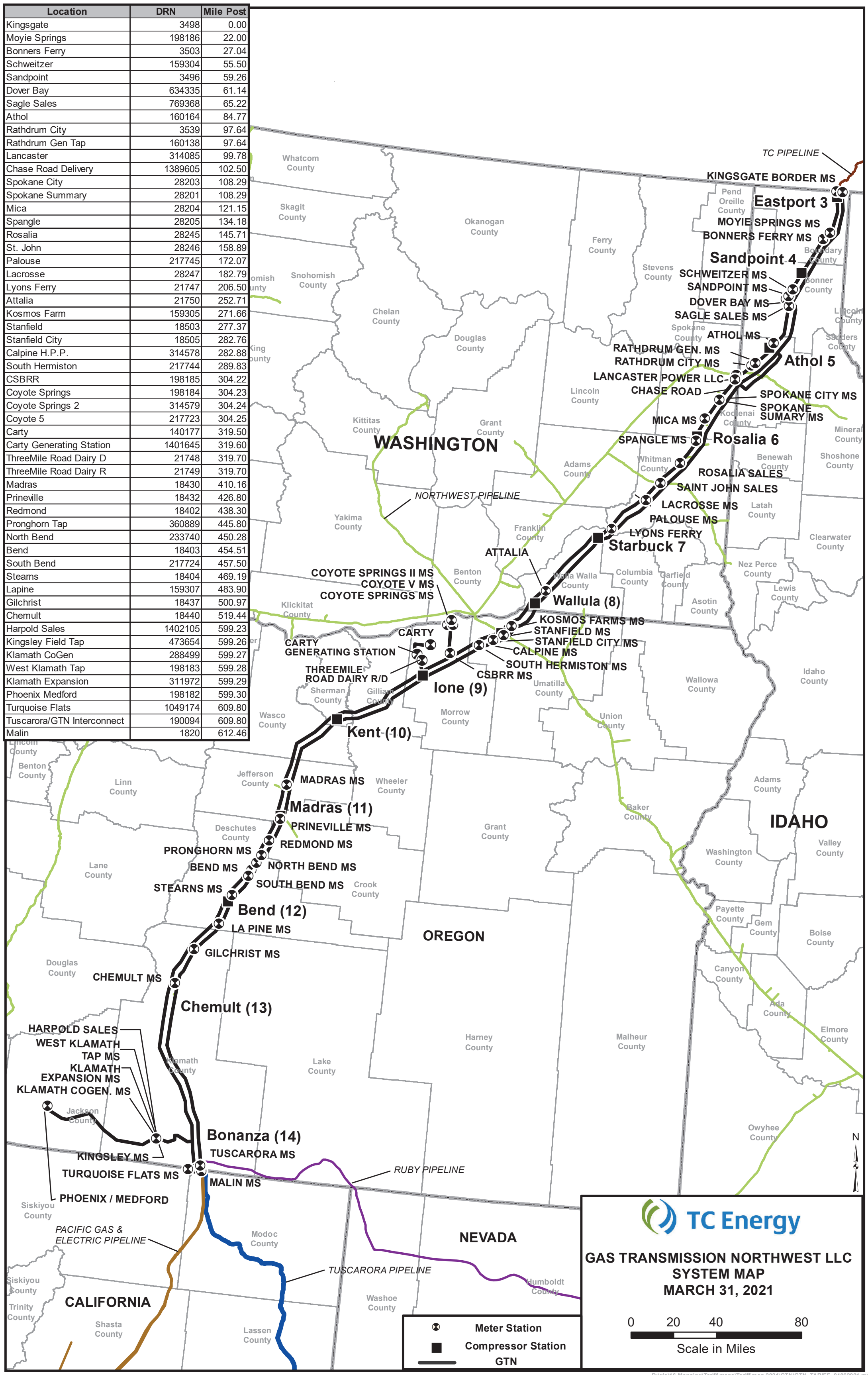
STATEMENT OF EFFECTIVE RATES AND CHARGES FOR
TRANSPORTATION OF NATURAL GAS

Rate Schedules FTS-1, LFS-1, and FHS

For Rate Schedules FTS-1 and LFS-1:

	RESERVATION DAILY MILEAGE (a) (Dth-MILE)		RESERVATION DAILY NON-MILEAGE (b) (Dth)		DELIVERY (c) (Dth-MILE)		FUEL (d) (Dth-MILE)	
	Max.	Min.	Max.	Min.	Max.	Min.	Max.	Min.
BASE	0.000362	0.000000	0.028612	0.000000	0.000016	0.000016	0.0050%	0.0000%
STF (e)	(e)	0.000000	(e)	0.000000	0.000016	0.000016	0.0050%	0.0000%
EXTENSION CHARGES								
MEDFORD								
E-1 (f)	0.002511	0.000000	0.004223	0.000000	0.000026	0.000026	---	---
E-2 (h) (Diamond 1)	0.002972	0.000000	---	---	0.000000	0.000000	---	---
E-2 (h) (Diamond 2)	0.001166	0.000000	---	---	0.000000	0.000000	---	---
COYOTE SPRINGS								
E-3 (i)	0.001167	0.000000	0.001168	0.000000	0.000000	0.000000	---	---
CARTY LATERAL								
E-4 (p)	---	---	0.151492	0.000000	0.000000	0.000000	---	---
OVERRUN CHARGE (j)	---	---	---	---	---	---	---	---
SURCHARGES								
ACA (k)	---	---	---	---	(k)	(k)	---	---

Location	DRN	Mile Post
Kingsgate	3498	0.00
Moyie Springs	198186	22.00
Bonners Ferry	3503	27.04
Schweitzer	159304	55.50
Sandpoint	3496	59.26
Dover Bay	634335	61.14
Sagle Sales	769368	65.22
Athol	160164	84.77
Rathdrum City	3539	97.64
Rathdrum Gen Tap	160138	97.64
Lancaster	314085	99.78
Chase Road Delivery	1389605	102.50
Spokane City	28203	108.29
Spokane Summary	28201	108.29
Mica	28204	121.15
Spangle	28205	134.18
Rosalia	28245	145.71
St. John	28246	158.89
Palouse	217745	172.07
Lacrosse	28247	182.79
Lyons Ferry	21747	206.50
Attalia	21750	252.71
Kosmos Farm	159305	271.66
Stanfield	18503	277.37
Stanfield City	18505	282.76
Calpine H.P.P.	314578	282.88
South Hermiston	217744	289.83
CSBRR	198185	304.22
Coyote Springs	198184	304.23
Coyote Springs 2	314579	304.24
Coyote 5	217723	304.25
Carty	140177	319.50
Carty Generating Station	1401645	319.60
ThreeMile Road Dairy D	21748	319.70
ThreeMile Road Dairy R	21749	319.70
Madras	18430	410.16
Prineville	18432	426.80
Redmond	18402	438.30
Pronghorn Tap	360889	445.80
North Bend	233740	450.28
Bend	18403	454.51
South Bend	217724	457.50
Stearns	18404	469.19
Lapine	159307	483.90
Gilchrist	18437	500.97
Chemult	18440	519.44
Harpold Sales	1402105	599.23
Kingsley Field Tap	473654	599.26
Klamath CoGen	288499	599.27
West Klamath Tap	198183	599.28
Klamath Expansion	311972	599.29
Phoenix Medford	198182	599.30
Turquoise Flats	1049174	609.80
Tuscarora/GTN Interconnect	190094	609.80
Malin	1820	612.46



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MOUNTAINWEST PIPELINE, LLC

(2 pages)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

MountainWest Pipeline, LLC
Docket No. RP23-222-000

Issued: December 15, 2022

On November 30, 2022, MountainWest Pipeline, LLC filed a tariff record[1] to reflect a decrease in its Fuel Gas Reimbursement Percentage from 1.05% to 0.90%. Pursuant to authority delegated to the Director, Division of Pipeline Regulation, under 18 C.F.R. § 375.307, the tariff record is accepted, effective January 1, 2023, as requested.

The filing was publicly noticed. No protests or adverse comments were filed. Pursuant to Rule 214 of the Commission's regulations (18 C.F.R. § 385.214), notices of intervention, timely-filed motions to intervene, and any unopposed motions to intervene out-of-time filed before the issuance date of this order are granted.

This action shall not be construed as a waiver of the requirements of section 7 of the Natural Gas Act, as amended; nor shall it be construed as constituting approval of the referenced filing or of any rate, charge, classification, or any rule, regulation, or practice affecting such rate or service contained in the applicant's tariff; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicant.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Issued by: Marsha K. Palazzi, Director, Division of Pipeline Regulation

[1] MountainWest Pipeline, LLC, Tariffs, Statement of Rates, Statement of Rates (21.0.0).

STATEMENT OF RATES

Rate Schedule/ Type of Charge (a)	Base Tariff Rate ($) (b)
PEAKING STORAGE	
Firm Peaking Storage Service - PKS	
Monthly Reservation Charge	
Maximum 4/	2.87375
Minimum	0.00000
Usage Charge	
Injection	0.03872
Withdrawal	0.03872
CLAY BASIN STORAGE	
Firm Storage Service - FSS	
Monthly Reservation Charge	
Deliverability	
Maximum 4/	2.85338
Minimum	0.00000
Capacity	
Maximum	0.02378
Minimum	0.00000
Usage Charge	
Injection1/	0.01049
Withdrawal	0.01781
Authorized Overrun Charge	
Maximum1/	0.30315
Minimum1/	0.01781
Interruptible Storage Service - ISS	
Usage Charge	
Inventory 5/	
Maximum	0.05927
Minimum	0.00000
Injection1/	0.01049
Withdrawal	0.01781
OPTIONAL VOLUMETRIC RELEASES /	
Peaking Storage Service - PKS	
Maximum 4/	3.40890
Minimum	0.00000
Firm Storage Service - FSS	
Maximum 4/	0.57068
Minimum	0.00000
Storage Usage Charges Applicable to Volumetric Releases 6/	
Peaking Storage Service - PKS:	
Injection	0.03872
Withdrawal	0.03872
Clay Basin Storage Service - FSS:	
Injection1/	0.01049
Withdrawal	0.01781
PARK AND LOAN SERVICE - PAL1	
Daily Charge	
Maximum	0.30315
Minimum	0.00000
Delivery Charge1/	0.02830

FUEL REIMBURSEMENT - 2.0% (0.2% utility and 1.8% compressor fuel) for Rate Schedule PAL1

FEDERAL ENERGY REGULATORY COMMISSION

ANNUAL CHARGES UNIT CHARGE

(1 page)

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2023 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 21, 2023

The annual charges unit charge (ACA) to be applied to in fiscal year 2024 for recovery of FY 2023 Current year and 2022 True-Up is **$0.0015** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2023.

The following calculations were used to determine the FY 2023 unit charge:

2023 CURRENT:

Estimated Program Cost $97,675,000 divided by 67,029,494,482 Dth	=	0.0014571943

2022 TRUE-UP:

Debit/Credit Cost $1,034,580 divided by 62,791,351,082 Dth	=	0.0000164765
TOTAL UNIT CHARGE	=	0.0014736708

If you have any questions, please contact Raven A. Rodriguez at (202)502-6276 or e-mail at Raven.Rodriguez@ferc.gov.

EXHIBIT NOS. 5-13

CASE NO. INT-G-23-04

INTERMOUNTAIN GAS COMPANY

(9 pages)

INTERMOUNTAIN GAS COMPANY
Summary of Gas Cost Changes

Line No.	Description	Annual Therms/ Billing Determinants INT-G-22-04	10/1/2022 & 2/1/2023 Prices INT-G-22-04 & INT-G-22-08	Total Annual Cost INT-G-22-04	Annual Therms/ Billing Determinants INT-G-23-04	10/1/2023 Prices INT-G-23-04	Total Annual Cost INT-G-23-04	Annual Difference	INT-G-23-04 Cost of Gas Allocators [1] RS	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**DEMAND CHARGES:**										
2	**Transportation:**										
3	NWP TF-1 Reservation (Full Rate) [2]	894,757,350	$ 0.03947	$ 35,317,622	897,208,740	$ 0.03756	$ 33,701,180	$ (1,616,442)	$ (1,104,612)	$ (486,053)	$ (25,777)
4	NWP TF-1 Reservation (Discounted) [3]	376,479,600	0.01580	5,949,095	344,588,640	0.01571	5,415,165	(533,930)	(364,866)	(160,549)	(8,515)
5	Upstream Capacity (Full Rate) [4]	921,690,430	0.01121	10,328,889	1,015,533,931	0.02894	29,388,759	19,059,870	13,024,753	5,731,169	303,948
6	Upstream Capacity (Discounted) [5]	452,311,650	0.02006	9,071,484	453,550,860	0.02121	9,620,616	549,132	375,255	165,120	8,757
7	**Storage:**										
8	SGS-2F										
9	Demand	303,370	0.00156	172,962 [6]	303,370	0.00222	245,990 [7]	73,028	49,904	21,959	1,165
10	Capacity Demand	10,920,990	0.00006	227,209 [6]	10,920,990	0.00008	323,102 [7]	95,894	65,530	28,835	1,529
11	TF-2 Reservation	10,920,990	0.03903	426,272	10,920,990	0.03728	407,081	(19,191)	(13,114)	(5,771)	(306)
12	TF-2 Redelivery Charge	10,920,990	0.00083	9,086	10,920,990	0.00094	10,211	1,125	769	338	18
13	LS-2F										
14	Demand	1,551,750	0.00259	1,465,249 [6]	1,551,750	0.00313	1,777,421 [7]	312,172	213,326	93,868	4,978
15	Capacity	14,751,350	0.00033	1,782,187 [6]	14,751,350	0.00040	2,160,567 [7]	378,380	258,570	113,776	6,034
16	Liquefaction	14,751,350	0.09086	1,340,234	14,751,350	0.05865	865,108	(475,126)	(324,682)	(142,867)	(7,577)
17	Vaporization	14,751,350	0.00339	49,948	14,751,350	0.00727	107,272	57,324	39,173	17,237	914
18	TF-2 Reservation	14,751,350	0.03903	575,725	14,751,350	0.03727	549,803	(25,922)	(17,714)	(7,795)	(413)
19	TF-2 Redelivery Charge	14,751,350	0.00083	12,273	14,751,350	0.00094	13,793	1,520	1,039	457	24
20	Other Storage Facilities							- [8]	-	-	-
21	**COMMODITY CHARGES:**										
22	Total Producer/Supplier Purchases Including Storage	440,589,194	0.52808	232,666,342	440,589,194	0.30455	134,181,439	(98,484,903) [9]	(63,780,335)	(31,404,572)	(3,299,996)
23	**TOTAL ANNUAL COST DIFFERENCE**							$ (80,627,069)	$ (51,577,004)	$ (26,034,848)	$ (3,015,217)
24	Normalized Sales Volumes (1/1/22 - 12/31/22)								285,332,326	140,493,766	14,763,102
25	Average Base Rate Change (Line 23 divided by Line 24)								$ (0.18076)	$ (0.18531)	$ (0.20424)
26	**Other Permanent Changes Proposed:**										
27	Elimination of Temporary Credits (Surcharges) from Case No. INT-G-22-04								0.00057	(0.01445)	(0.03247)
28	Adjustment to Fixed Cost Collection Rate [10]								(0.00457)	(0.01480)	(0.01194)
29	**Total Permanent Changes Proposed (Lines 25 through 28)**								(0.18476)	(0.21456)	(0.24865)
30	Temporary Surcharge (Credit) Proposed [11]								(0.00078)	(0.00377)	0.03253
31	**Proposed Average Per Therm Change in Intermountain Gas Company Tariff (Lines 29 through 30)**								$ (0.18554)	$ (0.21833)	$ (0.21612)

(1) See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)
(2) See Workpaper No. 1, Page 1
(3) See Workpaper No. 1, Page 2
(4) See Workpaper No. 2, Page 1
(5) See Workpaper No. 2, Page 2
(6) Price Reflects Daily Charge; Column (d) equals Column (b) times Column (c) times 365. Actual prices include 6 decimals.
(7) Price Reflects Daily Charge; Column (g) equals Column (e) times Column (f) times 366. Actual prices include 6 decimals.
(8) See Workpaper No. 3, Line 29, Column (e)
(9) Line 22 Column (f) minus Column (c) times Line 24 Columns (i) - (k)
(10) See Exhibit No. 6, Line 25, Columns (e) - (g)
(11) See Exhibit No. 7, Line 7, Columns (b) - (d)

INTERMOUNTAIN GAS COMPANY
Gas Transportation and Storage Costs
From Case No. INT-G-22-04

Line No.	Description	Annual Therms/ Billing Determinants INT-G-22-04	10/1/2022 Prices INT-G-22-04	Annual Cost INT-G-22-04	INT-G-23-04 Cost of Gas Allocators [1] RS	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**DEMAND CHARGES:**						
2	**Transportation:**						
3	NWP TF-1 Reservation (Full Rate)	894,757,350	$ 0.03947	$ 35,317,622	$ 24,134,650	$ 10,619,762	$ 563,210
4	NWP TF-1 Reservation (Discounted)	376,479,600	0.01580	5,949,095	4,065,374	1,788,851	94,870
5	Upstream Capacity (Full Rate)	921,690,430	0.01121	10,328,889	7,058,349	3,105,825	164,715
6	Upstream Capacity (Discounted)	452,311,650	0.02006	9,071,484	6,199,089	2,727,732	144,663
7	**Storage:**						
8	SGS-2F						
9	Demand	303,370	0.00156	172,962 [2]	118,196	52,008	2,758
10	Capacity Demand	10,920,990	0.00006	227,209 [2]	155,266	68,320	3,623
11	TF-2 Reservation	10,920,990	0.03903	426,272	291,297	128,177	6,798
12	TF-2 Redelivery Charge	10,920,990	0.00083	9,086	6,209	2,732	145
13	LS-2F						
14	Demand	1,551,750	0.00259	1,465,249 [2]	1,001,293	440,590	23,366
15	Capacity	14,751,350	0.00033	1,782,187 [2]	1,217,875	535,891	28,421
16	Liquefaction	14,751,350	0.09086	1,340,234	915,862	402,999	21,373
17	Vaporization	14,751,350	0.00339	49,948	34,132	15,019	797
18	TF-2 Reservation	14,751,350	0.03903	575,725	393,428	173,116	9,181
19	TF-2 Redelivery Charge	14,751,350	0.00083	12,273	8,387	3,690	196
20	Other Storage Facilities			2,585,620 [3]	1,766,909	777,478	41,233
21	**Total Fixed Gas Cost Charges**			$ 69,313,855	$ 47,366,316	$ 20,842,190	$ 1,105,349
22	Estimated Sales Volumes (10/1/23 - 9/30/24)				297,771,759	143,642,539	14,707,000
23	Fixed Cost Collection per Therm (Line 21 divided by Line 22)				$ 0.15907	$ 0.14510	$ 0.07516
24	INT-G-22-04 Fixed Cost Collection per Therm				0.16364	0.15990	0.08710
25	**Adjustment to Fixed Cost Collection (Line 23 minus Line 24)**				$ (0.00457)	$ (0.01480)	$ (0.01194)
26	**GAS TRANSPORTATION COST CALCULATION:**						
27	Adjusted Fixed Cost Collection Per Therm (Line 23)				$ 0.15907	$ 0.14510	$ 0.07516
28	Incremental Fixed Cost Collection [4]				0.04277	0.03822	0.01929
29	**INT-G-23-04 Gas Transportation Cost (Lines 27 through 28)**				$ 0.20184	$ 0.18332	$ 0.09445

(1) See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)
(2) Price Reflects Daily Charge; Column (d) equals Column (b) times Column (c) times 365. Actual prices include 6 decimals.
(3) See Workpaper No. 3, Line 14, Column (e)
(4) See Exhibit No. 5, sum of Lines 1 - 20 divided by Line 24, Columns (i) - (k)

INTERMOUNTAIN GAS COMPANY
Summary of Proposed Temporary Surcharges (Credits)

Line No.	Description	RS	GS-1	LV-1	T-3	T-4
	(a)	(b)	(c)	(d)	(e)	(f)
1	Management of Pipeline Transportation Capacity [1]	$ (0.01375)	$ (0.01229)	$ (0.00620)	$ -	$ -
2	Proposed Temporary Surcharge (Credit) - Fixed Costs [2]	(0.04846)	(0.05076)	(0.02204)	-	-
3	Proposed Temporary Surcharge (Credit) - Variable Costs	0.06156 [3]	0.06156 [3]	0.06195 [4]	(0.00031) [5]	(0.00587) [6]
4	LNG Sales Credits [7]	(0.00263)	(0.00234)	(0.00118)	-	(0.01827)
5	Deferred In-Person Payment Fees [8]	0.00009	0.00006	-	-	-
6	Residential Energy Efficiency Funds [9]	0.00241	-	-	-	-
7	**Total Proposed Temporary Surcharges (Credits)**	$ (0.00078)	$ (0.00377)	$ 0.03253	$ (0.00031)	$ (0.02414)

[1] See Exhibit No. 8, Line 5, Columns (c) - (e)
[2] See Exhibit No. 9, Line 9, Columns (c) - (e)
[3] See Exhibit No. 10, Line 6, Column (b) plus Line 14, Column (b)
[4] See Exhibit No. 10, Line 6, Column (b) plus Line 22, Column (b)
[5] See Exhibit No. 10, Line 22, Column (b)
[6] See Exhibit No. 10, Line 28, Column (b)
[7] See Exhibit No. 11, Line 7, Columns (c) - (f)
[8] See Exhibit No. 12, Line 6, Columns (c) - (d)
[9] See Exhibit No. 13, Line 5, Column (c)

INTERMOUNTAIN GAS COMPANY

Allocation of Annualized Credits Resulting from Management of Pipeline Transportation Capacity

			INT-G-23-04 Cost of Gas Allocators [1]		
Line No.	**Description**	**Total**	**RS**	**GS-1**	**LV-1**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**
1	Long-term Northwest Pipeline Capacity Releases	$ (4,010,000)	$ (2,740,274)	$ (1,205,779)	$ (63,947)
2	Upstream Pipeline Capacity Releases	(1,730,000)	(1,182,213)	(520,199)	(27,588)
3	**Total Management of Pipeline Transportation Capacity**	$ (5,740,000)	$ (3,922,487)	$ (1,725,978)	$ (91,535)
4	Normalized Sales Volumes (1/1/22 - 12/31/22)		285,332,326	140,493,766	14,763,102
5	**Proposed Per Therm Price Adjustment**		$ (0.01375)	$ (0.01229)	$ (0.00620)

[1] See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)

INTERMOUNTAIN GAS COMPANY
Proposed Temporary Surcharges (Credits) - Fixed Costs

Line No.	Description	Deferred Account 1910 Estimated Sept. 30, 2023 Balance [1]	RS	GS-1	LV-1
	(a)	(b)	(c)	(d)	(e)
1	Fixed Gas Cost Balance Approved in Prior PGA (Accounts 1910.2050 - 2090) [2]	$ 1,161,830	$ 709,214	$ 432,470	$ 20,146
2	Fixed Cost Collection Adjustment (Account 1910.2200) [2]	(22,166,389)	(14,316,317)	(7,510,190)	(339,882)
3	Capacity Releases (Account 1910.2320) [3]	(1,000,253)	(683,533)	(300,769)	(15,951)
4	Interest (Account 1910.2430) [3]	(554,660)	(379,033)	(166,782)	(8,845)
5	Pipeline Transportation Capacity Release Credit (Account 1910.2530) [2]	(6,402,719)	(4,306,276)	(1,992,168)	(104,275)
6	Amortization of 1910.2530 (Accounts 1910.2540 - 2550) [2]	7,678,302	5,149,036	2,405,820	123,446
7	**Total Fixed Costs**	$ (21,283,889)	$ (13,826,909)	$ (7,131,619)	$ (325,361)
8	Normalized Sales Volumes (1/1/22 - 12/31/22)		285,332,326	140,493,766	14,763,102
9	**Proposed Temporary Surcharge (Credit) - Fixed Costs**		$ (0.04846)	$ (0.05076)	$ (0.02204)

(1) See Workpaper No. 5, Pages 3 and 4
(2) See INT-G-22-04 Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)
(3) See Allocation Factor on Workpaper No. 4, Line 5, Columns (b) - (d)

INTERMOUNTAIN GAS COMPANY

Proposed Temporary Surcharges (Credits) - Variable Costs

Line No.	Description		Amount	
	(a)		(b)	
1	**Variable Amounts Which Apply to RS, GS-1, and LV-1:**			
2	Account 1910 Variable Costs	$	24,218,419	(1)
3	Short-Term Interest Expense		3,212,406	(2)
4	Total Variable Costs	$	27,430,825	
5	Normalized Sales Volumes (1/1/22 - 12/31/22)		440,589,194	
6	**Proposed Temporary Surcharge (Credit) - Variable Costs**	$	0.06226	
7	**Lost and Unaccounted For Gas Amounts Which Apply to RS and GS-1:**			
8	Lost and Unaccounted For Gas Amounts from INT-G-22-04 (Account 1910.2120)	$	(911,923)	(3)
9	Lost and Unaccounted For Gas Amortization (Account 1910.2130)		1,048,325	(4)
10	(Over)/Under Collection of Lost and Unaccounted For Gas from INT-G-22-04		136,402	
11	Lost and Unaccounted For Gas INT-G-23-04		(432,866)	(5)
12	Total Lost and Unaccounted For Gas Amounts Which Apply to RS and GS-1	$	(296,464)	
13	Normalized Sales Volumes (1/1/22 - 12/31/22)		425,826,092	
14	**Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs**	$	(0.00070)	
15	**Lost and Unaccounted For Gas Amounts Which Apply to LV-1, T-3, and T-4:**			
16	Lost and Unaccounted For Gas Amounts from INT-G-22-04 (Account 1910.2120)	$	(311,162)	(6)
17	Lost and Unaccounted For Gas Amortization (Account 1910.2140)		333,795	(7)
18	(Over)/Under Collection of Lost and Unaccounted For Gas from INT-G-22-04		22,633	
19	Lost and Unaccounted For Gas INT-G-23-04		(145,718)	(8)
20	Total Lost and Unaccounted For Gas Amounts Which Apply to LV-1, T-3, and T-4	$	(123,085)	
21	Normalized Sales Volumes (1/1/22 - 12/31/22)		399,061,477	
22	**Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs**	$	(0.00031)	
23	**Convert T-4 Lost and Unaccounted For Temporary from a Volumetric Rate to a Demand Rate:**			
24	Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For Gas Costs (Line 22)	$	(0.00031)	
25	Normalized T-4 Sales Volumes (1/1/22 - 12/31/22)		340,008,634	
26	Total Temporary Collected	$	(105,403)	
27	Billing Determinants Demand Volumes		17,962,920	
28	**Proposed Temporary Surcharge (Credit) - Lost and Unaccounted For T-4 Demand Rate (Line 26 Divided by Line 27)**	$	(0.00587)	

(1) See Workpaper No. 5, Page 1, Line 16, Column (f)
(2) See Workpaper No. 7, Line 8, Column (b)
(3) See Workpaper No. 5, Page 2, Line 2, Column (c)
(4) See Workpaper No. 5, Page 2, Line 8, Column (d)
(5) See Workpaper No. 5, Page 2, Line 30, Column (d), plus Line 36, Column (e)
(6) See Workpaper No. 5, Page 2, Line 3, Column (c)
(7) See Workpaper No. 5, Page 2, Line 14, Column (d)
(8) See Workpaper No. 5, Page 2, Line 31, Column (d), plus Line 40, Column (e)

INTERMOUNTAIN GAS COMPANY
Allocation of LNG Sales Credits

Line No.	Description	Deferred Account 1910 Estimated Sept. 30, 2023 Balance [1]	RS	GS-1	LV-1	T-4
	(a)	(b)	(c)	(d)	(e)	(f)
1	LNG Sales Credit Approved in Prior PGA (Accounts 1910.2800 - 2810) [2]	$ 41,015	$ 21,030	$ 10,543	$ 514	$ 8,928
2	Interest (Account 1910.2815) [3]	(23,608)	(12,418)	(5,464)	(290)	(5,436)
3	LNG Sales Deferral - Margin Sharing (Account 1910.2820) [3]	(1,311,319)	(689,776)	(303,517)	(16,096)	(301,930)
4	LNG Sales Deferral - O&M Recovery (Account 1910.2825) [3]	(129,188)	(67,955)	(29,902)	(1,586)	(29,745)
5	**Total LNG Sales Credits**	$ (1,423,100)	$ (749,119)	$ (328,340)	$ (17,458)	$ (328,183)
6	Normalized Sales Volumes (1/1/22 - 12/31/22)		285,332,326	140,493,766	14,763,102	17,962,920 [4]
7	**Proposed Price Adjustment Per Therm**		$ (0.00263)	$ (0.00234)	$ (0.00118)	$ (0.01827)

(1) See Workpaper No. 5, Page 4, Lines 22 - 46
(2) Balance tracked by rate class
(3) See Allocation Factor on Workpaper No. 4, Line 10, Columns (b) - (f)
(4) Annualized T-4 Contract Demand

INTERMOUNTAIN GAS COMPANY
Allocation of Deferred In-Person Payment Fees

Line No.	Description	Deferred Account 1823.7500 Estimated Sept. 30, 2023 Balance [1]	RS	GS-1
	(a)	(b)	(c)	(d)
1	Deferred In-Person Payment Fees Approved in Prior PGA (Account 1823.7500) [2]	$ 70,371	$ 51,062	$ 19,309
2	Amortization of Deferred In-Person Payment Fees Approved in Prior PGA [2]	(82,521)	(59,464)	(23,057)
3	Deferred In-Person Payment Fees (7/1/2022 - 1/31/2023) [3]	44,611	32,671	11,940
4	**Total Deferred In-Person Payment Fees**	$ 32,461	$ 24,269	$ 8,192
5	Normalized Sales Volumes (1/1/22 - 12/31/22)		285,332,326	140,493,766
6	**Proposed Price Adjustment Per Therm**		$ 0.00009	$ 0.00006

(1) See Workpaper No. 5, Page 6
(2) Balance tracked by rate class
(3) See Allocation Factor on Workpaper No. 4, Line 13, Columns (b) - (c)

INTERMOUNTAIN GAS COMPANY
Residential Energy Efficiency Funds

Line No.	Description	Deferred Account 2540.38107 Estimated Sept. 30, 2023 Balance (1)	RS
	(a)	(b)	(c)
1	Energy Efficiency Credit Approved in Prior PGA (Account 2540.38107)	$ (4,850,000)	$ (4,850,000)
2	Amortization of Energy Efficiency Credit Approved in Prior PGA	5,536,777	5,536,777
3	**Total Residential Energy Efficiency Funds - Over-Refund**	$ 686,777	$ 686,777
4	Normalized Sales Volumes (1/1/22 - 12/31/22)		284,776,158 (2)
5	**Proposed Per Therm Price Adjustment**		$ 0.00241

(1) See Workpaper No. 5, Page 7

(2) Does not include volumes for the IS-R rate class because the Energy Efficiency Charge is not applicable to Rate Schedule IS-R.

NEWS RELEASE

and

CUSTOMER NOTICE

CASE NO. INT-G-23-04

INTERMOUNTAIN GAS COMPANY

(2 pages)

NEWS RELEASE

INTERMOUNTAIN GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.

Intermountain Gas Company files decrease in prices as part of PGA filing

BOISE, ID – ***August 14, 2023*** – Intermountain Gas Company filed its annual purchased gas cost adjustment (PGA) application with the Idaho Public Utilities Commission to decrease its prices by an average of 20.6% or approximately $86.9 million. The PGA application is filed each year to ensure the costs Intermountain incurs on behalf of its customers are reflected in its sales prices. If approved, the decrease would be effective Oct. 1, 2023.

The primary reason for the proposed PGA decrease is a significant decrease in estimated gas commodity costs for the upcoming year when compared to Intermountain's recently approved interim PGA. If approved, a typical residential customer would see a monthly decrease of $11.96, or 19.3% based on average weather and usage. Commercial customers, on average, would see a decrease of $72.88, or 24.4%, per month. The cost of natural gas is a straight passthrough to customers; Intermountain does not earn a profit on the cost of natural gas.

Intermountain Gas urges all customers to use energy wisely. For more information about the company's energy efficiency program and available rebates for installing high efficiency equipment, visit www.intgas.com/saveenergy. Conservation tips, information on government payment energy assistance and programs to help consumers level out their energy bills over the year can be found on the company's website www.intgas.com.

The request is a proposal and is subject to public review and approval by the PUC. A copy of the applications are available for review at the commission, its homepage www.puc.idaho.gov, as well as the company's website www.intgas.com. Written comments regarding the applications may be filed with the commission. Customers may also subscribe to the commission's RSS feed to review periodic updates via email.

Intermountain Gas Company is a natural gas distribution company serving approximately 412,500 residential, commercial and industrial customers in 74 communities in southern Idaho. Intermountain is a subsidiary of MDU Resources Group, Inc., a member of the S&P MidCap 400 and the S&P High-Yield Dividend Aristocrats indices that provides essential products and services through its regulated energy delivery and construction services businesses. For more information about MDU Resources, see the company's website at www.mdu.com. For more information about Intermountain, visit www.intgas.com.

Media Contact: Mark Hanson at 701-530-1093 or mark.hanson@mduresources.com.

CUSTOMER NOTICE

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Intermountain Gas urges all customers to use energy wisely. For more information about the company's energy efficiency program and available rebates for installing high efficiency equipment, visit **www.intgas.com/saveenergy.** Conservation tips, information on government payment energy assistance and programs to help consumers level out their energy bills over the year can be found on the company's website **www.intgas.com.**

(continued on reverse side)

The request is a proposal and is subject to public review and approval by the PUC. A copy of the applications are available for review at the commission, its homepage www.puc.idaho.gov, as well as the company's website www.intgas.com. Written comments regarding the applications may be filed with the commission. Customers may also subscribe to the commission's RSS feed to review periodic updates via email.

Intermountain Gas Company is a natural gas distribution company serving approximately 412,500 residential, commercial and industrial customers in 74 communities in southern Idaho. Intermountain is a subsidiary of MDU Resources Group, Inc., a member of the S&P MidCap 400 and the S&P High-Yield Dividend Aristocrats indices that provides essential products and services through its regulated energy delivery and construction services businesses. For more information about MDU Resources, see the company's website at www.mdu.com.

For more information about Intermountain Gas Company, visit **www.intgas.com.**

08/15/23

CUSTOMER SERVICE: 800-548-3679
MON-FRI 7:30 a.m. - 6:30 p.m.

www.intgas.com

INTERMOUNTAIN® GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

WORKPAPER NOS. 1-7

CASE NO. INT-G-23-04

INTERMOUNTAIN GAS COMPANY

(14 pages)

INTERMOUNTAIN GAS COMPANY
Summary of Northwest Pipeline TF-1 Full Rate Demand Costs

Line No.	Transportation	INT-G-22-04 Annual Therms	INT-G-22-04 Prices[1]	INT-G-22-04 Annual Cost[2]
	(a)	(b)	(c)	(d)
1	TF-1 Reservation Contract #1	412,537,600	$ 0.039876	$ 16,450,268
2	TF-1 Reservation Contract #2	25,550,000	0.040789	1,042,155
3	TF-1 Reservation Contract #3	73,000,000	0.039033	2,849,412
4	TF-1 Reservation Contract #4	26,429,650	0.039033	1,031,629
5	TF-1 Reservation Contract #5	32,850,000	0.039033	1,282,233
6	TF-1 Reservation Contract #6	36,500,000	0.039033	1,424,702
7	TF-1 Reservation Contract #7	87,600,000	0.039033	3,419,296
8	TF-1 Reservation Contract #8	18,250,000	0.039033	712,353
9	TF-1 Reservation Contract #9	104,495,850	0.039033	4,078,784
10	TF-1 Reservation Contract #10	26,462,500	0.039033	1,032,914
11	TF-1 Reservation Contract #11	51,081,750	0.039033	1,993,876
12	**Total**	894,757,350		$ 35,317,622

Line No.	Transportation	INT-G-23-04 Annual Therms	INT-G-23-04 Prices[1]	INT-G-23-04 Annual Cost[2]
	(a)	(b)	(c)	(d)
13	TF-1 Reservation Contract #1	413,667,840	$ 0.038016	$ 15,726,192
14	TF-1 Reservation Contract #2	25,620,000	0.037174	952,390
15	TF-1 Reservation Contract #3	73,200,000	0.037174	2,721,113
16	TF-1 Reservation Contract #4	26,502,060	0.037174	985,177
17	TF-1 Reservation Contract #5	32,940,000	0.037174	1,224,503
18	TF-1 Reservation Contract #6	36,600,000	0.037174	1,360,556
19	TF-1 Reservation Contract #7	87,840,000	0.037174	3,265,335
20	TF-1 Reservation Contract #8	18,300,000	0.037174	680,278
21	TF-1 Reservation Contract #9	104,782,140	0.037174	3,895,134
22	TF-1 Reservation Contract #10	26,535,000	0.037174	986,403
23	TF-1 Reservation Contract #11	51,221,700	0.037174	1,904,099
24	**Total**	897,208,740		$ 33,701,180
25	**Total Annual Cost Difference (Line 24 minus Line 12)**			**$ (1,616,442)** [3]

[1] Column (d) divided by Column (b), rounded to 6 decimal places

[2] Sum of the calculated monthly costs

[3] See Exhibit No. 5, Line 3, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Northwest Pipeline TF-1 Discounted Demand Costs

Line No.	Transportation	INT-G-22-04 Annual Therms	INT-G-22-04 Prices[1]	INT-G-22-04 Annual Cost[2]
	(a)	(b)	(c)	(d)
1	TF-1 Reservation Contract #1	18,250,000	$ 0.025372	$ 463,030
2	TF-1 Reservation Contract #2	58,400,000	0.025371	1,481,690
3	TF-1 Reservation Contract #3	36,500,000	0.023420	854,818
4	TF-1 Reservation Contract #4	32,850,000	0.008500	279,225
5	TF-1 Reservation Contract #5	11,497,500	0.035130	403,904
6	TF-1 Reservation Contract #6	4,530,000	0.031227	141,457
7	TF-1 Reservation Contract #7	63,688,850	0.009758	621,492
8	TF-1 Reservation Contract #8	59,513,250	0.013662	813,041
9	TF-1 Reservation Contract #9	91,250,000	0.009758	890,438
10	**Total**	376,479,600		$ 5,949,095

Line No.	Transportation	INT-G-23-04 Annual Therms	INT-G-23-04 Prices[1]	INT-G-23-04 Annual Cost[2]
	(a)	(b)	(c)	(d)
11	TF-1 Reservation Contract #1	9,150,000	$ 0.024180	$ 221,243
12	TF-1 Reservation Contract #2	67,710,000	0.024161	1,635,916
13	TF-1 Reservation Contract #3	36,600,000	0.022304	816,332
14	TF-1 Reservation Contract #4	11,529,000	0.033456	385,718
15	TF-1 Reservation Contract #5	4,560,000	0.029751	135,665
16	TF-1 Reservation Contract #6	63,863,340	0.009293	593,508
17	TF-1 Reservation Contract #7	59,676,300	0.013011	776,434
18	TF-1 Reservation Contract #8	91,500,000	0.009293	850,349
19	**Total**	344,588,640		$ 5,415,165
20	**Total Annual Cost Difference (Line 19 minus Line 10)**			**$ (533,930)** [3]

[1] Column (d) divided by Column (b), rounded to 6 decimal places

[2] Sum of the calculated monthly costs

[3] See Exhibit No. 5, Line 4, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Upstream Capacity Full Rate Demand Costs

Line No.	Transportation	INT-G-22-04 Annual Therms	INT-G-22-04 Prices[(1)]	INT-G-22-04 Annual Cost[(2)]
	(a)	(b)	(c)	(d)
1	Upstream Agreement #1	25,933,250	$ 0.009103	$ 236,076
2	Upstream Agreement #2	351,503,260	0.009109	3,201,859
3	Upstream Agreement #3	26,962,550	0.009103	245,448
4	Upstream Agreement #4	37,244,600	0.009103	339,048
5	Upstream Agreement #5	26,126,700	0.013496	352,607
6	Upstream Agreement #6	128,898,520	0.013496	1,739,619
7	Upstream Agreement #7	54,750,000	0.013496	738,903
8	Upstream Agreement #8	62,050,000	0.013496	837,425
9	Upstream Agreement #9	133,590,000	0.013496	1,802,933
10	Upstream Agreement #10	36,974,500	0.013496	499,003
11	Upstream Agreement #11	37,657,050	0.022200	835,968
12	Total	921,690,430		10,828,889
13	Estimated Upstream Capacity Release Credits			(500,000)
14	**Total Annual Cost Including Capacity Release Credits**			$ 10,328,889

Line No.	Transportation	INT-G-23-04 Annual Therms	INT-G-23-04 Prices[(1)]	INT-G-23-04 Annual Cost[(2)]	
	(a)	(b)	(c)	(d)	
15	Upstream Agreement #1	24,082,210	$ 0.010062	$ 242,316	
16	Upstream Agreement #2	352,589,060	0.009321	3,286,545	
17	Upstream Agreement #3	27,036,420	0.009319	251,940	
18	Upstream Agreement #4	939,156	0.093186	87,516	(3)
19	Upstream Agreement #5	2,845,467	0.093184	265,152	(3)
20	Upstream Agreement #6	27,300,155	0.093323	2,547,743	(4)
21	Upstream Agreement #7	37,346,640	0.009318	348,012	
22	Upstream Agreement #8	26,198,280	0.013496	353,568	
23	Upstream Agreement #9	129,355,380	0.013496	1,745,760	
24	Upstream Agreement #10	54,900,000	0.013496	740,916	
25	Upstream Agreement #11	62,220,000	0.013496	839,707	
26	Upstream Agreement #12	133,956,000	0.013496	1,807,842	
27	Upstream Agreement #13	915,000	0.255938	234,183	(3)
28	Upstream Agreement #14	2,764,947	0.255939	707,658	(3)
29	Upstream Agreement #15	26,465,000	0.285938	7,567,348	(4)
30	Upstream Agreement #16	37,075,800	0.013496	500,369	
31	Upstream Agreement #17	954,528	0.234883	224,202	(3)
32	Upstream Agreement #18	2,829,363	0.234880	664,560	(3)
33	Upstream Agreement #19	28,000,305	0.235230	6,586,514	(4)
34	Upstream Agreement #20	37,760,220	0.023488	886,908	
35	Total	1,015,533,931		29,888,759	
36	Estimated Upstream Capacity Release Credits			(500,000)	
37	**Total Annual Cost Including Capacity Release Credits**			$ 29,388,759	
38	**Total Annual Cost Difference (Line 37 minus Line 14)**			**$ 19,059,870**	(5)

(1) Column (d) divided by Column (b), rounded to 6 decimal places
(2) Sum of the calculated monthly costs
(3) This contract and its monthly costs will begin April 1, 2024
(4) This contract and its montly costs are anticipated to begin November 1, 2023
(5) See Exhibit No. 5, Line 5, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Upstream Capacity Discounted Demand Costs

Line No.	Transportation	INT-G-22-04 Annual Therms	INT-G-22-04 Prices(1)	INT-G-22-04 Annual Cost(2)
	(a)	(b)	(c)	(d)
1	Upstream Agreement #1	452,311,650	$ 0.020056	$ 9,071,484
2	**Total**	452,311,650		$ 9,071,484

Line No.	Transportation	INT-G-23-04 Annual Therms	INT-G-23-04 Prices(1)	INT-G-23-04 Annual Cost(2)
	(a)	(b)	(c)	(d)
3	Upstream Agreement #1	453,550,860	$ 0.021212	$ 9,620,616
4	**Total**	453,550,860		$ 9,620,616
5	**Total Annual Cost Difference (Line 4 minus Line 2)**			**$ 549,132** (3)

(1) Column (d) divided by Column (b), rounded to 6 decimal places
(2) Sum of the calculated monthly costs
(3) See Exhibit No. 5, Line 6, Column (h)

INTERMOUNTAIN GAS COMPANY
Summary of Other Storage Facility Costs

Line No.	Storage Facilities	INT-G-22-04 Monthly Billing Determinant		INT-G-22-04 Prices	INT-G-22-04 Monthly Cost	INT-G-22-04 Annual Cost
	(a)	(b)		(c)	(d)	(e)
1	**Clay Basin Costs:**					
2	Clay Basin I Reservation	266,250	(1)	$ 0.285338	$ 75,971	$ 911,652
3	Clay Basin II Reservation	221,880	(1)	0.285338	63,311	759,732
4	Clay Basin III Reservation	213,010	(1)	0.285338	60,780	729,360
5	Clay Basin I Capacity	31,950,000	(2)	0.002378	75,977	911,724
6	Clay Basin II Capacity	26,625,000	(2)	0.002378	63,314	759,768
7	Clay Basin III Capacity	25,560,000	(2)	0.002378	60,782	729,384
8	Total Clay Basin Costs				$ 400,135	$ 4,801,620
9	**Rexburg LNG Facility:**					
10	Transportation Reservation					$ 66,000
11	Variable Transportation					18,000
12	Total Rexburg LNG Facility Costs					$ 84,000
13	Storage Demand Charge Credit					$ (2,300,000)
14	**Total Costs Including Storage Credit**					$ 2,585,620

Line No.	Storage Facilities	INT-G-23-04 Monthly Billing Determinant		INT-G-23-04 Prices	INT-G-23-04 Monthly Cost	INT-G-23-04 Annual Cost
	(a)	(b)		(c)	(d)	(e)
15	**Clay Basin Costs:**					
16	Clay Basin I Reservation	266,250	(1)	$ 0.285338	$ 75,971	$ 911,652
17	Clay Basin II Reservation	221,880	(1)	0.285338	63,311	759,732
18	Clay Basin III Reservation	213,010	(1)	0.285338	60,780	729,360
19	Clay Basin I Capacity	31,950,000	(2)	0.002378	75,977	911,724
20	Clay Basin II Capacity	26,625,000	(2)	0.002378	63,314	759,768
21	Clay Basin III Capacity	25,560,000	(2)	0.002378	60,782	729,384
22	Total Clay Basin Costs				$ 400,135	$ 4,801,620
23	**Rexburg LNG Facility:**					
24	Transportation Reservation					$ 66,000
25	Variable Transportation					18,000
26	Total Rexburg LNG Facility Costs					$ 84,000
27	Estimated Storage Demand Charge Credit					$ (2,300,000)
28	**Total Costs Including Storage Credit**					$ 2,585,620
29	**Total Annual Cost Difference (Line 28 minus Line 14)**					**$ -** (3)

(1) Charge Based on Maximum Daily Withdrawal

(2) Charge Based on Maximum Contractual Capacity

(3) See Exhibit No. 5, Line 20, Column (h)

INTERMOUNTAIN GAS COMPANY
Allocation Factors

Line No.	Description	Peak Demand RS	Peak Demand GS-1	Peak Demand LV-1	Peak Demand T-3	Peak Demand T-4	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**INT-G-23-04 Cost of Gas Allocators:**						
2	Peak Demand Per Customer	9.12	42.43				
3	January 2023 Actual Customers	374,976	35,465				
4	INT-G-23-04 Peak Demand Therms (Line 2 times Line 3)	3,419,781	1,504,780	79,805 (1)			5,004,366
5	Percent of Total	68.3360%	30.0693%	1.5947%	N/A	N/A	100.00%
6	**INT-G-23-04 LNG Sales Credit Demand Allocators:**						
7	Peak Demand Per Customer	9.12	42.43				
8	January 2023 Actual Customers	374,976	35,465				
9	INT-G-23-04 Peak Demand Therms (Line 7 times Line 8)	3,419,781	1,504,780	79,805 (1)		1,496,910 (1)	6,501,276
10	Percent of Total	52.6017%	23.1459%	1.2275%	N/A	23.0249%	100.00%
11	**Allocation of Base Rate Revenues to RS and GS-1 Rate Classes:**						
12	Order No. 35836 Approved Base Rate Revenues	$ 73,360,477	$ 26,811,471				$ 100,171,948
13	Percent of Total	73.2346%	26.7654%				100.00%

(1) Contract Demand

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2023

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 1910 VARIABLE AMOUNTS:**					
2	**Variable Gas Cost Balance Approved in Prior PGA in Acct 1910.2010 at 10/1/22**			$ 22,075,600.05		
3	Amortization in Acct 1910.2020 of Acct 1910.2010 Balance Approved in Prior PGA as of 6/30/23		$ (23,658,188.52)			
4	Estimated Therm Sales 7/1 through 9/30/23	32,871,049				
5	Amortization Rate	$ (0.05313)	(1,746,438.83)			
6	Estimated Amortization in Acct 1910.2020 of Acct 1910.2010 Balance Approved in Prior PGA at 9/30/23			(25,404,627.35)		
7	**Estimated Balance in Acct 1910.2010 at 9/30/23**				$ (3,329,027.30)	
8	**Variable Gas Cost Deferral of Current PGA Year Activity in Acct 1910.2180 at 10/1/22**			(5,869,311.51)		
9	Deferred Variable Gas Costs in Acct 1910.2180 through 6/30/23			41,766,152.26		
10	Estimated Deferred Variable Gas Costs in Acct 1910.2180 from 7/1 through 9/30/23			(9,125,810.35)		
11	**Estimated Balance in Acct 1910.2180 of Current PGA Year Activity at 9/30/23**				26,771,030.40	
12	**PGA Year Interest Deferred in Acct 1910.2340 at 10/1/22**			(2,020.99)		
13	PGA Year Interest Deferred in Acct 1910.2340 through 6/30/23			593,181.08		
14	Estimated PGA Year Interest from 7/1 through 9/30/23			185,256.24		
15	**Estimated Balance in Acct 1910.2340 at 9/30/23**				776,416.33	
16	**ESTIMATED ACCOUNT 1910 VARIABLE BALANCE AT 9/30/23**					$ 24,218,419.43

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2023

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 1910 LOST AND UNACCOUNTED FOR AMOUNTS:**					
2	RS and GS-1 Cumulative Deferred Lost and Unaccounted For Gas Balance Approved in Prior PGA in Acct 1910.2120 at 10/1/22		$ (911,922.81)			
3	Industrial Cumulative Deferred Lost and Unaccounted For Gas Balance Approved in Prior PGA in Acct 1910.2120 at 10/1/22		(311,161.92)			
4	**Net Cumulative Deferred Lost and Unaccounted For Gas Balance Approved in Prior PGA in Acct 1910.2120 at 10/1/22**			$ (1,223,084.73)		
5	RS and GS-1 Amortization in Acct 1910.2130 of Acct 1910.2120 Balance Approved in Prior PGA as of 6/30/23		$ 980,319.41			
6	Estimated Therm Sales 7/1 through 9/30/23	30,091,049				
7	Amortization Rate	$ 0.00226	68,005.77			
8	Estimated Amortization in Acct 1910.2130 of Acct 1910.2120 Balance Approved in Prior PGA at 9/30/23			1,048,325.18		
9	Industrial Amortization in Acct 1910.2140 of Acct 1910.2120 Balance Approved in Prior PGA as of 6/30/23		$ 247,029.41			
10	Estimated LV-1 and T-3 Therm Sales 7/1 through 9/30/23	19,283,000				
11	Amortization Rate	$ 0.00082	15,812.06			
12	Estimated T-4 Contract Demand 7/1 through 9/30/23	4,490,730				
13	Amortization Rate	$ 0.01580	70,953.53			
14	Estimated Amortization in Acct 1910.2140 of Acct 1910.2120 Balance Approved in Prior PGA at 9/30/23			333,795.00		
15	**Estimated Balance in Acct 1910.2120 at 9/30/23**				159,035.45	
16	**Lost and Unaccounted For Gas Deferral of Current PGA Year Activity in Acct 1910.2150 at 10/1/22**			0.00		
17	Deliveries to System through 6/30/23 (Therms)	745,739,868				
18	Lost and Unaccounted For Gas	0.0000%	-			
19	Less Therms Related to Line Breaks & Other Found Gas		-			
20	Net Lost and Unaccounted For Gas		-			
21	Average WACOG 10/1/22 through 6/30/23		$ -			
22	Lost and Unaccounted For Gas Deferral through 6/30/23			$ (507,620.83)		
23	Estimated Deliveries to System 7/1 through 9/30/23 (Therms)	32,995,130				
24	Lost and Unaccounted For Gas	0.0000%	-			
25	Estimated Average WACOG 7/1 through 9/30/23		$ -			
26	Estimated Lost and Unaccounted For Gas Deferral 7/1 through 9/30/23			$ -		
27	Plus: Annual Line Break Adjustment			(60,940.24)		
28	Plus: Prior Year Lost and Unaccounted For Gas True-Up					
29	**Estimated Lost and Unaccounted For Gas For Current PGA Year Activity at 9/30/23**			(568,561.07)		
30	RS and GS-1 Allocation of Lost and Unaccounted For Gas Deferral For Current PGA Year Activity	75%		(426,420.80)		
31	Industrial Allocation of Lost and Unaccounted For Gas Deferral For Current PGA Year Activity	25%		(142,140.27)		
32	**Estimated Balance in Acct 1910.2150 of Current PGA Year Activity at 9/30/23**				(568,561.07)	
33	**RS and GS-1 Lost and Unaccounted For Current PGA Interest Deferred in 1910.2420 at 10/1/22**			$ 1.99		
34	RS and GS-1 Lost and Unaccounted For Current PGA Interest Deferred in 1910.2420 through 6/30/23			(4,341.95)		
35	Estimated RS and GS-1 Current PGA Interest from 7/1 through 9/30/23			(2,105.13)		
36	**Estimated Balance in Acct 1910.2420 at 9/30/23**				(6,445.09)	
37	**Industrial Lost and Unaccounted For Current PGA Interest Deferred in Acct 1910.2360 at 10/1/22**			$ 0.05		
38	Industrial Lost and Unaccounted For Current PGA Interest Deferred in Acct 1910.2360 through 6/30/23			(2,513.46)		
39	Estimated Industrial Lost and Unaccounted For Current PGA Interest from 7/1 through 9/30/23			(1,064.59)		
40	**Estimated Balance in Acct 1910.2360 at 9/30/23**				(3,578.00)	
41	**ESTIMATED ACCOUNT 1910 LOST AND UNACCOUNTED FOR GAS BALANCE AT 9/30/23**					$ (419,548.71)

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2023

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 1910 FIXED AMOUNTS:**					
2	**Fixed Gas Cost Balance Approved in Prior PGA in Acct 1910.2050 at 10/1/22**			$ (7,425,611.63)		
3	RS Amortization in Acct 1910.2070 Balance at 10/1/22		$ 69,383.62			
4	Amortization for RS in Acct 1910.2070 of Acct 1910.2050 Balance Approved in Prior PGA through 6/30/23		4,904,019.87			
5	Estimated RS Therm Sales 7/1 through 9/30/23	18,612,257				
6	RS Amortization Rate	$ 0.01688	314,174.89			
7	Estimated RS Amortization in Acct 1910.2070 of Acct 1910.2050 Balance Approved in Prior PGA at 9/30/23			5,287,578.38		
8	GS-1 Amortization in Acct 1910.2080 Balance at 10/1/22		$ 29,620.07			
9	Amortization for GS-1 in Acct 1910.2080 of Acct 1910.2050 Balance Approved in Prior PGA through 6/30/23		2,878,568.03			
10	Estimated GS-1 Therm Sales 7/1 through 9/30/23	11,478,792				
11	GS-1 Amortization Rate	$ 0.02057	236,118.76			
12	Estimated GS-1 Amortization in Acct 1910.2080 of Acct 1910.2050 Balance Approved in Prior PGA at 9/30/23			3,144,306.86		
13	LV-1 Amortization in Acct 1910.2090 Balance at 10/1/22		$ 3,128.30			
14	Amortization for LV-1 in Acct 1910.2090 of Acct 1910.2050 Balance Approved in Prior PGA through 6/30/23		122,070.14			
15	Estimated LV-1 Block 1 Therm Sales 7/1 through 9/30/23	2,780,000				
16	LV-1 Amortization Rate	$ 0.01092	30,357.60			
17	Estimated LV-1 Amortization Balance in Acct 1910.2090 of Acct 1910.2050 Balance Approved in Prior PGA at 9/30/23			155,556.04		
18	**Estimated Balance in Acct 1910.2050 at 9/30/23**				$ 1,161,829.65	
19	RS Fixed Cost Collection Deferral Balance in Acct 1910.2200 at 10/1/22		$ (1,101,652.47)			
20	RS Fixed Cost Collection Deferred in Account 1910.2200 through 6/30/23		(21,844,466.60)			
21	Estimated RS Fixed Cost Collection Deferral from 7/1 through 9/30/23		8,629,802.18			
22	Estimated RS Balance in Acct 1910.2200 of Current PGA Year Activity at 9/30/23			$ (14,316,316.89)		
23	GS-1 Fixed Cost Collection Deferral Balance in Acct 1910.2200 at 10/1/22		$ (639,424.49)			
24	GS-1 Fixed Cost Collection Deferred in Account 1910.2200 through 6/30/23		(10,436,626.47)			
25	Estimated GS-1 Fixed Cost Collection Deferral from 7/1 through 9/30/23		3,565,860.65			
26	Estimated GS-1 Balance in Acct 1910.2200 of Current PGA Year Activity at 9/30/23			(7,510,190.31)		
27	LV-1 Fixed Cost Collection Deferral Balance in Acct 1910.2200 at 10/1/22		$ (28,942.02)			
28	LV-1 Fixed Cost Collection Deferred in Account 1910.2200 through 6/30/23		(351,519.62)			
29	Estimated LV-1 Fixed Cost Collection Deferral from 7/1 through 9/30/23		40,579.61			
30	Estimated LV-1 Balance in Acct 1910.2200 of Current PGA Year Activity at 9/30/23			(339,882.03)		
31	**Total Estimated Fixed Cost Collection Balance in Acct 1910.2200 at 9/30/23**				(22,166,389.23)	
32	**Capacity Releases Deferral Balance in Acct 1910.2320 at 10/1/22**			$ (94,627.29)		
33	Capacity Releases Deferred in Acct 1910.2320 through 6/30/23			-		
34	Estimated Capacity Releases Deferred from 7/1 through 9/30/23			(905,625.91)		
35	**Estimated Balance in Acct 1910.2320 of Current PGA Year Activity at 9/30/23**				(1,000,253.20)	
36	**Current PGA Interest in Acct 1910.2430 at 10/1/22**			$ (621.10)		
37	Current PGA Interest Deferred in Acct 1910.2430 through 6/30/23			(382,536.17)		
38	Estimated Current PGA Interest from 7/1 through 9/30/23			(171,503.19)		
39	**Estimated Balance in Acct 1910.2430 at 9/30/23**				(554,660.46)	

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1910 Surcharges (Credits)
Estimated September 30, 2023

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**Pipeline Transportation Capacity Release Deferred Approved in Prior PGA in Acct 1910.2530 at 10/1/22**		$ 0.00			
2	Balance in Acct 1910.2530 at 6/30/23		(5,370,344.95)			
3	Estimated Capacity Release 7/1 through 9/30/23		(1,032,374.09)			
4	Estimated Balance in Acct 1910.2530 at 9/30/23			$ (6,402,719.04)		
5	RS Amortization in Acct 1910.2540 Balance at 10/1/22		$ 66,653.65			
6	RS Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA through 6/30/23		4,776,397.84			
7	Estimated RS Therm Sales from 7/1 through 9/30/23	18,612,257				
8	RS Amortization Rate	$ 0.01644	305,985.50			
9	Estimated RS Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/23		5,149,036.99			
10	GS-1 Amortization in Acct 1910.2540 Balance at 10/1/22		$ 42,649.59			
11	GS-1 Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA through 6/30/23		2,183,641.90			
12	Estimated GS-1 Therm Sales from 7/1 through 9/30/23	11,478,792				
13	GS-1 Amortization Rate	$ 0.01564	179,528.31			
14	Estimated GS-1 Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/23		2,405,819.80			
15	Estimated Core Amortization in Acct 1910.2540 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/23 (Sum of Lines 9 & 14, Column (c))			7,554,856.79		
16	LV-1 Amortization in Acct 1910.2550 Balance at 10/1/22		$ 1,866.41			
17	LV-1 Amortization in Acct 1910.2550 of Acct 1910.2530 Balance Approved in Prior PGA through 6/30/23		97,365.47			
18	Estimated LV-1 Therm Sales from 7/1 through 9/30/23	2,780,000				
19	LV-1 Amortization Rate	$ 0.00871	24,213.80			
20	Estimated LV-1 Amortization in Acct 1910.2550 of Acct 1910.2530 Balance Approved in Prior PGA at 9/30/23			123,445.68		
21	**Estimated Balance in Acct 1910.2530 at 9/30/23**				$ 1,275,583.43	
22	**LNG Sales Credits Approved in Prior PGA Deferred in Acct 1910.2800 at 10/1/22**			$ (221,992.53)		
23	RS LNG Sales Credit Amortization in Acct 1910.2810 at 10/1/22	$ 5,501.97				
24	RS Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA through 6/30/23	118,253.16				
25	Estimated RS Amortization 7/1 through 9/30/23	7,631.03				
26	Estimated RS Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA at 9/30/23		131,386.16			
27	GS-1 LNG Sales Credit Amortization in Acct 1910.2810 at 10/1/22	$ 3,671.46				
28	GS-1 Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA through 6/30/23	49,591.87				
29	Estimated GS-1 Amortization 7/1 through 9/30/23	4,132.37				
30	Estimated GS-1 Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA at 9/30/23		57,395.70			
31	LV-1 LNG Sales Credit Amortization in Acct 1910.2810 at 10/1/22	$ 139.50				
32	LV-1 Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA through 6/30/23	2,347.49				
33	Estimated LV-1 Amortization 7/1 through 9/30/23	583.80				
34	Estimated LV-1 Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA at 9/30/23		3,070.79			
35	T-4 LNG Sales Credit Amortization in Acct 1910.2810 at 10/1/22	$ 1,738.50				
36	T-4 Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA through 6/30/23	51,992.73				
37	Estimated T-4 Amortization 7/1 through 9/30/23	17,424.03				
38	Estimated T-4 Amortization in Acct 1910.2810 of Acct 1910.2800 Balance Approved in Prior PGA at 9/30/23		71,155.26			
39	**Estimated Balance in Acct 1910.2810 at 9/30/23**			263,007.91		
40	**LNG Sales Current PGA Interest Deferred in Acct 1910.2815 at 10/1/22**		(83.50)			
41	LNG Sales Current PGA Interest Deferred in Acct 1910.2815 through 6/30/23		(14,331.29)			
42	Estimated LNG Sales Current PGA Interest from 7/1 through 9/30/23		(9,193.25)			
43	**Estimated Balance in Acct 1910.2815 at 9/30/23**			(23,608.04)		
44	LNG Sales Deferral - Margin Sharing Deferred in Acct 1910.2820 of Current PGA Year Activity through 6/30/23			(1,311,318.75)		
45	LNG Sales Deferral - O&M Recovery Deferred in Acct 1910.2825 of Current PGA Year Activity through 6/30/23			(129,188.07)		
46	**Estimated LNG Sales Credit Balance at 9/30/23**				$ (1,423,099.48)	
47	**ESTIMATED ACCOUNT 1910 FIXED BALANCE AT 9/30/23**					$ (22,706,989.29)
48	**TOTAL DEFERRED ACCOUNT 1910 BALANCE**					$ 1,091,881.43

INTERMOUNTAIN GAS COMPANY
Analysis of Account 1823.7500 Surcharge
Estimated September 30, 2023

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Subtotal (e)	Total (f)
1	**ACCOUNT 1823.7500 IN-PERSON CUSTOMER PAYMENT FEES DEFERRAL, CASE NOS. INT-G-18-01 & INT-G-21-02:**					
2	**In-Person Customer Payment Fees Deferral Approved in Prior PGA in Acct 1823.7500 at 6/30/22**			$ 70,370.84		
3	RS Amortization of In-Person Customer Payment Fees Approved in Prior PGA at 10/1/22			(713.99)		
4	RS Amortization of In-Person Customer Payment Fees Approved in Prior PGA through 6/30/23		$ (55,214.38)			
5	Estimated RS Therm Sales 7/1 through 9/30/23	18,612,257				
6	RS Amortization Rate	(0.00019)	(3,536.33)			
7	Estimated RS Amortization of In-Person Customer Payment Fees at 9/30/23			(58,750.71)		
8	GS-1 Amortization of In-Person Customer Payment Fees Approved in Prior PGA at 10/1/22			(386.47)		
9	GS-1 Amortization of In-Person Customer Payment Fees Approved in Prior PGA through 6/30/23		(20,948.48)			
10	Estimated GS-1 Therm Sales 7/1 through 9/30/23					
11	GS-1 Amortization Rate	11,478,792				
12	Estimated GS-1 Amortization of In-Person Customer Payment Fees at 9/30/23	(0.00015)	(1,721.82)	(22,670.30)		
13	**Estimated In-Person Customer Payment Fees Deferral at 9/30/23**				$ (12,150.63)	
14	In-Person Customer Payment Fees Deferred in 1823.7500 from 7/1/22 through 2/1/23 (1)				44,611.41	
15	**ESTIMATED BALANCE IN ACCT 1823.7500 AT 9/30/23**					$ 32,460.78

(1) Order No. 35836 in Case No. INT-G-22-07, approved the Company's request to collect In-Person Customer Payment fees in base rates going forward and to collect the fees incurred through February 1, 2023 in the 2023 PGA.

INTERMOUNTAIN GAS COMPANY
Analysis of Account 2540.38107 Surcharge
Estimated September 30, 2023

Line No.	Description (a)	Detail (b)	Detail (c)	Amount (d)	Total (e)
1	**ACCOUNT 2540.38107 Residential Energy Efficiency Funds:**				
2	**Residential Energy Efficiency Credit Approved in Prior PGA in Acct 2540.38107 at 10/1/22**			$ (4,850,000.00)	
3	RS Amortization of Residential Energy Efficiency Credit Approved in Prior PGA through 6/30/23		$ 5,203,617.40		
4	Estimated RS Therm Sales 7/1 through 9/30/23	18,612,257			
5	RS Amortization Rate	0.01790	333,159.40		
6	Estimated RS Amortization of Residential Energy Efficiency Credit at 9/30/23			5,536,776.80	
7	**ESTIMATED BALANCE IN ACCT 2540.38107 AT 9/30/23**				$ 686,776.80

INTERMOUNTAIN GAS COMPANY

Lost and Unaccounted for Gas

(Volumes in Therms)

Line No.	Description	Oct 2019- Sep 2020	Oct 2020 - Sept 2021	Oct 2021 - Sept 2022
	(a)	(b)	(c)	(d)
1	Core Customer Purchased Gas	394,224,154	403,730,817	429,712,484
2	Transportation Customer Gas	363,513,905	368,193,748	372,687,753
3	LNG Storage Withdrawals	1,455,818	4,623,368	4,583,559
4	Under Deliveries of Gas from Pipeline (Draft)	568,080	10,150	-
5	Total Deliveries to System	759,761,957	776,558,083	806,983,796
6	Core Customer Billed Gas	400,017,998	409,747,004	439,666,208
7	Unbilled Adjustment	(3,731,987)	634,162	(8,262,099)
8	Transportation Customer Billed Gas	363,513,905	368,193,748	372,687,753
9	Company Use Gas	318,139	182,923	474,937
10	LNG Storage Injections	1,086,497	3,068,540	2,110,199
11	Line Breaks - Found Gas	134,723	132,070	988,790
12	Other Found Gas	18,977	-	-
13	Over Deliveries of Gas from Pipeline (Pack)	-	-	914,530
14	Total Deliveries to Customers	761,358,252	781,958,447	808,580,318
15	**Lost/(Found) Gas (Line 5 minus 14)**	(1,596,295)	(5,400,364)	(1,596,522)
16	Average Purchase WACOG	$ 0.21239	$ 0.22682	$ 0.31795
17	Cost of Lost/(Found) Gas (Line 15 times Line 16)	$ (339,037)	$ (1,224,911)	$ (507,614)
18	**Lost Gas $/Therm (Line 17 divided by Line 5)**	$ (0.00045)	$ (0.00158)	$ (0.00063)
19	Lost/(Found) Gas (Line 15)	(1,596,295)	(5,400,364)	(1,596,522)
20	Lost/(Found) Gas Therms Deferred	745,782	-	-
21	Lost/(Found) Gas Adjustment (Line 19 minus Line 20)	(2,342,077)	(5,400,364)	(1,596,522)
22	Actual Lost Gas Rate (Line 15 divided by Line 5)	-0.2101%	-0.6954%	-0.1978%
23	**3-Year Average Lost Gas Rate**	-0.1193% (1)	-0.3617% (2)	-0.3678% (3)

(1) See Case No. INT-G-21-04
(2) See Case No. INT-G-22-04
(3) Current PGA 3-Year Average

INTERMOUNTAIN GAS COMPANY
Short-Term Interest Expense

Line No.	Description	Amount
	(a)	(b)
1	**Accounts 4310.1111, 4310.3111 and 4190.1331 Short-Term Interest Expense:**	
2	Short-Term Interest Expense for Gas Commodity Costs in Accts 4310.1111 from January to June 2023	$ 3,013,264
3	Estimated Short-Term Interest Expense for Gas Commodity Costs from July through September 2023	768,049
4	Total Estimated Short-Term Interest Expense for Gas Commodity Costs from January through September 2023	3,781,313
5	Less: PGA Interest on Deferral Balances in Account 4310.3111 from January to June 2023	(183,575)
6	Less: Estimated PGA Interest on Deferral Balances from July through September 2023	(2,112)
7	Less: Interest Income in Account 4190.1331 from January to April 2023	(383,220)
8	**Net Estimated Short-Term Interest Expense**	$ 3,212,406