Northern Natural Gas Company
P.O. Box 3330
Omaha, NE 68103-0330
402 398-7200

December 22, 2022

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Northern Natural Gas Company
Docket No. RP22-1033-_____
Motion to Place Base Case Revised Tariff Sheets into Effect

Dear Ms. Bose:

Pursuant to Section 4 of the Natural Gas Act ("NGA")[1] and Part 154 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] specifically 18 C.F.R. § 154.206(a) and 154.303(c)(2), Northern Natural Gas Company ("Northern") hereby submits for filing, as part of its FERC Gas Tariff, Sixth Revised Volume No. 1 ("Tariff"), the revised tariff sheets[3] listed in Appendix A of this filing ("Revised Tariff Sheets"). Northern is filing contemporaneously under separate cover to place Interim Rates[4] in effect on January 1, 2023.

Statement of Nature, Reasons and Basis

On July 1, 2022, Northern filed revised tariff records, proposed to be effective on August 1, 2022, to reflect a general NGA Section 4 rate increase ("July 1 Filing"). On July 29, 2022, the Commission issued an "Order Accepting and Suspending Tariff Records, Subject to Refund, and Establishing Hearing Procedures" in the referenced docket ("July 29 Order").[5] Ordering Paragraph (A) of the July 29 Order accepted and suspended the tariff sheets filed in the July 1 Filing, to be effective upon motion

[1] 15 U.S.C. § 717c.
[2] 18 C.F.R. Part 154 (2022).
[3] Tariff Sheets include revisions to the periodic rate adjustment, extension of TF Agreements, removal of the terms "minimum" and "maximum" for transmission commodity charges and housekeeping changes proposed in the July 1 Filing, accepted subject to refund and the outcome of a hearing, in the July 29 Order. *See Northern Natural Gas Company*, 180 FERC ¶ 61,066 (2022).
[4] The term "Interim Rates" shall have the meaning defined in the contemporaneously filed "Motion to Place Interim Rates into Effect" referred to herein.
[5] *Northern Natural*, 180 FERC ¶ 61,066.

January 1, 2023, subject to refund and the outcome of the hearing established by the July 29 Order ("Base Case").

The purpose of this filing is to place into effect on January 1, 2023, the Tariff Sheets that were suspended in the July 29 Order, including adjustments to eliminate the costs associated with facilities that will not be in service by December 31, 2022, the end of the test period. The suspended rates, as revised, are contained in the Revised Tariff Sheets.

In addition, since the July 1 Filing revisions to Sheet No. 54 are effective before the January 1, 2023 effective date of Thirty Second Sheet No. 54 accepted by the Commission in Docket No. RP22-871-000,[6] Northern is filing herein Thirty Third Revised Sheet No. 54 to be effective January 1, 2023 in order to reflect both the approved winter fuel rate from Docket No. RP22-871-000 and the revisions accepted in the July 29 Order.

Proposed Effective Date and Motion to Place Revised Tariff Sheets into Effect

Pursuant to Section 4(e) of the NGA, Northern hereby moves to place into effect on January 1, 2023, the Revised Tariff Sheets. Therefore, Northern respectfully requests certain suspended tariff sheets from the July 1 Filing, as listed in Appendix B attached to this filing, be replaced by the Revised Tariff Sheets.

In compliance with Section 154.303(c)(2) of the Commission's regulations,[7] Northern has removed costs associated with facilities not expected to be in service on December 31, 2022. Thus, as set forth in Appendix C, the costs underlying the rates submitted herein are based on the cost of gas plant in service as of December 31, 2022.[8] Workpapers that support the cost of service, cost allocation and rate design underlying the rates proposed herein are provided in Appendix C attached hereto.

Related Filing

Although Northern is hereby moving to place its Base Case rates into effect on January 1, 2023, consistent with its July 1 Filing, as adjusted, Northern is filing contemporaneously under separate cover for Interim Rates, also effective January 1, 2023. The purpose of the Interim Rates is to further settlement discussions in this proceeding. In the event settlement is reached, Northern anticipates that the Base Case rates included in this filing will not be charged, but that settlement rates will supersede the Interim Rates. However, if Northern determines that this matter cannot be

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[6] *Northern Natural Gas Company*, Letter Order dated June 13, 2022.
[7] 18 C.F.R. § 154.303(c)(2).
[8] The instant filing reflects, where available, the actual cost of gas plant in service as of November 30, 2022. Northern will close its books for the month of December in mid-January 2023. Therefore, consistent with past practice, Northern has included an estimate of the actual amounts expected to be closed to gas plant in service during the month of December. The rate submitted herein will be updated in a future filing if the actual costs are less than the estimated costs.

resolved through settlement, Northern may file to terminate the Interim Rates and place back into effect the Base Case rates filed herein. In that event, Northern will not seek to retroactively surcharge its customers for the difference between the Interim Rates and the Base Case rates filed herein. The Base Case rates and the Interim Rates are both being filed subject to refund pursuant to the Commission's direction. Northern reserves its right to support at hearing the Base Case rates filed herein.

Posting

Northern has served an electronic copy of this filing upon its customers and interested state regulatory commissions.

Marked Version

In accordance with Section 154.201 of the Commission's Regulations, Northern has submitted a marked version of the proposed tariff changes highlighting new additions and showing deletions by strikeout.

Data Processing Requirements

Northern is submitting this filing through FERC's electronic tariff filing process in a FERC-approved format.

Communication

It is respectfully requested that all Commission orders and correspondence, as well as pleadings and correspondence from other persons concerning this filing, be served upon each of the following:

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Respectfully submitted,

/s/ Kirk Lavengood

Kirk Lavengood
Vice President, General Counsel and Regulatory Affairs

Attachments

Appendix A
Sixth Revised Volume No. 1

Revised Tariff Sheets[1]

Effective January 1, 2023

Twentieth Revised Sheet No. 50
Twenty Third Revised Sheet No. 51
Twenty First Revised Sheet No. 52
Twenty Third Revised Sheet No. 53
Thirty Third Revised Sheet No. 54
Sixth Revised Sheet No. 55
Ninth Revised Sheet No. 59
Ninth Revised Sheet No. 59A
Twentieth Revised Sheet No. 60
Twentieth Revised Sheet No. 60A
Third Revised Sheet No. 103
Seventh Revised Sheet No. 206
Third Revised Sheet No. 206A
Sixth Revised Sheet No. 300
Fourth Revised Sheet No. 301C

[1] Tariff Sheets include revisions to the periodic rate adjustment, extension of TF Agreements, removal of the terms "minimum" and "maximum" for transmission commodity charges and housekeeping changes proposed in the July 1 Filing, accepted subject to refund and the outcome of a hearing, in the July 29 Order.

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET TF12 Base	MARKET-TO-MARKET TF12 Variable	MARKET-TO-MARKET TF5	FIELD-TO-FIELD/MARKET DEMARCATION TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	16.033	16.033	-0-	8.798
Winter (Nov-Mar)	28.859	39.120	42.754	15.837

COMMODITY RATES 2/ 3/

TF12 Base, TF12 Var., TF5 & TFF Receipt Point	Delivery Point	Market Area 4/ Commodity	Field Mileage Rate per 100 miles Commodity	Out-of Balance Commodity	Carlton Surcharge 5/ Maximum	Minimum
Market	Market	0.0260		0.0260	0.0175	0.0000
Field	Market	0.0260	0.0103		0.0175	0.0000
Market	Field		0.0103			
Field	Field		0.0103	0.0217		

1/ The minimum reservation rate is equal to zero.
2/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and ACA unit surcharge as posted on FERC’s website at https://www.ferc.gov.
3/ The firm transportation services commodity rates are not discountable. The commodity rate is the maximum and minimum commodity rate. The applicable MIDs commodity rate will be in addition to the TF reservation rates. The MIDs rates shown in Sheet Nos. 59-60A represent the throughput commodity rates for any transaction involving MIDs.
4/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.
5/ Applicable to Market Area Shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.

RATE SCHEDULE TFX

RESERVATION RATES	MARKET-TO-MARKET Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD Nov-Mar
Base Tariff Rates 1/	$16.033	$42.754	$8.798	$15.837

COMMODITY RATES 2/ 3/

TFX		Market Area 4/	Field Mileage Rate per 100 miles	Out-of-Balance	Carlton Surcharge 5/	
Receipt Point	Delivery Point	Commodity	Commodity	Commodity	Maximum	Minimum
Market	Market	0.0260		0.0260	0.0175	0.0000
Field	Market	0.0260	0.0103		0.0175	0.0000
Market	Field		0.0103			
Field	Field		0.0103	0.0217		

1/ The minimum reservation rate is equal to zero.
2/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.
3/ The firm transportation services commodity rates are not discountable. The commodity rate is the maximum and minimum commodity rate. The applicable MIDs commodity rate will be in addition to the TFX reservation rates. The MIDs rates shown in Sheet Nos. 59-60A represent the throughput commodity rates for any transaction involving MIDs.
4/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.
5/ Applicable to Market Area Shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.

RATE SCHEDULE TI

COMMODITY RATES 1/ 2/

TI		Market Area 3/		Field Mileage Rate per 100 miles		Out-of-Balance		Carlton Surcharge 4/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
NOVEMBER - MARCH									
Market	Market	1.4324	0.0260			1.4324	0.0260	0.0175	0.0000
Field	Market	1.4324	0.0260	0.2572	0.0103			0.0175	0.0000
Market	Field			0.2572	0.0103				
Field	Field			0.2572	0.0103	0.5427	0.0217		
APRIL - OCTOBER									
Market	Market	0.5534	0.0260			0.5534	0.0260	0.0000	0.0000
Field	Market	0.5534	0.0260	0.1475	0.0103			0.0000	0.0000
Market	Field			0.1475	0.0103				
Field	Field			0.1475	0.0103	0.3112	0.0217		

1/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.

2/ The MIDs rates shown in Sheet Nos. 59-60A represent the throughput commodity rates for any transaction involving MIDs.

3/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.

4/ Applicable to Market Area Shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.

	Commodity Charges Nov-Oct
GS-T COMMODITY THROUGHPUT RATE	
Market Area	1.9817 1/ 2/
Field to Demarcation	1.0282
Field-to-Market	3.0099 1/
BEAVER COMPRESSION FEE	
Incidental Jurisdictional Compression Fee	0.0400

WATERVILLE STORAGE

The Market Area transportation rate, Fuel and UAF is charged for delivery to Waterville storage point (POI 922), or other similarly situated third party storage points in the Market Area. If redelivery from Waterville, or other similarly situated third party storage points, is to a Market Area point, there are no additional transportation, Fuel or UAF charges. If the redelivery is to a Field Area delivery point, the Field Area mileage/MID transportation rate and Fuel is charged.

CAPACITY RELEASE FEE (Rate per transaction)	
Marketing	Negotiated 3/
DAILY DELIVERY VARIANCE CHARGE:	
Non-SOL/SUL/Critical Day	
Positive DDVC	4/
Negative DDVC	4/
Punitive DDVC	4/
SOL Day	
Positive DDVC	greater of 1.0000 or 1.25 times 5/
Negative DDVC	0.0000
Punitive DDVC	greater of 6/ or 2.0 times 5/
SUL Day	
Positive DDVC	0.0000
Negative DDVC	greater of 1.0000 or 1.25 times 5/
Punitive DDVC	0.0000
Critical Day	
Positive/Critical DDVC	
-First 2%	greater of 15.0000 or 1.50 times 5/
-Next 3%	greater of 22.0000 or 1.75 times 5/
Negative DDVC	0.0000
Punitive/Critical DDVC	
-Level I	greater of 56.5000 or 2.0 times 5/
-Level II	greater of 113.0000 or 3.0 times 5/
AUTHORIZED OVERRUN	
TF, TFX, TI and GS-T Rate Schedules	7/

1/ In addition, Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and the ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.
2/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.
3/ Northern will assess fee only in those instances outlined in Sheet No. 288.
4/ The rate will be the applicable maximum Winter Season or Summer Season Market Area TI Rate.
5/ The highest published Platts "Gas Daily" Midpoint price on the applicable day at any of the applicable index points of: Market Area - Northern, demarc and Northern, Ventura; or Field Area - Panhandle, Tx.-Okla. and El Paso, Permian.
6/ Charge equal to five (5) times the SMS monthly reservation fee.
7/ The Authorized Overrun Rate shall be equal to the TI rate for the applicable MID path shown in Sheet Nos. 59-60A.

RATE SCHEDULES TF, TFX, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/ 2/
Market Area (including Out-of-Balance)	1.20%
Field Area	3/ 4/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	-0.32% 2/ 5/ 7/
FDD STORAGE FUEL	1.51%
FDD URR PERCENTAGE	0.11% 1/

	Electric Compression
COMMODITY RATES:	1/ 2/
Market Area	$0.0002
Field Area	$0.0000

1/ Northern will adjust its Fuel, UAF and URR percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the GENERAL TERMS AND CONDITIONS of this Tariff.

2/ There will be no Fuel, electric compression or UAF charges for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no Fuel, electric compression or UAF charges for transportation as set forth in Sheet Nos. 141,142C and 147.

3/ Fuel percentages shall be determined by MIDs for the Field Area shown in Sheet Nos. 61-62.

4/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the Fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total Fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the Fuel that would be collected on the total path between the original receipt point and the ultimate delivery point, subject to the Shipper(s) providing Northern the requisite information.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from Fuel and UAF retention charges.

6/ The out-of-balance Fuel percentage for deliveries in MIDs 1-7 shall be the applicable Section 1 Transportation Fuel percentage, and for deliveries in MIDs 8-16B shall be the applicable Section 2 Transportation Fuel percentage.

7/ The UAF percentage utilizes the most recent twelve-month period ending December 31, 2021. For deliveries subject only to UAF, if the above UAF rate is negative, the UAF rate is zero; provided, however Northern will issue a volume credit on the Shipper’s monthly imbalance statement equivalent to the negative UAF percentage for such deliveries during the period in which the UAF rate is less than zero.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID Fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID Fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD, ILD & SMS

Rate Schedule FDD

Maximum Reservation Charge	4.3552	1/
Maximum Capacity Charge	0.9065	1/
Injection Charge - Firm	0.0232	
Withdrawal Charge - Firm	0.0232	
Annual Rollover Charge	0.9065	1/

Rate Schedule PDD

Maximum Capacity Charge	0.9065	1/
Maximum Monthly Inventory Charge	0.2188	1/
Injection Charge	0.0232	
Withdrawal Charge	0.0232	
Annual Rollover Charge	0.9065	1/

Rate Schedule IDD

Maximum Monthly Inventory Charge	0.2188	1/
Injection Charge	0.0232	
Withdrawal Charge	0.0232	
Annual Rollover Charge	0.9065	1/

Rate Schedule ILD

Maximum Charge	11.7500
Minimum Charge	0.5044
Performance Obligation Charge	2.0000

Rate Schedule SMS

Reservation Charge	7.0499
Commodity Rate	0.0208

1/ Minimum Rate is zero.

MILEAGE INDICATOR DISTRICTS (dollars per Dth)
DELIVERY DISTRICT

RECEIPT DISTRICT		1	2	3	4	5	6	7	7B	8	9
	TI Apr-Oct	0.0575	0.1387	0.2906	0.4130	0.4646	0.3304	0.3776	0.4971	0.8865	0.7641
1	TI Nov-Mar	0.1003	0.2418	0.5067	0.7202	0.8102	0.5761	0.6584	0.8668	1.5458	1.3323
	TF	0.0040	0.0097	0.0203	0.0288	0.0324	0.0231	0.0264	0.0347	0.0619	0.0534
	TI Apr-Oct	0.0679	0.0103	0.1047	0.2832	0.3673	0.2434	0.3068	0.4263	0.7906	0.6711
2	TI Nov-Mar	0.1183	0.0180	0.1826	0.4938	0.6404	0.4244	0.5350	0.7433	1.3786	1.1703
	TF	0.0047	0.0007	0.0073	0.0198	0.0256	0.0170	0.0214	0.0298	0.0552	0.0469
	TI Apr-Oct	0.4573	0.2965	0.0767	0.0900	0.4027	0.2493	0.1859	0.3053	0.8304	0.7095
3	TI Nov-Mar	0.7973	0.5170	0.1337	0.1569	0.7022	0.4347	0.3241	0.5324	1.4480	1.2371
	TF	0.0319	0.0207	0.0054	0.0063	0.0281	0.0174	0.0130	0.0213	0.0580	0.0495
	TI Apr-Oct	0.4410	0.3924	0.2773	0.0664	0.2434	0.1667	0.2611	0.3806	0.7582	0.6343
4	TI Nov-Mar	0.7690	0.6842	0.4835	0.1157	0.4244	0.2906	0.4552	0.6636	1.3220	1.1060
	TF	0.0308	0.0274	0.0194	0.0046	0.0170	0.0116	0.0182	0.0266	0.0529	0.0443
	TI Apr-Oct	0.4042	0.3643	0.2862	0.2567	0.0398	0.1121	0.2021	0.3216	0.7183	0.5959
5	TI Nov-Mar	0.7047	0.6353	0.4990	0.4475	0.0694	0.1955	0.3524	0.5607	1.2526	1.0391
	TF	0.0282	0.0254	0.0200	0.0179	0.0028	0.0078	0.0141	0.0225	0.0502	0.0416
	TI Apr-Oct	0.2567	0.2050	0.0738	0.1106	0.1519	0.0988	0.1165	0.2360	0.6638	0.4853
6	TI Nov-Mar	0.4475	0.3575	0.1286	0.1929	0.2649	0.1723	0.2032	0.4115	1.1574	0.8462
	TF	0.0179	0.0143	0.0052	0.0077	0.0106	0.0069	0.0081	0.0165	0.0464	0.0339
	TI Apr-Oct	0.4425	0.3850	0.3688	0.2921	0.3127	0.1844	0.1475	0.2670	0.4248	0.3009
7	TI Nov-Mar	0.7716	0.6713	0.6430	0.5093	0.5453	0.3215	0.2572	0.4655	0.7407	0.5247
	TF	0.0309	0.0269	0.0258	0.0204	0.0218	0.0129	0.0103	0.0186	0.0297	0.0210
	TI Apr-Oct	0.4425	0.3850	0.3688	0.2921	0.3127	0.1844	0.1475	0.0000	0.4248	0.3009
7B	TI Nov-Mar	0.7716	0.6713	0.6430	0.5093	0.5453	0.3215	0.2572	0.0000	0.7407	0.5247
	TF	0.0309	0.0269	0.0258	0.0204	0.0218	0.0129	0.0103	0.0000	0.0297	0.0210
	TI Apr-Oct	0.8865	0.8393	0.7759	0.7655	0.7582	0.6121	0.6343	0.5030	0.0118	0.3053
8	TI Nov-Mar	1.5458	1.4635	1.3529	1.3349	1.3220	1.0674	1.1060	0.8771	0.0206	0.5324
	TF	0.0619	0.0586	0.0542	0.0535	0.0529	0.0427	0.0443	0.0351	0.0008	0.0213
	TI Apr-Oct	0.7700	0.7169	0.6446	0.6003	0.5133	0.5236	0.3584	0.2272	0.1873	0.0988
9	TI Nov-Mar	1.3426	1.2500	1.1240	1.0468	0.8951	0.9131	0.6250	0.3961	0.3266	0.1723
	TF	0.0538	0.0501	0.0450	0.0419	0.0358	0.0366	0.0250	0.0159	0.0131	0.0069

NOTE: The MID rates include: (1) the appropriate Market Area Commodity rate for deliveries to MID 17; (2) the applicable Market Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MID 17; and (3) the applicable Field Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MIDs 1 - 16A. "TF" is applicable to Rate Schedules TF and TFX.

In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at https://www.ferc.gov and the Carlton surcharge, if applicable.

MILEAGE INDICATOR DISTRICTS (dollars per Dth)
DELIVERY DISTRICT

RECEIPT DISTRICT		1	2	3	4	5	6	7	7B	8	9
	TI Apr-Oct	0.7847	0.8113	0.7832	0.6785	0.5649	0.5738	0.4307	0.2994	0.2817	0.2419
10	TI Nov-Mar	1.3683	1.4146	1.3657	1.1831	0.9851	1.0005	0.7510	0.5221	0.4913	0.4218
	TF	0.0548	0.0567	0.0547	0.0474	0.0394	0.0401	0.0301	0.0209	0.0197	0.0169
	TI Apr-Oct	0.7537	0.6962	0.6298	0.5531	0.5443	0.3053	0.3791	0.2478	0.1578	0.1977
11	TI Nov-Mar	1.3143	1.2140	1.0982	0.9645	0.9491	0.5324	0.6610	0.4321	0.2752	0.3446
	TF	0.0526	0.0486	0.0440	0.0386	0.0380	0.0213	0.0265	0.0173	0.0110	0.0138
	TI Apr-Oct	0.8157	0.7582	0.7582	0.6461	0.6903	0.5590	0.4396	0.3083	0.2463	0.2331
12	TI Nov-Mar	1.4223	1.3220	1.3220	1.1265	1.2037	0.9748	0.7665	0.5375	0.4295	0.4064
	TF	0.0570	0.0529	0.0529	0.0451	0.0482	0.0390	0.0307	0.0215	0.0172	0.0163
	TI Apr-Oct	0.7700	0.7685	0.7788	0.6977	0.6992	0.5871	0.4720	0.3407	0.2596	0.2434
13	TI Nov-Mar	1.3426	1.3400	1.3580	1.2166	1.2191	1.0237	0.8230	0.5941	0.4527	0.4244
	TF	0.0538	0.0537	0.0544	0.0487	0.0488	0.0410	0.0330	0.0238	0.0181	0.0170
	TI Apr-Oct	0.9440	0.9853	0.9396	0.8614	0.7965	0.7552	0.6549	0.5236	0.4573	0.4484
14	TI Nov-Mar	1.6461	1.7181	1.6384	1.5020	1.3889	1.3169	1.1420	0.9131	0.7973	0.7819
	TF	0.0659	0.0688	0.0656	0.0602	0.0556	0.0527	0.0457	0.0366	0.0319	0.0313
	TI Apr-Oct	1.2420	1.1903	1.1712	1.0546	1.0266	0.9956	0.8835	0.7523	0.6741	0.6608
15	TI Nov-Mar	2.1656	2.0756	2.0422	1.8390	1.7901	1.7361	1.5406	1.3117	1.1754	1.1523
	TF	0.0867	0.0831	0.0818	0.0736	0.0717	0.0695	0.0617	0.0525	0.0471	0.0461
	TI Apr-Oct	1.0104	0.9455	0.9897	0.8186	0.8821	0.6947	0.6239	0.4927	0.4307	0.4219
16A	TI Nov-Mar	1.7618	1.6487	1.7258	1.4275	1.5381	1.2114	1.0880	0.8590	0.7510	0.7356
	TF	0.0706	0.0660	0.0691	0.0572	0.0616	0.0485	0.0436	0.0344	0.0301	0.0295
	TI Apr-Oct	1.1358	1.0237	1.0340	1.0148	0.9691	0.9396	0.6829	0.5517	0.5472	0.5399
16B	TI Nov-Mar	1.9804	1.7850	1.8030	1.7695	1.6898	1.6384	1.1908	0.9619	0.9542	0.9414
	TF	0.0793	0.0715	0.0722	0.0709	0.0677	0.0656	0.0477	0.0385	0.0382	0.0377
	TI Apr-Oct	1.6638	1.6048	1.3998	1.4529	1.4234	1.3673	1.2552	1.1240	1.0768	1.0679
17	TI Nov-Mar	2.9012	2.7983	2.4408	2.5334	2.4820	2.3842	2.1888	1.9599	1.8776	1.8621
	TF	0.1162	0.1121	0.0977	0.1015	0.0994	0.0955	0.0877	0.0785	0.0752	0.0746

NOTE: MID 16A represents the 14 county area south of the F/M Demarcation point.
MID 16B represents the F/M Demarcation point.
MID 17 represents the Market Area.
"TF" is applicable to Rate Schedules TF and TFX.

NOTE: The MID rates include: (1) the appropriate Market Area Commodity rate for deliveries to MID 17; (2) the applicable Market Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MID 17; and (3) the applicable Field Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MIDs 1 - 16A.

In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at https://www.ferc.gov and the Carlton surcharge, if applicable.

MILEAGE INDICATOR DISTRICTS (dollars per Dth)
DELIVERY DISTRICT

RECEIPT DISTRICT		10	11	12	13	14	15	16A	16B	17
	TI Apr-Oct	0.9042	0.7301	0.8201	0.8909	1.0178	1.0841	1.0119	1.1358	1.6894
1	TI Nov-Mar	1.5766	1.2731	1.4300	1.5535	1.7747	1.8904	1.7644	1.9804	3.4130
	TF	0.0631	0.0510	0.0573	0.0622	0.0711	0.0757	0.0707	0.0793	0.1055
	TI Apr-Oct	0.7847	0.6490	0.7242	0.7877	0.9160	1.0827	0.9204	1.0237	1.5773
2	TI Nov-Mar	1.3683	1.1317	1.2629	1.3734	1.5972	1.8878	1.6049	1.7850	3.2176
	TF	0.0548	0.0453	0.0506	0.0550	0.0640	0.0756	0.0643	0.0715	0.0977
	TI Apr-Oct	0.8098	0.6933	0.7670	0.8319	0.9927	1.1254	0.8437	1.0340	1.5876
3	TI Nov-Mar	1.4120	1.2088	1.3374	1.4506	1.7310	1.9624	1.4712	1.8030	3.2356
	TF	0.0565	0.0484	0.0536	0.0581	0.0693	0.0786	0.0589	0.0722	0.0984
	TI Apr-Oct	0.7036	0.6151	0.6903	0.7537	0.8894	1.0487	0.8673	1.0148	1.5684
4	TI Nov-Mar	1.2268	1.0725	1.2037	1.3143	1.5509	1.8287	1.5123	1.7695	3.2021
	TF	0.0491	0.0430	0.0482	0.0526	0.0621	0.0732	0.0606	0.0709	0.0971
	TI Apr-Oct	0.7419	0.5767	0.6520	0.7154	0.7847	0.9883	0.8821	0.9691	1.5227
5	TI Nov-Mar	1.2937	1.0057	1.1368	1.2474	1.3683	1.7232	1.5381	1.6898	3.1224
	TF	0.0518	0.0403	0.0455	0.0500	0.0548	0.0690	0.0616	0.0677	0.0939
	TI Apr-Oct	0.6741	0.5207	0.5974	0.6608	0.7921	0.9765	0.7847	0.9396	1.4932
6	TI Nov-Mar	1.1754	0.9079	1.0417	1.1523	1.3812	1.7027	1.3683	1.6384	3.0710
	TF	0.0471	0.0364	0.0417	0.0461	0.0553	0.0682	0.0548	0.0656	0.0918
	TI Apr-Oct	0.4410	0.2832	0.3570	0.4219	0.5561	0.8599	0.5502	0.6829	1.2365
7	TI Nov-Mar	0.7690	0.4938	0.6224	0.7356	0.9696	1.4995	0.9594	1.1908	2.6234
	TF	0.0308	0.0198	0.0249	0.0295	0.0388	0.0600	0.0384	0.0477	0.0739
	TI Apr-Oct	0.4410	0.2832	0.3570	0.4219	0.5561	0.8599	0.5502	0.6829	1.2365
7B	TI Nov-Mar	0.7690	0.4938	0.6224	0.7356	0.9696	1.4995	0.9594	1.1908	2.6234
	TF	0.0308	0.0198	0.0249	0.0295	0.0388	0.0600	0.0384	0.0477	0.0739
	TI Apr-Oct	0.3216	0.1918	0.2449	0.3098	0.4337	0.6549	0.4130	0.5472	1.1008
8	TI Nov-Mar	0.5607	0.3344	0.4270	0.5401	0.7562	1.1420	0.7202	0.9542	2.3868
	TF	0.0225	0.0134	0.0171	0.0216	0.0303	0.0457	0.0288	0.0382	0.0644
	TI Apr-Oct	0.2493	0.1121	0.2434	0.2478	0.3909	0.5989	0.4381	0.5399	1.0935
9	TI Nov-Mar	0.4347	0.1955	0.4244	0.4321	0.6816	1.0442	0.7639	0.9414	2.3740
	TF	0.0174	0.0078	0.0170	0.0173	0.0273	0.0418	0.0306	0.0377	0.0639

NOTE: MID 16A represents the 14 county area south of the F/M Demarcation point.
MID 16B represents the F/M Demarcation point.
MID 17 represents the Market Area.
"TF" is applicable to Rate Schedules TF and TFX.

NOTE: The MID rates include: (1) the appropriate Market Area Commodity rate for deliveries to MID 17; (2) the applicable Market Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MID 17; and (3) the applicable Field Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MIDs 1 - 16A.

In addition, Shipper shall pay the ACA unit surcharge as posted on FERC’s website at https://www.ferc.gov and the Carlton surcharge, if applicable.

MILEAGE INDICATOR DISTRICTS (dollars per Dth)

DELIVERY DISTRICT

RECEIPT DISTRICT		10	11	12	13	14	15	16A	16B	17
	TI Apr-Oct	0.0177	0.0723	0.2168	0.2773	0.4101	0.5694	0.3378	0.5369	1.0905
10	TI Nov-Mar	0.0309	0.1260	0.3781	0.4835	0.7150	0.9928	0.5890	0.9362	2.3688
	TF	0.0012	0.0050	0.0151	0.0194	0.0286	0.0398	0.0236	0.0375	0.0637
	TI Apr-Oct	0.1578	0.0354	0.0649	0.1814	0.3098	0.5030	0.2626	0.4027	0.9563
11	TI Nov-Mar	0.2752	0.0617	0.1132	0.3164	0.5401	0.8771	0.4578	0.7022	2.1348
	TF	0.0110	0.0025	0.0045	0.0127	0.0216	0.0351	0.0183	0.0281	0.0543
	TI Apr-Oct	0.2463	0.1210	0.1475	0.2257	0.3732	0.5340	0.3584	0.5030	1.0566
12	TI Nov-Mar	0.4295	0.2109	0.2572	0.3935	0.6507	0.9311	0.6250	0.8771	2.3097
	TF	0.0172	0.0084	0.0103	0.0158	0.0261	0.0373	0.0250	0.0351	0.0613
	TI Apr-Oct	0.3230	0.1254	0.1844	0.0826	0.1829	0.3938	0.1490	0.2906	0.8442
13	TI Nov-Mar	0.5633	0.2186	0.3215	0.1440	0.3189	0.6867	0.2598	0.5067	1.9393
	TF	0.0226	0.0088	0.0129	0.0058	0.0128	0.0275	0.0104	0.0203	0.0465
	TI Apr-Oct	0.2847	0.3201	0.3997	0.1254	0.0354	0.5045	0.2832	0.4322	0.9858
14	TI Nov-Mar	0.4964	0.5581	0.6970	0.2186	0.0617	0.8796	0.4938	0.7536	2.1862
	TF	0.0199	0.0224	0.0279	0.0088	0.0025	0.0352	0.0198	0.0302	0.0564
	TI Apr-Oct	0.6446	0.5177	0.6018	0.3820	0.5236	0.0369	0.2522	0.3865	0.9401
15	TI Nov-Mar	1.1240	0.9028	1.0494	0.6661	0.9131	0.0643	0.4398	0.6739	2.1065
	TF	0.0450	0.0362	0.0420	0.0267	0.0366	0.0026	0.0176	0.0270	0.0532
	TI Apr-Oct	0.4882	0.2817	0.3629	0.1490	0.2891	0.2419	0.0251	0.1387	0.6923
16A	TI Nov-Mar	0.8513	0.4913	0.6327	0.2598	0.5041	0.4218	0.0437	0.2418	1.6744
	TF	0.0341	0.0197	0.0253	0.0104	0.0202	0.0169	0.0018	0.0097	0.0359
	TI Apr-Oct	0.5369	0.4027	0.5030	0.2906	0.4322	0.3865	0.1387	0.0000	0.5536
16B	TI Nov-Mar	0.9362	0.7022	0.8771	0.5067	0.7536	0.6739	0.2418	0.0000	1.4326
	TF	0.0375	0.0281	0.0351	0.0203	0.0302	0.0270	0.0097	0.0000	0.0262
	TI Apr-Oct	1.0841	0.9263	1.0089	0.7655	0.5458	0.5620	0.4307	0.6195	0.5536
17	TI Nov-Mar	1.8904	1.6152	1.7592	1.3349	0.9516	0.9799	0.7510	1.0802	1.4326
	TF	0.0757	0.0647	0.0705	0.0535	0.0381	0.0392	0.0301	0.0433	0.0262

NOTE: MID 16A represents the 14 county area south of the F/M Demarcation point.
MID 16B represents the F/M Demarcation point.
MID 17 represents the Market Area.
"TF" is applicable to Rate Schedules TF and TFX.

NOTE: The MID rates include: (1) the appropriate Market Area Commodity rate for deliveries to MID 17; (2) the applicable Market Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MID 17; and (3) the applicable Field Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MIDs 1 - 16A.

In addition, Shipper shall pay the ACA unit surcharge as posted on FERC’s website at https://www.ferc.gov and the Carlton surcharge, if applicable.

RATE SCHEDULE TF
Firm Throughput Services

(2) Changes to Primary Delivery Points. If a Primary Delivery Point is deleted or the MDQ is reduced through an amendment, the deleted or reduced capacity at that Primary Delivery Point will not be held for the Shipper.

b) Alternate Firm Delivery Points.

Flexibility. All delivery points on the system will be available for use as alternate firm delivery points (including zone deliveries to a specific customer) provided by the TF Agreement and subject to operational conditions.

c) Discounts.

Any discount granted at the Primary Delivery Point will not be automatically granted at an amended or Alternate Delivery Point.

d) Delivery Point Allocation.

Allocation of available capacity is pursuant to Section 26 of the GENERAL TERMS AND CONDITIONS of this Tariff.

Northern shall have the right to interrupt or curtail service under this Rate Schedule TF as a result of a force majeure event as defined in Section 10, "Force Majeure" of the GENERAL TERMS AND CONDITIONS of this Tariff, or in accordance with Section 19, "Limitation of Northern's Obligation to Provide Firm Services" of the GENERAL TERMS AND CONDITIONS of the Tariff. Curtailment shall be in accordance with Section 29, "Allocation of Capacity" of the GENERAL TERMS AND CONDITIONS of this Tariff.

3. THROUGHPUT SERVICES OFFERED.

The Throughput Service(s) available under Rate Schedule TF are as follows:

TF12 Base is a Firm Throughput Service available for twelve (12) consecutive months. The TF12 Base MDQ is determined as provided in Section 8 of this Rate Schedule TF.

TF12 Variable is a Firm Throughput Service available for twelve (12) consecutive months. The TF12 Variable MDQ is determined as provided in Section 8 of this Rate Schedule TF.

TF5 is a Firm Throughput Service available during the consecutive months of November, December, January, February and March.

TFF MDQ in the TF Agreement is for twelve (12) consecutive months for receipt in the Field Area and delivery to the F/M Demarcation point, for ultimate redelivery into the Market Area.

Although a TF Agreement may contain one or more of these services, each service (TF12 Base, TF12 Variable, and TF5) is distinct for purposes of rates.

Notwithstanding the above, and in accordance with any extension right in the TF Agreement, if Shipper extends its TF Agreement, or portions of its TF Agreement, for twelve (12) consecutive months or more the term date may be extended to the end of a Summer Season or Winter Season.

4. OVERRUN

Overrun Volumes. Northern agrees to transport volumes in excess of the Total Aggregate MDQ contracted for ("Overrun Volumes") on an interruptible basis for Shipper in accordance with the terms and conditions of this Rate Schedule and the GENERAL TERMS

GENERAL TERMS AND CONDITIONS

Releasing Shipper. The term “Releasing Shipper” shall mean a Shipper who has firm contractual rights on Northern’s system and is offering to release or has released its capacity.

Replacement Shipper. The term “Replacement Shipper” shall mean a Shipper who has acquired capacity from a Releasing Shipper.

Right of Way Grantor. The term "Right of Way Grantor" shall mean a party who grants a strip of land, the use of which is acquired for the construction and operation of the pipeline.

Section 1. The term "Section 1" shall mean the fuel zone located in the Field Area that represent the Permian Area portion of Northern’s system. Includes MIDs 1-7.

Section 2. The term "Section 2" shall mean the fuel zone located in the Field Area that represent the Mid-Continent portion of Northern’s system. Includes MIDs 8-16B.

Section 3. The term "Section 3" shall mean the fuel zone that represent the Market Area portion of Northern’s system. Includes MID 17.

Shipper. The term "Shipper" shall be defined to be a party who: 1) requests transportation under a Throughput Service Rate Schedule; or 2) executes a Throughput Service Agreement.

Small Customers. Small Customers are those listed on Appendix C of the Global Settlement and found in Sheet No. 510 of this Tariff.

Storage point. The term “storage point” or “deferred delivery point” shall mean the point at which the Shipper has natural gas quantities transported to or received from Northern on a deferred basis.

Summer Season. The consecutive months April through October.

Tariff. The term "Tariff" shall mean Northern's FERC Gas Tariff.

Thermally Equivalent Volumes. The term "thermally equivalent volumes" shall mean that during any given period of time the volumes of gas delivered hereunder at the Point(s) of Delivery multiplied by the total heating value of the gas at the delivery point(s) shall equal the volumes of gas received at the point(s) of receipt multiplied by the total heating value of the gas at the receipt point(s).

Tier Relationship Factors. The term "Tier Relationship Factors" shall mean the mathematical relationship of the rates for the Market Area TF12 Base, TF12 Variable, and TF5, and the Field Area TFF Throughput Services. The Tier Relationship Factors for the Reservation Rates shall be as follows:

	Services	Winter Months (Nov-Mar)	Summer Months (Apr-Oct)	Annual
Market Area:	TF 12 Base	1.35	.75	12.0
	TF 12 Variable	1.83	.75	14.4
	TF 5	2.00	N/A	10.0
Field Area:	TFF	1.35	.75	12.0

GENERAL TERMS AND CONDITIONS

Tolling Agreement. A tolling agreement or arrangement means that the owner of the electric generator has agreed with an LDC to convert natural gas owned and provided by the LDC to electricity owned by the LDC.

Total or Gross Heating Value. The term "total or gross heating value" means the total calorific value, expressed in Btus when one cubic foot of anhydrous gas at sixty degrees Fahrenheit (60 F) is combusted with dry air at the same temperature and the products of combustion are cooled to sixty degrees Fahrenheit (60 F). The Btu specified is on a higher heating value (HHV) basis. A conversion factor is required to convert lower heating value to a higher heating value basis to correctly calculate the expected fuel usage of certain equipment. For estimating purposes, the higher heating value of natural gas is approximately 10 percent more than the lower heating value.

Town Border Station (TBS). The term "Town Border Station" ("TBS") shall mean the physical location where the LDC receives gas from Northern. The TBS generally consists of facilities to regulate gas pressure and measure gas quality and volumes.

UAF. The term “UAF” shall mean unaccounted-for gas.

Unauthorized Gas. "Unauthorized Gas" shall mean any volumes delivered to Northern from receipt points which have not been nominated in any amount by any Shipper for that month and which have not been scheduled by Northern.

Valid Request. Any reference in this Tariff to a "valid request" used in conjunction with Section 26 "Requests for Service" shall also include any requests submitted electronically through Northern's Internet website.

Winter Season. The consecutive months November through March.

Wobbe Index - The term "Wobbe Index" shall mean a number which indicates the interchangeability of gas. The Wobbe Index is determined by dividing the higher heating value of the gas in Btu per standard cubic foot by the square root of its specific gravity with the respect to air. Wobbe Index is used as an indicator of the heat release rate of combustion equipment employing fixed orifices such as boilers, stoves, water heaters, and furnaces.

GENERAL TERMS AND CONDITIONS

53A. PERIODIC RATE ADJUSTMENT (PRA) - FUEL

1. Purpose and Applicability: This Section 53 establishes a Fuel PRA mechanism for the purpose of deriving the TRANSPORTATION FUEL PERCENTAGES, the UNACCOUNTED-FOR (UAF) PERCENTAGE, the FDD STORAGE FUEL, and FDD STORAGE UNDER-RECOVERY RETAINAGE (URR) PERCENTAGE as set forth in Tariff Sheet No. 54 and Sheet Nos. 61-64, applicable to all Rate Schedules included in Northern's FERC Gas Tariff TF, TFX, GS-T, TI and FDD respectively. The Market Area Fuel percentages will be determined seasonally. The Field Area Fuel percentages will be determined annually.

2. Definitions.

(a) Adjustment Amount. The true-up between actual volumes and estimated volumes.

(b) Annual. The consecutive months January through December.

(c) Fuel. Fuel consists of fuel burned and company used fuels: compressor, heater, dehydrate, actuators, un-metered, blow-down and purge.

(d) Injection Period. The calendar months of June through October.

(e) PRA Period. The twelve month period ending December 31 each year.

(f) PRA Settlement. Per Docket Nos. RP97-275-002 and TM97-2-59-000.

(g) Pre URR Balance. The accumulated under-recoveries of storage gas in the Redfield and Lyons storage fields prior to January 1, 2020.

(h) Post URR Balance. The net balance of under-recovered storage quantities recovered through the URR Percentage.

(i) Throughput. Throughput is the actual volumes received, inclusive of Fuel and UAF, from the respective receipt points on Northern's system.

(j) Transportation Fuel. The transportation Fuel retention percentage for each Section.

(k) Under-Recovery Retainage (URR). The difference between the quantity of natural gas placed into the Redfield and Lyons storage fields as compared to the amount of gas withdrawn during an annual storage cycle, as adjusted for line losses and other field surface adjustments. A negative URR rate shall only apply to the extent that the Post URR Balance is a positive amount.

(l) URR Adjustment. The quantity of the under/over-recovery calculated in the FDD Storage URR for the prior cycle year.

(m) URR Percentage. The percentage applied to FDD injections during the Injection Period.

GENERAL TERMS AND CONDITIONS

(iii) UAF

Northern shall annually compare the volume of UAF retained for the most recent PRA Period with the volume of actual UAF for the same period to determine the UAF Adjustment Amount. The UAF Adjustment Amount will be divided by the applicable Throughput to determine the UAF Adjustment Percent to be added to the UAF retention percentage for the period beginning the subsequent April 1. Under-retainage will result in a positive Adjustment Amount. Over-retainage will result in a negative Adjustment Amount. For purposes of determining the Adjustment Amount for years subsequent to the initial year of the PRA, the Adjustment Amount for the prior year is first added to the actual UAF retained for the prior year. To determine the Adjustment Amount for the subsequent year, the balance of the UAF retained will be compared to the actual UAF.

5. PRA Filing. Northern will file to change the Fuel, UAF and URR retained percentages as provided herein. For Section 3 Transportation Fuel, Northern will file each February 1 for the Summer Season Transportation Fuel to be effective the following April 1; Northern will file each May 1 for the Winter Season Transportation Fuel to be effective the following November 1. Furthermore, Northern will post on its website by December 1 of each year an estimated Section 3 Summer Season Transportation Fuel to be effective the following April 1.

Northern will file each February 1 for the Section 1 and 2 Transportation Fuel, Storage Fuel and URR, and UAF retained percentages to be effective the following April 1. In the event of a change to the makeup of the Sections 1 and 2 in a PRA or Section 4 or Section 5 filing, the effectiveness of the Fuel retention percentages derived therefrom shall be prospective only. For in-kind Fuel reimbursement procedures, Fuel rates will be made effective only at the beginning of the month.

Notwithstanding the filing dates above, Northern may file to revise any of the Fuel and UAF percentages at any time due to an anticipated over- or under-recovered volume.

RATE SCHEDULE TF

RESERVATION RATES	MARKET-TO-MARKET TF12 Base	MARKET-TO-MARKET TF12 Variable	MARKET-TO-MARKET TF5	FIELD-TO-FIELD/MARKET DEMARCATION TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	16.033~~157~~	16.033~~157~~	-0-	8.798~~939~~
Winter (Nov-Mar)	28~~9~~.859~~082~~	39.120~~423~~	42~~3~~.754~~085~~	15~~6~~.837~~090~~

COMMODITY RATES 2/ 3/

TF12 Base, TF12 Var., TF5 & TFF Receipt Point	Delivery Point	Market Area 4/ Commodity	Field Mileage Rate per 100 miles Commodity	Out-of Balance Commodity	Carlton Surcharge 5/ Maximum	Carlton Surcharge 5/ Minimum
Market	Market	0.0260		0.0260	0.0175	0.0000
Field	Market	0.0260	0.0103		0.0175	0.0000
Market	Field		0.0103			
Field	Field		0.0103	0.0217		

1/ The minimum reservation rate is equal to zero.
2/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.
3/ The firm transportation services commodity rates are not discountable. The commodity rate is the maximum and minimum commodity rate. The applicable MIDs commodity rate will be in addition to the TF reservation rates. The MIDs rates shown in Sheet Nos. 59-60A represent the throughput commodity rates for any transaction involving MIDs.
4/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.
5/ Applicable to Market Area Shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.

RATE SCHEDULE TFX

RESERVATION RATES	MARKET-TO-MARKET Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD Nov-Mar
Base Tariff Rates 1/	$16.033~~157~~	$42~~3~~.754~~085~~	$8.798~~939~~	$15~~6~~.837~~090~~

COMMODITY RATES 2/ 3/

TFX Receipt Point	TFX Delivery Point	Market Area 4/ Commodity	Field Mileage Rate per 100 miles Commodity	Out-of-Balance Commodity	Carlton Surcharge 5/ Maximum	Carlton Surcharge 5/ Minimum
Market	Market	0.0260		0.0260	0.0175	0.0000
Field	Market	0.0260	0.0103		0.0175	0.0000
Market	Field		0.0103			
Field	Field		0.0103	0.0217		

1/ The minimum reservation rate is equal to zero.
2/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.
3/ The firm transportation services commodity rates are not discountable. The commodity rate is the maximum and minimum commodity rate. The applicable MIDs commodity rate will be in addition to the TFX reservation rates. The MIDs rates shown in Sheet Nos. 59-60A represent the throughput commodity rates for any transaction involving MIDs.
4/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.
5/ Applicable to Market Area Shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.

RATE SCHEDULE TI

COMMODITY RATES 1/ 2/

TI		Market Area 3/		Field Mileage Rate per 100 miles		Out-of-Balance		Carlton Surcharge 4/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
NOVEMBER - MARCH									
Market	Market	1.4324~~433~~	0.0260			1.4324~~433~~	0.0260	0.0175	0.0000
Field	Market	1.4324~~433~~	0.0260	0.2572~~611~~	0.0103			0.0175	0.0000
Market	Field			0.2572~~611~~	0.0103				
Field	Field			0.2572~~611~~	0.0103	0.5427~~509~~	0.0217		
APRIL - OCTOBER									
Market	Market	0.5534~~75~~	0.0260			0.5534~~75~~	0.0260	0.0000	0.0000
Field	Market	0.5534~~75~~	0.0260	0.1475~~96~~	0.0103			0.0000	0.0000
Market	Field			0.1475~~96~~	0.0103				
Field	Field			0.1475~~96~~	0.0103	0.3112~~57~~	0.0217		

1/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.
2/ The MIDs rates shown in Sheet Nos. 59-60A represent the throughput commodity rates for any transaction involving MIDs.
3/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.
4/ Applicable to Market Area Shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.

	Commodity Charges Nov-Oct	
GS-T COMMODITY THROUGHPUT RATE		
Market Area	1.9817~~970~~	1/ 2/
Field to Demarcation	1.0282~~446~~	
Field-to-Market	3.0099~~416~~	1/
BEAVER COMPRESSION FEE		
Incidental Jurisdictional Compression Fee	0.0400	

WATERVILLE STORAGE

The Market Area transportation rate, Fuel and UAF is charged for delivery to Waterville storage point (POI 922), or other similarly situated third party storage points in the Market Area. If redelivery from Waterville, or other similarly situated third party storage points, is to a Market Area point, there are no additional transportation, Fuel or UAF charges. If the redelivery is to a Field Area delivery point, the Field Area mileage/MID transportation rate and Fuel is charged.

CAPACITY RELEASE FEE (Rate per transaction)	
Marketing	Negotiated 3/
DAILY DELIVERY VARIANCE CHARGE:	
Non-SOL/SUL/Critical Day	
Positive DDVC	4/
Negative DDVC	4/
Punitive DDVC	4/
SOL Day	
Positive DDVC	greater of 1.0000 or 1.25 times 5/
Negative DDVC	0.0000
Punitive DDVC	greater of 6/ or 2.0 times 5/
SUL Day	
Positive DDVC	0.0000
Negative DDVC	greater of 1.0000 or 1.25 times 5/
Punitive DDVC	0.0000
Critical Day	
Positive/Critical DDVC	
-First 2%	greater of 15.0000 or 1.50 times 5/
-Next 3%	greater of 22.0000 or 1.75 times 5/
Negative DDVC	0.0000
Punitive/Critical DDVC	
-Level I	greater of 56.5000 or 2.0 times 5/
-Level II	greater of 113.0000 or 3.0 times 5/
AUTHORIZED OVERRUN	
TF, TFX, TI and GS-T Rate Schedules	7/

1/ In addition, Shipper shall pay the applicable Electric Compression commodity rate as shown in Sheet No. 54 and the ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.
2/ There will be no commodity charge for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no commodity charge for transportation as set forth in Sheet Nos. 141, 142C and 147.
3/ Northern will assess fee only in those instances outlined in Sheet No. 288.
4/ The rate will be the applicable maximum Winter Season or Summer Season Market Area TI Rate.
5/ The highest published Platts "Gas Daily" Midpoint price on the applicable day at any of the applicable index points of: Market Area - Northern, demarc and Northern, Ventura; or Field Area - Panhandle, Tx.-Okla. and El Paso, Permian.
6/ Charge equal to five (5) times the SMS monthly reservation fee.
7/ The Authorized Overrun Rate shall be equal to the TI rate for the applicable MID path shown in Sheet Nos. 59-60A.

RATE SCHEDULES TF, TFX, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/ 2~~7~~/
Market Area (including Out-of-Balance)	1.20%
Field Area	3~~2~~/ 4~~3~~/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	-0.32% 2~~4~~/ 5/ 7/
FDD STORAGE FUEL	1.51%
FDD URR PERCENTAGE	0.11% 1/

	Electric Compression
COMMODITY RATES:	1/ 2~~7~~/
Market Area	$0.0002
Field Area	$0.0000

1/ Northern will adjust its Fuel, UAF and URR percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the GENERAL TERMS AND CONDITIONS of this Tariff.

2/ There will be no Fuel, electric compression or UAF charges for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no Fuel, electric compression or UAF charges for transportation as set forth in Sheet Nos. 141,142C and 147.~~Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.~~

3/ Fuel percentages shall be determined by MIDs for the Field Area shown in Sheet Nos. 61-62.~~Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the Fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total Fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the Fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the Shipper(s) providing Northern the requisite information.~~

4/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the Fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total Fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the Fuel that would be collected on the total path between the original receipt point and the ultimate delivery point, subject to the Shipper(s) providing Northern the requisite information.~~The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2021. For deliveries subject only to UAF, if the above UAF rate is negative, the UAF rate is zero; provided, however Northern will issue a volume credit on the Shipper’s monthly imbalance statement equivalent to the negative UAF percentage for such deliveries during the period in which the UAF rate is less than zero.~~

5/ Sheet No. 54A identifies the specific transportation transactions exempt from Fuel and UAF retention charges.

6/ The out-of-balance Fuel percentage for deliveries in MID~~S~~s 1-7 shall be the applicable Section 1 Transportation Fuel percentage, and for deliveries in MID~~S~~s 8-16B shall be the applicable Section 2 Transportation Fuel percentage.

7/ The UAF percentage utilizes the most recent twelve-month period ending December 31, 2021. For deliveries subject only to UAF, if the above UAF rate is negative, the UAF rate is zero; provided, however Northern will issue a volume credit on the Shipper’s monthly imbalance statement equivalent to the negative UAF percentage for such deliveries during the period in which the UAF rate is less than zero.~~There will be no Fuel, electric compression or UAF charges~~

~~for transportation from the Ventura pooling point (POI 78623) to the NBPL/NNG Ventura point (POI 192) and from the Ventura pooling point (POI 78623) to the MID 17 pooling point (POI 71458). In addition, there will be no Fuel, electric compression or UAF charges for transportation as set forth in Sheet Nos. 141,142C and 147.~~

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID Fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID Fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD, ILD & SMS

Rate Schedule FDD

Maximum Reservation Charge	4.3552~~679~~	1/
Maximum Capacity Charge	0.9065~~91~~	1/
Injection Charge - Firm	0.0232	
Withdrawal Charge - Firm	0.0232	
Annual Rollover Charge	0.9065~~91~~	1/

Rate Schedule PDD

Maximum Capacity Charge	0.9065~~91~~	1/
Maximum Monthly Inventory Charge	0.2188~~94~~	1/
Injection Charge	0.0232	
Withdrawal Charge	0.0232	
Annual Rollover Charge	0.9065~~91~~	1/

Rate Schedule IDD

Maximum Monthly Inventory Charge	0.2188~~94~~	1/
Injection Charge	0.0232	
Withdrawal Charge	0.0232	
Annual Rollover Charge	0.9065~~91~~	1/

Rate Schedule ILD

Maximum Charge	11.7500
Minimum Charge	0.5044
Performance Obligation Charge	2.0000

Rate Schedule SMS

Reservation Charge	7.0499~~1043~~
Commodity Rate	0.0208

1/ Minimum Rate is zero.

MILEAGE INDICATOR DISTRICTS (dollars per Dth)
DELIVERY DISTRICT

RECEIPT DISTRICT		1	2	3	4	5	6	7	7B	8	9
	~~TI Apr-Oct~~	~~0.0583~~	~~0.1406~~	~~0.2947~~	~~0.4189~~	~~0.4712~~	~~0.3351~~	~~0.3830~~	~~0.5042~~	~~0.8991~~	~~0.7749~~
~~1~~	~~TI Nov-Mar~~	~~0.1018~~	~~0.2454~~	~~0.5144~~	~~0.7311~~	~~0.8225~~	~~0.5849~~	~~0.6684~~	~~0.8799~~	~~1.5692~~	~~1.3525~~
	~~TF~~	~~0.0040~~	~~0.0097~~	~~0.0203~~	~~0.0288~~	~~0.0324~~	~~0.0231~~	~~0.0264~~	~~0.0347~~	~~0.0619~~	~~0.0534~~
	~~TI Apr-Oct~~	~~0.0688~~	~~0.0105~~	~~0.1062~~	~~0.2872~~	~~0.3725~~	~~0.2468~~	~~0.3112~~	~~0.4323~~	~~0.8019~~	~~0.6807~~
~~2~~	~~TI Nov-Mar~~	~~0.1201~~	~~0.0183~~	~~0.1854~~	~~0.5013~~	~~0.6501~~	~~0.4308~~	~~0.5431~~	~~0.7546~~	~~1.3995~~	~~1.1880~~
	~~TF~~	~~0.0047~~	~~0.0007~~	~~0.0073~~	~~0.0198~~	~~0.0256~~	~~0.0170~~	~~0.0214~~	~~0.0298~~	~~0.0552~~	~~0.0469~~
	~~TI Apr-Oct~~	~~0.4638~~	~~0.3007~~	~~0.0778~~	~~0.0913~~	~~0.4084~~	~~0.2528~~	~~0.1885~~	~~0.3097~~	~~0.8422~~	~~0.7196~~
~~3~~	~~TI Nov-Mar~~	~~0.8094~~	~~0.5248~~	~~0.1358~~	~~0.1593~~	~~0.7128~~	~~0.4413~~	~~0.3290~~	~~0.5405~~	~~1.4700~~	~~1.2559~~
	~~TF~~	~~0.0319~~	~~0.0207~~	~~0.0054~~	~~0.0063~~	~~0.0281~~	~~0.0174~~	~~0.0130~~	~~0.0213~~	~~0.0580~~	~~0.0495~~
	~~TI Apr-Oct~~	~~0.4473~~	~~0.3979~~	~~0.2812~~	~~0.0673~~	~~0.2468~~	~~0.1690~~	~~0.2648~~	~~0.3860~~	~~0.7689~~	~~0.6433~~
~~4~~	~~TI Nov-Mar~~	~~0.7807~~	~~0.6945~~	~~0.4909~~	~~0.1175~~	~~0.4308~~	~~0.2950~~	~~0.4621~~	~~0.6736~~	~~1.3421~~	~~1.1227~~
	~~TF~~	~~0.0308~~	~~0.0274~~	~~0.0194~~	~~0.0046~~	~~0.0170~~	~~0.0116~~	~~0.0182~~	~~0.0266~~	~~0.0529~~	~~0.0443~~
	~~TI Apr-Oct~~	~~0.4099~~	~~0.3695~~	~~0.2902~~	~~0.2603~~	~~0.0404~~	~~0.1137~~	~~0.2050~~	~~0.3261~~	~~0.7286~~	~~0.6044~~
~~5~~	~~TI Nov-Mar~~	~~0.7154~~	~~0.6449~~	~~0.5065~~	~~0.4543~~	~~0.0705~~	~~0.1984~~	~~0.3577~~	~~0.5692~~	~~1.2716~~	~~1.0548~~
	~~TF~~	~~0.0282~~	~~0.0254~~	~~0.0200~~	~~0.0179~~	~~0.0028~~	~~0.0078~~	~~0.0141~~	~~0.0225~~	~~0.0502~~	~~0.0416~~
	~~TI Apr-Oct~~	~~0.2603~~	~~0.2079~~	~~0.0748~~	~~0.1122~~	~~0.1541~~	~~0.1002~~	~~0.1182~~	~~0.2394~~	~~0.6732~~	~~0.4922~~
~~6~~	~~TI Nov-Mar~~	~~0.4543~~	~~0.3629~~	~~0.1306~~	~~0.1958~~	~~0.2689~~	~~0.1749~~	~~0.2063~~	~~0.4178~~	~~1.1750~~	~~0.8590~~
	~~TF~~	~~0.0179~~	~~0.0143~~	~~0.0052~~	~~0.0077~~	~~0.0106~~	~~0.0069~~	~~0.0081~~	~~0.0165~~	~~0.0464~~	~~0.0339~~
	~~TI Apr-Oct~~	~~0.4488~~	~~0.3905~~	~~0.3740~~	~~0.2962~~	~~0.3172~~	~~0.1870~~	~~0.1496~~	~~0.2708~~	~~0.4308~~	~~0.3052~~
~~7~~	~~TI Nov-Mar~~	~~0.7833~~	~~0.6815~~	~~0.6528~~	~~0.5170~~	~~0.5535~~	~~0.3264~~	~~0.2611~~	~~0.4726~~	~~0.7520~~	~~0.5326~~
	~~TF~~	~~0.0309~~	~~0.0269~~	~~0.0258~~	~~0.0204~~	~~0.0218~~	~~0.0129~~	~~0.0103~~	~~0.0186~~	~~0.0297~~	~~0.0210~~
	~~TI Apr-Oct~~	~~0.4488~~	~~0.3905~~	~~0.3740~~	~~0.2962~~	~~0.3172~~	~~0.1870~~	~~0.1496~~	~~0.0000~~	~~0.4308~~	~~0.3052~~
~~7B~~	~~TI Nov-Mar~~	~~0.7833~~	~~0.6815~~	~~0.6528~~	~~0.5170~~	~~0.5535~~	~~0.3264~~	~~0.2611~~	~~0.0000~~	~~0.7520~~	~~0.5326~~
	~~TF~~	~~0.0309~~	~~0.0269~~	~~0.0258~~	~~0.0204~~	~~0.0218~~	~~0.0129~~	~~0.0103~~	~~0.0000~~	~~0.0297~~	~~0.0210~~
	~~TI Apr-Oct~~	~~0.8991~~	~~0.8512~~	~~0.7869~~	~~0.7764~~	~~0.7689~~	~~0.6208~~	~~0.6433~~	~~0.5101~~	~~0.0120~~	~~0.3097~~
~~8~~	~~TI Nov-Mar~~	~~1.5692~~	~~1.4857~~	~~1.3734~~	~~1.3551~~	~~1.3421~~	~~1.0836~~	~~1.1227~~	~~0.8904~~	~~0.0209~~	~~0.5405~~
	~~TF~~	~~0.0619~~	~~0.0586~~	~~0.0542~~	~~0.0535~~	~~0.0529~~	~~0.0427~~	~~0.0443~~	~~0.0351~~	~~0.0008~~	~~0.0213~~
	~~TI Apr-Oct~~	~~0.7809~~	~~0.7271~~	~~0.6538~~	~~0.6089~~	~~0.5206~~	~~0.5311~~	~~0.3635~~	~~0.2304~~	~~0.1900~~	~~0.1002~~
~~9~~	~~TI Nov-Mar~~	~~1.3629~~	~~1.2689~~	~~1.1410~~	~~1.0627~~	~~0.9086~~	~~0.9269~~	~~0.6345~~	~~0.4021~~	~~0.3316~~	~~0.1749~~
	~~TF~~	~~0.0538~~	~~0.0501~~	~~0.0450~~	~~0.0419~~	~~0.0358~~	~~0.0366~~	~~0.0250~~	~~0.0159~~	~~0.0131~~	~~0.0069~~
	TI Apr-Oct	0.0575	0.1387	0.2906	0.4130	0.4646	0.3304	0.3776	0.4971	0.8865	0.7641
1	TI Nov-Mar	0.1003	0.2418	0.5067	0.7202	0.8102	0.5761	0.6584	0.8668	1.5458	1.3323
	TF	0.0040	0.0097	0.0203	0.0288	0.0324	0.0231	0.0264	0.0347	0.0619	0.0534
	TI Apr-Oct	0.0679	0.0103	0.1047	0.2832	0.3673	0.2434	0.3068	0.4263	0.7906	0.6711
2	TI Nov-Mar	0.1183	0.0180	0.1826	0.4938	0.6404	0.4244	0.5350	0.7433	1.3786	1.1703
	TF	0.0047	0.0007	0.0073	0.0198	0.0256	0.0170	0.0214	0.0298	0.0552	0.0469
	TI Apr-Oct	0.4573	0.2965	0.0767	0.0900	0.4027	0.2493	0.1859	0.3053	0.8304	0.7095
3	TI Nov-Mar	0.7973	0.5170	0.1337	0.1569	0.7022	0.4347	0.3241	0.5324	1.4480	1.2371
	TF	0.0319	0.0207	0.0054	0.0063	0.0281	0.0174	0.0130	0.0213	0.0580	0.0495
	TI Apr-Oct	0.4410	0.3924	0.2773	0.0664	0.2434	0.1667	0.2611	0.3806	0.7582	0.6343
4	TI Nov-Mar	0.7690	0.6842	0.4835	0.1157	0.4244	0.2906	0.4552	0.6636	1.3220	1.1060
	TF	0.0308	0.0274	0.0194	0.0046	0.0170	0.0116	0.0182	0.0266	0.0529	0.0443
	TI Apr-Oct	0.4042	0.3643	0.2862	0.2567	0.0398	0.1121	0.2021	0.3216	0.7183	0.5959
5	TI Nov-Mar	0.7047	0.6353	0.4990	0.4475	0.0694	0.1955	0.3524	0.5607	1.2526	1.0391
	TF	0.0282	0.0254	0.0200	0.0179	0.0028	0.0078	0.0141	0.0225	0.0502	0.0416
	TI Apr-Oct	0.2567	0.2050	0.0738	0.1106	0.1519	0.0988	0.1165	0.2360	0.6638	0.4853
6	TI Nov-Mar	0.4475	0.3575	0.1286	0.1929	0.2649	0.1723	0.2032	0.4115	1.1574	0.8462
	TF	0.0179	0.0143	0.0052	0.0077	0.0106	0.0069	0.0081	0.0165	0.0464	0.0339
	TI Apr-Oct	0.4425	0.3850	0.3688	0.2921	0.3127	0.1844	0.1475	0.2670	0.4248	0.3009

7	TI Nov-Mar	0.7716	0.6713	0.6430	0.5093	0.5453	0.3215	0.2572	0.4655	0.7407	0.5247
	TF	0.0309	0.0269	0.0258	0.0204	0.0218	0.0129	0.0103	0.0186	0.0297	0.0210
	TI Apr-Oct	0.4425	0.3850	0.3688	0.2921	0.3127	0.1844	0.1475	0.0000	0.4248	0.3009
7B	TI Nov-Mar	0.7716	0.6713	0.6430	0.5093	0.5453	0.3215	0.2572	0.0000	0.7407	0.5247
	TF	0.0309	0.0269	0.0258	0.0204	0.0218	0.0129	0.0103	0.0000	0.0297	0.0210
	TI Apr-Oct	0.8865	0.8393	0.7759	0.7655	0.7582	0.6121	0.6343	0.5030	0.0118	0.3053
8	TI Nov-Mar	1.5458	1.4635	1.3529	1.3349	1.3220	1.0674	1.1060	0.8771	0.0206	0.5324
	TF	0.0619	0.0586	0.0542	0.0535	0.0529	0.0427	0.0443	0.0351	0.0008	0.0213
	TI Apr-Oct	0.7700	0.7169	0.6446	0.6003	0.5133	0.5236	0.3584	0.2272	0.1873	0.0988
9	TI Nov-Mar	1.3426	1.2500	1.1240	1.0468	0.8951	0.9131	0.6250	0.3961	0.3266	0.1723
	TF	0.0538	0.0501	0.0450	0.0419	0.0358	0.0366	0.0250	0.0159	0.0131	0.0069

NOTE: The MID rates include: (1) the appropriate Market Area Commodity rate for deliveries to MID 17; (2) the applicable Market Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MID 17; and (3) the applicable Field Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MIDs 1 - 16A. "TF" is applicable to Rate Schedules TF and TFX.

In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at https://www.ferc.gov and the Carlton surcharge, if applicable.

MILEAGE INDICATOR DISTRICTS (dollars per Dth)

DELIVERY DISTRICT

RECEIPT DISTRICT		1	2	3	4	5	6	7	7B	8	9
	~~TI Apr-Oct~~	~~0.7959~~	~~0.8228~~	~~0.7944~~	~~0.6882~~	~~0.5730~~	~~0.5819~~	~~0.4368~~	~~0.3037~~	~~0.2857~~	~~0.2453~~
~~10~~	~~TI Nov-Mar~~	~~1.3891~~	~~1.4361~~	~~1.3864~~	~~1.2011~~	~~1.0000~~	~~1.0157~~	~~0.7624~~	~~0.5300~~	~~0.4987~~	~~0.4282~~
	~~TF~~	~~0.0548~~	~~0.0567~~	~~0.0547~~	~~0.0474~~	~~0.0394~~	~~0.0401~~	~~0.0301~~	~~0.0209~~	~~0.0197~~	~~0.0169~~
	~~TI Apr-Oct~~	~~0.7645~~	~~0.7061~~	~~0.6388~~	~~0.5610~~	~~0.5520~~	~~0.3097~~	~~0.3845~~	~~0.2513~~	~~0.1601~~	~~0.2005~~
~~11~~	~~TI Nov-Mar~~	~~1.3342~~	~~1.2324~~	~~1.1149~~	~~0.9791~~	~~0.9635~~	~~0.5405~~	~~0.6710~~	~~0.4386~~	~~0.2794~~	~~0.3499~~
	~~TF~~	~~0.0526~~	~~0.0486~~	~~0.0440~~	~~0.0386~~	~~0.0380~~	~~0.0213~~	~~0.0265~~	~~0.0173~~	~~0.0110~~	~~0.0138~~
	~~TI Apr-Oct~~	~~0.8273~~	~~0.7689~~	~~0.7689~~	~~0.6552~~	~~0.7001~~	~~0.5670~~	~~0.4458~~	~~0.3127~~	~~0.2498~~	~~0.2364~~
~~12~~	~~TI Nov-Mar~~	~~1.4439~~	~~1.3421~~	~~1.3421~~	~~1.1436~~	~~1.2219~~	~~0.9896~~	~~0.7781~~	~~0.5457~~	~~0.4360~~	~~0.4125~~
	~~TF~~	~~0.0570~~	~~0.0529~~	~~0.0529~~	~~0.0451~~	~~0.0482~~	~~0.0390~~	~~0.0307~~	~~0.0215~~	~~0.0172~~	~~0.0163~~
	~~TI Apr-Oct~~	~~0.7809~~	~~0.7794~~	~~0.7899~~	~~0.7076~~	~~0.7091~~	~~0.5954~~	~~0.4787~~	~~0.3456~~	~~0.2633~~	~~0.2468~~
~~13~~	~~TI Nov-Mar~~	~~1.3629~~	~~1.3603~~	~~1.3786~~	~~1.2350~~	~~1.2376~~	~~1.0392~~	~~0.8355~~	~~0.6031~~	~~0.4595~~	~~0.4308~~
	~~TF~~	~~0.0538~~	~~0.0537~~	~~0.0544~~	~~0.0487~~	~~0.0488~~	~~0.0410~~	~~0.0330~~	~~0.0238~~	~~0.0181~~	~~0.0170~~
	~~TI Apr-Oct~~	~~0.9574~~	~~0.9993~~	~~0.9530~~	~~0.8737~~	~~0.8078~~	~~0.7660~~	~~0.6642~~	~~0.5311~~	~~0.4638~~	~~0.4548~~
~~14~~	~~TI Nov-Mar~~	~~1.6710~~	~~1.7441~~	~~1.6632~~	~~1.5248~~	~~1.4099~~	~~1.3368~~	~~1.1593~~	~~0.9269~~	~~0.8094~~	~~0.7937~~
	~~TF~~	~~0.0659~~	~~0.0688~~	~~0.0656~~	~~0.0602~~	~~0.0556~~	~~0.0527~~	~~0.0457~~	~~0.0366~~	~~0.0319~~	~~0.0313~~
	~~TI Apr-Oct~~	~~1.2596~~	~~1.2073~~	~~1.1878~~	~~1.0696~~	~~1.0412~~	~~1.0098~~	~~0.8961~~	~~0.7630~~	~~0.6837~~	~~0.6702~~
~~15~~	~~TI Nov-Mar~~	~~2.1985~~	~~2.1071~~	~~2.0731~~	~~1.8669~~	~~1.8173~~	~~1.7624~~	~~1.5640~~	~~1.3316~~	~~1.1932~~	~~1.1697~~
	~~TF~~	~~0.0867~~	~~0.0831~~	~~0.0818~~	~~0.0736~~	~~0.0717~~	~~0.0695~~	~~0.0617~~	~~0.0525~~	~~0.0471~~	~~0.0461~~
	~~TI Apr-Oct~~	~~1.0248~~	~~0.9589~~	~~1.0038~~	~~0.8303~~	~~0.8946~~	~~0.7046~~	~~0.6328~~	~~0.4997~~	~~0.4368~~	~~0.4279~~
~~16A~~	~~TI Nov-Mar~~	~~1.7885~~	~~1.6737~~	~~1.7520~~	~~1.4491~~	~~1.5614~~	~~1.2298~~	~~1.1045~~	~~0.8721~~	~~0.7624~~	~~0.7467~~
	~~TF~~	~~0.0706~~	~~0.0660~~	~~0.0691~~	~~0.0572~~	~~0.0616~~	~~0.0485~~	~~0.0436~~	~~0.0344~~	~~0.0301~~	~~0.0295~~
	~~TI Apr-Oct~~	~~1.1519~~	~~1.0382~~	~~1.0487~~	~~1.0292~~	~~0.9829~~	~~0.9530~~	~~0.6926~~	~~0.5595~~	~~0.5550~~	~~0.5475~~
~~16B~~	~~TI Nov-Mar~~	~~2.0105~~	~~1.8120~~	~~1.8303~~	~~1.7964~~	~~1.7154~~	~~1.6632~~	~~1.2089~~	~~0.9765~~	~~0.9687~~	~~0.9556~~
	~~TF~~	~~0.0793~~	~~0.0715~~	~~0.0722~~	~~0.0709~~	~~0.0677~~	~~0.0656~~	~~0.0477~~	~~0.0385~~	~~0.0382~~	~~0.0377~~
	~~TI Apr-Oct~~	~~1.6875~~	~~1.6276~~	~~1.4197~~	~~1.4736~~	~~1.4436~~	~~1.3868~~	~~1.2731~~	~~1.1400~~	~~1.0921~~	~~1.0831~~
~~17~~	~~TI Nov-Mar~~	~~2.9452~~	~~2.8408~~	~~2.4778~~	~~2.5718~~	~~2.5196~~	~~2.4204~~	~~2.2220~~	~~1.9896~~	~~1.9060~~	~~1.8904~~
	~~TF~~	~~0.1162~~	~~0.1121~~	~~0.0977~~	~~0.1015~~	~~0.0994~~	~~0.0955~~	~~0.0877~~	~~0.0785~~	~~0.0752~~	~~0.0746~~
	TI Apr-Oct	0.7847	0.8113	0.7832	0.6785	0.5649	0.5738	0.4307	0.2994	0.2817	0.2419
10	TI Nov-Mar	1.3683	1.4146	1.3657	1.1831	0.9851	1.0005	0.7510	0.5221	0.4913	0.4218
	TF	0.0548	0.0567	0.0547	0.0474	0.0394	0.0401	0.0301	0.0209	0.0197	0.0169
	TI Apr-Oct	0.7537	0.6962	0.6298	0.5531	0.5443	0.3053	0.3791	0.2478	0.1578	0.1977
11	TI Nov-Mar	1.3143	1.2140	1.0982	0.9645	0.9491	0.5324	0.6610	0.4321	0.2752	0.3446
	TF	0.0526	0.0486	0.0440	0.0386	0.0380	0.0213	0.0265	0.0173	0.0110	0.0138
	TI Apr-Oct	0.8157	0.7582	0.7582	0.6461	0.6903	0.5590	0.4396	0.3083	0.2463	0.2331
12	TI Nov-Mar	1.4223	1.3220	1.3220	1.1265	1.2037	0.9748	0.7665	0.5375	0.4295	0.4064
	TF	0.0570	0.0529	0.0529	0.0451	0.0482	0.0390	0.0307	0.0215	0.0172	0.0163
	TI Apr-Oct	0.7700	0.7685	0.7788	0.6977	0.6992	0.5871	0.4720	0.3407	0.2596	0.2434
13	TI Nov-Mar	1.3426	1.3400	1.3580	1.2166	1.2191	1.0237	0.8230	0.5941	0.4527	0.4244
	TF	0.0538	0.0537	0.0544	0.0487	0.0488	0.0410	0.0330	0.0238	0.0181	0.0170
	TI Apr-Oct	0.9440	0.9853	0.9396	0.8614	0.7965	0.7552	0.6549	0.5236	0.4573	0.4484
14	TI Nov-Mar	1.6461	1.7181	1.6384	1.5020	1.3889	1.3169	1.1420	0.9131	0.7973	0.7819
	TF	0.0659	0.0688	0.0656	0.0602	0.0556	0.0527	0.0457	0.0366	0.0319	0.0313
	TI Apr-Oct	1.2420	1.1903	1.1712	1.0546	1.0266	0.9956	0.8835	0.7523	0.6741	0.6608
15	TI Nov-Mar	2.1656	2.0756	2.0422	1.8390	1.7901	1.7361	1.5406	1.3117	1.1754	1.1523
	TF	0.0867	0.0831	0.0818	0.0736	0.0717	0.0695	0.0617	0.0525	0.0471	0.0461
	TI Apr-Oct	1.0104	0.9455	0.9897	0.8186	0.8821	0.6947	0.6239	0.4927	0.4307	0.4219
16A	TI Nov-Mar	1.7618	1.6487	1.7258	1.4275	1.5381	1.2114	1.0880	0.8590	0.7510	0.7356
	TF	0.0706	0.0660	0.0691	0.0572	0.0616	0.0485	0.0436	0.0344	0.0301	0.0295
	TI Apr-Oct	1.1358	1.0237	1.0340	1.0148	0.9691	0.9396	0.6829	0.5517	0.5472	0.5399
16B	TI Nov-Mar	1.9804	1.7850	1.8030	1.7695	1.6898	1.6384	1.1908	0.9619	0.9542	0.9414
	TF	0.0793	0.0715	0.0722	0.0709	0.0677	0.0656	0.0477	0.0385	0.0382	0.0377

	TI	Apr-Oct	1.6638	1.6048	1.3998	1.4529	1.4234	1.3673	1.2552	1.1240	1.0768	1.0679
17	TI	Nov-Mar	2.9012	2.7983	2.4408	2.5334	2.4820	2.3842	2.1888	1.9599	1.8776	1.8621
	TF		0.1162	0.1121	0.0977	0.1015	0.0994	0.0955	0.0877	0.0785	0.0752	0.0746

NOTE: MID 16A represents the 14 county area south of the F/M Demarcation point.
MID 16B represents the F/M Demarcation point.
MID 17 represents the Market Area.
"TF" is applicable to Rate Schedules TF and TFX.

NOTE: The MID rates include: (1) the appropriate Market Area Commodity rate for deliveries to MID 17; (2) the applicable Market Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MID 17; and (3) the applicable Field Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MIDs 1 - 16A.

In addition, Shipper shall pay the ACA unit surcharge as posted on FERC’s website at https://www.ferc.gov and the Carlton surcharge, if applicable.

MILEAGE INDICATOR DISTRICTS (dollars per Dth)
DELIVERY DISTRICT

RECEIPT DISTRICT		10	11	12	13	14	15	16A	16B	17
	~~TI Apr-Oct~~	~~0.9170~~	~~0.7405~~	~~0.8318~~	~~0.9036~~	~~1.0322~~	~~1.0996~~	~~1.0263~~	~~1.1519~~	~~1.7096~~
~~1~~	~~TI Nov-Mar~~	~~1.6005~~	~~1.2924~~	~~1.4517~~	~~1.5770~~	~~1.8016~~	~~1.9191~~	~~1.7911~~	~~2.0105~~	~~3.4540~~
	~~TF~~	~~0.0631~~	~~0.0510~~	~~0.0573~~	~~0.0622~~	~~0.0711~~	~~0.0757~~	~~0.0707~~	~~0.0793~~	~~0.1055~~
	~~TI Apr-Oct~~	~~0.7959~~	~~0.6582~~	~~0.7345~~	~~0.7989~~	~~0.9290~~	~~1.0981~~	~~0.9335~~	~~1.0382~~	~~1.5959~~
~~2~~	~~TI Nov-Mar~~	~~1.3891~~	~~1.1488~~	~~1.2820~~	~~1.3943~~	~~1.6214~~	~~1.9165~~	~~1.6293~~	~~1.8120~~	~~3.2555~~
	~~TF~~	~~0.0548~~	~~0.0453~~	~~0.0506~~	~~0.0550~~	~~0.0640~~	~~0.0756~~	~~0.0643~~	~~0.0715~~	~~0.0977~~
	~~TI Apr-Oct~~	~~0.8213~~	~~0.7031~~	~~0.7779~~	~~0.8437~~	~~1.0068~~	~~1.1414~~	~~0.8557~~	~~1.0487~~	~~1.6064~~
~~3~~	~~TI Nov-Mar~~	~~1.4334~~	~~1.2272~~	~~1.3577~~	~~1.4726~~	~~1.7572~~	~~1.9922~~	~~1.4935~~	~~1.8303~~	~~3.2738~~
	~~TF~~	~~0.0565~~	~~0.0484~~	~~0.0536~~	~~0.0581~~	~~0.0693~~	~~0.0786~~	~~0.0589~~	~~0.0722~~	~~0.0984~~
	~~TI Apr-Oct~~	~~0.7136~~	~~0.6238~~	~~0.7001~~	~~0.7645~~	~~0.9021~~	~~1.0637~~	~~0.8796~~	~~1.0292~~	~~1.5869~~
~~4~~	~~TI Nov-Mar~~	~~1.2454~~	~~1.0888~~	~~1.2219~~	~~1.3342~~	~~1.5744~~	~~1.8564~~	~~1.5353~~	~~1.7964~~	~~3.2399~~
	~~TF~~	~~0.0491~~	~~0.0430~~	~~0.0482~~	~~0.0526~~	~~0.0621~~	~~0.0732~~	~~0.0606~~	~~0.0709~~	~~0.0971~~
	~~TI Apr-Oct~~	~~0.7525~~	~~0.5849~~	~~0.6612~~	~~0.7256~~	~~0.7959~~	~~1.0023~~	~~0.8946~~	~~0.9829~~	~~1.5406~~
~~5~~	~~TI Nov-Mar~~	~~1.3133~~	~~1.0209~~	~~1.1541~~	~~1.2663~~	~~1.3891~~	~~1.7494~~	~~1.5614~~	~~1.7154~~	~~3.1589~~
	~~TF~~	~~0.0518~~	~~0.0403~~	~~0.0455~~	~~0.0500~~	~~0.0548~~	~~0.0690~~	~~0.0616~~	~~0.0677~~	~~0.0939~~
	~~TI Apr-Oct~~	~~0.6837~~	~~0.5281~~	~~0.6059~~	~~0.6702~~	~~0.8034~~	~~0.9904~~	~~0.7959~~	~~0.9530~~	~~1.5107~~
~~6~~	~~TI Nov-Mar~~	~~1.1932~~	~~0.9217~~	~~1.0575~~	~~1.1697~~	~~1.4021~~	~~1.7285~~	~~1.3891~~	~~1.6632~~	~~3.1067~~
	~~TF~~	~~0.0471~~	~~0.0364~~	~~0.0417~~	~~0.0461~~	~~0.0553~~	~~0.0682~~	~~0.0548~~	~~0.0656~~	~~0.0918~~
	~~TI Apr-Oct~~	~~0.4473~~	~~0.2872~~	~~0.3620~~	~~0.4279~~	~~0.5640~~	~~0.8722~~	~~0.5580~~	~~0.6926~~	~~1.2503~~
~~7~~	~~TI Nov-Mar~~	~~0.7807~~	~~0.5013~~	~~0.6319~~	~~0.7467~~	~~0.9843~~	~~1.5222~~	~~0.9739~~	~~1.2089~~	~~2.6524~~
	~~TF~~	~~0.0308~~	~~0.0198~~	~~0.0249~~	~~0.0295~~	~~0.0388~~	~~0.0600~~	~~0.0384~~	~~0.0477~~	~~0.0739~~
	~~TI Apr-Oct~~	~~0.4473~~	~~0.2872~~	~~0.3620~~	~~0.4279~~	~~0.5640~~	~~0.8722~~	~~0.5580~~	~~0.6926~~	~~1.2503~~
~~7B~~	~~TI Nov-Mar~~	~~0.7807~~	~~0.5013~~	~~0.6319~~	~~0.7467~~	~~0.9843~~	~~1.5222~~	~~0.9739~~	~~1.2089~~	~~2.6524~~
	~~TF~~	~~0.0308~~	~~0.0198~~	~~0.0249~~	~~0.0295~~	~~0.0388~~	~~0.0600~~	~~0.0384~~	~~0.0477~~	~~0.0739~~
	~~TI Apr-Oct~~	~~0.3261~~	~~0.1945~~	~~0.2483~~	~~0.3142~~	~~0.4398~~	~~0.6642~~	~~0.4189~~	~~0.5550~~	~~1.1127~~
~~8~~	~~TI Nov-Mar~~	~~0.5692~~	~~0.3394~~	~~0.4334~~	~~0.5483~~	~~0.7676~~	~~1.1593~~	~~0.7311~~	~~0.9687~~	~~2.4122~~
	~~TF~~	~~0.0225~~	~~0.0134~~	~~0.0171~~	~~0.0216~~	~~0.0303~~	~~0.0457~~	~~0.0288~~	~~0.0382~~	~~0.0644~~
	~~TI Apr-Oct~~	~~0.2528~~	~~0.1137~~	~~0.2468~~	~~0.2513~~	~~0.3964~~	~~0.6074~~	~~0.4443~~	~~0.5475~~	~~1.1052~~
~~9~~	~~TI Nov-Mar~~	~~0.4413~~	~~0.1984~~	~~0.4308~~	~~0.4386~~	~~0.6919~~	~~1.0601~~	~~0.7755~~	~~0.9556~~	~~2.3991~~
	~~TF~~	~~0.0174~~	~~0.0078~~	~~0.0170~~	~~0.0173~~	~~0.0273~~	~~0.0418~~	~~0.0306~~	~~0.0377~~	~~0.0639~~
	TI Apr-Oct	0.9042	0.7301	0.8201	0.8909	1.0178	1.0841	1.0119	1.1358	1.6894
1	TI Nov-Mar	1.5766	1.2731	1.4300	1.5535	1.7747	1.8904	1.7644	1.9804	3.4130
	TF	0.0631	0.0510	0.0573	0.0622	0.0711	0.0757	0.0707	0.0793	0.1055
	TI Apr-Oct	0.7847	0.6490	0.7242	0.7877	0.9160	1.0827	0.9204	1.0237	1.5773
2	TI Nov-Mar	1.3683	1.1317	1.2629	1.3734	1.5972	1.8878	1.6049	1.7850	3.2176
	TF	0.0548	0.0453	0.0506	0.0550	0.0640	0.0756	0.0643	0.0715	0.0977
	TI Apr-Oct	0.8098	0.6933	0.7670	0.8319	0.9927	1.1254	0.8437	1.0340	1.5876
3	TI Nov-Mar	1.4120	1.2088	1.3374	1.4506	1.7310	1.9624	1.4712	1.8030	3.2356
	TF	0.0565	0.0484	0.0536	0.0581	0.0693	0.0786	0.0589	0.0722	0.0984
	TI Apr-Oct	0.7036	0.6151	0.6903	0.7537	0.8894	1.0487	0.8673	1.0148	1.5684
4	TI Nov-Mar	1.2268	1.0725	1.2037	1.3143	1.5509	1.8287	1.5123	1.7695	3.2021
	TF	0.0491	0.0430	0.0482	0.0526	0.0621	0.0732	0.0606	0.0709	0.0971
	TI Apr-Oct	0.7419	0.5767	0.6520	0.7154	0.7847	0.9883	0.8821	0.9691	1.5227
5	TI Nov-Mar	1.2937	1.0057	1.1368	1.2474	1.3683	1.7232	1.5381	1.6898	3.1224
	TF	0.0518	0.0403	0.0455	0.0500	0.0548	0.0690	0.0616	0.0677	0.0939
	TI Apr-Oct	0.6741	0.5207	0.5974	0.6608	0.7921	0.9765	0.7847	0.9396	1.4932
6	TI Nov-Mar	1.1754	0.9079	1.0417	1.1523	1.3812	1.7027	1.3683	1.6384	3.0710
	TF	0.0471	0.0364	0.0417	0.0461	0.0553	0.0682	0.0548	0.0656	0.0918
	TI Apr-Oct	0.4410	0.2832	0.3570	0.4219	0.5561	0.8599	0.5502	0.6829	1.2365

7	TI	Nov-Mar	0.7690	0.4938	0.6224	0.7356	0.9696	1.4995	0.9594	1.1908	2.6234
	TF		0.0308	0.0198	0.0249	0.0295	0.0388	0.0600	0.0384	0.0477	0.0739
	TI	Apr-Oct	0.4410	0.2832	0.3570	0.4219	0.5561	0.8599	0.5502	0.6829	1.2365
7B	TI	Nov-Mar	0.7690	0.4938	0.6224	0.7356	0.9696	1.4995	0.9594	1.1908	2.6234
	TF		0.0308	0.0198	0.0249	0.0295	0.0388	0.0600	0.0384	0.0477	0.0739
	TI	Apr-Oct	0.3216	0.1918	0.2449	0.3098	0.4337	0.6549	0.4130	0.5472	1.1008
8	TI	Nov-Mar	0.5607	0.3344	0.4270	0.5401	0.7562	1.1420	0.7202	0.9542	2.3868
	TF		0.0225	0.0134	0.0171	0.0216	0.0303	0.0457	0.0288	0.0382	0.0644
	TI	Apr-Oct	0.2493	0.1121	0.2434	0.2478	0.3909	0.5989	0.4381	0.5399	1.0935
9	TI	Nov-Mar	0.4347	0.1955	0.4244	0.4321	0.6816	1.0442	0.7639	0.9414	2.3740
	TF		0.0174	0.0078	0.0170	0.0173	0.0273	0.0418	0.0306	0.0377	0.0639

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MILEAGE INDICATOR DISTRICTS (dollars per Dth)
DELIVERY DISTRICT

RECEIPT DISTRICT		10	11	12	13	14	15	16A	16B	17
	~~TI Apr-Oct~~	~~0.0180~~	~~0.0733~~	~~0.2199~~	~~0.2812~~	~~0.4159~~	~~0.5775~~	~~0.3426~~	~~0.5445~~	~~1.1022~~
~~10~~	~~TI Nov-Mar~~	~~0.0313~~	~~0.1279~~	~~0.3838~~	~~0.4909~~	~~0.7259~~	~~1.0078~~	~~0.5979~~	~~0.9504~~	~~2.3939~~
	~~TF~~	~~0.0012~~	~~0.0050~~	~~0.0151~~	~~0.0194~~	~~0.0286~~	~~0.0398~~	~~0.0236~~	~~0.0375~~	~~0.0637~~
	~~TI Apr-Oct~~	~~0.1601~~	~~0.0359~~	~~0.0658~~	~~0.1840~~	~~0.3142~~	~~0.5101~~	~~0.2663~~	~~0.4084~~	~~0.9661~~
~~11~~	~~TI Nov-Mar~~	~~0.2794~~	~~0.0627~~	~~0.1149~~	~~0.3212~~	~~0.5483~~	~~0.8904~~	~~0.4648~~	~~0.7128~~	~~2.1563~~
	~~TF~~	~~0.0110~~	~~0.0025~~	~~0.0045~~	~~0.0127~~	~~0.0216~~	~~0.0351~~	~~0.0183~~	~~0.0281~~	~~0.0543~~
	~~TI Apr-Oct~~	~~0.2498~~	~~0.1227~~	~~0.1496~~	~~0.2289~~	~~0.3785~~	~~0.5416~~	~~0.3635~~	~~0.5101~~	~~1.0678~~
~~12~~	~~TI Nov-Mar~~	~~0.4360~~	~~0.2141~~	~~0.2611~~	~~0.3995~~	~~0.6606~~	~~0.9452~~	~~0.6345~~	~~0.8904~~	~~2.3339~~
	~~TF~~	~~0.0172~~	~~0.0084~~	~~0.0103~~	~~0.0158~~	~~0.0261~~	~~0.0373~~	~~0.0250~~	~~0.0351~~	~~0.0613~~
	~~TI Apr-Oct~~	~~0.3276~~	~~0.1272~~	~~0.1870~~	~~0.0838~~	~~0.1855~~	~~0.3994~~	~~0.1511~~	~~0.2947~~	~~0.8524~~
~~13~~	~~TI Nov-Mar~~	~~0.5718~~	~~0.2219~~	~~0.3264~~	~~0.1462~~	~~0.3238~~	~~0.6971~~	~~0.2637~~	~~0.5144~~	~~1.9579~~
	~~TF~~	~~0.0226~~	~~0.0088~~	~~0.0129~~	~~0.0058~~	~~0.0128~~	~~0.0275~~	~~0.0104~~	~~0.0203~~	~~0.0465~~
	~~TI Apr-Oct~~	~~0.2887~~	~~0.3246~~	~~0.4054~~	~~0.1272~~	~~0.0359~~	~~0.5116~~	~~0.2872~~	~~0.4383~~	~~0.9960~~
~~14~~	~~TI Nov-Mar~~	~~0.5039~~	~~0.5666~~	~~0.7076~~	~~0.2219~~	~~0.0627~~	~~0.8930~~	~~0.5013~~	~~0.7650~~	~~2.2085~~
	~~TF~~	~~0.0199~~	~~0.0224~~	~~0.0279~~	~~0.0088~~	~~0.0025~~	~~0.0352~~	~~0.0198~~	~~0.0302~~	~~0.0564~~
	~~TI Apr-Oct~~	~~0.6538~~	~~0.5251~~	~~0.6104~~	~~0.3875~~	~~0.5311~~	~~0.0374~~	~~0.2558~~	~~0.3920~~	~~0.9497~~
~~15~~	~~TI Nov-Mar~~	~~1.1410~~	~~0.9165~~	~~1.0653~~	~~0.6762~~	~~0.9269~~	~~0.0653~~	~~0.4465~~	~~0.6841~~	~~2.1276~~
	~~TF~~	~~0.0450~~	~~0.0362~~	~~0.0420~~	~~0.0267~~	~~0.0366~~	~~0.0026~~	~~0.0176~~	~~0.0270~~	~~0.0532~~
	~~TI Apr-Oct~~	~~0.4952~~	~~0.2857~~	~~0.3680~~	~~0.1511~~	~~0.2932~~	~~0.2453~~	~~0.0254~~	~~0.1406~~	~~0.6983~~
~~16A~~	~~TI Nov-Mar~~	~~0.8642~~	~~0.4987~~	~~0.6423~~	~~0.2637~~	~~0.5118~~	~~0.4282~~	~~0.0444~~	~~0.2454~~	~~1.6889~~
	~~TF~~	~~0.0341~~	~~0.0197~~	~~0.0253~~	~~0.0104~~	~~0.0202~~	~~0.0169~~	~~0.0018~~	~~0.0097~~	~~0.0359~~
	~~TI Apr-Oct~~	~~0.5445~~	~~0.4084~~	~~0.5101~~	~~0.2947~~	~~0.4383~~	~~0.3920~~	~~0.1406~~	~~0.0000~~	~~0.5577~~
~~16B~~	~~TI Nov-Mar~~	~~0.9504~~	~~0.7128~~	~~0.8904~~	~~0.5144~~	~~0.7650~~	~~0.6841~~	~~0.2454~~	~~0.0000~~	~~1.4435~~
	~~TF~~	~~0.0375~~	~~0.0281~~	~~0.0351~~	~~0.0203~~	~~0.0302~~	~~0.0270~~	~~0.0097~~	~~0.0000~~	~~0.0262~~
	~~TI Apr-Oct~~	~~1.0996~~	~~0.9395~~	~~1.0233~~	~~0.7764~~	~~0.5535~~	~~0.5700~~	~~0.4368~~	~~0.6283~~	~~0.5577~~
~~17~~	~~TI Nov-Mar~~	~~1.9191~~	~~1.6397~~	~~1.7859~~	~~1.3551~~	~~0.9661~~	~~0.9948~~	~~0.7624~~	~~1.0966~~	~~1.4435~~
	~~TF~~	~~0.0757~~	~~0.0647~~	~~0.0705~~	~~0.0535~~	~~0.0381~~	~~0.0392~~	~~0.0301~~	~~0.0433~~	~~0.0262~~
	TI Apr-Oct	0.0177	0.0723	0.2168	0.2773	0.4101	0.5694	0.3378	0.5369	1.0905
10	TI Nov-Mar	0.0309	0.1260	0.3781	0.4835	0.7150	0.9928	0.5890	0.9362	2.3688
	TF	0.0012	0.0050	0.0151	0.0194	0.0286	0.0398	0.0236	0.0375	0.0637
	TI Apr-Oct	0.1578	0.0354	0.0649	0.1814	0.3098	0.5030	0.2626	0.4027	0.9563
11	TI Nov-Mar	0.2752	0.0617	0.1132	0.3164	0.5401	0.8771	0.4578	0.7022	2.1348
	TF	0.0110	0.0025	0.0045	0.0127	0.0216	0.0351	0.0183	0.0281	0.0543
	TI Apr-Oct	0.2463	0.1210	0.1475	0.2257	0.3732	0.5340	0.3584	0.5030	1.0566
12	TI Nov-Mar	0.4295	0.2109	0.2572	0.3935	0.6507	0.9311	0.6250	0.8771	2.3097
	TF	0.0172	0.0084	0.0103	0.0158	0.0261	0.0373	0.0250	0.0351	0.0613
	TI Apr-Oct	0.3230	0.1254	0.1844	0.0826	0.1829	0.3938	0.1490	0.2906	0.8442
13	TI Nov-Mar	0.5633	0.2186	0.3215	0.1440	0.3189	0.6867	0.2598	0.5067	1.9393
	TF	0.0226	0.0088	0.0129	0.0058	0.0128	0.0275	0.0104	0.0203	0.0465
	TI Apr-Oct	0.2847	0.3201	0.3997	0.1254	0.0354	0.5045	0.2832	0.4322	0.9858
14	TI Nov-Mar	0.4964	0.5581	0.6970	0.2186	0.0617	0.8796	0.4938	0.7536	2.1862
	TF	0.0199	0.0224	0.0279	0.0088	0.0025	0.0352	0.0198	0.0302	0.0564
	TI Apr-Oct	0.6446	0.5177	0.6018	0.3820	0.5236	0.0369	0.2522	0.3865	0.9401
15	TI Nov-Mar	1.1240	0.9028	1.0494	0.6661	0.9131	0.0643	0.4398	0.6739	2.1065
	TF	0.0450	0.0362	0.0420	0.0267	0.0366	0.0026	0.0176	0.0270	0.0532
	TI Apr-Oct	0.4882	0.2817	0.3629	0.1490	0.2891	0.2419	0.0251	0.1387	0.6923
16A	TI Nov-Mar	0.8513	0.4913	0.6327	0.2598	0.5041	0.4218	0.0437	0.2418	1.6744
	TF	0.0341	0.0197	0.0253	0.0104	0.0202	0.0169	0.0018	0.0097	0.0359
	TI Apr-Oct	0.5369	0.4027	0.5030	0.2906	0.4322	0.3865	0.1387	0.0000	0.5536
16B	TI Nov-Mar	0.9362	0.7022	0.8771	0.5067	0.7536	0.6739	0.2418	0.0000	1.4326
	TF	0.0375	0.0281	0.0351	0.0203	0.0302	0.0270	0.0097	0.0000	0.0262

	TI Apr-Oct	1.0841	0.9263	1.0089	0.7655	0.5458	0.5620	0.4307	0.6195	0.5536
17	TI Nov-Mar	1.8904	1.6152	1.7592	1.3349	0.9516	0.9799	0.7510	1.0802	1.4326
	TF	0.0757	0.0647	0.0705	0.0535	0.0381	0.0392	0.0301	0.0433	0.0262

NOTE: MID 16A represents the 14 county area south of the F/M Demarcation point.
MID 16B represents the F/M Demarcation point.
MID 17 represents the Market Area.
"TF" is applicable to Rate Schedules TF and TFX.

NOTE: The MID rates include: (1) the appropriate Market Area Commodity rate for deliveries to MID 17; (2) the applicable Market Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MID 17; and (3) the applicable Field Area Electric Compression commodity rate as set forth in Sheet No. 54 for deliveries to MIDs 1 - 16A.

In addition, Shipper shall pay the ACA unit surcharge as posted on FERC’s website at https://www.ferc.gov and the Carlton surcharge, if applicable.

RATE SCHEDULE TF
Firm Throughput Services

(2) Changes to Primary Delivery Points. If a Primary Delivery Point is deleted or the MDQ is reduced through an amendment, the deleted or reduced capacity at that Primary Delivery Point will not be held for the Shipper.

b) Alternate Firm Delivery Points.

Flexibility. All delivery points on the system will be available for use as alternate firm delivery points (including zone deliveries to a specific customer) provided by the TF Agreement and subject to operational conditions.

c) Discounts.

Any discount granted at the Primary Delivery Point will not be automatically granted at an amended or Alternate Delivery Point.

d) Delivery Point Allocation.

Allocation of available capacity is pursuant to Section 26 of the GENERAL TERMS AND CONDITIONS of this Tariff.

Northern shall have the right to interrupt or curtail service under this Rate Schedule TF as a result of a force majeure event as defined in Section 10, "Force Majeure" of the GENERAL TERMS AND CONDITIONS of this Tariff, or in accordance with Section 19, "Limitation of Northern's Obligation to Provide Firm Services" of the GENERAL TERMS AND CONDITIONS of the Tariff. Curtailment shall be in accordance with Section 29, "Allocation of Capacity" of the GENERAL TERMS AND CONDITIONS of this Tariff.

3. THROUGHPUT SERVICES OFFERED.

The Throughput Service(s) available under Rate Schedule TF are as follows:

TF12 Base is a Firm Throughput Service available for twelve (12) consecutive months. The TF12 Base MDQ is determined as provided in Section 8 of this Rate Schedule TF.

TF12 Variable is a Firm Throughput Service available for twelve (12) consecutive months. The TF12 Variable MDQ is determined as provided in Section 8 of this Rate Schedule TF.

TF5 is a Firm Throughput Service available during the consecutive months of November, December, January, February and March.

TFF MDQ in the TF Agreement is for twelve (12) consecutive months for receipt in the Field Area and delivery to the F/M Demarcation point, for ultimate redelivery into the Market Area.

Although a TF Agreement may contain one or more of these services, each service (TF12 Base, TF12 Variable, and TF5) is distinct for purposes of rates.

Notwithstanding the above, and in accordance with any extension right in the TF Agreement, if Shipper extends its TF Agreement, or portions of its TF Agreement, for twelve (12) consecutive months or more the term date may be extended to the end of a Summer Season or Winter Season.

4. OVERRUN

Overrun Volumes. Northern agrees to transport volumes in excess of the Total Aggregate MDQ contracted for ("Overrun Volumes") on an interruptible basis for Shipper in accordance with the terms and conditions of this Rate Schedule and the GENERAL TERMS

GENERAL TERMS AND CONDITIONS

Releasing Shipper. The term “Releasing Shipper” shall mean a Shipper who has firm contractual rights on Northern’s system and is offering to release or has released its capacity.

Replacement Shipper. The term “Replacement Shipper” shall mean a Shipper who has acquired capacity from a Releasing Shipper.

Right of Way Grantor. The term "Right of Way Grantor" shall mean a party who grants a strip of land, the use of which is acquired for the construction and operation of the pipeline.

Section 1. The term "Section 1" shall mean the fuel zone located in the Field Area that represent the Permian Area portion of Northern’s system. Includes MIDs 1-7.

Section 2. The term "Section 2" shall mean the fuel zone located in the Field Area that represent the Mid-Continent portion of Northern’s system. Includes MIDs 8-16B.

Section 3. The term "Section 3" shall mean the fuel zone that represent the Market Area portion of Northern’s system. Includes MID 17.

Shipper. The term "Shipper" shall be defined to be a party who: 1) requests transportation under a Throughput Service Rate Schedule; or 2) executes a Throughput Service Agreement.

Small Customers. Small Customers are those listed on Appendix C of the Global Settlement and found in Sheet No. 510 of this Tariff.

Storage point. The term “storage point” or “deferred delivery point” shall mean the point at which the Shipper has natural gas quantities transported to or received from Northern on a deferred basis.

Summer Season. The consecutive months April through October.

Tariff. The term "Tariff" shall mean Northern's FERC Gas Tariff.

Thermally Equivalent Volumes. The term "thermally equivalent volumes" shall mean that during any given period of time the volumes of gas delivered hereunder at the Point(s) of Delivery multiplied by the total heating value of the gas at the delivery point(s) shall equal the volumes of gas received at the point(s) of receipt multiplied by the total heating value of the gas at the receipt point(s).

Tier Relationship Factors. The term "Tier Relationship Factors" shall mean the mathematical relationship of the rates for the Market Area TF12 Base, TF12 Variable, and TF5, and the Field Area TFF Throughput Services. The Tier Relationship Factors for the Reservation Rates shall be as follows:

	Services	Winter Months (Nov-Mar)	Summer Months (Apr-Oct)	Annual
Market Area:	TF 12 Base	1.35	.75	12.0
	TF 12 Variable	1.83	.75	14.4
	TF 5	2.00	N/A	10.0
Field Area:	TFF	1.35	.75	12.0

GENERAL TERMS AND CONDITIONS

Tolling Agreement. A tolling agreement or arrangement means that the owner of the electric generator has agreed with an LDC to convert natural gas owned and provided by the LDC to electricity owned by the LDC.

Total or Gross Heating Value. The term "total or gross heating value" means the total calorific value, expressed in Btus when one cubic foot of anhydrous gas at sixty degrees Fahrenheit (60 F) is combusted with dry air at the same temperature and the products of combustion are cooled to sixty degrees Fahrenheit (60 F). The Btu specified is on a higher heating value (HHV) basis. A conversion factor is required to convert lower heating value to a higher heating value basis to correctly calculate the expected fuel usage of certain equipment. For estimating purposes, the higher heating value of natural gas is approximately 10 percent more than the lower heating value.

Town Border Station (TBS). The term "Town Border Station" ("TBS") shall mean the physical location where the LDC receives gas from Northern. The TBS generally consists of facilities to regulate gas pressure and measure gas quality and volumes.

UAF. The term “UAF” shall mean unaccounted-for gas.

Unauthorized Gas. "Unauthorized Gas" shall mean any volumes delivered to Northern from receipt points which have not been nominated in any amount by any Shipper for that month and which have not been scheduled by Northern.

Valid Request. Any reference in this Tariff to a "valid request" used in conjunction with Section 26 "Requests for Service" shall also include any requests submitted electronically through Northern's Internet website.

Winter Season. The consecutive months November through March.

Wobbe Index - The term "Wobbe Index" shall mean a number which indicates the interchangeability of gas. The Wobbe Index is determined by dividing the higher heating value of the gas in Btu per standard cubic foot by the square root of its specific gravity with the respect to air. Wobbe Index is used as an indicator of the heat release rate of combustion equipment employing fixed orifices such as boilers, stoves, water heaters, and furnaces.

GENERAL TERMS AND CONDITIONS

53A. PERIODIC RATE ADJUSTMENT (PRA) - FUEL

1. Purpose and Applicability: This Section 53 establishes a Fuel PRA mechanism for the purpose of deriving the TRANSPORTATION FUEL PERCENTAGES, the UNACCOUNTED-FOR (UAF) PERCENTAGE, the FDD STORAGE FUEL, and FDD STORAGE UNDER-RECOVERY RETAINAGE (URR) PERCENTAGE as set forth in Tariff Sheet No. 54 and Sheet Nos. 61-64, applicable to all Rate Schedules included in Northern's FERC Gas Tariff TF, TFX, GS-T, TI and FDD respectively. The Market Area Fuel percentages will be determined seasonally. The Field Area Fuel percentages will be determined annually.

2. Definitions.

(a) Adjustment Amount. The true-up between actual volumes and estimated volumes.

(b) Annual. The consecutive months January through December.

(c) Fuel. Fuel consists of fuel burned and company used fuels: compressor, heater, dehydrate, actuators, un-metered, blow-down and purge.

(d) Injection Period. The calendar months of June through October.

(e) PRA Period. The twelve month period ending December 31 each year.

(f) PRA Settlement. Per Docket Nos. RP97-275-002 and TM97-2-59-000.

(g) Pre URR Balance. The accumulated under-recoveries of storage gas in the Redfield and Lyons storage fields prior to January 1, 2020.

(h) Post URR Balance. The net balance of under-recovered storage quantities recovered through the URR Percentage.

(i) Throughput. Throughput is the actual volumes received, inclusive of Fuel and UAF, from the respective receipt points on Northern's system.

(j) Transportation Fuel. The transportation Fuel retention percentage for each Section.

(k) Under-Recovery Retainage (URR). The difference between the quantity of natural gas placed into the Redfield and Lyons storage fields as compared to the amount of gas withdrawn during an annual storage cycle, as adjusted for line losses and other field surface adjustments. A negative URR rate shall only apply to the extent that the Post URR Balance is a positive amount.

(l) URR Adjustment. The quantity of the under/over-recovery calculated in the FDD Storage URR for the prior cycle year.

(m) URR Percentage. The percentage applied to FDD injections during the Injection Period.

GENERAL TERMS AND CONDITIONS

(iii) UAF

Northern shall annually compare the volume of UAF retained for the most recent PRA Period with the volume of actual UAF for the same period to determine the UAF Adjustment Amount. The UAF Adjustment Amount will be divided by the applicable Throughput to determine the UAF Adjustment Percent to be added to the UAF retention percentage for the period beginning the subsequent April 1. Under-retainage will result in a positive Adjustment Amount. Over-retainage will result in a negative Adjustment Amount. For purposes of determining the Adjustment Amount for years subsequent to the initial year of the PRA, the Adjustment Amount for the prior year is first added to the actual UAF retained for the prior year. To determine the Adjustment Amount for the subsequent year, the balance of the UAF retained will be compared to the actual UAF.

5. PRA Filing. Northern will file to change the Fuel, UAF and URR retained percentages as provided herein. For Section 3 Transportation Fuel, Northern will file each February 1 for the Summer Season Transportation Fuel to be effective the following April 1; Northern will file each May 1 for the Winter Season Transportation Fuel to be effective the following November 1. Furthermore, Northern will post on its website by December 1 of each year an estimated Section 3 Summer Season Transportation Fuel to be effective the following April 1.

Northern will file each February 1 for the Section 1 and 2 Transportation Fuel, Storage Fuel and URR, and UAF retained percentages to be effective the following April 1. In the event of a change to the makeup of the Sections 1 and 2 in a PRA or Section 4 or Section 5 filing, the effectiveness of the Fuel retention percentages derived therefrom shall be prospective only. For in-kind Fuel reimbursement procedures, Fuel rates will be made effective only at the beginning of the month.

Notwithstanding the filing dates above, Northern may file to revise any of the Fuel and UAF percentages at any time due to an anticipated over- or under-recovered volume.

Appendix B
Sixth Revised Volume No. 1
July 1 Filing Tariff Sheets

Requested to be replaced by the Revised Tariff Sheets in Appendix A

Nineteenth Revised Sheet No. 50
Twenty Second Revised Sheet No. 51
Twentieth Revised Sheet No. 52
Twenty Second Revised Sheet No. 53
First Revised Thirty First Revised Sheet No. 54
Fifth Revised Sheet No. 55
Eighth Revised Sheet No. 59
Eighth Revised Sheet No. 59A
Nineteenth Revised Sheet No. 60
Nineteenth Revised Sheet No. 60A

Appendix C

Cost of Service Details

NORTHERN NATURAL GAS COMPANY

OVERALL COST OF SERVICE
Test Period Ended December 31, 2022

Line No.	Particulars [a]		Schedule Reference [b]		Total Test Period Amount [c]		Storage [d]		Transmission [e]
1	O & M Expenses		H-1	$	335,156,979	$	59,437,449	$	275,719,531
2	Depreciation and Amortization of Gas								
3	Plant In Service		H-2(1)		342,874,382		44,307,635		298,566,747
4	Amortization of Certain Reg Assets		B-2		(14,969,595)		(1,975,622)		(12,993,973)
5	Income Taxes								
6	Federal Income at	21.00%	H-3		98,400,928		12,986,526		85,414,402
7	State Income at	7.12%	H-3		35,943,967		4,743,728		31,200,239
8	Taxes Other Than Income		H-4						
9	Payroll Taxes				8,584,984		1,271,440		7,313,543
10	Franchise Taxes				50,100		6,612		43,488
11	Fuel Use Tax				-		-		-
12	Ad Valorem				88,095,043		11,421,630		76,673,413
13	Total Taxes Other Than Income				96,730,127		12,699,682		84,030,445
					-				
14	Return at	10.45%	B		429,341,684		56,662,646		372,679,038
15	Other Operating Revenues		G-5		(817,204)		-		(817,204)
16	Total Overall Cost of Service			$	1,322,661,268	$	188,862,044	$	1,133,799,224

NORTHERN NATURAL GAS COMPANY

RATE BASE AND RETURN ALLOWANCE
Test Period Ended December 31, 2022

Line No.	Particulars		Schedule Reference	Total	Storage	Transmission	Intangible and General	F/N
	[a]		[b]	[c]	[d]	[e]	[f]	
1	Utility Plant							
2	Gas Plant in Service		C	$ 6,622,425,099	$ 879,015,918	$ 5,433,335,273	$ 310,073,908	
3	Regulatory Assets & Liabilities		B-2	(304,846,415)	(40,232,303)	(264,614,112)	-	1/
4	Sub-total			6,317,578,685	838,783,615	5,168,721,161	310,073,908	
5	Classification of Intangible and General			-	40,922,204	269,151,704	(310,073,908)	1/
6	Total Classified Gas Plant in Service			6,317,578,685	879,705,820	5,437,872,865	-	
7	Accumulated Provision for Depreciation and Amortization		D	1,530,399,609	230,232,015	1,166,182,621	133,984,974	
8	Classification of Intangible and General			-	17,682,753	116,302,220	(133,984,974)	1/
9	Classified Accum. Provision for Depr. and Amort.			1,530,399,609	247,914,768	1,282,484,841	-	
10	Net Utility Plant			4,787,179,075	631,791,051	4,155,388,024	-	
11	Working Capital		E	70,482,945	9,302,032	61,180,913	-	1/
12	Total Rate Base Before Deductions			4,857,662,020	641,093,083	4,216,568,937	-	
13	Total Rate Base Before Deductions			4,857,662,020	641,093,083	4,216,568,937	-	
14	Less: Accumulated Deferred Income Taxes		B-1	(747,601,549)	(98,665,197)	(648,936,352)	-	1/
15	Total Rate Base			4,110,060,471	542,427,886	3,567,632,585	-	
16	Return Allowance	10.45%	of Line 15					
17	Interest Expense	1.51%	H-3	62,030,636	8,186,533	53,844,102	-	
18	Allowance on Common Stock Equity	8.94%	H-3	367,311,049	48,476,113	318,834,936	-	
19	Total Return Allowance			$ 429,341,684	$ 56,662,646	$ 372,679,038	$ -	

1/ Allocated to functions on a net plant basis per Schedule I-1(d).

NORTHERN NATURAL GAS COMPANY

Accumulated Deferred Income Taxes
Test Period Ended December 31, 2022
Accounts 190, 282, and 283

Line No.	Description	Account 190 Amount	Account 282 Amount	Account 283 Amount
	[a]	[b]	[c]	[d]
1	Balances at:			
2	April 30, 2021	$ 103,980,836	$ (727,556,250)	$ (16,578,356)
3	May 31	104,112,698	(728,622,600)	(16,133,718)
4	June 30	112,368,702	(732,215,953)	(16,147,511)
5	July 31	112,431,953	(734,057,847)	(16,026,356)
6	August 31	112,309,475	(740,328,029)	(16,072,096)
7	September 30	113,062,592	(744,394,205)	(17,406,151)
8	October 31	113,177,023	(746,955,074)	(16,867,451)
9	November 30	112,665,586	(756,977,505)	(16,328,596)
10	December 31	108,839,953	(787,380,387)	(15,467,612)
11	January 31, 2022	107,694,813	(789,354,231)	(13,367,943)
12	February 28	106,560,323	(790,349,794)	(12,552,718)
13	March 31, 2022	106,530,399	(792,828,435)	(13,260,747)
14	"AS Filed" End of Test Period Balances	$ 105,298,594	$ (841,809,268)	$ (12,279,010)
15	"As Filed" Amount Included in Rate Base	$ (748,789,685)		
	Dec 2022 Fcst vs "As Filed" Plant Adjustments			
16	Deferred Tax on Plant	$ -	$ 2,206,740	$ -
17	Deferred Tax on AFUDC Gross Up	-	-	(1,018,604)
18	Total Test Period Adjustments	$ -	$ 2,206,740	$ (1,018,604)
19	Adjusted Balance	$ 105,298,594	$ (839,602,528)	$ (13,297,615)
20	Amount Included in Rate Base	$ 105,298,594	$ (839,602,528)	$ (13,297,615)
21	Total Amount Included in Rate Base	$ (747,601,549)		

Docket RP22-1033
Schedule B-2

NORTHERN NATURAL GAS COMPANY

Regulatory Assets & Liabilities Included in Rate Base
Test Period Ended December 31, 2022
Accounts 182.3 & 254

Line No.	Particulars	RP19-1353 Rate Case Expenses	RP22-1033 Rate Case Expenses	Equity AFUDC Gross Up	Smart Pigging Hydrostatic Testing	Deferred Loss on Fuel Derivatives	Total Acct 182.3	Excess Deferred Income Taxes	IA Rate Change EDIT	NE Rate Change EDIT	OK Rate Change EDIT	Total Acct 254	Total
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]
1	April 30, 2021	$ 2,482,304	$ -	$ 23,513,793	$ 17,116,798	$ 16,661,729	$ 59,774,624	$ (361,671,951)	$ (4,647,771)	$ -	$ -	$ (366,319,722)	$ (306,545,098)
2	May 31	2,371,389	-	23,849,847	16,589,434	15,650,575	58,461,245	(362,158,535)	(4,653,435)	-	-	(366,811,970)	(308,350,725)
3	June 30	2,246,570	-	24,222,117	16,067,883	14,642,157	57,178,727	(361,617,459)	(4,646,541)	(2,239,806)	(2,593,519)	(371,097,325)	(313,918,598)
4	July 31	2,121,750	-	24,657,709	15,548,652	13,636,704	55,964,815	(361,850,558)	(4,649,254)	(2,239,806)	(2,593,519)	(371,333,137)	(315,368,322)
5	August 31	1,996,931	-	25,084,958	15,039,997	12,632,961	54,754,847	(361,399,191)	(4,644,000)	(2,239,806)	(2,593,519)	(370,876,516)	(316,121,669)
6	September 30	1,872,112	-	25,474,064	14,539,801	11,629,217	53,515,194	(361,270,874)	(4,642,507)	(2,239,806)	(2,593,519)	(370,746,706)	(317,231,513)
7	October 31	1,747,292	-	25,884,343	14,039,606	10,628,666	52,299,907	(361,672,544)	(4,647,155)	(2,239,669)	(2,593,360)	(371,152,728)	(318,852,821)
8	November 30	1,622,473	-	26,256,903	13,539,410	9,636,484	51,055,270	(359,807,789)	(4,625,476)	(2,239,806)	(2,593,519)	(369,266,590)	(318,211,320)
9	December 31	1,497,653	-	26,599,744	13,045,580	8,668,748	49,811,725	(358,544,027)	(4,603,792)	(2,239,184)	(2,593,515)	(367,980,518)	(318,168,792)
10	January 31, 2022	1,372,834	-	26,866,102	12,621,895	7,972,099	48,832,930	(354,364,816)	(4,555,228)	(2,217,366)	(2,568,252)	(363,705,662)	(314,872,732)
11	February 28	1,248,015	-	27,120,368	12,198,211	7,272,599	47,839,193	(350,224,476)	(4,507,116)	(2,195,750)	(2,543,225)	(359,470,567)	(311,631,374)
12	March 31, 2022	1,123,195	-	27,078,889	11,780,719	6,566,601	46,549,404	(347,293,863)	(4,473,061)	(2,180,450)	(2,525,510)	(356,472,884)	(309,923,480)
13	As Filed TP Balance	$ -	$ 6,111,000	$ 30,340,890	$ 8,443,017	$ -	$ 44,894,907	$ (342,776,744)	$ (4,420,570)	$ (2,156,867)	$ (2,498,205)	$ (351,852,387)	$ (306,957,480)
14	Plant Related Changes	-	-	2,111,065	-	-	2,111,065	-	-	-	-	-	2,111,065
15	Test Period Balance	$ -	$ 6,111,000	$ 32,451,955	$ 8,443,017	$ -	$ 47,005,972	$ (342,776,744)	$ (4,420,570)	$ (2,156,867)	$ (2,498,205)	$ (351,852,387)	$ (304,846,415)
16	Total Amount Included in Rate Base												$ (304,846,415)
17	Allocated to Storage (Net Plant)												$ (40,232,303)
18	Allocated to Transmission (Net Plant)												$ (264,614,112)
19	Amortization		1/	$ 1,158,535		1/		$ (15,767,282)	$ (183,222)	$ (82,317)	$ (95,309)		$ (14,969,595)
20	Allocated to Storage (Net Plant)												$ (1,975,622)
21	Allocated to Transmission (Net Plant)												$ (12,993,973)

1/ Amortization is reflected as part of O&M.

NORTHERN NATURAL GAS COMPANY

COST OF PLANT
Test Period Ended December 31, 2022

Line No.	Description	Account Number	Schedule Reference	Book Balances 11/30/2022	Adjustments	Adjusted Book Balances 12/31/2022
	[a]	[b]	[c]	[e]	[f]	[g]
1	Gas Plant in Service	101, 106	C-1	$ 6,354,598,831	$ 191,428,410	$ 6,546,027,241
2	Gas Plant Held For Future Use	105	C-1	6,756,930	-	6,756,930
3	Gas Stored Underground, Non-Current	117.1	C-3	28,429,396	-	28,429,396
4	System Balancing Gas	117.2	C-3	41,211,532	-	41,211,532
5	Total Gas Plant Included in Rate Base			6,430,996,689	191,428,410	6,622,425,099
6	Asset Retirement Obligation	101		12,162,911	-	12,162,911
7	Construction Work in Progress-Incomplete	107		246,850,298	(198,195,150)	48,655,148
8	Total Northern Natural Gas Company			$ 6,690,009,898	$ (6,766,740)	$ 6,683,243,158

NORTHERN NATURAL GAS COMPANY

Gas Plant in Service
Test Period Ended December 31, 2022

Line No.	FERC Account Number	Description	Book Balance 11/30/2022	Test Period Adjustments Additions	Retirements	Net	Test Period Balance 12/31/2022	F/N
	[a]	[b]	[c]	[d]	[e]	[f] = [d]+[e]	[g] = [c]+[f]	
1		Intangible Plant						
2	301	Organization	$ 4,841,691	$ -	$ -	$ -	$ 4,841,691	
3	303	Miscellaneous Intangible Plant- CIAC	22,249,189	-	-	-	22,249,189	
4	303	Miscellaneous Intangible Plant - Software	123,270,575	2,345,863	-	2,345,863	125,616,438	
5	303	Miscellaneous Intangible Plant - Leasehold Improvements	-	120,001	-	120,001	120,001	
6		Total	150,361,455	2,465,864	-	2,465,864	152,827,319	
7		Natural Gas Production and Gathering Plant						
8	325.4	Rights-of-way	-	-	-	-	-	
9	328	Field Meas/Reg Stat structure	-	-	-	-	-	
10	329	Other Structures	-	-	-	-	-	
11	332	Field Lines	1,528,820	-	-	-	1,528,820	
12	333	Field Compressor Stat Equipment	-	-	-	-	-	
13	334	Field Measure/Reg Stat Equipment	16,922	-	-	-	16,922	
14	336	Purification Equipment	-	-	-	-	-	
15	337	Other Equipment	-	-	-	-	-	
16		Total	1,545,742	-	-	-	1,545,742	
17		Underground Storage Plant						
18	350.1	Land	2,384,812	-	-	-	2,384,812	
19	350.2	Rights-of-way	2,632,868	-	-	-	2,632,868	
20	351	Structures & Improvements	47,628,166	1,219,730	-	1,219,730	48,847,896	
21	352	Wells	164,112,466	14,753,864	(15,000)	14,738,864	178,851,329	
22	352.1	Storage Leaseholds and Rights	20,532,180	-	-	-	20,532,180	
23	352.2	Reservoirs	16,755,757	-	-	-	16,755,757	
24	352.3	Non-recoverable Natural Gas	32,972,796	-	-	-	32,972,796	
25	353	Lines	98,839,199	866,578	(5,000)	861,578	99,700,777	
26	354	Compressor Station Equipment	128,109,482	149,459	-	149,459	128,258,941	
27	354.1	Compressor Computer Control Systems	10,676,377	11,206	(8,000)	3,206	10,679,583	
28	355	Meas & Reg Equipment	24,075,621	-	-	-	24,075,621	
29	356	Purification Equipment	78,179,856	-	-	-	78,179,856	
30	357	Other Equipment	7,098,077	34,449	530,000	564,449	7,662,527	
31	357.1	Shop, Comm, & Office Equipment	464,910	-	-	-	464,910	
32		Total	634,462,565	17,035,286	502,000	17,537,286	651,999,851	

NORTHERN NATURAL GAS COMPANY

Gas Plant in Service
Test Period Ended December 31, 2022

Line No.	FERC Account Number	Description	Book Balance 11/30/2022	Test Period Adjustments Additions	Retirements	Net	Test Period Balance 12/31/2022	F/N
	[a]	[b]	[c]	[d]	[e]	[f] = [d]+[e]	[g] = [c]+[f]	
33		LNG Storage Plant						
34	360	Land	639,698	-	-	-	639,698	
35	361	Structures and Improvements	31,490,250	1,970,861	(2,000)	1,968,861	33,459,111	
36	362	Gas Holders	20,121,837	-	-	-	20,121,837	
37	363	Purification Equipment	15,546,703	84,130	(10,000)	74,130	15,620,833	
38	363.1	Liquefaction Equipment	19,597,582	-	-	-	19,597,582	
39	363.2	Vaporizing Equipment	13,045,999	-	-	-	13,045,999	
40	363.3	Compressor Equipment	38,465,211	8,716,679	-	8,716,679	47,181,890	
41	363.31	Compr Computer Control System	1,061,533	-	-	-	1,061,533	
42	363.4	Meas & Reg Equipment	3,527,812	139,429	-	139,429	3,667,241	
43	363.5	Other Equipment	2,369,005	610,660	(250)	610,410	2,979,416	
44		Total	145,865,630	11,521,759	(12,250)	11,509,509	157,375,138	
45		Base Load LNG Terminal and Processing Plant						
46	364.3	LNG Processing Terminal Equipment	5,769,360	-	-	-	5,769,360	
47	364.4	LNG Transportation Equipment	1,619,444	-	-	-	1,619,444	
48	364.5	Measuring Equipment	917,064	-	-	-	917,064	
49		Total	8,305,868	-	-	-	8,305,868	
50		Transmission Plant						
51	365.1	Land and Land Rights	4,514,596	1,638,539	-	1,638,539	6,153,135	
52	365.2	Rights-of-way	93,032,452	3,239,873	-	3,239,873	96,272,325	
53	366	Structures and Improvements	178,693,222	11,934,208	(52,560)	11,881,648	190,574,869	
54	367	Mains	3,133,734,354	90,362,108	(2,652,098)	87,710,010	3,221,444,364	
55	368	Compressor Station Equipment	1,335,733,288	25,942,880	(4,934,000)	21,008,880	1,356,742,168	
56	368.1	Compressor Control Equipment	47,431,840	1,560,273	(5,750)	1,554,523	48,986,364	
57	369	Meas & Reg Station Equipment	467,199,316	19,991,992	387,918	20,379,910	487,579,226	
58	369.1	Meas & Reg Computer Equipment	7,649,875	1,909,776	-	1,909,776	9,559,651	
59	370	Communication Equipment-Radio	3,670,874	317,003	-	317,003	3,987,877	
60	371	Other Equipment	2,183,685	-	-	-	2,183,685	
61		Total	5,273,843,501	156,896,652	(7,256,490)	149,640,162	5,423,483,663	

NORTHERN NATURAL GAS COMPANY

Gas Plant in Service
Test Period Ended December 31, 2022

Line No.	FERC Account Number	Description	Book Balance 11/30/2022	Test Period Adjustments Additions	Retirements	Net	Test Period Balance 12/31/2022	F/N
	[a]	[b]	[c]	[d]	[e]	[f] = [d]+[e]	[g] = [c]+[f]	
62		General Plant						
63	389	Land	1,948,874	-	-	-	1,948,874	
64	390	Structures & Improvements	33,797,209	2,802,381	-	2,802,381	36,599,590	
65	391	Office Furniture & Equipment	10,117,062	795,152	-	795,152	10,912,214	
66	391.1	Office Furniture Computers	21,155,590	2,270,119	-	2,270,119	23,425,709	
67	392	Transportation Equipment	27,000,097	31,209	-	31,209	27,031,306	
68	393	Stores Equipment	-	-	-	-	-	
69	394	Tools, Shop & Garage Equip	32,317,066	2,788,483	-	2,788,483	35,105,549	
70	395	Laboratory Equipment	2,423,483	-	-	-	2,423,483	
71	396	Power Operated Equipment	15,051,241	1,301,439	-	1,301,439	16,352,680	
72	397	Communication Equipment	2,255,711	286,806	-	286,806	2,542,517	
73	398	Miscellaneous Equipment	904,670	-	-	-	904,670	
74	399	Other Tangible Property	-	-	-	-	-	
75		Total	146,971,000	10,275,589	-	10,275,589	157,246,589	
76		Total	$ 6,361,355,761	$ 198,195,150	$ (6,766,740)	$ 191,428,410	$ 6,552,784,171	1/

1/ Ties to Statement C, Column (j), Rows (1 + 2).

NORTHERN NATURAL GAS COMPANY

ACCUMULATED PROVISION FOR DEPRECIATION, DEPLETION AND AMORTIZATION
Test Period Ended December 31, 2022

										Test Period Adjustments			
Line No.	Account Number	Description	F/N	Book Balances 3/31/2022	Provisions	Net Retirements	Transfers and Reclass-ifications	Book Balances 11/30/2022	Stmt D Part 2 Col (h) Provision	Net Cost of Retirements	Transfers and Reclass-ifications	Plant Retirements	Test Period Balance 12/31/2022
	[a]	[b]		[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]
1		Accumulated Provision for Depreciation											
2		of Gas Utility Plant											
3		Production and Gathering Plant											
4	108	Offshore Fully Depreciated		$ 1,545,742	$ -	$ -	$ -	$ 1,545,742	$ -	$ -	$ -	$	$ 1,545,742
5	108	Offshore Interim Negative Salvage		-	-	-	-	-	-	-			-
6	108	Offshore Negative Salvage - ARO		9,769,658	25,864	-	-	9,795,522	3,233	-			9,798,755
7		Total Production and Gathering Plant		11,315,400	25,864	-	-	11,341,264	3,233	-	-	-	11,344,497
8		Natural Gas Storage Plant											
9	108	Underground Storage Plant		161,989,511	5,726,202	(921,248)	(10,616)	166,783,849	724,669	(128,647)		502,000	167,881,871
10	108	LNG Storage Plant		50,410,296	2,916,286	(1,118,752)	(3,462)	52,204,368	377,397	(11,243)		(12,250)	52,558,272
11		Total Natural Gas Storage Plant		212,399,807	8,642,488	(2,040,000)	(14,078)	218,988,217	1,102,066	(139,890)		489,750	220,440,143
12	108	Base Load LNG Terminaling & Processing Plant		2,405,009	132,148	669,554	-	3,206,711	30,014	-	-	-	3,236,725
13		Total Base Load LNG Terminaling & Processing Plant		2,405,009	132,148	669,554	-	3,206,711	30,014	-	-	-	3,236,725
14		Transmission Plant											
15	108	Onshore		1,044,454,433	80,821,189	(1,875,984)	14,078	1,123,413,716	10,344,850	(8,783,933)	-	(7,256,490)	1,117,718,144
16	108	Onshore Interim Negative Salvage		(7,668,947)	3,313,391	-	-	(4,355,556)	437,793	-	-	-	(3,917,763)
17	108	Offshore Negative Salvage - ARO		(537,492)	491,425	-	-	(46,067)	61,428	-	-	-	15,361
18		Total Transmission Plant		1,036,247,994	84,626,005	(1,875,984)	14,078	1,119,012,093	10,844,071	(8,783,933)	-	(7,256,490)	1,113,815,742
19	108	General Plant		51,364,961	12,495,111	(4,586,758)	-	59,273,314	1,224,432	(51,613)	-	-	60,446,133
20		Total General Plant		51,364,961	12,495,111	(4,586,758)	-	59,273,314	1,224,432	(51,613)	-	-	60,446,133
21	108	Plant Held for Future Use		567,717		-	-	567,717	-	-			567,717
22		Total - Plant Held for Future Use		567,717	-	-	-	567,717	-	-	-	-	567,717
23		Total Account 108		1,314,300,888	105,921,616	(7,833,188)	-	1,412,389,316	13,203,817	(8,975,436)	-	(6,766,740)	1,409,850,957

NORTHERN NATURAL GAS COMPANY

ACCUMULATED PROVISION FOR DEPRECIATION, DEPLETION AND AMORTIZATION
Test Period Ended December 31, 2022

										Test Period Adjustments			
Line No.	Account Number	Description	F/N	Book Balances 3/31/2022	Provisions	Net Retirements	Transfers and Reclass-ifications	Book Balances 11/30/2022	Stmt D Part 2 Col (h) Provision	Net Cost of Retirements	Transfers and Reclass-ifications	Plant Retirements	Test Period Balance 12/31/2022
	[a]	[b]		[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]
24		Accumulated Provision for Amortization and Depletion of Gas											
25		Natural Gas Storage Plant											
26	111	Underground Storage Land and Land Rights		8,666,846	169,690	-	-	8,836,536	21,388				8,857,924
27	111	Underground Storage Right of Way		909,800	21,405	-	-	931,205	2,743				933,948
28		Total Natural Gas Storage Plant		9,576,646	191,095	-	-	9,767,741	24,131	-		-	9,791,872
29		Transmission Plant											
30	111	Onshore Right of Way		28,322,193	1,370,577	3,478,835		33,171,605	158,028	-	-	-	33,329,633
31	111	Onshore Land Rights Renewal		3,540,924	309,633	-	-	3,850,557	37,750	-	-	-	3,888,307
32		Total Transmission Plant		31,863,117	1,680,210	3,478,835	-	37,022,162	195,778	-	-	-	37,217,940
33	111	Other Gas Plant		74,214,071	12,456,977	(14,666,255)	-	72,004,793	1,534,048			-	73,538,841
34		Total Other Gas Plant		74,214,071	12,456,977	(14,666,255)	-	72,004,793	1,534,048	-	-	-	73,538,841
35	111	Plant Held for Future Use		17,717	-	-	-	17,717	-	-	-	-	17,717
36		Total Account 111		115,671,551	14,328,282	(11,187,420)	-	118,812,413	1,753,957	-	-	-	120,566,370
37		Total Northern Natural Gas Company		$ 1,429,972,439	120,249,898 $	(19,020,608) $	- $	1,531,201,729 $	14,957,773 $	(8,975,436) $	- $	(6,766,740) $	1,530,417,326

NORTHERN NATURAL GAS COMPANY

Calculation of Depreciation Provision for December 2022

Line No.	Particulars	F/N	Depreciable Plant Balances 11/30/2022	Depr. Provision for December 2022 On Base Period Plant	On Test Period Additions	On Test Period Reductions	Total
	[a]		[b]	[c]	[d]	[e]	[f]
1	Natural Gas Production & Gathering						
2	Offshore		$ -	$ -	$ -	$ -	$ -
3	Offshore Fully Depreciated		1,545,742	-	-	-	-
4	Offshore Negative Salvage - Interim Retirements		-	-	-	-	-
5	Offshore Negative Salvage - ARO	1/	-	3,233	-	-	3,233
6	Total Natural Gas Production & Gathering		1,545,742	3,233	-	-	3,233
7	Natural Gas Storage Plant - 1.25%						
8	Underground Storage						
9	Storage Leaseholds and Rights		20,532,180	21,388	-	-	21,388
10	Right of Way		2,632,868	2,743	-	-	2,743
11	Operating Plant		597,771,418	622,679	8,867	266	631,811
12	Shop & Communication Equipment - 10%		464,910	3,874	-	-	3,874
13	Computers - 10%		10,676,377	88,970	47	(33)	88,983
14	Total Underground Storage		632,077,753	739,654	8,913	232	748,800
15	LNG Storage - 2.95%						
16	Operating Plant		144,164,400	354,404	14,162	(15)	368,551
17	Computers - 10%		1,061,533	8,846	-	-	8,846
18	Total Other Storage		145,225,932	363,250	14,162	(15)	377,397
19	Total Natural Gas Storage Plant		777,303,685	1,102,904	23,076	217	1,126,197
20	Base Load LNG Terminaling and Processing Plant						
21	Base Load LNG Processing Equipment - 2.95%		6,672,555	16,403	-	-	16,403
22	Base Load LNG Computers - 10%		13,870	116	-	-	116
23	Base Load LNG Transportation Equipment - 10%		1,619,444	13,495	-	-	13,495
24	Total Base Load LNG Terminaling and Processing Plant		8,305,868	30,014	-	-	30,014

NORTHERN NATURAL GAS COMPANY

Calculation of Depreciation Provision for December 2022

Line No.	Particulars	F/N	Depreciable Plant Balances 11/30/2022	Depr. Provision for December 2022 On Base Period Plant	On Test Period Additions	On Test Period Reductions	Total
	[a]		[b]	[c]	[d]	[e]	[f]
25	Transmission Plant						
26	Mainline						
27	Offshore - Not Fully Depreciated			-	-	-	-
28	Offshore - Fully Depreciated		14,105,434	-	-	-	-
29	Offshore Computers 10%			-	-	-	-
30	Offshore Right of Way - Fully Depreciated		(102)	-	-	-	-
31	Offshore Land Rights Renewal - Fully Depreciated		700,317	-	-	-	-
32	Offshore - Interim Negative Salvage		-	-	-	-	-
33	Offshore - Negative Salvage, ARO	1/	-	61,428	-	-	61,428
34	Total Offshore Transmission		14,805,649	61,428	-	-	61,428
35	Onshore - 2.3%		5,099,613,803	9,774,260	143,885	(6,949)	9,911,196
36	Onshore Right of Way- 2.3%		80,829,625	154,923	3,105	-	158,028
37	Onshore Land Rights Renewal - 2.63%		607,911	1,332	-	-	1,332
38	Onshore Land Rights Renewal - 3.33%		4,575,176	12,696	-	-	12,696
39	Onshore Land Rights Renewal - 4.17%		2,684,386	9,328	-	-	9,328
40	Onshore Land Rights Renewal - 5.0%		3,454,576	14,394	-	-	14,394
41	Onshore - Interim Negative Salvage- 0.1%		-	431,704	6,391	(302)	437,793
42	Computers - 10%		47,431,840	395,265	6,501	(24)	401,742
43	Radio Communications - 10%		3,670,874	30,591	1,321	-	31,912
44	Total Onshore		5,242,868,192	10,824,493	161,203	(7,275)	10,978,421
45	Total Transmission Plant		5,257,673,841	10,885,921	161,203	(7,275)	11,039,849
46	Total Operating Facilities		$ 6,044,829,137	$ 12,022,072	$ 184,278	$ (7,057)	$ 12,199,293
47	Intangible Plant						
48	Intangible Plant - 13%		123,270,575	1,335,431	12,707	-	1,348,138
49	Intangible Cost - CIACs at 10%		22,249,189	185,410	-	-	185,410
50	Intangible Cost - Leasehold Improvements 10%		-	-	500	-	500
51	Intangible Cost - Leasehold Improvements - Fully Depreciated		-	-	-	-	-
52	Total Intangible Plant		145,519,764	1,520,841	13,207	-	1,534,048

NORTHERN NATURAL GAS COMPANY

Calculation of Depreciation Provision for December 2022

Line No.	Particulars	F/N	Depreciable Plant Balances 11/30/2022	Depr. Provision for December 2022 On Base Period Plant	On Test Period Additions	On Test Period Reductions	Total
	[a]		[b]	[c]	[d]	[e]	[f]
53	General Plant						
54	General Structure - 2.75%		33,797,209	77,452	3,211	-	80,663
55	Computer Equipment - 20%		21,155,590	352,593	18,918	-	371,511
56	Office Furniture and Equipment - 10%		10,117,062	84,309	3,313	-	87,622
57	Tools and Work Equipment - 10%		32,317,066	269,309	11,619	-	280,928
58	Laboratory Equipment - 10%		2,423,483	20,196	-	-	20,196
59	Communication Equipment - 10%		2,255,711	18,798	1,195	-	19,993
60	Transportation and Powered Work Equip. 10%		42,051,337	350,428	5,553	-	355,981
61	Miscellaneous Equipment - 10%		904,670	7,539	-	-	7,539
62	Total General Plant		145,022,127	1,180,624	43,808	-	1,224,432
63	Total Depreciable Plant		$ 6,335,371,027	$ 14,723,537	$ 241,293	$ (7,057)	$ 14,957,773
64	Non-Depreciable Plant						
65	Land		9,487,979				
66	Plant Held for Future Use		6,756,930				
67	Transmission Recoverable Line Pack		4,898,134				
68	Organization Costs - Fully Amortized		4,841,691				
69	Total Non-Depreciable Plant		$ 25,984,734				
70	Total Gas Plant in Service		$ 6,361,355,761				

1/ Represents 1 months of ARO recovery recorded in FERC Account 108.

Docket RP22-1033
Statement H-2

NORTHERN NATURAL GAS COMPANY

Depreciation and Amortization Expense
Test Period Ended December 31, 2022

		Base Period Plant November 31, 2022			Adjustments			End of Test Period Plant			
Line No.	Particulars	Depreciation Provision	Negative Salvage Provision	Total Depreciation Provision	Depreciation	Negative Salvage	Total Adjustment	Depreciation Provision	Negative Salvage Provision	Total Depreciation Provision	F/N
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	
1	Natural Gas Production & Gathering										
2	Offshore	$ -	$ 38,797	$ 38,797	$ -	$ -	$ -	$ -	$ 38,797	$ 38,797	
3	Total Natural Gas Production & Gathering	-	38,797	38,797	-	-	-	-	38,797	38,797	
4	Natural Gas Storage Plant										
5	Underground Storage Plant	8,875,834	-	8,875,834	18,415,907	5,427,000	23,842,907	27,291,742	5,427,000	32,718,741	
6	LNG Storage Plant	4,359,003	-	4,359,003	604,176	1,105,285	1,709,461	4,963,179	1,105,285	6,068,464	
7	Total Natural Gas Storage Plant	13,234,838	-	13,234,838	19,020,083	6,532,284	25,552,368	32,254,921	6,532,284	38,787,205	
8	Base Load LNG Terminal & Processing Plant	360,172	-	360,172	11,343	-	11,343	371,515	-	371,515	
9	Transmission Plant										
10	Mainline										
11	Onshore	124,713,479	5,180,443	129,893,923	71,195,629	59,271,096	130,466,725	195,909,108	64,451,540	260,360,648	
12	Offshore	-	737,138	737,138	-	-	-	-	737,138	737,138	
13	Total Natural Transmission Plant	124,713,479	5,917,582	130,631,061	71,195,629	59,271,096	130,466,725	195,909,108	65,188,678	261,097,786	
14	General Plant	14,167,474	-	14,167,474	1,051,398	-	1,051,398	15,218,872	-	15,218,872	
15	Intangible Plant	18,250,094	-	18,250,094	9,110,113	-	9,110,113	27,360,207	-	27,360,207	
16	Total Depreciation and Amortization Expense	$ 170,726,056	$ 5,956,378	$ 176,682,435	$ 100,388,566	$ 65,803,381	$ 166,191,947	$ 271,114,623	$ 71,759,759	$ 342,874,382	1/

1/ Column [j] ties to Schedule H-2 (1), column [o], line 66.

NORTHERN NATURAL GAS COMPANY

Calculation of Test Period Depreciation and Amortization Expense
Test Period Ended December 31, 2022

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Annual Proposed Rate	Annual Proposed Negative Salvage	Depreciable Book Plant Balances 11/30/2022	Test Period Adjustments: Plant Additions	Plant Transfer	Plant Retirements	Period Adjustments	Test Period Plant	Annual Depreciation Expense	Annual Negative Salvage	Total Annual Provision	F/N
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]	[n]	
1	Natural Gas Gas Production & Gathering														
2	Offshore Fully Depreciated	0.00%	0.00%	0.00%	0.00% $	1,545,742 $	- $	- $	- $	- $	1,545,742 $	- $	- $	-	
3	Offshore Negative Salvage - ARO		775,935		775,935		-	-	-	-	-	-	38,797	38,797	1/
4	Total Natural Gas Production & Gathering					1,545,742	-		-	-	1,545,742	-	38,797	38,797	
5	Natural Gas Storage Plant -														
6	Underground Storage														
7	Storage Leaseholds and Rights	1.25%	0.00%	4.10%	0.85%	20,532,180	-	-	-	-	20,532,180 $	841,819 $	174,524 $	1,016,343	
8	Right of Way	1.25%	0.00%	4.10%	0.85%	2,632,868	-	-	-	-	2,632,868	107,948	22,379	130,327	
9	Operating Plant	1.25%	0.00%	4.10%	0.85%	597,771,418	17,024,080	-	510,000	17,534,080	615,305,499	25,227,525	5,230,097	30,457,622	
10	Shop & Communication Equipment - 10%	10.00%	0.00%	10.00%	0.00%	464,910	-	-	-	-	464,910	46,491	-	46,491	
11	Computers - 10%	10.00%	0.00%	10.00%	0.00%	10,676,377	11,206	-	(8,000)	3,206	10,679,583	1,067,958	-	1,067,958	
12	Total Underground Storage					632,077,753	17,035,286		502,000	17,537,286	649,615,040	27,291,742	5,427,000	32,718,741	
13	LNG Storage														
14	Operating Plant	2.95%	0.00%	3.12%	0.71%	144,164,400	11,521,759	-	(12,250)	11,509,509	155,673,908	4,857,026	1,105,285	5,962,311	
15	Computers - 10%	10.00%	0.00%	10.00%	0.00%	1,061,533	-	-	-	-	1,061,533	106,153	-	106,153	
16	Total Other Storage Plant					145,225,932	11,521,759	-	(12,250)	11,509,509	156,735,441	4,963,179	1,105,285	6,068,464	
17	Total Natural Gas Storage Plant					777,303,685	28,557,045	-	489,750	29,046,795	806,350,480	32,254,921	6,532,284	38,787,205	
18	Base Load LNG Terminal & Processing Plant														
19	Base Load LNG Processing Equipment	2.95%	0.00%	3.12%	0.00%	6,672,555	-	-	-	-	6,672,555	208,184	-	208,184	
20	Base Load LNG Computers	10.00%	0.00%	10.00%	0.00%	13,870	-	-	-	-	13,870	1,387	-	1,387	
21	Base Load LNG Transportation Equipment	10.00%	0.00%	10.00%	0.00%	1,619,444	-	-	-	-	1,619,444	161,944	-	161,944	
22	Total Base Load LNG Terminal & Processing Plant					8,305,868	-	-	-	-	8,305,868	371,515	-	371,515	
23	Transmission Plant														
24	Mainline														
25	Offshore														
26	Offshore - Not Fully Depreciated 4.89%	4.64%	0.00%	4.64%	0.00%	-	-	-	-	-	-	-	-	-	
27	Offshore - Fully Depreciated	0.00%	0.00%	0.00%	0.00%	14,105,434	-	-	-	-	14,105,434	-	-	-	
28	Offshore Right of Way - Fully Depreciated	0.00%	0.00%	0.00%	0.00%	(102)	-	-	-	-	(102)	-	-	-	
29	Offshore Land Rights Renewal - FD	0.00%	0.00%	0.00%	0.00%	700,317	-	-	-	-	700,317	-	-	-	
30	Offshore - Negative Salvage, ARO		775,935	0.00%	775,935	-	-	-	-	-	-	-	737,138	737,138	1/
31	Total Offshore					14,805,649	-		-	-	14,805,649	-	737,138	737,138	
32	Onshore														
33	Onshore	2.30%	0.10%	3.57%	1.21%	5,099,613,803	150,140,963	-	(7,250,740)	142,890,224	5,242,504,027	187,157,394	63,434,299	250,591,692	
34	Onshore Right of Way	2.30%	0.10%	3.57%	1.21%	80,829,625	3,239,873	-	-	3,239,873	84,069,498	3,001,281	1,017,241	4,018,522	
35	Onshore Land Rights Renewal	2.63%	0.00%	2.63%	0.00%	607,911	-	-	-	-	607,911	15,988	-	15,988	
36	Onshore Land Rights Renewal	3.33%	0.00%	3.33%	0.00%	4,575,176	-	-	-	-	4,575,176	152,353	-	152,353	
37	Onshore Land Rights Renewal	4.17%	0.00%	4.17%	0.00%	2,684,386	-	-	-	-	2,684,386	111,939	-	111,939	
38	Onshore Land Rights Renewal	5.00%	0.00%	5.00%	0.00%	3,454,576	-	-	-	-	3,454,576	172,729	-	172,729	
39	Computers - 10%	10.00%	0.00%	10.00%	0.00%	47,431,840	1,560,273	-	(5,750)	1,554,523	48,986,364	4,898,636	-	4,898,636	
40	Radio Communications - 10%	10.00%	0.00%	10.00%	0.00%	3,670,874	317,003	-	-	317,003	3,987,877	398,788	-	398,788	
41	Total Onshore					5,242,868,192	155,258,113	-	(7,256,490)	148,001,623	5,390,869,815	195,909,108	64,451,540	260,360,648	
42	Total Transmission Plant					5,257,673,841	155,258,113	-	(7,256,490)	148,001,623	5,405,675,464	195,909,108	65,188,678	261,097,786	

NORTHERN NATURAL GAS COMPANY

Calculation of Test Period Depreciation and Amortization Expense
Test Period Ended December 31, 2022

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Annual Proposed Rate	Annual Proposed Negative Salvage	Depreciable Book Plant Balances 11/30/2022	Test Period Adjustments Plant Additions	Plant Transfer	Plant Retirements	Period Adjustments	Test Period Plant	Annual Depreciation Expense	Annual Negative Salvage	Total Annual Provision	F/N
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]	[n]	
43	Intangible Plant														
44	Intangible Plant - Other	13.00%	0.00%	20.00%	0.00%	123,270,575	2,345,863	-	-	2,345,863	125,616,438	25,123,288	-	25,123,288	
45	Intangible Cost - CIACs - Depr Rate 10%	10.00%	0.00%	10.00%	0.00%	22,249,189	-	-	-	-	22,249,189	2,224,919	-	2,224,919	
46	Intangible Cost - Leasehold Improvements 1(	10.00%	0.00%	10.00%	0.00%	-	120,001	-	-	120,001	120,001	12,000	-	12,000	
47	Total Intangible Plant					145,519,764	2,465,864	-	-	2,465,864	147,985,628	27,360,207	-	27,360,207	
48	General Plant														
49	General Structure - 2.75%	2.75%	0.00%	2.75%	0.00%	33,797,209	2,802,381	-	-	2,802,381	36,599,590	1,006,489	-	1,006,489	
50	Computer Equipment - 20%	20.00%	0.00%	20.00%	0.00%	21,155,590	2,270,119	-	-	2,270,119	23,425,709	4,685,142	-	4,685,142	
51	Office Furniture and Equipment - 10%	10.00%	0.00%	10.00%	0.00%	10,117,062	795,152	-	-	795,152	10,912,214	1,091,221	-	1,091,221	
52	Tools and Work Equipment - 10%	10.00%	0.00%	10.00%	0.00%	32,317,066	2,788,483	-	-	2,788,483	35,105,549	3,510,555	-	3,510,555	
53	Laboratory Equipment - 10%	10.00%	0.00%	10.00%	0.00%	2,423,483	-	-	-	-	2,423,483	242,348	-	242,348	
54	Communication Equipment - 10%	10.00%	0.00%	10.00%	0.00%	2,255,711	286,806	-	-	286,806	2,542,517	254,252	-	254,252	
55	Transportation and Powered Work Equip. 10%	10.00%	0.00%	10.00%	0.00%	42,051,337	1,332,648	-	-	1,332,648	43,383,985	4,338,399	-	4,338,399	
56	Miscellaneous Equipment - 10%	10.00%	0.00%	10.00%	0.00%	904,670	-	-	-	-	904,670	90,467	-	90,467	
57	Total General Plant					145,022,127	10,275,589	-	-	10,275,589	155,297,716	15,218,872	-	15,218,872	
58	Total Depreciable Plant					6,335,371,027	196,556,611	-	(6,766,740)	189,789,871	6,525,160,898	271,114,623	71,759,759	342,874,382	
59	Non-Depreciable Plant														
60	Land					9,487,979	1,638,539	-	-	1,638,539	11,126,518				
61	Plant Held for Future Use					6,756,930	-	-	-	-	6,756,930				
62	Transmission Recoverable Linepack					4,898,134	-	-	-	-	4,898,134				
63	Organization Costs - Fully Amortized					4,841,691	-	-	-	-	4,841,691				
64	Total Non-Depreciable Plant					25,984,734	1,638,539	-	-	1,638,539	27,623,273				
65	Total Gas Plant in Service					$ 6,361,355,761	$ 198,195,150	$ -	$ (6,766,740)	$ 191,428,410	$ 6,552,784,171	$ 271,114,623	$ 71,759,759	$ 342,874,382	2/

1/ The ARO negative salvage allowance is allocated between offshore transmission and gathering based on estimated cost of abandonment for each and is adjusted from time to time based on actual cost incurred and change in estimate.

2/ Total annual proposed provision for depreciation and negative salvage are computed by multiplying the depreciable plant amount in column (l) by the depreciation and negative salvage rates in columns [d] and [e] respectively.

NORTHERN NATURAL GAS COMPANY

Calculation of Base Period Depreciation and Amortization Expense
12-Month Period Ended December 31, 2022

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Adjusted Balance 11/30/2022	Annual Depreciation Expense	Annual Negative Salvage Provision	Total Annual Base Period Provision
	[a]	[b]	[c]	[d]	[e]	[f]	[g]
1	Natural Gas Production & Gathering						
2	Offshore Fully Depreciated	0.00%	0.00%	$ 1,545,742	$ -	$ -	$ -
3	Offshore Negative Salvage - ARO	0.00%	775,935	-	-	38,797	38,797
4	Total Natural Gas Production & Gathering			1,545,742	-	38,797	38,797
5	Natural Gas Storage Plant						
6	Underground Storage						
7	Storage Leaseholds and Rights	1.25%	0.00%	20,532,180	256,652	-	256,652
8	Right of Way	1.25%	0.00%	2,632,868	32,911	-	32,911
9	Operating Plant	1.25%	0.00%	597,771,418	7,472,143	-	7,472,143
10	Shop & Communication Equipment - 10%	10.00%	0.00%	464,910	46,491	-	46,491
11	Computers - 10%	10.00%	0.00%	10,676,377	1,067,638	-	1,067,638
12	Total Underground Storage Plant			632,077,753	8,875,834	-	8,875,834
13	LNG Storage						
14	Operating Plant	2.95%	0.00%	144,164,400	4,252,850	-	4,252,850
15	Computers - 10%	10.00%	0.00%	1,061,533	106,153	-	106,153
16	Total LNG Storage Plant			145,225,932	4,359,003	-	4,359,003
17	Total Natural Gas Storage Plant			777,303,685	13,234,838	-	13,234,838
18	Base Load LNG Terminal & Processing Plant						
19	Base Load LNG Processing Equipment	2.95%	0.00%	6,672,555	196,840	-	196,840
20	Base Load LNG Computers	10.00%	0.00%	13,870	1,387	-	1,387
21	Base Load LNG Transportation Equipment	10.00%	0.00%	1,619,444	161,944	-	161,944
22	Total Base Load LNG Terminal & Processing Plant			8,305,868	360,172	-	360,172

NORTHERN NATURAL GAS COMPANY

Calculation of Base Period Depreciation and Amortization Expense
12-Month Period Ended December 31, 2022

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Adjusted Balance 11/30/2022	Annual Depreciation Expense	Annual Negative Salvage Provision	Total Annual Base Period Provision
	[a]	[b]	[c]	[d]	[e]	[f]	[g]
23	Transmission Plant						
24	Mainline						
25	Offshore						
26	Offshore - Not Fully Depreciated 4.89%	4.64%	0.00%	-	-	-	-
27	Offshore - Fully Depreciated	0.00%	0.00%	14,105,434	-	-	-
28	Offshore Right of Way - Fully Depreciated	0.00%	0.00%	(102)	-	-	-
29	Offshore Land Rights Renewal - Fully Depreciated	0.00%	0.00%	700,317	-	-	-
30	Offshore - Negative Salvage, ARO	0.00%	775,935	-	-	737,138	737,138
31	Total Offshore			14,805,649	-	737,138	737,138
32	Onshore						
33	Onshore - 2.3%	2.30%	0.10%	5,099,613,803	117,291,117	5,099,614	122,390,731
34	Onshore Right of Way- 2.3%	2.30%	0.10%	80,829,625	1,859,081	80,830	1,939,911
35	Onshore Land Rights Renewal	2.63%	0.00%	607,911	15,988	-	15,988
36	Onshore Land Rights Renewal	3.33%	0.00%	4,575,176	152,353	-	152,353
37	Onshore Land Rights Renewal	4.17%	0.00%	2,684,386	111,939	-	111,939
38	Onshore Land Rights Renewal	5.00%	0.00%	3,454,576	172,729	-	172,729
39	Computers - 10%	10.00%	0.00%	47,431,840	4,743,184	-	4,743,184
40	Radio Communications - 10%	10.00%	0.00%	3,670,874	367,087	-	367,087
41	Total Onshore			5,242,868,192	124,713,479	5,180,443	129,893,923
42	Total Transmission Plant			5,257,673,841	124,713,479	5,917,582	130,631,061
43	Total Operating Facilities			6,044,829,137	138,308,489	5,956,378	144,264,867
44	Intangible Plant						
45	Intangible Plant - Other	13.00%	0.00%	123,270,575	16,025,175	-	16,025,175
46	Intangible Cost - CIACs - Depr Rate 10%	10.00%	0.00%	22,249,189	2,224,919	-	2,224,919
47	Intangible Cost - Leasehold Improvements 10%	10.00%	0.00%	-	-	-	-
48	Total Intangible Plant			145,519,764	18,250,094	-	18,250,094

NORTHERN NATURAL GAS COMPANY

Calculation of Base Period Depreciation and Amortization Expense
12-Month Period Ended December 31, 2022

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Adjusted Balance 11/30/2022	Annual Depreciation Expense	Annual Negative Salvage Provision	Total Annual Base Period Provision
	[a]	[b]	[c]	[d]	[e]	[f]	[g]
49	General Plant						
50	General Structure - 2.75%	2.75%	0.00%	33,797,209	929,423	-	929,423
51	Computer Equipment - 20%	20.00%	0.00%	21,155,590	4,231,118	-	4,231,118
52	Office Furniture and Equipment - 10%	10.00%	0.00%	10,117,062	1,011,706	-	1,011,706
53	Tools and Work Equipment - 10%	10.00%	0.00%	32,317,066	3,231,707	-	3,231,707
54	Laboratory Equipment - 10%	10.00%	0.00%	2,423,483	242,348	-	242,348
55	Communication Equipment - 10%	10.00%	0.00%	2,255,711	225,571	-	225,571
56	Transportation and Powered Work Equip. 10%	10.00%	0.00%	42,051,337	4,205,134	-	4,205,134
57	Miscellaneous Equipment - 10%	10.00%	0.00%	904,670	90,467	-	90,467
58	Total General Plant			145,022,127	14,167,474	-	14,167,474
59	Total Depreciable Plant			6,335,371,027	170,726,056	5,956,378	176,682,435
60	Non-Depreciable Plant						
61	Land			9,487,979			
62	Plant Held for Future Use			6,756,930			
63	Transmission Recoverable Line Pack			4,898,134			
64	Organization Costs - Fully Amortized			4,841,691			
65	Total Non-Depreciable Plant			25,984,734			
66	Total Gas Plant in Service			$ 6,361,355,761	$ 170,726,056	$ 5,956,378	$ 176,682,435

NORTHERN NATURAL GAS COMPANY

Computation of Federal and State Income Taxes
Test Period Ended December 31, 2022

Line No.	Particulars		Schedule Reference		Total	Storage	Transmission	F/N
	[a]		[b]		[c]	[d]	[e]	
1	Return Allowance							
2	Interest Expense		H-3, P. 2	$	62,030,636			
3	Allowance on Common Stock Equity		H-3, P. 2		367,311,049			
4	Total Return Allowance		B		429,341,685	56,662,646	372,679,038	1/
5	Eliminate Interest Expense (Line 2)		H-3, P. 2		(62,030,636)	(8,186,533)	(53,844,102)	1/
6	Taxable Portion of Return Allowance [Line 4 + Line 5]				367,311,049	48,476,113	318,834,936	
7	Adjustments:							
8	Amortization of under funded deferred income taxes		H-3[2]		-	-	-	
9	Amortization of Equity AFUDC				$2,863,872	377,961	2,485,911	
10	Total Adjustments				2,863,872	377,961	2,485,911	
11	Taxable Income After Income Taxes [Line 6 + Line 10]				370,174,921	48,854,074	321,320,847	
12	Add: Federal Income Tax	[	26.58% of line 11]		98,400,927			
13	Taxable Income Before Income Taxes			$	468,575,848			
14	Federal Income Tax Applicable To:							
15	Common Stock Equity Component	[	26.58% of line 6]		97,639,645	12,886,055	84,753,590	2/
16	Other Tax Adjustments Component	[	26.58% of line 10]		761,283	100,471	660,812	2/
17	Total Federal Income Tax	[	21.00% of line 13]		98,400,928	12,986,526	85,414,402	2/
18	State Income Tax Applicable To:							
19	Common Stock Equity Component	[	7.67% of line 6 + 17]		35,724,282	4,714,735	31,009,547	2/
20	Other Tax Adjustments Component	[	7.67% of line 10]		219,685	28,993	190,692	2/
21	Total State Income Tax	[	7.12% of line 13+19+20]		35,943,967	4,743,728	31,200,239	2/
22	Total Federal and State Income Taxes			$	134,344,895			

1/ Allocated to functions on basis of Statement B, Line 19.
2/ Allocated to functions on basis of line 6.

NORTHERN NATURAL GAS COMPANY

Interest Expense Applicable to Investment in Rate Base
Test Period Ended December 31, 2022

Line No.	Particulars [a]	% of Rate Base [b]	F/N		Amount [c]
1	Test Period Rate Base		1/	$	4,110,060,471
2	Test Period Return Allowances by Components:				
3	Interest Expense	1.51%	2/		62,030,636
4	Allowance on Common Stock Equity	8.94%	2/		367,311,049
5	Total Return Allowance	10.45%	2/		429,341,685
6	Interest Expense Applicable to Investment				
7	in Rate Base [Line 3]			$	62,030,636

1/ Statement B Line 15.

2/ Statement F- 2

NORTHERN NATURAL GAS COMPANY

State Income Tax Rate
Test Period Ended December 31, 2022

Line No.	Particulars	Total	Illinois	Iowa	Kansas	Louisiana	Michigan	Minnesota	Nebraska	New Mexico	North Dakota	Oklahoma	Texas 4/	Wisconsin	District of Columbia	F/N
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	(m)	(n)	(o)	
1	Taxable Income After Income Tax	$ 370,174,921														1/
2	Add: Federal Income Tax	98,400,927														1/
3	Total	$ 468,575,848														
4	Taxable Income for Apportionment	$ 468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	468,575,848	
5	Less Federal Income Tax Deduction [50% of line 2 for Iowa]					98,400,927										
6	Add Back State Income Taxes															
7	Not Allowed as a Deduction:															
8	Own State		137,903	10,172,519	5,210,240	(11,250)	281,184	9,059,994	-	-	(915)	832,328	-	1,421,656	-	
9	Other States		-	-	28,183,126	-	33,113,920	24,331,989	-	-	33,396,117	32,562,583	-	31,973,049	33,395,202	
10	Total for Apportionment		468,713,751	478,748,368	501,969,214	370,163,671	501,970,952	501,967,832	468,575,848	468,575,848	501,971,050	501,970,759	468,575,848	501,970,553	501,971,050	
11	Apportionment Factors		0.30970%	21.68179%	14.82800%	0	0.93360%	18.41730%	16.51010%	0.60620%	0.00000%	4.14530%		3.58500%	0.00000%	2/
12	Net Apportioned Taxable Income		1,451,606	103,801,216	74,431,995	-	4,686,401	92,448,922	77,362,341	2,840,506	-	20,808,194	-	17,995,644	-	
13	Less Amounts Taxed at Other Rates		-	-	-	150,000	-	-	100,000	500,000	50,000	-	-	-	-	
14	Amount Subject to State Tax Rate		1,451,606	103,801,216	74,431,995	(150,000)	4,686,401	92,448,922	77,262,341	2,340,506	(50,000)	20,808,194	-	17,995,644	-	
15	Tax Rate - %		9.5000%	9.8000%	7.0000%	7.5000%	6.0000%	9.8000%	7.5000%	5.9000%	4.3100%	4.0000%		7.9000%	0.0000%	3/
16	Subtotal [Line 14*Line 15]		$ 137,903	$ 10,172,519	$ 5,210,240	$ (11,250)	$ 281,184	$ 9,059,994	$ 5,794,676	$ 138,090	$ (2,155)	$ 832,328	$ -	$ 1,421,656	$ -	
17	Tax on Line 13 Amounts		-	-	-	-	-	-	5,580	24,000	1,240	-	-	-	-	
18	Apportioned State Income Taxes	$ 33,383,177	$ 137,903	$ 10,172,519	$ 5,210,240	$ (11,250)	$ 281,184	$ 9,059,994	$ 5,800,256	$ 162,090	$ (915)	$ 832,328	$ 317,174	$ 1,421,656	$ -	
19	Composite State Income Tax Rate [Line 18/Line 4]	7.1244%														
20	Gross-Up State Income Taxes	$ 35,943,966														

1/ From Statement H[3], Page 1, Lines 11 and 13.
2/ Apportionment data available is for the Year 2020
3/ State income tax rates available are for the Year 2021
4/ Texas income tax covered under "gross receipt" taxes.

NORTHERN NATURAL GAS COMPANY

Basis for allocating General Costs to Functions

Line No.	Particulars	Schedule Reference	Total	Storage	Transmission
	[a]	[b]	[c]	[d]	[e]
1	Direct Labor				
2	Test Period Payroll Expenses,	H-1 (1)(a)	$ 61,565,269	$ 9,117,848	$ 52,447,421
3	Excluding Administrative and	(Lines 56 & 89)			
4	General				
5	Ratio - %		100.00%	14.81%	85.19%
6	Net Utility Plant (excluding Intangible Plant)				
7	Test Period Classified	B	$ 4,915,936,556	$ 648,783,903	$ 4,267,152,653
8	Ratio - %	(Line 2 less 7)	100.00%	13.20%	86.80%
9	Kansas Nebraska Method				
10	KN Allocated A&G (See Page 2)	H-1	$ 95,224,614	$ 14,080,935	$ 81,143,679
11	Ratio - % (See Page 2)		100.00%	14.79%	85.21%
12	Operating Plant				
13	Test Period Classified	C-1	$ 6,242,710,263	$ 809,374,990	$ 5,433,335,273
14	Ratio - %	(Stg - Lines 32 & 44, Trans. - Lines 16, 49, & 60)	100.00%	12.97%	87.03%

NORTHERN NATURAL GAS COMPANY

Calculation of Kansas Nebraska Formula

		Split Between Labor, Plant and Other					Calculation of Kansas Nebraska Ratio			
Line No.	Particulars	As Filed	As Adjusted	Labor Related	Plant Related	Total Lab & Plant	Other	Labor Related	Plant Related	Total
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]
1	910	157	157	-	-	-	157	-	-	157
2	912	643	643	-	-	-	643	-	-	643
3	913	1,975	1,975	-	-	-	1,975	-	-	1,975
4	920	35,429,787	35,429,787	35,429,787	-	35,429,787	-	35,429,787	-	35,429,787
5	921	12,512,482	12,512,482	12,512,482	-	12,512,482	-	12,512,482	-	12,512,482
6	922-L	(902,904)	(902,904)	(902,904)	-	(902,904)	-	(902,904)	-	(902,904)
7	922-O	(328,144)	(328,144)	-	-	-	(328,144)	-	-	(328,144)
8	923-L	1,438,056	1,438,056	1,438,056	-	1,438,056	-	1,438,056	-	1,438,056
9	923-O	21,301,462	21,301,462	-	-	-	21,301,462	-	-	21,301,462
10	924	868,211	868,211	-	868,211	868,211	-	-	868,211	868,211
11	925	2,024,927	2,024,927	2,024,927	-	2,024,927	-	2,024,927	-	2,024,927
12	926	17,754,758	17,754,758	17,754,758	-	17,754,758	-	17,754,758	-	17,754,758
13	928	2,037,000	2,037,000	-	-	-	2,037,000	-	-	2,037,000
14	930.2	2,176,834	2,176,834	-	-	-	2,176,834	-	-	2,176,834
15	931	588,088	588,088	588,088	-	588,088	-	588,088	-	588,088
16	932	66,599	66,599	-	-	-	66,599	-	-	66,599
17	426.1	135,000	135,000	-	-	-	135,000	-	-	135,000
18	426.5	119,683	119,683	-	-	-	119,683	-	-	119,683
19		95,224,614	95,224,614	68,845,194	868,211	69,713,405	25,511,209	68,845,194	868,211	95,224,614
20		Labor/Plant Ratio		98.75%	1.25%			98.75%	1.25%	100.00%
21							**Transmission:**	85.19%	87.03%	
22		**Labor and Plant Ratios for Storage and Transmission**								
23			**Labor**		**Plant**		**KN Trans:**	84.13%	1.08%	**85.21%**
24		Transmission Labor & Plant	52,447,421	85.19%	5,433,335,273	87.03%				
25		Storage labor & Plant	9,117,848	14.81%	809,374,990	12.97%	**Storage:**	14.81%	12.97%	
26		Total	$ 61,565,269	100.00%	$ 6,242,710,263	100.00%				
27							**KN Stor:**	14.63%	0.16%	**14.79%**
28										**100.00%**

Docket RP22-1033
Schedule I-a(1)

NORTHERN NATURAL GAS COMPANY

LNG Storage Cost of Service
Test Period Ended December 31, 2022

Line No.	Particulars [a]	F/N			Test Period 12/31/2022 [b]
	Cost of Service				
1	A&G Expenses	1/		$	4,050,418
2	O & M Expenses	5/			8,945,778
3	Depreciation and Amortization of Gas Plant In Service				7,141,858
4	Amortization of Certain Reg Assets	2/			(319,179)
5	Income Taxes				
6	Federal Income at		21.00%		2,098,090
7	State Income at		7.12%		766,392
8	Taxes Other Than Income				
9	Payroll Taxes	3/			367,042
10	Franchise Taxes	2/			1,068
11	Fuel Use Tax				-
12	Ad Valorem	4/			2,220,825
13	Total Taxes Other Than Income				2,588,935
14	Return at		10.45%		9,154,359
15	Total Overall Cost of Service			$	34,426,651
	Rate Base and Return Allowance				
16	Utility Plant				
17	Gas Plant in Service			$	157,375,138
18	Regulatory Assets & Liabilities	2/			(6,499,890)
19	Sub-total				150,875,249
20	Classification of Intangible and General	2/			6,611,350
21	Total Classified Gas Plant in Service				157,486,598
22	Accumulated Provision for Depreciation and Amortization				52,558,272
23	Classification of Intangible and General	2/			2,856,808
24	Classified Accum. Provision for Depr. and Amort.				55,415,080
25	Net Utility Plant				102,071,519
26	Working Capital	2/			1,502,827
27	Total Rate Base Before Deductions				103,574,345
28	Less: Accumulated Deferred Income Taxes -	2/			(15,940,249)
29	Total Rate Base				87,634,097
30	Return Allowance		10.45%		
31	Interest Expense		1.51%		1,322,608
32	Allowance on Common Stock Equity		8.94%		7,831,751
33	Total Return Allowance			$	9,154,359

NORTHERN NATURAL GAS COMPANY

LNG Storage Cost of Service
Test Period Ended December 31, 2022

Line No.	Particulars	F/N			Test Period 12/31/2022
	[a]				[b]
	Income Taxes				
34	Return Allowance				
35	Allowance on Common Stock Equity			$	7,831,751
36	Equity AFUDC Adjustment	2/			61,063
37	Taxable Income After Income Taxes				7,892,814
38	Income Tax Allowance				
39	Federal Income Tax Allowance		21.00%		2,098,090
40	State Income Tax Allowance		7.12%		766,392
41	Total Income Tax Allowance			$	2,864,482
	Basis for Allocation of General Costs				
42	Net LNG Plant (excluding Intangible Plant)				
43	Test Period Classified			$	104,816,866
44	Ratio - %				2.13%
45	LNG Operating Plant				
46	Test Period Classified			$	157,375,138
47	Ratio - %				2.52%
48	LNG Direct Labor				
49	Test Period O&M Payroll Expenses, excluding A&G			$	2,632,156
50	Ratio - %				4.28%
51	KN LNG				
52	KN labor (LNG Direct Labor Ratio * A&G Labor Ratio)				4.22%
53	KN plant (LNG Operating Plant Ratio * A&G Plant Ratio)				0.03%
54	Total KN LNG ratio - %				4.25%

1/ Allocated to LNG using KN ratio per line 54.
2/ Allocated to LNG on a net plant basis per line 44.
3/ Allocated to LNG on direct labor basis per line 50.
4/ Allocated to LNG on a gross plant basis per line 47.
5/ Variable O&M Expenses for Compressor supplies of $231,838

Docket RP22-1033
Schedule I-a(2)

NORTHERN NATURAL GAS COMPANY

Northern Lights 2021 Cost of Service
Test Period Ended December 31, 2022

Line No.	Particulars [a]			Test Period 12/31/2022 [b]
1	Cost of Service			
2	O&M		$	394,829
3	Annual Depreciation & Negative Salvage 1/			3,519,808
4	Federal Income Tax	21.00%		1,777,681
5	State Income Tax	7.12%		649,353
6	Return	10.45%		
7	Debt	1.51%		1,129,364
8	Equity	8.94%		6,687,466
9	Other Taxes - Ad Valorem			944,849
10	Total Cost of Service		$	15,103,350
11	Rate Base			
12	Plant Investment		$	73,636,156
13	Accumulated Depreciation			(1,680,220)
14	Accumulated Deferred Income Tax			2,874,076
15	Excess Deferred Income Tax Regulatory Liability			-
16	Net Rate Base		$	74,830,012
17	Income Taxes			
18	Return	10.45%	$	7,816,830
19	Less: Interest	1.51%		(1,129,364)
20	Taxable Income After Tax			6,687,466
21	Add Federal Income Tax	26.58%		1,777,681
22	Taxable Income Before Tax		$	8,465,147
23	Federal Income Tax	21.00%	$	1,777,681
24	State Income Tax	7.12%	$	649,353
25	Taxes Other Than Income			
26	Plant Investment by State			
27	Minnesota	1.28%	$	73,534,666
28	Wisconsin	0.87%		101,490
29	Total Plant Investment by State			73,636,156
30	Total Ad Valorem Taxes		$	944,849

1/ Includes depreciation and negative salvage per schedule H-2(1).

Line No.	Particulars (a)	Schedule Reference	Total Costs (b)	Storage Costs (c)	Transmission Costs (d)
1	O & M Expense	H-1	$ 335,156,979	$ 59,437,449	$ 275,719,531
2					
3	Depreciation and Amortization of Gas Plant in Service	H-2, B-2	327,904,786	42,332,013	285,572,774
4					
5	Taxes				
6	Federal Income Tax	H-3	98,400,928	12,986,526	85,414,402
7					
8	State Income Tax	H-3	35,943,967	4,743,728	31,200,239
9					
10	Taxes Other Than Income	H-4	96,730,127	12,699,682	84,030,445
11					
12	Return	B	429,341,684	56,662,646	372,679,038
13					
14	Other Operating Revenue	G-5	(817,204)	-	(817,204)
15					
16					
17	Total Overall Cost of Service		$ 1,322,661,268	$ 188,862,044	$ 1,133,799,224

Line No.	Particulars	Statement I-1(a) - Page 3 Line Reference		Overall Cost of Service
	(a)	(b)		(c)
1	Storage Costs			
2	Fixed Costs	Col. (b), L. 3 + L. 4	$	184,478,082
3	Variable Costs	Col. (b), L. 6		4,383,962
4				
5	Transmission Costs			
6	Fixed Costs -- Mileage	Col. (b), L. 11 + L. 12		1,015,579,694
7	Variable Costs -- Mileage	Col. (b), L. 14		37,075,851
8				
9	Other Non-Mileage			
10	Fixed Costs	Col. (b), L. 16		81,143,679
11	Total Classified Cost of Service		$	1,322,661,268
12				
13	Fixed Costs		$	1,281,201,455
14	Variable Costs			41,459,813
15	Total Cost of Service Allocated in Schedule I-1(a)		$	1,322,661,268

Northern Natural Gas Company
Classified Overall Cost of Service

Docket No. RP22-1033-000
Schedule I-1(a)

Line No.	Particulars		Total Overall Cost of Service		Operation & Maintenance Expenses		Depreciation, Depletion & Amortization		Taxes: Federal Income		Taxes: State Income		Taxes: Other than Income		Return		Other Operating Revenues
	(a)		(b)		(c)		(d)		(e)		(f)		(g)		(h)		(i)
1	**Storage Costs:**																
2	Fixed:																
3	Return and Related Income Taxes	$	74,392,900	$	-	$	-	$	12,986,526	$	4,743,728	$	-	$	56,662,646	$	-
4	Other Fixed		110,085,181		55,053,487		42,332,013		-		-		12,699,682		-		-
5	Variable:																
6	Other Variable		4,383,962		4,383,962		-		-		-		-		-		-
7	Total Storage Costs	$	188,862,044	$	59,437,449	$	42,332,013	$	12,986,526	$	4,743,728	$	12,699,682	$	56,662,646	$	0
8																	
9	**Transmission Costs:**																
10	Mileage -- Fixed:																
11	Return and Related Income Taxes	$	489,293,679	$	-	$	-	$	85,414,402	$	31,200,239	$	-	$	372,679,038	$	-
12	Other Mileage Fixed		526,286,015		157,500,001		285,572,774		-		-		84,030,445		-		(817,204)
13	Mileage -- Variable:																
14	Other Mileage Variable		37,075,851		37,075,851		-		-		-		-		-		-
15																	
16	**Other Non-Mileage Fixed Costs**		81,143,679		81,143,679		-		-		-		-		-		-
17	Total Transmission Costs	$	1,133,799,224	$	275,719,531	$	285,572,774	$	85,414,402	$	31,200,239	$	84,030,445	$	372,679,038	$	(817,204)
18																	
19	Total Cost of Service	$	1,322,661,268	$	335,156,979	$	327,904,786	$	98,400,928	$	35,943,967	$	96,730,127	$	429,341,684	$	(817,204)

NORTHERN NATURAL GAS COMPANY
Assignment of Fixed Costs to Specific Rate Schedules and Services

Line No.	Particulars		Storage		Transmission Mileage		Transmission All Other		Total
	(a)		(b)		(c)		(d)		(e)
1	Total Classified Overall Fixed Cost of Service: 1/	$	184,478,082	$	1,015,579,694	$	81,143,679	$	1,281,201,455
2									
3	Less: Costs Assigned to Specific Services								
4	Transmission				-		-		-
5	Storage 2/		184,478,082						184,478,082
6									
7	Total Costs Assigned to Specific Services		184,478,082		-		-		184,478,082
8	Net Classified Overall								
9	Cost of Service	$	-	$	1,015,579,694	$	81,143,679	$	1,096,723,373
10									
11	1/ Schedule I-1(a), Page 2, Fixed Costs								
12	2/ Schedule I-1(a), Page 2, Line 2								

Line No.	Particulars		Storage		Transmission		Total
	(a)		(b)		(c)		(d)
1	Total Classified Overall Variable Cost of Service: 1/	$	4,383,962	$	37,075,851	$	41,459,813
2							
3	Less: Costs Assigned to Specific Services						
4							
5	Transmission				-		-
6							
7	Storage 2/		4,383,962				4,383,962
8							
9	Total Costs Assigned to Specific Rate Schedules & Services	$	4,383,962	$	-	$	4,383,962
10	Net Classified Overall						
11	Cost of Service	$	-	$	37,075,851	$	37,075,851
12							
13	1/ Schedule I-1(a), Page 2, Variable Costs						
14	2/ Schedule I-1(a), Page 2, Line 3						

NORTHERN NATURAL GAS COMPANY
Classification of Storage Revenue

Line No.	Particulars (a)		Rate (b)	Volume (c)	Amount (d)
1	Underground Storage Service Revenue	1/			
2	Proposed FDD Rates:				
3	Reservation		$ 4.3552	12,486,475	$ 54,381,097
4	Capacity		0.9065	59,992,480	54,383,183
5	Injection		0.0232	71,644,926	1,662,162
6	Withdrawal		$ 0.0232	71,644,926	1,662,162
7	Total FDD Revenue to Cost of Service				$ 112,088,605
8					
9	Revenue Credits				
10	MBR Reservation Revenue				$ 10,161,975
11	MBR Commodity Revenue				370,519
12	Discounted FDD Reservation Revenue				1,889,315
13	Total Revenue Credits for Storage	2/			$ 12,421,809
14					
15	LNG Directly Assigned to Transmission				
16	Total Costs to Market Area Demand Rate				$ 34,194,813
17	Total Costs to Market Area Commodity Rate				231,838
18	Total LNG Directly Assigned to Transmission	3/			$ 34,426,651
19					
20	Operational Storage Allocation to Transmission				
21	Total Costs to Market Area Demand Rate				$ 29,370,548
22	Total Cost to Field Area Demand Rate				100,000
23	Total Costs to Market Area Commodity Rate				463,377
24	Total Operational Storage Costs to Transmission	4/			$ 29,933,925
25					
26	Total Storage Related Revenue to Cost of Service				$ 188,870,990
27					
28	Classification of Storage Cost of Service				
29	Storage Demand				$ 184,478,082
30	Storage Variable				4,383,962
31	Total Classified Storage Revenue				$ 188,862,044
32					

33 1/ Schedule J-2, Page 6
34 2/ Schedule J-2, Page 6, Lines 14 - 16
35 3/ Schedule I-a(1), Line 15
4/ Schedule I-3(d), Line 30, Column (d)

Line No.	Particulars		Storage Plant		Transmission Plant		Totals
	(a)		(b)		(c)		(d)
1	Depreciation, Depletion and Amortization Expense 1/						
2	Storage:						
3	Fixed Costs	$	42,332,013			$	42,332,013
4							
5	Transmission Allocated on a Mileage Basis:						
6	Fixed Costs				285,572,774		285,572,774
7							
8	Total Depreciation, Depletion and Amortization Expense	$	42,332,013	$	285,572,774	$	327,904,786
9							
10							
11	1/ Per Schedule H-2 and B-2						

Line No.	Particulars		Ad Valorem Taxes		Payroll Taxes		Miscellaneous Taxes		Totals
	(a)		(b)		(c)		(d)		(e)
1	Taxes - Other than Income 1/								
2									
3	Storage:								
4	Fixed Costs	$	11,421,630	$	1,271,440	$	6,612	$	12,699,682
5									
6	Transmission Allocated on a Mileage Basis:								
7	Fixed Costs		76,673,413		7,313,543		43,488		84,030,445
8									
9	Total Taxes - Other than Income	$	88,095,043	$	8,584,984	$	50,100	$	96,730,127
10			2/		3/		4/		
11									
12	1/ Per Statement H-4								
13	2/ Allocated to functions on Operating Gas Plant in Service basis, Schedule I-1(d)								
14	3/ Allocated to functions on Direct Labor basis, Schedule I-1(d)								
15	4/ Allocated to functions on Net Utility Plant, Schedule I-1(d)								

NORTHERN NATURAL GAS COMPANY
Classification of Other Operating Revenue

Line No.	Particulars (a)	Rent from Gas Property (b)	Miscellaneous Non-Operating Income (c)	Other Deductions (d)	Sales for Resale (e)	Other Gas Revenues (f)	Totals (g)
1	Other Operating Revenues						
2	Storage:						
3	Fixed Costs	$ -	$ -	$ -	$ -	$ -	$ -
4							
5	Transmission Allocated on a Mileage Basis:						
6	Fixed Costs	-	-	-	-	(817,204)	(817,204)
7							
8	Total Other Operating Revenues-Credit	$ -	$ -	$ -	$ -	$ (817,204)	$ (817,204) 1/
9							
10							
11	1/ Per Schedule G-5						

Line No.	Particulars		Storage Expenses		Transmission Expenses		Administrative and General Expenses		Totals	
	(a)		(b)		(c)		(d)		(e)	
1	Other Operation & Maintenance Expenses									
2										
3	Storage:									
4	Fixed Costs	$	40,972,552	$		$	14,080,935	$	55,053,487	
5	Variable Costs		4,383,962						4,383,962	
6										
7	Transmission:									
8	Fixed Costs -- Mileage				157,500,001				157,500,001	
9	Variable Costs -- Mileage				37,075,851				37,075,851	
10										
11	Transmission :									
12	Other Non-Mileage Fixed Costs						81,143,679		81,143,679	
13										
14	Total Other Operation & Maintenance Expenses	$	45,356,514	$	194,575,852	$	95,224,614	$	335,156,979	1/
15										
16	1/ Per Schedule H-1									

NORTHERN NATURAL GAS COMPANY
Classification of Various Cost of Service Items

Line No.	Particulars	Total	Fixed	Variable
	(a)	(b)	(c)	(d)
1	Underground Storage Expenses:			
2	Operation:			
3	Supervision and Engineering	$ 622,804	$ 622,804	$ -
4	Well Expenses - Fuel	-	-	-
5	Compressor Station Expenses - Payroll	483,210	483,210	-
6	Compressor Station Expenses - Supplies & Exp.	2,319,982	-	2,319,982
7	Compressor Station Expenses - Fuel	-	-	-
8	Purification Expenses - Payroll	455,345	455,345	-
9	Purification Expenses - Supplies & Expenses	279,537	279,537	-
10	Storage Service Expenses	-	-	-
11	Other Operating Expenses	6,004,816	6,004,816	-
12	Total Operation	$ 10,165,694	$ 7,845,712	$ 2,319,982
13				
14	Maintenance:			
15	Supervision and Engineering	$ 404,678	$ 404,678	$ -
16	Compressor Station Equipment - Payroll	548,715	548,715	-
17	Compressor Station Equipment - Supplies & Exp.	1,832,142	-	1,832,142
18	Purification Expenses - Payroll	356,939	356,939	-
19	Purification Expenses - Supplies & Expenses	932,463	932,463	-
20	Other Maintenance Expenses	22,170,105	22,170,105	-
21	Total Maintenance	$ 26,245,042	$ 24,412,900	$ 1,832,142
22	Total Underground Storage Expenses	$ 36,410,736	$ 32,258,612	$ 4,152,124
23				
24	LNG Storage Expenses:			
25	Operation:			
26	Supervision and Engineering	$ 247,733	$ 247,733	$ -
27	Power	345,734	345,734	-
28	Other Operating Expenses	4,253,774	4,253,774	-
29	Total Operation	$ 4,847,241	$ 4,847,241	$ -
30				
31	Maintenance:			
32	Supervision and Engineering	$ 10,944	$ 10,944	$ -
33	Gas Holders - Payroll	92,612	92,612	-
34	Gas Holders - Supplies & Expenses	-	-	-
35	Compr., Measuring & Other Equip.-Payroll	150,378	150,378	-
36	Compr., Measuring & Other Equip.- Supplies & Expenses	231,838	-	231,838
37	Other Maintenance Expense	3,612,765	3,612,765	-
38	Total Maintenance	$ 4,098,537	$ 3,866,699	$ 231,838
39				
40	Total LNG Storage Expenses	$ 8,945,778	$ 8,713,940	$ 231,838
41				
42				
43				
44	Total Underground and LNG Storage Expense	$ 45,356,514	$ 40,972,552	$ 4,383,962
45				
46	Administrative and General Expenses:			
47	Underground Storage	$ 14,080,935	$ 14,080,935	$ -
48				
49	Total Natural Gas Storage Expenses	$ 59,437,449	$ 55,053,487	$ 4,383,962

Line No.	Particulars		Total		Fixed		Variable
	(a)		(b)		(c)		(d)
1	Transmission Expenses:						
2	Operation:						
3	Supervision & Engineering	$	3,255,729	$	3,255,729	$	-
4	Compressor Station Expenses						
5	Payroll		6,609,940		6,609,940		-
6	Supplies and Expenses		12,926,082		-		12,926,082
7	Transportation & Compression						
8	of Gas by Others		-		-		-
9	SPR Encroachment		-		-		
10	Other Operating Expenses		32,091,747		32,091,747		-
11	Other Gas Supply Expenses		20,361		20,361		-
12	Other Expenses		8,746,242		8,746,242		-
13	Total Operation	$	63,650,101	$	50,724,019	$	12,926,082
14							
15	Maintenance:						
16	Supervision & Engineering	$	2,190,257	$	2,190,257	$	-
17	Compressor Station Equipment						
18	Payroll		10,864,071		10,864,071		-
19	Supplies and Expenses		24,149,769		-		24,149,769
20	Other Maintenance Expenses		93,721,653		93,721,653		-
21	Total Maintenance	$	130,925,750	$	106,775,981	$	24,149,769
22							
23	Total Transmission Expenses	$	194,575,852	$	157,500,001	$	37,075,851
24							
25	Administrative and General Expenses:						
26	Transmission	$	81,143,679	$	81,143,679	$	-
27							
28	Total Transmission Expenses	$	275,719,531	$	238,643,680	$	37,075,851

NORTHERN NATURAL GAS COMPANY
Summary of Total Allocated Cost of Service

Line No.	Particulars		Total Allocated Costs		Total Fixed Costs		Total Variable Costs
	(a)		(b)		(c)		(d)
1	Total Classified Overall Cost of Service 1/	$	1,322,661,268	$	1,281,201,455	$	41,459,813
2	Less: Costs Assigned to Specific Rate Schedules & Services 2/		188,862,044		184,478,082		4,383,962
3	Net Classified Cost of Service	$	1,133,799,224	$	1,096,723,373	$	37,075,851
4							
5	Allocation:						
6	Market Area	$	981,193,057	$	954,557,580	$	26,635,477
7	Field Area		152,606,168		142,165,794		10,440,374
8	Total	$	1,133,799,224	$	1,096,723,373	$	37,075,851
9					3/		4/
10							
11	1/ Schedule I-1(a), Page 2						
12	2/ Schedule I-1(b), Page 1, Line 7 and Page 2, Line 9						
13	3/ Schedule I-3(a), Page 2						
14	4/ Schedule I-3(a), Page 3						

		Allocation of Costs				Allocation Percentages /3	
Line No.	Particulars	Total Fixed Costs	Storage Fixed Costs	Transmission Mileage Fixed Costs	All Other Fixed Costs	Transmission Mileage Fixed Costs	All Other Fixed Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Total Classified Overall Cost of Service 1/	$ 1,281,201,455	$ 184,478,082	$ 1,015,579,694	$ 81,143,679		
2	Less: Costs Assigned to Specific Rate Schedules & Services 2/	184,478,082	184,478,082	-	-		
3	Net Classified Cost of Service	$ 1,096,723,373	$ -	$ 1,015,579,694	$ 81,143,679		
4							
5	Allocation:						
6	Market Area	$ 954,557,580	$ -	$ 885,328,552	$ 69,229,028	0.871747	0.853166
7	Field Area	142,165,794	-	130,251,143	11,914,651	0.128253	0.146834
8	Total	$ 1,096,723,373	$ -	$ 1,015,579,694	$ 81,143,679	1.000000	1.000000
9							
10	1/ Schedule I-1(a), Page 2						
11	2/ Schedule I-1(b), Page 1, Line 7						
12	3/ Schedule I-3(b), Page 1						

Line No.	Particulars	Allocation of Costs: Total Variable Costs	Allocation of Costs: Storage Variable Costs	Allocation of Costs: Transmission Mileage Variable Costs	Allocation Percentages 3/: Transmission Mileage Variable Costs
	(a)	(b)	(c)	(d)	(e)
1	Total Classified Overall Cost of Service 1/	$ 41,459,813	$ 4,383,962	$ 37,075,851	$
2	Less: Costs Assigned to Specific Rate Schedules & Services 2/	4,383,962	4,383,962	0	
3	Net Classified Cost of Service	$ 37,075,851	$ 0	$ 37,075,851	$
4					
5	Allocation:				
6	Market Area	$ 26,635,477	$ 0	$ 26,635,477	0.718405
7	Field Area	10,440,374	0	10,440,374	0.281595
8	Total	$ 37,075,851	$ 0	$ 37,075,851	1.000000
9					
10	1/ Schedule I-1(a), Page 2				
11	2/ Schedule I-1(b), Page 2, Line 9				
12	3/ Schedule I-3(b), Page 2				

NORTHERN NATURAL GAS COMPANY
Derivation of Fixed Cost Allocation Percentages

		Allocation Factors 1/		Allocation Percentages	
Line No.	Particulars	Transmission Mileage Fixed Costs AMDCQ 2/ Miles	All Other Fixed Costs AMDCQ 2/	Transmission Mileage Fixed Costs	All Other Fixed Costs
	(a)	(b)	(c)	(d)	(e)
1	Market Area	6,174,371,184	24,896,658	0.871747	0.853166
2					
3	Field Area	908,384,596	4,284,833	0.128253	0.146834
4					
5	Total	7,082,755,780	29,181,491	1.000000	1.000000
6					
7	1/ Schedule I-3(c), Page 1				
8	2/ AMDCQ is Annual Maximum Daily Contract Quantity				

Line No.	Particulars	Allocation Factors: Transmission Mileage Variable Costs — Throughput Dth - Miles 1/	Allocation Percentages: Transmission Mileage Variable Costs
	(a)	(b)	(c)
1	Market Area	256,004,968	0.718405
2			
3	Field Area	100,346,934	0.281595
4			
5	Total	356,351,902	1.000000
6			
7	1/ Schedule I-3(c), Page 2; units are shown in 1,000s		

		For Allocation of Transmission Fixed Costs			
		Mileage Fixed Costs	All Other Fixed Costs		
Line No.	Particulars	AMDCQ Miles 1/	AMDCQ		Average Miles of Haul 2/
	(a)	(b)	(c)		(d)
1	Allocation Factors:				
2					
3	Market Area	6,174,371,184	24,896,658	3/	248
4					
5	Field Area	908,384,596	4,284,833	4/	212
6					
7	Total	7,082,755,780	29,181,491		
8					
9	1/ Column (c) times Column (d)				
10	2/ Based on Exhibit No. NNG-00024, Mileage Study Results for April 2021 to March 2022.				
11	3/ Schedule J-1, Page 1, Lines 2 through 11, Column (e)				
12	4/ Schedule J-1, Page 1, Line 20, Column (e)				

Line No.		Particulars	For Allocation of Transmission Variable Costs		
			Throughput Dth Miles 1/	Throughput Quantity 2/	Average Miles of Haul 3/
		(a)	(b)	(c)	(d)
1		Allocation Factors			
2					
3		Market Area	256,004,968	1,032,278,097	248
4					
5		Field Area	100,346,934	473,334,594	212
6					
7	1/	Column (c) times Column (d); units are shown in 1,000s			
8	2/	Schedule J-1, Page 2, Column (d)			
9	3/	Based on Exhibit No. NNG-00024, Mileage Study Results for April 2021 to March 2022.			

Northern Natural Gas Company
Storage Cost Allocation

Docket No. RP22-1033-000
Schedule I-3(d)
Page 1 of 1

Line No.	Description (a)	Total Storage (b)	Storage Services (c)	Operational Storage (d)
1	Allocation Basis:			
2	Deliverability	1,676,950 Dth	1,226,950 Dth	450,000 Dth
3	Capacity	80,740,013 Dth	70,740,013 Dth	10,000,000 Dth
4	Injections/Withdrawals	179,289,852 Dth	159,289,852 Dth	20,000,000 Dth
5				
6	Deliverability Allocation Factors:			
7	Deliverability	1.00000	0.73170	0.26830
8	Capacity	1.00000	0.87610	0.12390
9	Injections/Withdrawals	1.00000	0.88840	0.11160
10				
11	Cost of Service			
12	Fixed Cost	$ 184,478,082 1/		
13	Variable Cost	4,383,962 2/		
14	Total Cost of Service	$ 188,862,044		
15				
16	Less LNG Storage Cost Directly Assigned to Transmission:			4,000,000 Dth
17	Fixed Cost	$ 34,194,813		
18	Variable Cost	231,838		
19	Total LNG Storage Cost	$ 34,426,651		
20				
21	Total Underground Storage:			
22	Fixed Costs	$ 150,283,268		
23	Variable Costs	4,152,124		
24	Total Underground Storage	$ 154,435,392		
25				
26	Cost of Service Allocation:			
27	Deliverability	$ 75,141,634 3/	54,981,134 5/	20,160,500 5/
28	Capacity	75,141,634 3/	65,831,586 5/	9,310,048 5/
29	Injections/Withdrawals	4,152,124 4/	3,688,747 5/	463,377 5/
30	Total Cost of Service	$ 154,435,392	124,501,467	29,933,925
31				
32	1/ Schedule I-1(a), Page 2 of 3, Line 2			
33	2/ Schedule I-1(a), Page 2 of 3, Line 3			
34	3/ Per Equitable method which assigns 50% of fixed costs to each of the capacity and deliverability components			
35	4/ Per Equitable method which assigns 100% of variable costs to the Injection and Withdrawal components.			
36	5/ Applicable Deliverability Allocation Factor (Lines 7-9) times Total Storage Cost of Service Allocation Component			

Line No.	Particulars (a)	Test Period Revenues at Proposed Rates (b)	Test Period Cost of Service (c)	Revenue Excess (Deficiency) (d)
1	Transportation Revenue			
2	Rate Schedule TF	$ 364,801,779		
3	Rate Schedule TFX	795,961,693		
4	Rate Schedule GS-T	13,585		
5	Rate Schedule TI	-		
6	Rate Schedule ILD	-		
7	Rate Schedule SMS	34,523,130		
8				
9				
10	Transportation Costs		$ 1,133,799,224 2/	
11	Less Northern Lights 2021 Revenue Deficiency		(2,829,576) 3/	
12	Plus Operational Storage Costs		29,933,925 4/	
13	Plus LNG Costs		34,426,651 5/	
14	Total Transportation	$ 1,195,300,187	$ 1,195,330,226	$ (30,039)
15				
16				
17	Storage Revenue			
18	Rate Schedule FDD	$ 103,132,740		
19	Rate Schedule IDD and PDD	10,845,158		
20	Rate Schedule FDD Market Based Revenues		(10,532,495) 6/	
21				
22	Storage Costs		$ 188,862,044 7/	
23	Less Operational Storage Costs		(29,933,925) 4/	
24	Less LNG Costs		(34,426,651) 5/	
25	Total Storage	$ 113,977,898	$ 113,968,972	$ 8,925
26				
27	Total	$ 1,309,278,084 1/	$ 1,309,299,198 8/	$ (21,114)
28				
29				
30	1/ Total Revenue at Proposed Rates			
31	2/ Schedule I-1(a), Page 1, Line 17, Col. (d)			
32	3/ Schedule J-2, Page 1, Line 5, Col. (d)			
33	4/ Schedule I-1(b), Page 3, Line 24, Col. (d)			
34	5/ Schedule I-1(b), Page 3, Line 18, Col. (d)			
35	6/ Schedule J-2, Page 6, Lines 14 and 15, Col. (d)			
36	7/ Schedule I-1(a), Page 1, Line 17, Col. (c)			
37	8/ Schedule I-1(a), Page 1, Line 17, Col. (b), as adjusted for the Northern Lights and the MBR credits shown on Schedule J-2, Pages 1 and 6			

Line No.	Description	Schedule G-2 Volumes	Discount Adjustment	Imputed Units	Schedule J-2 Volumes (at Max Rate)
		Reservation Units - Dth			
	(a)	(b)	(c)	(d)	(e)
1	Market Area:				
2	TF Base Summer	5,194,476	(1,926,862)	-	3,267,614
3	TF Base Winter	3,706,275	(1,356,735)	-	2,349,540
4	TF Variable Summer	4,699,492	(2,224,992)	-	2,474,500
5	TF Variable Winter	3,360,845	(1,575,915)	-	1,784,930
6	TF 5	2,541,375	(1,108,380)	-	1,432,995
7	TFX Summer	19,475,313	(13,132,531)	-	6,342,782
8	TFX Winter	20,370,715	(13,127,045)	-	7,243,670
9	GS-T	-	-	627	627
10	TI Summer	-	-	-	-
11	TI Winter	-	-	-	-
12	Total Market Area	59,348,491	(34,452,460)	627	24,896,658
13					
14	Field Area:				
15	TFX Summer	12,538,771	(10,027,058)	-	2,511,713
16	TFX Winter	9,143,542	(7,370,422)	-	1,773,120
17	TI Summer	-	-	-	-
18	TI Winter	-	-	-	-
19					
20	Total Field Area	21,682,313	(17,397,480)	-	4,284,833
21					
22					
23	FDD/PDD/IDD:				
24	Reservation Fee	11,890,572	(571,860)	1,167,760	12,486,472
25	Capacity Fee	57,129,614	(2,747,533)	5,610,399	59,992,480
26					
27	SMS: 1/				
28	Market Area	3,643,325	-	-	3,643,325
29	Field Area	1,167,600	-	-	1,167,600
30	Total	4,810,925	-	-	4,810,925
31					

32 1/ The SMS revenue is credited to the cost of service on Schedule J-2 pages 1 and 4, and the SMS billing determinants are not included for rate design purposes

NORTHERN NATURAL GAS COMPANY **Docket No. RP22-1033-000**
Summary of Billing Determinants, Commodity Units, and Discount Adjustments **Schedule J-1**

Line No.	Description (a)		Commodity Units - Dth: Schedule G-2 Volumes (b)	Discount Adjustment (c)	Schedule J-2 Volumes (at Max Rate) (d)
1	Market Area:				
2	TF		320,192,457	-	320,192,457
3	TFX		712,078,785	-	712,078,785
4	TI		-	-	-
5	GS-T		6,855	-	6,855
6	Total Market Area		1,032,278,097	-	1,032,278,097
7					
8	Field Area:				
9	TF		-	-	-
10	TFX		473,334,594	-	473,334,594
11	TI		-	-	-
12	Total Field Area		473,334,594	-	473,334,594
13					
14	Storage:				
15	FDD Injection		57,129,615	-	57,129,615
16	FDD Withdrawal		57,129,615	-	57,129,615
17	PDD Injection		9,156,508	-	9,156,508
18	PDD Withdrawal		13,380,193	-	13,380,193
19	IDD Injection		3,239,979	-	3,239,979
20	IDD Withdrawal		3,253,942	-	3,253,942
21	Storage Total		143,289,852	-	143,289,852
22					
23	SMS:	1/			
24	Market Area		21,312,888	-	21,312,888
25	Field Area		7,850,086	-	7,850,086
26	Total		29,162,974	-	29,162,974
27					

28 1/ The SMS revenue is credited to the cost of service on Schedule J-2, Pages 2 and 5, and the SMS billing determinants are not included for rate design purposes

Line No.	Particulars (a)		AMDCQ (b)	Tier Relationship Factors (c)	Amount (d)
1	Market Area Reservation Rate Costs:				
2	Total Transmission Fixed Costs	1/			$ 954,557,580
3	less: SMS Reservation Revenue Credits	2/			(25,685,077)
4	less: Discounted Reservation Revenue	3/			(287,243,409)
5	less: Northern Lights 2021 Revenue Deficiency	4/			(2,829,576)
6	plus: Operational Storage Fixed Costs	5/			29,370,548
7	plus: LNG Storage Fixed Costs	6/			34,194,813
8	Net Market Area Fixed Costs for Reservation Rates				$ 702,364,880.59
9					
10	Market Area Billing Determinants:				
11	TF Base Summer		3,267,614	0.7500	2,450,711
12	TF Base Winter		2,349,540	1.3500	3,171,879
13	Annual TF Base	7/	5,617,154		5,622,590
14					
15	TF Variable Summer		2,474,500	0.7500	1,855,875
16	TF Variable Winter		1,784,930	1.8300	3,266,422
17	Annual TF Variable	7/	4,259,430		5,122,297
18					
19	TF5	7/	1,432,995	2.0000	2,865,990
20					
21	TFX Summer		6,342,782	0.7500	4,757,087
22	TFX Winter		7,243,670	2.0000	14,487,340
23	Annual TFX	7/	13,586,452		19,244,427
24					
25	GS-T Imputed Units	7/	627	1.0000	627
26	TI Summer Imputed Units		-	1.0000	-
27	TI Winter Imputed Units		-	1.0000	-
28	Annual Units	7/	24,896,658		32,855,929.900
29					
30	Market Area Reservation Rates:				
31	Base Unit Rate				$ 21.377
32					
33	TF Base Summer Reservation Rate				$ 16.033
34	TF Base Winter Reservation Rate				$ 28.859
35					
36	TF Variable Summer Reservation Rate				$ 16.033
37	TF Variable Winter Reservation Rate				$ 39.120
38					
39	TF5 Reservation Rate				$ 42.754
40					
41	TFX Summer Reservation Rate				$ 16.033
42	TFX Winter Reservation Rate				$ 42.754
43					
44					
45	1/ Schedule I-3(a), Page 2, Line 6, Column (b)				
46	2/ SMS Reservation units of 3,643,325, Schedule J-1, Page 1, Line 28,		3,643,325		
47	multiplied by SMS Reservation rate of $7.0499 = $25,685,077 in Market		7.0499		
48	Area SMS Reservation revenue.		$ 25,685,077		
49	3/ The sum of discounted Market Area reservation revenue				
50	4/ As supported by Witness Laura Demman in her Direct Testimony in Exhibit Nos. NNG-00001				
51	5/ Schedule J-2, Page 6, Line 20				
52	6/ Schedule J-2, Page 6, Line 9				
53	7/ Schedule J-1, Page 1, Lines 2 through 9, Column (e)				

NORTHERN NATURAL GAS COMPANY
Derivation of Market Area Commodity Rates

Line No.	Particulars (a)		Volumes (b)	Amount (c)
1	Market Area Commodity Rate Costs:			
2	Total Transmission Variable Costs	1/		$ 26,635,477
3	less: SMS Commodity Revenue Credits	2/		(443,308)
4	plus: Operational Storage Variable Costs	3/		463,377
5	plus: LNG Storage Variable Costs	4/		231,838
6	Net Allocated Costs to Market Area Commodity Rates			$ 26,887,383.67
7				
8	Market Area Throughput Volumes:			
9	TF, TFX, TI, GS-T		1,032,278,097 5/	
10				
11	Market Area Commodity Rates:			
12				
13	TF/TFX Commodity Rate:			
14	TF/TFX Commodity Rate			$ 0.0260
15				
16	Summer (April through October) TI Commodity Rate:			
17	TF Reservation Rate - $/Dth/Month		$ 16.0330 7/	
18	TF Reservation Rate - 100% Load Factor Rate		0.5274	
19	TF Commodity Rate		0.0260	
20	Summer TI Maximum Commodity Rate			$ 0.5534
21				
22	Summer TI Minimum Commodity Rate			$ 0.0260 6/
23				
24	Winter (November through March) TI Maximum Commodity Rate:			
25	TF5 Reservation Rate - $/Dth/Month		$ 42.7540 8/	
26	TF5 Reservation Rate - 100% Load Factor Rate		1.4064	
27	TF Commodity Rate		0.0260	
28	Winter TI Maximum Commodity Rate			$ 1.4324
29				
30	Winter TI Minimum Commodity Rate			$ 0.0260 6/
31				
32				
33	1/ Schedule I-3(a), Page 3, Line 6, Column (d)			
34	2/ SMS Commodity throughput of 21,312,888, Schedule J-1, Page 2, Line		21,312,888	
35	24, multiplied by SMS Commodity rate of $0.0208 = $443,308 in Market		0.0208	
36	Area SMS Commodity revenue.		$ 443,308	
37	3/ Schedule J-2, Page 6, Line 22			
38	4/ Schedule J-2, Page 6, Line 10			
39	5/ Schedule J-1, Page 2, Line 6. Column (d)			
40	6/ The minimum TI rate is the TF/TFX commodity rate			
41	7/ Schedule J-2 , Page 1, Line 41			
42	8/ Schedule J-2, Page 1, Line 39			

Line No.	Particulars		Amount	
	(a)		(b)	
1	GS-T Rate Design (Market Area)			
2				
3	Proposed TF12 Demand Rate	$	21.377	1/
4				
5	Reservation Portion of GS-T Rate		1.9557	
6	Proposed TF12 Commodity Rate		0.0260	2/
7	Total Proposed Market Area GS-T Commodity Rate	$	1.9817	
8				
9	GS-T Rate Design (Field Area)			
10	Proposed Field Demand Rate	$	11.731	3/
11				
12	Reservation Portion of GS-T Rate		1.0065	
13	Proposed Average Field Mileage Charge		0.0217	4/
14	Total Proposed Field Area GS-T Commodity Rate	$	1.0282	
15				
16	GS-T Rate Design (Field-to-Market)			
17	Total Proposed Market Area GS-T Commodity Rate	$	1.9817	
18	Total Proposed Field Area GS-T Commodity Rate		1.0282	
19	GS-T Field-to-Market Commodity Rate	$	3.0099	
20				
21	1/ Schedule J-2, Page 1, Line 31			
22	2/ Schedule J-2, Page 2, Line 14			
23	3/ Schedule J-2, Page 4, Line 14			
24	4/ Schedule J-2, Page 5, Line 8 times average mileage per 100 miles			

NORTHERN NATURAL GAS COMPANY
Derivation of Field Reservation Rates

Line No.	Particulars		Annualized Field Demand Units	Tier Relationship Factors	Amount
	(a)		(b)	(c)	(d)
1	Field Area Reservation Rate Costs:				
2	Total Transmission Fixed Costs	1/			$ 142,165,794
3	less: SMS Reservation Revenue Credits	2/			(8,231,463)
4	less: Discounted Reservation Revenue				(83,854,678)
5	plus: Allocated Operational Storage Costs	4/			100,000
6	Net Allocated Field Reservation Costs				$ 50,179,651.82
7					
8	Field Area Billing Determinants:				
9	TFF/TFX Summer		2,511,713	0.75	1,883,785
10	TFF/TFX Winter		1,773,120	1.35	2,393,712
11	Total Field Billing Determinants	5/	4,284,833		4,277,497
12					
13	Field Area Reservation Rates:				
14	Base Unit Rate				$ 11.731
15					
16	TFF/TFX Field Summer Reservation Rate				$ 8.798
17					
18	TFF/TFX Field Winter Reservation Rate				$ 15.837
19					
20	1/ Statement I-3(a), page 2, Line 7				
21	2/ SMS Reservation units of 1,167,600, Schedule J-1, page 1, Line 29, multiplied		1,167,600		
22	by SMS Reservation rate of $7.0499 = $8,231,463 in Field Area SMS Reservation		7.0499		
23	revenue.		$ 8,231,463		
24	3/ The sum of discounted Field Area reservation revenue				
25	4/ Schedule J-2, Page 6, Line 21				
26	5/ Schedule J-1, Page 1, Line 20, Column (e)				

Line No.	Particulars			Annualized Field Commodity Units	Amount
	(a)			(b)	(c)
1	Field Area Commodity Rate Costs: Mileage Rates (Per 100 Miles):				
2	Total Transmission Variable Costs	1/			$ 10,440,374
3	less: SMS Commodity Revenue Credits	2/			(163,282)
4	Total Variable Costs				10,277,092.47
5					
6	Dth Commodity Miles	3/		998,735,993	
7					
8	Firm Commodity Mileage Rate (Line 4/Line 6)				$ 0.0103
9					
10	TI Summer Rate:				
11	Maximum TFF/TFX Firm Reservation Rate		$ 8.7980		
12	TFF/TFX Rate /30.4/Field Mileage		0.1372		
13	Firm Commodity Mileage Rate		$ 0.0103		
14	Maximum TI Commodity Mileage Rate				$ 0.1475
15					
16					
17	TI Winter Rate:				
18	Maximum TFF/TFX Firm Reservation Rate		$ 15.8370		
19	TFF/TFX Rate /30.4/Field Mileage		0.2469		
20	Firm Commodity Mileage Rate		$ 0.0103		
21	Maximum TI Commodity Mileage Rate				$ 0.2572
22					
23	Minimun TI Commodity Mileage Rate	4/			$ 0.0103
24					
25					
26	1/ Statement I-3(a), Page 3, Line 7, Column (d)			7,850,086	
27	2/ SMS Commodity throughput of 7,850,086, Schedule J-1, page 2,			0.0208	
28	Line 25, multiplied by SMS Commodity rate of $0.0208 = $163,282			$ 163,282	
29	in Field Area SMS Commodity revenue.				
30	3/ Total Field Area commodity throughput (Schedule J-1, Page 2, Line 12, Column (d)) times average mileage per 100 miles				
31	4/ The minimum rate is the Firm Commodity Mileage Rate				

NORTHERN NATURAL GAS COMPANY
Derivation of FDD, PDD and IDD Rates

Docket No. RP22-1033-000
Schedule J-2

Line No.	Particulars	Peak Day Withdrawal Dth	Annual Cycle Volume-Dth	Amount	Unit Rate
	(a)	(b)	(c)	(d)	(e)
1	Storage Rate Design Units	1,040,540	59,992,480		
2					
3	Total Cost of Service				
4	Fixed			$ 184,478,082 1/	
5	Variable			4,383,962 2/	
6	Cost of Service			$ 188,862,044	
7					
8	Less LNG Storage Cost Directly Assigned to Transmission:				
9	Fixed Cost			$ 34,194,813	
10	Variable Cost			231,838	
11	Total LNG Storage Cost			$ 34,426,651 3/	
12					
13	Less Revenue Credits:				
14	MBR Reservation Revenue			$ 10,161,975 4/	
15	MBR Commodity Revenue			370,519 4/	
16	Discounted FDD Reservation Revenue			1,889,315 5/	
17	Total Revenue Credits for Storage			$ 12,421,809	
18					
19	Less Operational Storage Allocated to Transmission:				
20	Fixed Cost Allocated to Market Area Reservation Rate			$ 29,370,548	
21	Fixed Cost Allocated to Field Area Reservation Rate			100,000	
22	Variable Cost Allocated to Market Area Commodity Rate			463,377	
23	Total Operational Storage Allocated to Transmission			$ 29,933,925 6/	
24					
25					
26	Net Cost of Service For FDD			$ 112,079,658	
27					
28		Billing	Annual	Allocated	Unit
29	FDD Rate Derivation	Units 7/	Cycle 8/	Cost	Rate
30	Reservation Rate	12,486,475		$ 54,380,715	$ 4.3552
31	Capacity Rate		59,992,480	54,380,715	$ 0.9065
32	Injection Rate		71,644,926	1,659,114	$ 0.0232
33	Withdrawal Rate		71,644,926	1,659,114	$ 0.0232
34				$ 112,079,658	
35					
36	IDD/PDD Rate Design				
37					
38	IDD/PDD Monthly Capacity Charge:				
39	FDD Reservation Charge @ 100% Load Factor				$ 0.1433
40	FDD Capacity Rate per Month				$ 0.0755
41	PDD/IDD Monthly Inventory Charge				$ 0.2188
42					
43	PDD Capacity Charge				$ 0.9065
44					
45	IDD/PDD Monthly Capacity Charge Minimum Rate				$ 0.0000
46					
47	IDD/PDD Injection Rate				$ 0.0232
48	IDD/PDD Withdrawal Rate				$ 0.0232
49					
50	1/ Schedule I-3(d), Page 1, Line 12, Column (b)				
51	2/ Schedule I-3(d), Page 1, Line 13, Column (b)				
52	3/ Schedule I-3(d), Page 1, Line 19, Column (b)				
53	4/ Market-based revenue credit as agreed in 2020 Settlement in Docket No. RP19-1353				
54	5/ Revenue crediting of discounted FDD revenue				
55	6/ Schedule I-3(d), Page 1, Line 30, Column (d)				
56	7/ Line 1, Column (b) times 12				
57	8/ Line 1, Column (c)				