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

December 30, 2025

Ms. Debbie-Anne Reese, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Northern Natural Gas Company
Docket Nos. RP25-989-000; RP25-989-001
Motion to Place Base Case Revised Tariff Sections into Effect

Dear Ms. Reese:

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, Seventh Revised Volume No. 1 ("Tariff"), the revised base case tariff sections listed in Appendix A of this filing ("Revised Tariff Sections") to be effective January 1, 2026. Northern is filing contemporaneously under separate cover to place Interim Rates[3] in effect on January 1, 2026.

<u>Statement of Nature, Reasons and Basis</u>

On July 1, 2025, and as amended on July 18, 2025, Northern filed revised tariff records, proposed to be effective on August 1, 2025, to reflect a general NGA Section 4 rate increase ("July 1 Filing"). On July 31, 2025, the Commission issued an "Order Accepting and Suspending Tariff Records, Subject to Refund, and Establishing Hearing Procedures" in the referenced docket ("July 31 Order").[4] Ordering Paragraph (A) of the July 31 Order accepted and suspended the tariff records filed in the July 1 Filing, to be effective upon motion January 1, 2026, subject to refund and the outcome of the hearing established by the July 31 Order ("Base Case"). Ordering Paragraph (E) of the July 31 Order required Northern to remove facilities not in service before the effective date.

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[1] 15 U.S.C. § 717c.
[2] 18 C.F.R. Part 154 (2025).
[3] The term "Interim Rates" shall have the meaning defined in the contemporaneously filed "Motion to Place Interim Rates into Effect" referred to herein.
[4] *Northern Natural Gas Co.*, 192 FERC ¶ 61,104 (2025).

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

Pursuant to Section 4(e) of the NGA, Northern hereby moves to place into effect on January 1, 2026, the Revised Tariff Sections superseding the suspended tariff sections from the July 1 Filing, as listed in Appendix B attached to this filing.

In compliance with Section 154.303(c)(2) of the Commission's regulations,[5] Northern has removed costs associated with storage facilities not expected to be in service on December 31, 2025. The costs associated with transmission facilities placed in service by December 31, 2025, exceed the costs included in the July 1 Filing. Thus, Northern has adjusted the storage rates submitted in the July 1 Filing and makes no adjustments to the transmission rates submitted in the July 1 Filing.[6] Workpapers that support the cost of service, rate base and rate design underlying the rates submitted in this motion 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, 2026, consistent with its July 1 Filing, Northern is filing contemporaneously under separate cover for Interim Rates, also effective January 1, 2026. 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 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.

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[5] 18 C.F.R. § 154.303(c)(2).

[6] The instant filing reflects Northern's cost of gas plant in service as of December 31, 2025. Northern will close its books for the month of December in mid-January 2026. Therefore, consistent with past practice, Northern has included an estimate of the actual gas plant expected to be in service by the end of the Test Period.

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/ Luis Valdivia

Luis Valdivia
Director, Regulatory Policy and Rates

Attachments

Appendix A

SEVENTH REVISED VOLUME NO. 1

Revised Tariff Sections

Effective January 1, 2026

Part 4, Section 1 - TF, Version 4.0.0
Part 4, Section 2 - TFX, Version 3.0.0
Part 4, Section 3 - GS-T, Version 3.0.0
Part 4, Section 4 - TI, Version 3.0.0
Part 4, Section 5 - SMS, Version 3.0.0
Part 4, Section 6 - FDD, PDD and IDD, Version 2.0.0
Part 4, Section 9 - Mileage Indicator District Charges, Version 4.0.0

1. RATE SCHEDULE TF

Reservation Rates - Base Tariff Rates 1/ 2/

	Winter (Nov-Mar)	**Summer (Apr-Oct)**
Market-to-Market		
TF12 Base	$32.225	$17.903
TF12 Variable	$43.682	$17.903
TF5	$47.740	
Field-to-Field/Market Demarcation		
TFF	$30.925	$17.180

Commodity Rates 3/ 4/

TF12 Base, TF12 Variable, TF5 & TFF		**Market Area** 5/	**Field Mileage Rate per 100 miles**	**Out-of Balance**	**Carlton Surcharge** 6/	
Receipt Point	Delivery Point	Commodity	Commodity	Commodity	Maximum	Minimum
Market	Market	$0.0228		$0.0228	$0.0175	$0.0000
Field	Market	$0.0228	$0.0082		$0.0175	$0.0000
Market	Field		$0.0082			
Field	Field		$0.0082	$0.0216		

1/ The minimum reservation rate is equal to zero.

2/ Northern and Shipper may agree to charge an average of the maximum TF12 and TF5 or TFF rates during the applicable months of service as set forth in the Firm Throughput Service Agreement without exceeding the maximum rate.

3/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.

4/ 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 Part 4, Section 9 represent the throughput commodity rates for any transaction involving MIDs.

5/ 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

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

2. RATE SCHEDULE TFX

Reservation Rates - Base Tariff Rates 1/ 2/

	Winter (Nov-Mar)	Summer (Apr-Oct)
Market-to-Market		
TFX	$47.740	$17.903
Field-to-Field		
TFX	$30.925	$17.180

Commodity Rates 3/ 4/

TFX		Market Area 5/	Field Mileage Rate per 100 miles	Out-of Balance	Carlton Surcharge 6/	
Receipt Point	Delivery Point	Commodity	Commodity	Commodity	Maximum	Minimum
Market	Market	$0.0228		$0.0228	$0.0175	$0.0000
Field	Market	$0.0228	$0.0082		$0.0175	$0.0000
Market	Field		$0.0082			
Field	Field		$0.0082	$0.0216		

1/ The minimum reservation rate is equal to zero.

2/ Northern and Shipper may agree to charge an average of the maximum Market Area or Field Area rates during the applicable months of service as set forth in the Firm Throughput Service Agreement without exceeding the maximum rate.

3/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.

4/ 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 Part 4, Section 9 represent the throughput commodity rates for any transaction involving MIDs.

5/ 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

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

3. GS-T COMMODITY THROUGHPUT RATE

Commodity Charges

	Nov-Oct	
Market Area	$2.1952	1/ 2/
Field to Demarcation	$1.9652	
Field-to-Market	$4.1604	1/

1/ In addition, Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

4. RATE SCHEDULE TI

Commodity Rates 1/ 2/

Winter (November – March)

TI		**Market Area** 3/		**Field Mileage Rate per 100 miles**		**Out-of Balance**	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	$1.5932	$0.0228			$1.5932	$0.0228
Field	Market	$1.5932	$0.0228	$0.3935	$0.0082		
Market	Field			$0.3935	$0.0082		
Field	Field			$0.3935	$0.0082	$1.0388	$0.0216

Carlton Surcharge 4/			
Receipt Point	Delivery Point	Maximum	Minimum
Market	Market	$0.0175	$0.0000
Field	Market	$0.0175	$0.0000

Summer (April – October)

TI		**Market Area** 3/		**Field Mileage Rate per 100 miles**		**Out-of Balance**	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	$0.6117	$0.0228			$0.6117	$0.0228
Field	Market	$0.6117	$0.0228	$0.2223	$0.0082		
Market	Field			$0.2223	$0.0082		
Field	Field			$0.2223	$0.0082	$0.5869	$0.216

Carlton Surcharge 4/			
Receipt Point	Delivery Point	Maximum	Minimum
Market	Market	$0.0000	$0.0000
Field	Market	$0.0000	$0.0000

1/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.

2/ The MIDs rates shown in Part 4, Section 9 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

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

5. RATE SCHEDULE SMS

Reservation Charge	$7.8726
Commodity Rate	$0.0208

6. RATE SCHEDULES FDD, PDD & IDD

Rate Schedule FDD

Maximum Reservation Charge	$4.7237	1/
Maximum Capacity Charge	$0.9832	1/
Injection Charge – Firm	$0.0228	
Withdrawal Charge – Firm	$0.0228	
Annual Rollover Charge	$0.9832	1/

Rate Schedule PDD

Maximum Capacity Charge	$0.9832	1/
Maximum Monthly Inventory Charge	$0.2373	1/
Injection Charge	$0.0228	
Withdrawal Charge	$0.0228	
Annual Rollover Charge	$0.9832	1/

Rate Schedule IDD

Maximum Monthly Inventory Charge	$0.2373	1/
Injection Charge	$0.0228	
Withdrawal Charge	$0.0228	
Annual Rollover Charge	$0.9832	1/

1/ Minimum Rate is zero.

Rate Schedule FDD
2008 Market-Based Rate Expansion

Shipper	Reservation Charge	Capacity Charge	Injection Charge Firm	Withdrawal Charge Firm	100% Load Factor
Cascade Municipal Utilities	$3.4920	$0.7268	MAX	MAX	1.50
City of Remsen, Iowa	$3.4920	$0.7268	MAX	MAX	1.50
City of West Bend, Iowa	$3.4920	$0.7268	MAX	MAX	1.50
Woodbine Municipal Natural Gas Systems	$3.4920	$0.7268	MAX	MAX	1.50
Preston Municipal Natural Gas Department	$3.4920	$0.7268	MAX	MAX	1.50
City of Whittemore	$3.4920	$0.7268	MAX	MAX	1.50
City of Rolfe, Iowa	$3.4920	$0.7268	MAX	MAX	1.50
City of Scribner	$3.4920	$0.7268	MAX	MAX	1.50
City of Round Lake, MN	$3.4920	$0.7268	MAX	MAX	1.50
City of Fairbank	$3.4920	$0.7268	MAX	MAX	1.50
Wall Lake Municipal Gas	$3.4920	$0.7268	MAX	MAX	1.50
Black Hills Utility Holdings, Inc.	$3.2775	$0.6822	MAX	MAX	1.4107
Minnesota Energy Resources Corporation	$3.2758	$0.6818	MAX	MAX	1.41
Northern States Power - Generation	$3.0115	$0.6268	MAX	MAX	1.30
Southwestern Public Service Co.	$3.0115	$0.6268	MAX	MAX	1.30

9. MILEAGE INDICATOR DISTRICT CHARGES

MILEAGE INDICATOR DISTRICT CHARGES (dollars per Dth) Receipt MIDs 1-9 and Delivery MIDs 1-9

Receipt District		Delivery District									
		1	2	3	4	5	6	7	7B	8	9
1	TI Apr-Oct	0.0867	0.2090	0.4379	0.6224	0.7002	0.4980	0.5691	0.7492	1.3360	1.1515
	TI Nov-Mar	0.1535	0.3699	0.7752	1.1018	1.2395	0.8814	1.0074	1.3261	2.3649	2.0383
	TF	0.0032	0.0077	0.0162	0.0230	0.0258	0.0184	0.0210	0.0276	0.0493	0.0425
2	TI Apr-Oct	0.1023	0.0156	0.1578	0.4268	0.5535	0.3668	0.4624	0.6424	1.1915	1.0115
	TI Nov-Mar	0.1810	0.0275	0.2794	0.7555	0.9798	0.6493	0.8185	1.1372	2.1092	1.7904
	TF	0.0038	0.0006	0.0058	0.0157	0.0204	0.0135	0.0171	0.0237	0.0440	0.0373
3	TI Apr-Oct	0.6891	0.4468	0.1156	0.1356	0.6069	0.3757	0.2801	0.4602	1.2515	1.0693
	TI Nov-Mar	1.2199	0.7909	0.2046	0.2400	1.0743	0.6650	0.4958	0.8145	2.2154	1.8927
	TF	0.0254	0.0165	0.0043	0.0050	0.0224	0.0139	0.0103	0.0170	0.0462	0.0394
4	TI Apr-Oct	0.6647	0.5913	0.4179	0.1000	0.3668	0.2512	0.3935	0.5735	1.1426	0.9559
	TI Nov-Mar	1.1766	1.0467	0.7398	0.1771	0.6493	0.4447	0.6965	1.0152	2.0226	1.6921
	TF	0.0245	0.0218	0.0154	0.0037	0.0135	0.0093	0.0145	0.0212	0.0421	0.0353
5	TI Apr-Oct	0.6091	0.5491	0.4313	0.3868	0.0600	0.1689	0.3046	0.4846	1.0826	0.8981
	TI Nov-Mar	1.0782	0.9719	0.7634	0.6847	0.1062	0.2991	0.5391	0.8578	1.9163	1.5897
	TF	0.0225	0.0203	0.0159	0.0143	0.0022	0.0062	0.0112	0.0179	0.0399	0.0331
6	TI Apr-Oct	0.3868	0.3090	0.1112	0.1667	0.2290	0.1489	0.1756	0.3557	1.0004	0.7314
	TI Nov-Mar	0.6847	0.5470	0.1968	0.2951	0.4053	0.2636	0.3109	0.6296	1.7708	1.2946
	TF	0.0143	0.0114	0.0041	0.0062	0.0084	0.0055	0.0065	0.0131	0.0369	0.0270
7	TI Apr-Oct	0.6669	0.5802	0.5558	0.4402	0.4713	0.2779	0.2223	0.4024	0.6402	0.4535
	TI Nov-Mar	1.1805	1.0270	0.9838	0.7791	0.8342	0.4919	0.3935	0.7122	1.1333	0.8027
	TF	0.0246	0.0214	0.0205	0.0162	0.0174	0.0103	0.0082	0.0148	0.0236	0.0167
7B	TI Apr-Oct	0.6669	0.5802	0.5558	0.4402	0.4713	0.2779	0.2223	0.0000	0.6402	0.4535
	TI Nov-Mar	1.1805	1.0270	0.9838	0.7791	0.8342	0.4919	0.3935	0.0000	1.1333	0.8027
	TF	0.0246	0.0214	0.0205	0.0162	0.0174	0.0103	0.0082	0.0000	0.0236	0.0167
8	TI Apr-Oct	1.3360	1.2649	1.1693	1.1537	1.1426	0.9225	0.9559	0.7580	0.0178	0.4602
	TI Nov-Mar	2.3649	2.2390	2.0698	2.0423	2.0226	1.6330	1.6921	1.3418	0.0315	0.8145
	TF	0.0493	0.0467	0.0431	0.0426	0.0421	0.0340	0.0353	0.0280	0.0007	0.0170
9	TI Apr-Oct	1.1604	1.0804	0.9715	0.9048	0.7736	0.7892	0.5402	0.3423	0.2823	0.1489
	TI Nov-Mar	2.0541	1.9124	1.7196	1.6015	1.3694	1.3969	0.9562	0.6060	0.4997	0.2636
	TF	0.0428	0.0399	0.0358	0.0334	0.0285	0.0291	0.0199	0.0126	0.0104	0.0055

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 Part 4, Section 10.A. for deliveries to MID 17; and

(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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 DISTRICT CHARGES (dollars per Dth) Receipt MIDs 10-17 and Delivery MIDs 1-9

Receipt District		Delivery District									
		1	2	3	4	5	6	7	7B	8	9
10	TI Apr-Oct	1.1826	1.2227	1.1804	1.0226	0.8514	0.8647	0.6491	0.4513	0.4246	0.3646
	TI Nov-Mar	2.0934	2.1643	2.0895	1.8101	1.5071	1.5307	1.1490	0.7988	0.7516	0.6453
	TF	0.0436	0.0451	0.0435	0.0377	0.0314	0.0319	0.0239	0.0166	0.0157	0.0134
11	TI Apr-Oct	1.1360	1.0493	0.9492	0.8336	0.8203	0.4602	0.5713	0.3735	0.2379	0.2979
	TI Nov-Mar	2.0108	1.8573	1.6802	1.4756	1.4520	0.8145	1.0113	0.6611	0.4210	0.5273
	TF	0.0419	0.0387	0.0350	0.0308	0.0303	0.0170	0.0211	0.0138	0.0088	0.0110
12	TI Apr-Oct	1.2293	1.1426	1.1426	0.9737	1.0404	0.8425	0.6625	0.4646	0.3712	0.3512
	TI Nov-Mar	2.1761	2.0226	2.0226	1.7235	1.8416	1.4914	1.1726	0.8224	0.6571	0.6217
	TF	0.0453	0.0421	0.0421	0.0359	0.0384	0.0311	0.0244	0.0171	0.0137	0.0130
13	TI Apr-Oct	1.1604	1.1582	1.1737	1.0515	1.0537	0.8848	0.7114	0.5135	0.3912	0.3668
	TI Nov-Mar	2.0541	2.0501	2.0777	1.8613	1.8652	1.5661	1.2592	0.9090	0.6926	0.6493
	TF	0.0428	0.0427	0.0433	0.0388	0.0389	0.0326	0.0262	0.0189	0.0144	0.0135
14	TI Apr-Oct	1.4227	1.4850	1.4161	1.2982	1.2004	1.1382	0.9870	0.7892	0.6891	0.6758
	TI Nov-Mar	2.5184	2.6286	2.5066	2.2980	2.1249	2.0147	1.7471	1.3969	1.2199	1.1962
	TF	0.0525	0.0548	0.0522	0.0479	0.0443	0.0420	0.0364	0.0291	0.0254	0.0249
15	TI Apr-Oct	1.8718	1.7940	1.7651	1.5894	1.5472	1.5005	1.3316	1.1337	1.0159	0.9959
	TI Nov-Mar	3.3133	3.1755	3.1244	2.8135	2.7388	2.6561	2.3571	2.0069	1.7983	1.7629
	TF	0.0690	0.0662	0.0651	0.0586	0.0571	0.0554	0.0491	0.0418	0.0375	0.0367
16A	TI Apr-Oct	1.5228	1.4249	1.4916	1.2338	1.3294	1.0470	0.9403	0.7425	0.6491	0.6358
	TI Nov-Mar	2.6955	2.5223	2.6404	2.1839	2.3531	1.8534	1.6645	1.3143	1.1490	1.1254
	TF	0.0562	0.0526	0.0550	0.0455	0.0490	0.0386	0.0347	0.0274	0.0239	0.0235
16B	TI Apr-Oct	1.7117	1.5428	1.5583	1.5294	1.4605	1.4161	1.0292	0.8314	0.8247	0.8136
	TI Nov-Mar	3.0300	2.7309	2.7584	2.7073	2.5853	2.5066	1.8219	1.4717	1.4599	1.4402
	TF	0.0631	0.0569	0.0575	0.0564	0.0539	0.0522	0.0380	0.0307	0.0304	0.0300
17	TI Apr-Oct	2.5075	2.4186	2.1096	2.1897	2.1452	2.0607	1.8918	1.6939	1.6228	1.6095
	TI Nov-Mar	4.4387	4.2813	3.7343	3.8760	3.7973	3.6477	3.3487	2.9985	2.8726	2.8489
	TF	0.0925	0.0892	0.0778	0.0808	0.0791	0.0760	0.0698	0.0625	0.0599	0.0594

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 Part 4, Section 10.A. for deliveries to MID 17; and
(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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 DISTRICT CHARGES (dollars per Dth) Receipt MIDs 1-9 and Delivery MIDs 10-17

Receipt District		**Delivery District**								
		10	**11**	**12**	**13**	**14**	**15**	**16A**	**16B**	**17**
1	**TI Apr-Oct**	1.3627	1.1004	1.2360	1.3427	1.5339	1.6339	1.5250	1.7117	2.3239
	TI Nov-Mar	2.4122	1.9478	2.1879	2.3767	2.7152	2.8922	2.6994	3.0300	4.6237
	TF	0.0503	0.0406	0.0456	0.0495	0.0566	0.0603	0.0563	0.0631	0.0864
2	**TI Apr-Oct**	1.1826	0.9781	1.0915	1.1871	1.3805	1.6317	1.3872	1.5428	2.1550
	TI Nov-Mar	2.0934	1.7314	1.9321	2.1013	2.4436	2.8883	2.4554	2.7309	4.3246
	TF	0.0436	0.0361	0.0403	0.0438	0.0509	0.0602	0.0512	0.0569	0.0802
3	**TI Apr-Oct**	1.2204	1.0448	1.1560	1.2538	1.4961	1.6961	1.2716	1.5583	2.1705
	TI Nov-Mar	2.1603	1.8495	2.0462	2.2193	2.6483	3.0024	2.2508	2.7584	4.3521
	TF	0.0450	0.0385	0.0426	0.0462	0.0552	0.0626	0.0469	0.0575	0.0808
4	**TI Apr-Oct**	1.0604	0.9270	1.0404	1.1360	1.3405	1.5806	1.3071	1.5294	2.1416
	TI Nov-Mar	1.8770	1.6409	1.8416	2.0108	2.3728	2.7978	2.3138	2.7073	4.3010
	TF	0.0391	0.0342	0.0384	0.0419	0.0494	0.0583	0.0482	0.0564	0.0797
5	**TI Apr-Oct**	1.1182	0.8692	0.9826	1.0782	1.1826	1.4894	1.3294	1.4605	2.0727
	TI Nov-Mar	1.9793	1.5386	1.7393	1.9085	2.0934	2.6365	2.3531	2.5853	4.1790
	TF	0.0412	0.0321	0.0362	0.0398	0.0436	0.0549	0.0490	0.0539	0.0772
6	**TI Apr-Oct**	1.0159	0.7847	0.9003	0.9959	1.1938	1.4716	1.1826	1.4161	2.0283
	TI Nov-Mar	1.7983	1.3891	1.5937	1.7629	2.1131	2.6050	2.0934	2.5066	4.1003
	TF	0.0375	0.0289	0.0332	0.0367	0.0440	0.0543	0.0436	0.0522	0.0755
7	**TI Apr-Oct**	0.6647	0.4268	0.5380	0.6358	0.8381	1.2960	0.8292	1.0292	1.6414
	TI Nov-Mar	1.1766	0.7555	0.9523	1.1254	1.4835	2.2941	1.4678	1.8219	3.4156
	TF	0.0245	0.0157	0.0198	0.0235	0.0309	0.0478	0.0306	0.0380	0.0613
7B	**TI Apr-Oct**	0.6647	0.4268	0.5380	0.6358	0.8381	1.2960	0.8292	1.0292	1.6414
	TI Nov-Mar	1.1766	0.7555	0.9523	1.1254	1.4835	2.2941	1.4678	1.8219	3.4156
	TF	0.0245	0.0157	0.0198	0.0235	0.0309	0.0478	0.0306	0.0380	0.0613
8	**TI Apr-Oct**	0.4846	0.2890	0.3690	0.4668	0.6536	0.9870	0.6224	0.8247	1.4369
	TI Nov-Mar	0.8578	0.5116	0.6532	0.8264	1.1569	1.7471	1.1018	1.4599	3.0536
	TF	0.0179	0.0107	0.0136	0.0172	0.0241	0.0364	0.0230	0.0304	0.0537
9	**TI Apr-Oct**	0.3757	0.1689	0.3668	0.3735	0.5891	0.9025	0.6602	0.8136	1.4258
	TI Nov-Mar	0.6650	0.2991	0.6493	0.6611	1.0428	1.5976	1.1687	1.4402	3.0339
	TF	0.0139	0.0062	0.0135	0.0138	0.0217	0.0333	0.0244	0.0300	0.0533

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 Part 4, Section 10.A. for deliveries to MID 17; and
(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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 DISTRICT CHARGES (dollars per Dth) Receipt MIDs 10-17 and Delivery MIDs 10-17

Receipt District		Delivery District								
		10	11	12	13	14	15	16A	16B	17
10	TI Apr-Oct	0.0267	0.1089	0.3268	0.4179	0.6180	0.8581	0.5091	0.8092	1.4214
	TI Nov-Mar	0.0472	0.1928	0.5784	0.7398	1.0939	1.5189	0.9011	1.4323	3.0260
	TF	0.0010	0.0040	0.0121	0.0154	0.0228	0.0317	0.0188	0.0298	0.0531
11	TI Apr-Oct	0.2379	0.0534	0.0978	0.2734	0.4668	0.7580	0.3957	0.6069	1.2191
	TI Nov-Mar	0.4210	0.0944	0.1731	0.4840	0.8264	1.3418	0.7004	1.0743	2.6680
	TF	0.0088	0.0020	0.0036	0.0101	0.0172	0.0280	0.0146	0.0224	0.0457
12	TI Apr-Oct	0.3712	0.1823	0.2223	0.3401	0.5624	0.8047	0.5402	0.7580	1.3702
	TI Nov-Mar	0.6571	0.3227	0.3935	0.6021	0.9956	1.4245	0.9562	1.3418	2.9355
	TF	0.0137	0.0067	0.0082	0.0125	0.0207	0.0297	0.0199	0.0280	0.0513
13	TI Apr-Oct	0.4868	0.1890	0.2779	0.1245	0.2757	0.5935	0.2245	0.4379	1.0501
	TI Nov-Mar	0.8618	0.3345	0.4919	0.2204	0.4879	1.0506	0.3974	0.7752	2.3689
	TF	0.0180	0.0070	0.0103	0.0046	0.0102	0.0219	0.0083	0.0162	0.0395
14	TI Apr-Oct	0.4290	0.4824	0.6024	0.1890	0.0534	0.7603	0.4268	0.6513	1.2635
	TI Nov-Mar	0.7595	0.8539	1.0664	0.3345	0.0944	1.3458	0.7555	1.1530	2.7467
	TF	0.0158	0.0178	0.0222	0.0070	0.0020	0.0280	0.0157	0.0240	0.0473
15	TI Apr-Oct	0.9715	0.7803	0.9070	0.5758	0.7892	0.0556	0.3801	0.5824	1.1946
	TI Nov-Mar	1.7196	1.3812	1.6055	1.0192	1.3969	0.0984	0.6729	1.0310	2.6247
	TF	0.0358	0.0288	0.0335	0.0212	0.0291	0.0021	0.0140	0.0215	0.0448
16A	TI Apr-Oct	0.7358	0.4246	0.5469	0.2245	0.4357	0.3646	0.0378	0.2090	0.8212
	TI Nov-Mar	1.3025	0.7516	0.9680	0.3974	0.7713	0.6453	0.0669	0.3699	1.9636
	TF	0.0271	0.0157	0.0202	0.0083	0.0161	0.0134	0.0014	0.0077	0.0310
16B	TI Apr-Oct	0.8092	0.6069	0.7580	0.4379	0.6513	0.5824	0.2090	0.0000	0.6122
	TI Nov-Mar	1.4323	1.0743	1.3418	0.7752	1.1530	1.0310	0.3699	0.0000	1.5937
	TF	0.0298	0.0224	0.0280	0.0162	0.0240	0.0215	0.0077	0.0000	0.0233
17	TI Apr-Oct	1.6339	1.3960	1.5205	1.1537	0.8225	0.8470	0.6491	0.9337	0.6122
	TI Nov-Mar	2.8922	2.4712	2.6915	2.0423	1.4560	1.4992	1.1490	1.6527	1.5937
	TF	0.0603	0.0515	0.0561	0.0426	0.0303	0.0312	0.0239	0.0344	0.0233

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 Part 4, Section 10.A. for deliveries to MID 17; and

(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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.

1. RATE SCHEDULE TF

Reservation Rates - Base Tariff Rates 1/ 2/

	Winter (Nov-Mar)	Summer (Apr-Oct)
Market-to-Market		
TF12 Base	$32.225	$17.903
TF12 Variable	$43.682	$17.903
TF5	$47.740	
Field-to-Field/Market Demarcation		
TFF	$30.925	$17.180

Commodity Rates 3/ 4/

TF12 Base, TF12 Variable, TF5 & TFF		Market Area 5/	Field Mileage Rate per 100 miles	Out-of Balance	Carlton Surcharge 6/	
Receipt Point	Delivery Point	Commodity	Commodity	Commodity	Maximum	Minimum
Market	Market	$0.0228		$0.0228	$0.0175	$0.0000
Field	Market	$0.0228	$0.0082		$0.0175	$0.0000
Market	Field		$0.0082			
Field	Field		$0.0082	$0.0216		

1/ The minimum reservation rate is equal to zero.

2/ Northern and Shipper may agree to charge an average of the maximum TF12 and TF5 or TFF rates during the applicable months of service as set forth in the Firm Throughput Service Agreement without exceeding the maximum rate.

3/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.

4/ 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 Part 4, Section 9 represent the throughput commodity rates for any transaction involving MIDs.

5/ 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

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

2. RATE SCHEDULE TFX

Reservation Rates - Base Tariff Rates 1/ 2/

	Winter (Nov-Mar)	Summer (Apr-Oct)
Market-to-Market		
TFX	$47.740	$17.903
Field-to-Field		
TFX	$30.925	$17.180

Commodity Rates 3/ 4/

TFX		Market Area 5/	Field Mileage Rate per 100 miles	Out-of Balance	Carlton Surcharge 6/	
Receipt Point	Delivery Point	Commodity	Commodity	Commodity	Maximum	Minimum
Market	Market	$0.0228		$0.0228	$0.0175	$0.0000
Field	Market	$0.0228	$0.0082		$0.0175	$0.0000
Market	Field		$0.0082			
Field	Field		$0.0082	$0.0216		

1/ The minimum reservation rate is equal to zero.

2/ Northern and Shipper may agree to charge an average of the maximum Market Area or Field Area rates during the applicable months of service as set forth in the Firm Throughput Service Agreement without exceeding the maximum rate.

3/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.

4/ 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 Part 4, Section 9 represent the throughput commodity rates for any transaction involving MIDs.

5/ 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

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

3. GS-T COMMODITY THROUGHPUT RATE

Commodity Charges

	Nov-Oct	
Market Area	$2.1952	1/ 2/
Field to Demarcation	$1.9652	
Field-to-Market	$4.1604	1/

1/ In addition, Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

4. RATE SCHEDULE TI

Commodity Rates 1/ 2/

Winter (November – March)

TI		**Market Area** 3/		**Field Mileage Rate per 100 miles**		**Out-of Balance**	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	$1.5932	$0.0228			$1.5932	$0.0228
Field	Market	$1.5932	$0.0228	$0.3935	$0.0082		
Market	Field			$0.3935	$0.0082		
Field	Field			$0.3935	$0.0082	$1.0388	$0.0216

Carlton Surcharge 4/			
Receipt Point	Delivery Point	Maximum	Minimum
Market	Market	$0.0175	$0.0000
Field	Market	$0.0175	$0.0000

Summer (April – October)

TI		**Market Area** 3/		**Field Mileage Rate per 100 miles**		**Out-of Balance**	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	$0.6117	$0.0228			$0.6117	$0.0228
Field	Market	$0.6117	$0.0228	$0.2223	$0.0082		
Market	Field			$0.2223	$0.0082		
Field	Field			$0.2223	$0.0082	$0.5869	$0.216

Carlton Surcharge 4/			
Receipt Point	Delivery Point	Maximum	Minimum
Market	Market	$0.0000	$0.0000
Field	Market	$0.0000	$0.0000

1/ Shipper shall pay the applicable Electric Compression commodity rate as shown in Part 4, Section 10.A. and ACA unit surcharge as posted on FERC's website at https://www.ferc.gov.

2/ The MIDs rates shown in Part 4, Section 9 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 Part 7, Section 6.G., Section 7.E. and Section 8.H.

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

5. RATE SCHEDULE SMS

Reservation Charge	$7.8726
Commodity Rate	$0.0208

6. RATE SCHEDULES FDD, PDD & IDD

Rate Schedule FDD

Maximum Reservation Charge	$4.7237~~4.8003~~ 1/
Maximum Capacity Charge	$0.9832~~0.9991~~ 1/
Injection Charge – Firm	$0.0228
Withdrawal Charge – Firm	$0.0228
Annual Rollover Charge	$0.9832~~0.9991~~ 1/

Rate Schedule PDD

Maximum Capacity Charge	$0.9832~~0.9991~~ 1/
Maximum Monthly Inventory Charge	$0.2373~~0.2412~~ 1/
Injection Charge	$0.0228
Withdrawal Charge	$0.0228
Annual Rollover Charge	$0.9832~~0.9991~~ 1/

Rate Schedule IDD

Maximum Monthly Inventory Charge	$0.2373~~0.2412~~ 1/
Injection Charge	$0.0228
Withdrawal Charge	$0.0228
Annual Rollover Charge	$0.9832~~0.9991~~ 1/

1/ Minimum Rate is zero.

Rate Schedule FDD
2008 Market-Based Rate Expansion

Shipper	Reservation Charge	Capacity Charge	Injection Charge Firm	Withdrawal Charge Firm	100% Load Factor
Cascade Municipal Utilities	$3.4920	$0.7268	MAX	MAX	1.50
City of Remsen, Iowa	$3.4920	$0.7268	MAX	MAX	1.50
City of West Bend, Iowa	$3.4920	$0.7268	MAX	MAX	1.50
Woodbine Municipal Natural Gas Systems	$3.4920	$0.7268	MAX	MAX	1.50
Preston Municipal Natural Gas Department	$3.4920	$0.7268	MAX	MAX	1.50
City of Whittemore	$3.4920	$0.7268	MAX	MAX	1.50
City of Rolfe, Iowa	$3.4920	$0.7268	MAX	MAX	1.50
City of Scribner	$3.4920	$0.7268	MAX	MAX	1.50
City of Round Lake, MN	$3.4920	$0.7268	MAX	MAX	1.50
City of Fairbank	$3.4920	$0.7268	MAX	MAX	1.50
Wall Lake Municipal Gas	$3.4920	$0.7268	MAX	MAX	1.50
Black Hills Utility Holdings, Inc.	$3.2775	$0.6822	MAX	MAX	1.4107
Minnesota Energy Resources Corporation	$3.2758	$0.6818	MAX	MAX	1.41
Northern States Power - Generation	$3.0115	$0.6268	MAX	MAX	1.30
Southwestern Public Service Co.	$3.0115	$0.6268	MAX	MAX	1.30

9. MILEAGE INDICATOR DISTRICT CHARGES

MILEAGE INDICATOR DISTRICT CHARGES (dollars per Dth) Receipt MIDs 1-9 and Delivery MIDs 1-9

Receipt District		Delivery District									
		1	2	3	4	5	6	7	7B	8	9
1	TI Apr-Oct	0.0867	0.2090	0.4379	0.6224	0.7002	0.4980	0.5691	0.7492	1.3360	1.1515
	TI Nov-Mar	0.1535	0.3699	0.7752	1.1018	1.2395	0.8814	1.0074	1.3261	2.3649	2.0383
	TF	0.0032	0.0077	0.0162	0.0230	0.0258	0.0184	0.0210	0.0276	0.0493	0.0425
2	TI Apr-Oct	0.1023	0.0156	0.1578	0.4268	0.5535	0.3668	0.4624	0.6424	1.1915	1.0115
	TI Nov-Mar	0.1810	0.0275	0.2794	0.7555	0.9798	0.6493	0.8185	1.1372	2.1092	1.7904
	TF	0.0038	0.0006	0.0058	0.0157	0.0204	0.0135	0.0171	0.0237	0.0440	0.0373
3	TI Apr-Oct	0.6891	0.4468	0.1156	0.1356	0.6069	0.3757	0.2801	0.4602	1.2515	1.0693
	TI Nov-Mar	1.2199	0.7909	0.2046	0.2400	1.0743	0.6650	0.4958	0.8145	2.2154	1.8927
	TF	0.0254	0.0165	0.0043	0.0050	0.0224	0.0139	0.0103	0.0170	0.0462	0.0394
4	TI Apr-Oct	0.6647	0.5913	0.4179	0.1000	0.3668	0.2512	0.3935	0.5735	1.1426	0.9559
	TI Nov-Mar	1.1766	1.0467	0.7398	0.1771	0.6493	0.4447	0.6965	1.0152	2.0226	1.6921
	TF	0.0245	0.0218	0.0154	0.0037	0.0135	0.0093	0.0145	0.0212	0.0421	0.0353
5	TI Apr-Oct	0.6091	0.5491	0.4313	0.3868	0.0600	0.1689	0.3046	0.4846	1.0826	0.8981
	TI Nov-Mar	1.0782	0.9719	0.7634	0.6847	0.1062	0.2991	0.5391	0.8578	1.9163	1.5897
	TF	0.0225	0.0203	0.0159	0.0143	0.0022	0.0062	0.0112	0.0179	0.0399	0.0331
6	TI Apr-Oct	0.3868	0.3090	0.1112	0.1667	0.2290	0.1489	0.1756	0.3557	1.0004	0.7314
	TI Nov-Mar	0.6847	0.5470	0.1968	0.2951	0.4053	0.2636	0.3109	0.6296	1.7708	1.2946
	TF	0.0143	0.0114	0.0041	0.0062	0.0084	0.0055	0.0065	0.0131	0.0369	0.0270
7	TI Apr-Oct	0.6669	0.5802	0.5558	0.4402	0.4713	0.2779	0.2223	0.4024	0.6402	0.4535
	TI Nov-Mar	1.1805	1.0270	0.9838	0.7791	0.8342	0.4919	0.3935	0.7122	1.1333	0.8027
	TF	0.0246	0.0214	0.0205	0.0162	0.0174	0.0103	0.0082	0.0148	0.0236	0.0167
7B	TI Apr-Oct	0.6669	0.5802	0.5558	0.4402	0.4713	0.2779	0.2223	0.0000	0.6402	0.4535
	TI Nov-Mar	1.1805	1.0270	0.9838	0.7791	0.8342	0.4919	0.3935	0.0000	1.1333	0.8027
	TF	0.0246	0.0214	0.0205	0.0162	0.0174	0.0103	0.0082	0.0000	0.0236	0.0167
8	TI Apr-Oct	1.3360	1.2649	1.1693	1.1537	1.1426	0.9225	0.9559	0.7580	0.0178	0.4602
	TI Nov-Mar	2.3649	2.2390	2.0698	2.0423	2.0226	1.6330	1.6921	1.3418	0.0315	0.8145
	TF	0.0493	0.0467	0.0431	0.0426	0.0421	0.0340	0.0353	0.0280	0.0007	0.0170
9	TI Apr-Oct	1.1604	1.0804	0.9715	0.9048	0.7736	0.7892	0.5402	0.3423	0.2823	0.1489
	TI Nov-Mar	2.0541	1.9124	1.7196	1.6015	1.3694	1.3969	0.9562	0.6060	0.4997	0.2636
	TF	0.0428	0.0399	0.0358	0.0334	0.0285	0.0291	0.0199	0.0126	0.0104	0.0055

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 Part 4, Section 10.A. for deliveries to MID 17; and

(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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 DISTRICT CHARGES (dollars per Dth) Receipt MIDs 10-17 and Delivery MIDs 1-9

Receipt District		**Delivery District**									
		1	**2**	**3**	**4**	**5**	**6**	**7**	**7B**	**8**	**9**
10	**TI Apr-Oct**	1.1826	1.2227	1.1804	1.0226	0.8514	0.8647	0.6491	0.4513	0.4246	0.3646
	TI Nov-Mar	2.0934	2.1643	2.0895	1.8101	1.5071	1.5307	1.1490	0.7988	0.7516	0.6453
	TF	0.0436	0.0451	0.0435	0.0377	0.0314	0.0319	0.0239	0.0166	0.0157	0.0134
11	**TI Apr-Oct**	1.1360	1.0493	0.9492	0.8336	0.8203	0.4602	0.5713	0.3735	0.2379	0.2979
	TI Nov-Mar	2.0108	1.8573	1.6802	1.4756	1.4520	0.8145	1.0113	0.6611	0.4210	0.5273
	TF	0.0419	0.0387	0.0350	0.0308	0.0303	0.0170	0.0211	0.0138	0.0088	0.0110
12	**TI Apr-Oct**	1.2293	1.1426	1.1426	0.9737	1.0404	0.8425	0.6625	0.4646	0.3712	0.3512
	TI Nov-Mar	2.1761	2.0226	2.0226	1.7235	1.8416	1.4914	1.1726	0.8224	0.6571	0.6217
	TF	0.0453	0.0421	0.0421	0.0359	0.0384	0.0311	0.0244	0.0171	0.0137	0.0130
13	**TI Apr-Oct**	1.1604	1.1582	1.1737	1.0515	1.0537	0.8848	0.7114	0.5135	0.3912	0.3668
	TI Nov-Mar	2.0541	2.0501	2.0777	1.8613	1.8652	1.5661	1.2592	0.9090	0.6926	0.6493
	TF	0.0428	0.0427	0.0433	0.0388	0.0389	0.0326	0.0262	0.0189	0.0144	0.0135
14	**TI Apr-Oct**	1.4227	1.4850	1.4161	1.2982	1.2004	1.1382	0.9870	0.7892	0.6891	0.6758
	TI Nov-Mar	2.5184	2.6286	2.5066	2.2980	2.1249	2.0147	1.7471	1.3969	1.2199	1.1962
	TF	0.0525	0.0548	0.0522	0.0479	0.0443	0.0420	0.0364	0.0291	0.0254	0.0249
15	**TI Apr-Oct**	1.8718	1.7940	1.7651	1.5894	1.5472	1.5005	1.3316	1.1337	1.0159	0.9959
	TI Nov-Mar	3.3133	3.1755	3.1244	2.8135	2.7388	2.6561	2.3571	2.0069	1.7983	1.7629
	TF	0.0690	0.0662	0.0651	0.0586	0.0571	0.0554	0.0491	0.0418	0.0375	0.0367
16A	**TI Apr-Oct**	1.5228	1.4249	1.4916	1.2338	1.3294	1.0470	0.9403	0.7425	0.6491	0.6358
	TI Nov-Mar	2.6955	2.5223	2.6404	2.1839	2.3531	1.8534	1.6645	1.3143	1.1490	1.1254
	TF	0.0562	0.0526	0.0550	0.0455	0.0490	0.0386	0.0347	0.0274	0.0239	0.0235
16B	**TI Apr-Oct**	1.7117	1.5428	1.5583	1.5294	1.4605	1.4161	1.0292	0.8314	0.8247	0.8136
	TI Nov-Mar	3.0300	2.7309	2.7584	2.7073	2.5853	2.5066	1.8219	1.4717	1.4599	1.4402
	TF	0.0631	0.0569	0.0575	0.0564	0.0539	0.0522	0.0380	0.0307	0.0304	0.0300
17	**TI Apr-Oct**	2.5075	2.4186	2.1096	2.1897	2.1452	2.0607	1.8918	1.6939	1.6228	1.6095
	TI Nov-Mar	4.4387	4.2813	3.7343	3.8760	3.7973	3.6477	3.3487	2.9985	2.8726	2.8489
	TF	0.0925	0.0892	0.0778	0.0808	0.0791	0.0760	0.0698	0.0625	0.0599	0.0594

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 Part 4, Section 10.A. for deliveries to MID 17; and
(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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 DISTRICT CHARGES (dollars per Dth) Receipt MIDs 1-9 and Delivery MIDs 10-17

Receipt District		**Delivery District**								
		10	**11**	**12**	**13**	**14**	**15**	**16A**	**16B**	**17**
1	**TI Apr-Oct**	1.3627	1.1004	1.2360	1.3427	1.5339	1.6339	1.5250	1.7117	2.3239
	TI Nov-Mar	2.4122	1.9478	2.1879	2.3767	2.7152	2.8922	2.6994	3.0300	4.6237
	TF	0.0503	0.0406	0.0456	0.0495	0.0566	0.0603	0.0563	0.0631	0.0864
2	**TI Apr-Oct**	1.1826	0.9781	1.0915	1.1871	1.3805	1.6317	1.3872	1.5428	2.1550
	TI Nov-Mar	2.0934	1.7314	1.9321	2.1013	2.4436	2.8883	2.4554	2.7309	4.3246
	TF	0.0436	0.0361	0.0403	0.0438	0.0509	0.0602	0.0512	0.0569	0.0802
3	**TI Apr-Oct**	1.2204	1.0448	1.1560	1.2538	1.4961	1.6961	1.2716	1.5583	2.1705
	TI Nov-Mar	2.1603	1.8495	2.0462	2.2193	2.6483	3.0024	2.2508	2.7584	4.3521
	TF	0.0450	0.0385	0.0426	0.0462	0.0552	0.0626	0.0469	0.0575	0.0808
4	**TI Apr-Oct**	1.0604	0.9270	1.0404	1.1360	1.3405	1.5806	1.3071	1.5294	2.1416
	TI Nov-Mar	1.8770	1.6409	1.8416	2.0108	2.3728	2.7978	2.3138	2.7073	4.3010
	TF	0.0391	0.0342	0.0384	0.0419	0.0494	0.0583	0.0482	0.0564	0.0797
5	**TI Apr-Oct**	1.1182	0.8692	0.9826	1.0782	1.1826	1.4894	1.3294	1.4605	2.0727
	TI Nov-Mar	1.9793	1.5386	1.7393	1.9085	2.0934	2.6365	2.3531	2.5853	4.1790
	TF	0.0412	0.0321	0.0362	0.0398	0.0436	0.0549	0.0490	0.0539	0.0772
6	**TI Apr-Oct**	1.0159	0.7847	0.9003	0.9959	1.1938	1.4716	1.1826	1.4161	2.0283
	TI Nov-Mar	1.7983	1.3891	1.5937	1.7629	2.1131	2.6050	2.0934	2.5066	4.1003
	TF	0.0375	0.0289	0.0332	0.0367	0.0440	0.0543	0.0436	0.0522	0.0755
7	**TI Apr-Oct**	0.6647	0.4268	0.5380	0.6358	0.8381	1.2960	0.8292	1.0292	1.6414
	TI Nov-Mar	1.1766	0.7555	0.9523	1.1254	1.4835	2.2941	1.4678	1.8219	3.4156
	TF	0.0245	0.0157	0.0198	0.0235	0.0309	0.0478	0.0306	0.0380	0.0613
7B	**TI Apr-Oct**	0.6647	0.4268	0.5380	0.6358	0.8381	1.2960	0.8292	1.0292	1.6414
	TI Nov-Mar	1.1766	0.7555	0.9523	1.1254	1.4835	2.2941	1.4678	1.8219	3.4156
	TF	0.0245	0.0157	0.0198	0.0235	0.0309	0.0478	0.0306	0.0380	0.0613
8	**TI Apr-Oct**	0.4846	0.2890	0.3690	0.4668	0.6536	0.9870	0.6224	0.8247	1.4369
	TI Nov-Mar	0.8578	0.5116	0.6532	0.8264	1.1569	1.7471	1.1018	1.4599	3.0536
	TF	0.0179	0.0107	0.0136	0.0172	0.0241	0.0364	0.0230	0.0304	0.0537
9	**TI Apr-Oct**	0.3757	0.1689	0.3668	0.3735	0.5891	0.9025	0.6602	0.8136	1.4258
	TI Nov-Mar	0.6650	0.2991	0.6493	0.6611	1.0428	1.5976	1.1687	1.4402	3.0339
	TF	0.0139	0.0062	0.0135	0.0138	0.0217	0.0333	0.0244	0.0300	0.0533

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 Part 4, Section 10.A. for deliveries to MID 17; and
(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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 DISTRICT CHARGES (dollars per Dth) Receipt MIDs 10-17 and Delivery MIDs 10-17

Receipt District		Delivery District								
		10	11	12	13	14	15	16A	16B	17
10	TI Apr-Oct	0.0267	0.1089	0.3268	0.4179	0.6180	0.8581	0.5091	0.8092	1.4214
	TI Nov-Mar	0.0472	0.1928	0.5784	0.7398	1.0939	1.5189	0.9011	1.4323	3.0260
	TF	0.0010	0.0040	0.0121	0.0154	0.0228	0.0317	0.0188	0.0298	0.0531
11	TI Apr-Oct	0.2379	0.0534	0.0978	0.2734	0.4668	0.7580	0.3957	0.6069	1.2191
	TI Nov-Mar	0.4210	0.0944	0.1731	0.4840	0.8264	1.3418	0.7004	1.0743	2.6680
	TF	0.0088	0.0020	0.0036	0.0101	0.0172	0.0280	0.0146	0.0224	0.0457
12	TI Apr-Oct	0.3712	0.1823	0.2223	0.3401	0.5624	0.8047	0.5402	0.7580	1.3702
	TI Nov-Mar	0.6571	0.3227	0.3935	0.6021	0.9956	1.4245	0.9562	1.3418	2.9355
	TF	0.0137	0.0067	0.0082	0.0125	0.0207	0.0297	0.0199	0.0280	0.0513
13	TI Apr-Oct	0.4868	0.1890	0.2779	0.1245	0.2757	0.5935	0.2245	0.4379	1.0501
	TI Nov-Mar	0.8618	0.3345	0.4919	0.2204	0.4879	1.0506	0.3974	0.7752	2.3689
	TF	0.0180	0.0070	0.0103	0.0046	0.0102	0.0219	0.0083	0.0162	0.0395
14	TI Apr-Oct	0.4290	0.4824	0.6024	0.1890	0.0534	0.7603	0.4268	0.6513	1.2635
	TI Nov-Mar	0.7595	0.8539	1.0664	0.3345	0.0944	1.3458	0.7555	1.1530	2.7467
	TF	0.0158	0.0178	0.0222	0.0070	0.0020	0.0280	0.0157	0.0240	0.0473
15	TI Apr-Oct	0.9715	0.7803	0.9070	0.5758	0.7892	0.0556	0.3801	0.5824	1.1946
	TI Nov-Mar	1.7196	1.3812	1.6055	1.0192	1.3969	0.0984	0.6729	1.0310	2.6247
	TF	0.0358	0.0288	0.0335	0.0212	0.0291	0.0021	0.0140	0.0215	0.0448
16A	TI Apr-Oct	0.7358	0.4246	0.5469	0.2245	0.4357	0.3646	0.0378	0.2090	0.8212
	TI Nov-Mar	1.3025	0.7516	0.9680	0.3974	0.7713	0.6453	0.0669	0.3699	1.9636
	TF	0.0271	0.0157	0.0202	0.0083	0.0161	0.0134	0.0014	0.0077	0.0310
16B	TI Apr-Oct	0.8092	0.6069	0.7580	0.4379	0.6513	0.5824	0.2090	0.0000	0.6122
	TI Nov-Mar	1.4323	1.0743	1.3418	0.7752	1.1530	1.0310	0.3699	0.0000	1.5937
	TF	0.0298	0.0224	0.0280	0.0162	0.0240	0.0215	0.0077	0.0000	0.0233
17	TI Apr-Oct	1.6339	1.3960	1.5205	1.1537	0.8225	0.8470	0.6491	0.9337	0.6122
	TI Nov-Mar	2.8922	2.4712	2.6915	2.0423	1.4560	1.4992	1.1490	1.6527	1.5937
	TF	0.0603	0.0515	0.0561	0.0426	0.0303	0.0312	0.0239	0.0344	0.0233

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(3) the applicable Field Area Electric Compression commodity rate as set forth in Part 4, Section 10.A. 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.

Appendix B

SEVENTH REVISED VOLUME NO. 1

July 1 Filing Tariff Sections

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

Part 4, Section 1 - TF, Version 2.0.0
Part 4, Section 2 - TFX, Version 1.0.0
Part 4, Section 3 - GS-T, Version 1.0.0
Part 4, Section 4 - TI, Version 1.0.0
Part 4, Section 5 - SMS, Version 1.0.0
Part 4, Section 6 - FDD,PDD and IDD, Version 1.0.0
Part 4, Section 9 - Mileage Indicator District Charges, Version 2.0.0

Appendix C

Cost of Service Details

NORTHERN NATURAL GAS COMPANY

COST OF SERVICE COMPARISON

Line No.	Particulars		Schedule Reference	Updated Cost of Service Test Period Ended December 31, 2025			July 1 Filing Cost of Service 12-Months Ended March 31, 2025, as Adjusted for Test Period		
				Total Test Period Amount	Storage	Transmission	Total Test Period Amount	Storage	Transmission
	[a]		[b]	[c]	[d]	[e]	[f]	[g]	[h]
1	O & M Expenses		H-1	$ 430,862,695	$ 63,451,611	$ 367,411,084	$ 430,862,695	$ 63,460,203	$ 367,402,492
2	Depreciation and Amortization of Gas								
3	Plant In Service		H-2(1)	407,633,829	44,037,586	363,596,243	407,840,599	44,546,598	363,294,001
4	Amortization of Certain Reg Assets		B-2	(15,405,969)	(1,973,860)	(13,432,108)	(15,405,969)	(2,001,061)	(13,404,907)
5	Income Taxes								
6	Federal Income at	21.00%	H-3	119,799,455	15,349,077	104,450,378	119,710,602	15,549,056	104,161,546
7	State Income at	6.13%	H-3	37,232,074	4,770,288	32,461,786	37,203,725	4,832,344	32,371,381
8	Taxes Other Than Income		H-4						
9	Payroll Taxes			8,829,535	1,361,122	7,468,413	8,829,535	1,361,122	7,468,413
10	Franchise Taxes			20,100	2,575	17,525	20,100	2,611	17,489
11	Sales and Use Tax			-	-	-	-	-	-
12	Ad Valorem			90,970,571	11,655,431	79,315,140	90,970,571	11,816,050	79,154,521
13	Total Taxes Other Than Income			99,820,206	13,019,129	86,801,077	99,820,206	13,179,783	86,640,423
				-			-		
14	Return at	10.21%	B	535,446,535	68,603,066	466,843,469	534,870,702	69,473,665	465,397,036
15	Other Operating Revenues		G-5	(616,873)	-	(616,873)	(616,873)	-	(616,873)
16	Total Overall Cost of Service			$ 1,614,771,952	$ 207,256,897	$ 1,407,515,055	$ 1,614,285,686	$ 209,040,588	$ 1,405,245,098

NORTHERN NATURAL GAS COMPANY

RATE BASE AND RETURN ALLOWANCE COMPARISON

Line No.	Particulars		Schedule Reference	F/N	Updated Rate Base Test Period Ended December 31, 2025 Total	Storage	Transmission	Intangible and General	July 1 Filing Rate Base 12-Months Ended March 31, 2025, as Adjusted for Test Period Total	Storage	Transmission	Intangible and General
	[a]		[b]		[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]
1	Utility Plant											
2	Gas Plant in Service		C		$ 8,158,051,945	$ 1,038,197,358	$ 6,747,258,206	$ 372,596,381	$ 8,115,808,515	$ 1,043,332,078	$ 6,680,706,787	$ 391,769,651
3	Regulatory Assets & Liabilities		B-2	1/	(286,530,653)	(36,711,193)	(249,819,460)	-	(286,796,528)	(37,251,631)	(249,544,897)	-
4	Sub-total				7,871,521,292	1,001,486,165	6,497,438,746	372,596,381	7,829,011,987	1,006,080,447	6,431,161,890	391,769,651
5	Classification of Intangible and General			1/	-	47,738,201	324,858,180	(372,596,381)	-	50,886,455	340,883,196	(391,769,651)
6	Total Classified Gas Plant in Service				7,871,521,292	1,049,224,365	6,822,296,926	-	7,829,011,987	1,056,966,901	6,772,045,086	-
7	Accumulated Provision for Depreciation and Amortization		D		1,883,105,514	260,328,089	1,453,862,325	168,915,100	1,849,937,792	256,018,372	1,406,572,150	187,347,270
8	Classification of Intangible and General			1/	-	21,641,925	147,273,175	(168,915,100)	-	24,334,295	163,012,975	(187,347,270)
9	Classified Accum. Provision for Depr. and Amort.				1,883,105,514	281,970,014	1,601,135,500	-	1,849,937,792	280,352,667	1,569,585,125	-
10	Net Utility Plant				5,988,415,778	767,254,351	5,221,161,426	-	5,979,074,195	776,614,234	5,202,459,961	-
11	Working Capital		E	1/	126,583,741	16,218,300	110,365,441	-	126,583,741	16,441,799	110,141,942	-
12	Total Rate Base Before Deductions				6,114,999,519	783,472,652	5,331,526,867	-	6,105,657,937	793,056,033	5,312,601,904	-
13	Total Rate Base Before Deductions				6,114,999,519	783,472,652	5,331,526,867	-	6,105,657,937	793,056,033	5,312,601,904	-
14	Less: Accumulated Deferred Income Taxes		B-1	1/	(868,891,480)	(111,325,064)	(757,566,416)	-	(865,191,699)	(112,378,634)	(752,813,066)	-
15	Total Rate Base				5,246,108,039	672,147,588	4,573,960,451	-	5,240,466,237	680,677,399	4,559,788,838	-
16	Return Allowance	10.21%	of Line 15									
17	Interest Expense	1.70%	H-3		88,958,779	11,397,674	77,561,105	-	88,863,110	11,542,315	77,320,795	-
18	Allowance on Common Stock Equity	8.51%	H-3		446,487,757	57,205,392	389,282,364	-	446,007,592	57,931,351	388,076,241	-
19	Total Return Allowance				$ 535,446,535	$ 68,603,066	$ 466,843,469	$ -	$ 534,870,702	$ 69,473,665	$ 465,397,036	$ -

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, 2025
Accounts 190, 282, and 283

Line No.	Description [a]	Account 190 Amount [b]	Account 282 Amount [c]	Account 283 Amount [d]
1	Balances at:			
2	April 30, 2024	$ 96,346,758	$ (856,201,303)	$ (10,629,340)
3	May 31	96,287,008	(857,306,655)	(10,686,295)
4	June 30	96,943,207	(859,618,043)	(10,682,662)
5	July 31	96,986,532	(860,042,266)	(10,632,445)
6	August 31	96,933,149	(861,673,384)	(11,297,910)
7	September 30	99,040,687	(864,141,626)	(12,915,295)
8	October 31	99,150,939	(866,987,681)	(12,814,769)
9	November 30	98,680,297	(871,061,853)	(12,683,543)
10	December 31	96,495,272	(890,233,391)	(12,737,751)
11	January 31, 2025	95,387,457	(891,879,555)	(12,636,227)
12	February 28	94,362,958	(894,323,283)	(12,457,398)
13	March 31	95,171,335	(895,816,271)	(12,496,679)
14	April 30	95,169,459	(898,266,680)	(12,315,822)
15	May 31	95,169,553	(899,943,113)	(12,177,627)
16	June 30	99,606,572	(904,626,299)	(12,037,749)
17	July 31	99,688,004	(906,153,614)	(11,915,700)
18	August 31	99,688,044	(909,067,342)	(11,790,001)
19	September 30	100,597,168	(911,649,504)	(11,726,182)
20	October 31, 2025	100,515,481	(922,712,210)	(11,636,702)
21	Deferred Tax Changes on Plant - Nov & Dec	-	(35,159,771)	-
22	Deferred Tax on AFUDC Gross Up - Nov & Dec	-	-	101,723
23	Total Test Period Adjustments	-	(35,159,771)	101,723
24	Adjusted Balance December 31, 2025	$ 100,515,481	$ (957,871,981)	$ (11,534,979)
25	Amount Included in Rate Base	$ 100,515,481	$ (957,871,981)	$ (11,534,979)
26	Total Amount Included in Rate Base	$ (868,891,480)		

COST OF SERVICE COMPARISON

Regulatory Assets & Liabilities Included in Rate Base
Test Period Ended December 31, 2025
Accounts 182.3 & 254

Line No.	Particulars	RP-22-1033 Rate Case Expenses	RP-25- Rate Case Expenses	Equity AFUDC Gross Up	Smart Pigging Hydrostatic Testing	Total Acct 182.3	Excess Deferred Income Taxes	IA Rate Change EDIT	NE Rate Change EDIT	OK Rate Change EDIT	KS Rate Change EDIT	Total Acct 254	Total
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]
1	April 30, 2024	$ 1,277,611	$ -	$ 33,367,445	$ 6,191,710	$ 40,836,766	$ (310,453,243)	$ (22,881,046)	$ (16,427,762)	$ (2,288,914)	$ (2,532,573)	$ (354,583,538)	$ (313,746,772)
2	May 31	1,155,917	-	34,288,383	6,050,993	41,495,294	(310,235,196)	(22,869,782)	(16,423,946)	(2,287,737)	(2,531,442)	(354,348,103)	(312,852,809)
3	June 30	1,095,070	-	34,788,961	5,910,277	41,794,307	(310,088,493)	(22,862,203)	(16,421,379)	(2,286,945)	(2,530,680)	(354,189,700)	(312,395,393)
4	July 31	1,034,223	-	35,138,008	5,769,560	41,941,791	(310,246,599)	(22,870,371)	(16,424,146)	(2,287,799)	(2,531,501)	(354,360,416)	(312,418,625)
5	August 31	973,375	-	35,725,320	5,628,844	42,327,539	(310,051,786)	(22,860,307)	(16,420,737)	(2,286,747)	(2,530,489)	(354,150,066)	(311,822,527)
6	September 30	912,528	-	36,376,441	5,488,127	42,777,096	(310,150,773)	(22,865,420)	(16,422,469)	(2,287,282)	(2,531,003)	(354,256,947)	(311,479,851)
7	October 31	851,681	-	36,985,005	5,347,410	43,184,096	(310,100,550)	(23,605,096)	(16,418,732)	(2,286,851)	(2,530,503)	(354,941,732)	(311,757,636)
8	November 30	790,834	-	37,226,517	5,206,694	43,224,045	(308,418,439)	(23,476,326)	(16,389,296)	(2,277,775)	(2,521,771)	(353,083,607)	(309,859,562)
9	December 31	729,987	-	36,929,728	5,065,977	42,725,692	(306,549,232)	(23,377,328)	(16,356,553)	(2,267,687)	(2,512,069)	(351,062,869)	(308,337,177)
10	January 31, 2025	669,140	-	36,910,361	4,925,261	42,504,762	(302,543,108)	(23,157,817)	(16,254,735)	(2,245,047)	(2,490,283)	(346,690,990)	(304,186,228)
11	February 28	608,292	-	36,879,342	4,784,544	42,272,178	(298,822,438)	(22,953,876)	(16,177,993)	(2,224,015)	(2,470,049)	(342,648,371)	(300,376,193)
12	March 31, 2025	547,445	-	36,976,535	4,643,827	42,167,808	(295,834,070)	(22,790,075)	(16,092,416)	(2,207,124)	(2,453,798)	(339,377,483)	(297,209,675)
13	As Filed Test Period Balances	$ -	$ 6,080,400	$ 39,402,703	$ 3,377,378	$ 48,860,481	$ (292,422,540)	$ (22,603,079)	$ (16,008,304)	$ (2,187,840)	$ (2,435,246)	$ (335,657,009)	$ (286,796,528)
14	Plant Related Variances	-	-	265,875	-	265,875	-	-	-	-	-	-	265,875
15	Estimated Test Period Balance	$ -	$ 6,080,400	$ 39,668,578	$ 3,377,378	$ 49,126,356	$ (292,422,540)	$ (22,603,079)	$ (16,008,304)	$ (2,187,840)	$ (2,435,246)	$ (335,657,009)	$ (286,530,653)
16	Total Amount Included in Rate Base												$ (286,530,653)
17	Allocated to Storage (Net Plant)												$ (36,711,193)
18	Allocated to Transmission (Net Plant)												$ (249,819,460)
19	Amortization	1/					$ 14,126,671	$ 774,325	$ 348,298	$ 79,852	$ 76,823		$ 15,405,969
20	Allocated to Storage (Net Plant)												$ 1,973,860
21	Allocated to Transmission (Net Plant)												$ 13,432,108

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

COST OF SERVICE COMPARISON

COST OF PLANT
Test Period Ended December 31, 2025

Line No.	Description	Account Number	Schedule Reference	Book Balances 10/31/2025	Adjustments	Adjusted Book Balances 12/31/2025
	[a]	[b]	[c]	[d]	[e]	[f]
1	Gas Plant in Service	101, 106	C-1	$ 7,772,435,541	$ 309,350,444	$ 8,081,785,985
2	Gas Plant Held For Future Use	105	C-1	6,625,032	-	6,625,032
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			7,848,701,501	309,350,444	8,158,051,945
6	Asset Retirement Obligation	101		13,742,119	-	13,742,119
7	Construction Work in Progress-Incomplete	107		347,231,136	(226,605,163)	120,625,973
8	Total Northern Natural Gas Company			$ 8,209,674,756	$ 82,745,281	$ 8,292,420,037

COST OF SERVICE COMPARISON

Gas Plant in Service
Test Period Ended December 31, 2025

Line No.	FERC Account Number	Description	Book Balance 10/31/2025	Test Period Additions	Retirements	Net	Test Period Balance 12/31/2025	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	38,508,460	57,292	-	57,292	38,565,752	
4	303	Miscellaneous Intangible Plant - Software	175,756,044	8,627,021	(14,156,637)	(5,529,616)	170,226,428	
5	303	Miscellaneous Intangible Plant - Leasehold Improvements	-	-	-	-	-	
6		Total	219,106,195	8,684,313	(14,156,637)	(5,472,324)	213,633,871	
7		Underground Storage Plant						
8	350.1	Land	2,384,812	-	-	-	2,384,812	
9	350.2	Rights-of-way	1,782,481	1,226,085	-	1,226,085	3,008,566	
10	351	Structures & Improvements	51,542,658	582,112	-	582,112	52,124,770	
11	352	Wells	206,395,847	21,948,906	(1,703,549)	20,245,357	226,641,204	
12	352.1	Storage Leaseholds and Rights	21,961,106	-	-	-	21,961,106	
13	352.2	Reservoirs	16,755,757	-	-	-	16,755,757	
14	352.3	Non-recoverable Natural Gas	32,972,796	-	-	-	32,972,796	
15	353	Lines	109,575,864	4,506,271	-	4,506,271	114,082,135	
16	354	Compressor Station Equipment	132,169,268	1,476,156	-	1,476,156	133,645,424	
17	354.1	Compressor Computer Control Systems	11,516,171	21,722	-	21,722	11,537,893	
18	355	Meas & Reg Equipment	25,563,225	2,277,404	-	2,277,404	27,840,629	
19	356	Purification Equipment	79,377,599	6,082,976	-	6,082,976	85,460,575	
20	357	Other Equipment	7,390,138	943,383	-	943,383	8,333,521	
21	357.1	Shop, Comm, & Office Equipment	2,310,130	-	-	-	2,310,130	
22		Total	701,697,852	39,065,015	(1,703,549)	37,361,466	739,059,318	

COST OF SERVICE COMPARISON

Gas Plant in Service
Test Period Ended December 31, 2025

Line No.	FERC Account Number	Description	Book Balance 10/31/2025	Test Period Additions	Retirements	Net	Test Period Balance 12/31/2025	F/N
	[a]	[b]	[c]	[d]	[e]	[f] = [d]+[e]	[g] = [c]+[f]	
23		LNG Storage Plant						
24	360	Land	639,698	-	-	-	639,698	
25	361	Structures and Improvements	57,555,862	-	-	-	57,555,862	
26	362	Gas Holders	20,121,837	-	-	-	20,121,837	
27	363	Purification Equipment	16,451,570	121,595	-	121,595	16,573,165	
28	363.1	Liquefaction Equipment	24,647,696	-	-	-	24,647,696	
29	363.2	Vaporizing Equipment	13,803,452	74,942	-	74,942	13,878,394	
30	363.3	Compressor Equipment	79,052,256	4,988,506	-	4,988,506	84,040,762	
31	363.31	Compressor Computer Control Systems	784,239	1,313	-	1,313	785,552	
32	363.4	Meas & Reg Equipment	5,183,082	2,132,688	-	2,132,688	7,315,770	
33	363.5	Other Equipment	3,919,582	18,794	-	18,794	3,938,376	
34		Total	222,159,274	7,337,838	-	7,337,838	229,497,112	
35		Base Load LNG Terminal and Processing Plant						
36	364.3	LNG Processing Terminal Equipment	5,769,360	-	-	-	5,769,360	
37	364.4	LNG Transportation Equipment	-	-	-	-	-	
38	364.5	Measuring Equipment	525,194	-	-	-	525,194	
39		Total	6,294,554	-	-	-	6,294,554	
40		Transmission Plant						
41	365.1	Land and Land Rights	5,378,346	817,672	-	817,672	6,196,018	
42	365.2	Rights-of-way	94,575,888	817,158	-	817,158	95,393,046	
43	366	Structures and Improvements	234,179,243	15,250,371	-	15,250,371	249,429,614	
44	367	Mains	3,918,734,782	116,362,459	(10,560,593)	105,801,866	4,024,536,648	
45	368	Compressor Station Equipment	1,538,885,987	112,663,642	-	112,663,642	1,651,549,629	
46	368.1	Compressor Control Equipment	52,405,070	934,529	-	934,529	53,339,599	
47	369	Meas & Reg Station Equipment	600,565,717	30,789,248	-	30,789,248	631,354,965	
48	369.1	Meas & Reg Computer Equipment	9,634,520	1,670,465	-	1,670,465	11,304,985	
49	370	Communication Equipment-Radio	4,883,075	1,233,371	-	1,233,371	6,116,446	
50	371	Other Equipment	4,579,444	538,226	-	538,226	5,117,670	
51		Total	6,463,822,072.00	281,077,141	(10,560,593)	270,516,548	6,734,338,620	

COST OF SERVICE COMPARISON

Gas Plant in Service
Test Period Ended December 31, 2025

Line No.	FERC Account Number	Description		Book Balance 10/31/2025		Test Period Additions		Retirements		Net		Test Period Balance 12/31/2025	F/N
	[a]	[b]		[c]		[d]		[e]		[f] = [d]+[e]		[g] = [c]+[f]	
52		General Plant											
53	389	Land		1,948,874		-		-		-		1,948,874	
54	390	Structures & Improvements		40,050,961		672,296		-		672,296		40,723,257	
55	391	Office Furniture & Equipment		12,664,183		542,228		(2,455,350)		(1,913,122)		10,751,061	
56	391.1	Office Computer Equipment		16,569,001		-		-		-		16,569,001	
57	392	Transportation Equipment		30,562,533		-		-		-		30,562,533	
58	393	Stores Equipment		-		-		-		-		-	
59	394	Tools, Shop & Garage Equip		35,647,501		18,157		-		18,157		35,665,658	
60	395	Laboratory Equipment		2,220,184		-		-		-		2,220,184	
61	396	Power Operated Equipment		17,280,312		-		-		-		17,280,312	
62	397	Communication Equipment		1,524,866		829,585		-		829,585		2,354,451	
63	398	Miscellaneous Equipment		887,179		-		-		-		887,179	
64	399	Other Tangible Property		-		-		-		-		-	
65		Total		159,355,594		2,062,266		(2,455,350)		(393,084)		158,962,510	
66		Total	$	7,772,435,541	$	338,226,573	$	(28,876,129)	$	309,350,444	$	8,081,785,985	1/

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

COST OF SERVICE COMPARISON

ACCUMULATED PROVISION FOR DEPRECIATION, DEPLETION AND AMORTIZATION
Test Period Ended December 31, 2025

Line No.	Account Number	Description	F/N	Book Balances 4/1/2024	Provisions	Net Retirements	Transfers and Reclass-ifications	Book Balances 10/31/2025	Test Period Adjustments: Stmt D Part 2 Col (h) Provision	Test Period Adjustments: Plant Retirements	Test Period Balance 12/31/2025
	[a]	[b]		[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]=[g]+[h]+[i]
1		Accumulated Provision for Depreciation									
2		of Gas Utility Plant									
3		Natural Gas Storage Plant									
4	108	Underground Storage Plant		$ 176,785,817	$ 14,663,678	$ (4,623,319)	$ 1,418,182	$ 188,244,358	$ 1,684,669	$ (1,703,549)	$ 188,225,478
5	108	LNG Storage Plant		57,447,498	9,713,981	(7,802,934)	935,091	60,293,636	1,141,773	-	61,435,409
6		Total Natural Gas Storage Plant		234,233,315	24,377,659	(12,426,253)	2,353,273	248,537,994	2,826,442	(1,703,549)	249,660,887
7	108	Base Load LNG Terminaling & Processing Plant		1,490,074	317,613	(551,285)	-	1,256,402	32,984	-	1,289,386
8		Total Base Load LNG Terminaling & Processing Plant		1,490,074	317,613	(551,285)	-	1,256,402	32,984	-	1,289,386
9		Transmission Plant									
10	108	Accumulated Depreciation Provision		1,352,986,059	251,035,725	(76,737,418)	(115,675)	1,527,168,691	28,326,458	(10,560,593)	1,544,934,555
11	108	Onshore Interim Negative Salvage		(136,940,492)	9,538,231	(20,326,398)	(19,699)	(147,748,357)	1,104,145	-	(146,644,212)
12	108	Offshore Negative Salvage - ARO		6,334,468	1,228,564	-	-	7,563,032	129,323	-	7,692,355
13		Total Transmission Plant		1,222,380,035	261,802,520	(97,063,816)	(135,374)	1,386,983,365	29,559,926	(10,560,593)	1,405,982,698
14	108	General Plant		72,523,297	21,301,896	(20,872,046)	(1,272,570)	71,680,577	2,400,971	(2,455,350)	71,626,198
15		Total General Plant		72,523,297	21,301,896	(20,872,046)	(1,272,570)	71,680,577	2,400,971	(2,455,350)	71,626,198
16	108	Plant Held for Future Use		518,379	154,566	(97,119)	(154,566)	421,260	-	-	421,260
17		Total - Plant Held for Future Use		518,379	154,566	(97,119)	(154,566)	421,260	-	-	421,260
18		Total Account 108		1,531,145,100	307,954,254	(131,010,519)	790,763	1,708,879,598	34,820,323	(14,719,492)	1,728,980,429

COST OF SERVICE COMPARISON

ACCUMULATED PROVISION FOR DEPRECIATION, DEPLETION AND AMORTIZATION
Test Period Ended December 31, 2025

Line No.	Account Number	Description	F/N	Book Balances 4/1/2024	Provisions	Net Retirements	Transfers and Reclass-ifications	Book Balances 10/31/2025	Test Period Adjustments: Stmt D Part 2 Col (h) Provision	Test Period Adjustments: Plant Retirements	Test Period Balance 12/31/2025
	[a]	[b]		[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]=[g]+[h]+[i]
19		Accumulated Provision for Amortization									
20		and Depletion of Gas									
21		Natural Gas Storage Plant									
22	111	Underground Storage Land and Land Rights		9,177,379	413,912	-	538,451	10,129,742	48,306	-	10,178,048
23	111	Underground Storage Right of Way		977,647	46,244	-	(538,451)	485,440	3,714	-	489,154
24		Total Natural Gas Storage Plant		10,155,026	460,156	-	-	10,615,182	52,020	-	10,667,202
25		Transmission Plant									
26	111	Right of Way		36,269,018	4,846,182	(114,419)	(655,220)	40,345,561	346,111	-	40,691,672
27	111	Land Rights Renewal		4,662,212	729,250	(5,011)	(2,587)	5,383,864	75,728	-	5,459,592
28	111	Plant Held for Future Use		17,717	-	-	-	17,717	-	-	17,717
29		Total Transmission Plant		40,948,947	5,575,432	(119,430)	(657,807)	45,747,142	421,839	-	46,168,981
30	111	Other Gas Plant		85,790,783	39,078,596	(17,346,955)	(407,888)	107,114,536	4,331,003	(14,156,637)	97,288,902
31		Total Other Gas Plant		85,790,783	39,078,596	(17,346,955)	(407,888)	107,114,536	4,331,003	(14,156,637)	97,288,902
32		Total Account 111		136,894,756	45,114,184	(17,466,385)	(1,065,695)	163,476,860	4,804,862	(14,156,637)	154,125,085
33		Total Northern Natural Gas Company		$ 1,668,039,856	$ 353,068,438	$ (148,476,904)	$ (274,932)	$ 1,872,356,458	$ 39,625,185	$ (28,876,129)	$ 1,883,105,514

NORTHERN NATURAL GAS COMPANY

Calculation of Depreciation Provision
for Nov 25 - Dec 25 Period

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	F/N	Depreciable Plant Balances 10/31/2025	Plant Additions	Depreciable Adjusted Plant Balances 12/31/2025	Depr. Provision for Nov 25 - Dec 25 Period On Base Period Plant	Depr. Provision for Nov 25 - Dec 25 Period On Test Period Additions	Total
	[a]	[b]	[c]		[d]	[e]	[f]=[d]+[e]	[g]	[h]	[i] = [g]+[h]
1	Natural Gas Storage Plant									
2	Underground Storage									
3	Operating Plant	1.25%			661,743,152	36,113,659	697,856,811	1,378,632	75,237	1,453,869
4	Storage Leaseholds and Rights	1.25%			21,961,106	1,226,085	23,187,191	45,752	2,554	48,306
5	Rights-of-way	1.25%			1,782,481	-	1,782,481	3,714	-	3,714
6	Shop, Communication, & Office Equipment	10.00%			2,310,130	-	2,310,130	38,502	-	38,502
7	Compressor Computer Control Systems	10.00%			11,516,171	21,722	11,537,893	191,936	362	192,298
8	Total Underground Storage				699,313,040	37,361,466	736,674,506	1,658,536	78,153	1,736,689
9	LNG Storage									
10	Operating Plant	2.95%			220,111,732	7,336,525	227,448,257	1,082,216	36,071	1,118,287
11	Computer Control Systems	10.00%			1,407,844	1,313	1,409,157	23,464	22	23,486
12	Total Other Storage				221,519,576	7,337,838	228,857,414	1,105,680	36,093	1,141,773
13	Total Natural Gas Storage Plant				920,832,616	44,699,304	965,531,920	2,764,216	114,246	2,878,462
14	Base Load LNG Terminaling and Processing Plant									
15	LNG Processing Terminal Equipment	2.95%			6,121,269	-	6,121,269	30,096	-	30,096
16	LNG Transportation Equipment	10.00%			-	-	-	-	-	-
17	LNG Computers	10.00%			173,285	-	173,285	2,888	-	2,888
18	Total Base Load LNG Terminaling and Processing Plant				6,294,554	-	6,294,554	32,984	-	32,984

NORTHERN NATURAL GAS COMPANY

Calculation of Depreciation Provision
for Nov 25 - Dec 25 Period

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	F/N	Depreciable Plant Balances 10/31/2025	Plant Additions	Depreciable Adjusted Plant Balances 12/31/2025	Depr. Provision for Nov 25 - Dec 25 Period On Base Period Plant	Depr. Provision for Nov 25 - Dec 25 Period On Test Period Additions	Total
	[a]	[b]	[c]		[d]	[e]	[f]=[d]+[e]	[g]	[h]	[i] = [g]+[h]
19	Transmission Plant									
20	Mainline	2.49%			6,276,428,234	265,043,353	6,541,471,587	26,047,177	1,099,930	27,147,107
21	Right of Way	2.49%			82,583,163	817,158	83,400,321	342,720	3,391	346,111
22	Land Rights Renewal- 2.63%	2.63%			607,911	-	607,911	2,665	-	2,665
23	Land Rights Renewal- 3.33%	3.33%			4,405,176	-	4,405,176	24,449	-	24,449
24	Land Rights Renewal- 4.17%	4.17%			2,684,551	-	2,684,551	18,658	-	18,658
25	Land Rights Renewal- 5.0%	5.00%			3,594,770	-	3,594,770	29,956	-	29,956
26	Land Rights Renewal-20%	20.00%			-		-	-	-	-
27	Compressor Control Equipment	10.00%			62,039,590	2,604,994	64,644,584	1,033,993	43,417	1,077,410
28	Communication Equipment-Radio	10.00%			4,883,075	1,233,371	6,116,446	81,385	20,556	101,941
29	Onshore Interim Negative Salvage		0.10%		-		-	1,059,835	44,310	1,104,145
30	Offshore - Negative Salvage, ARO		775,935	1/	-		-	129,323	-	129,323
31	Total Onshore				6,437,226,470	269,698,876	6,706,925,346	28,770,161	1,211,604	29,981,765
32	Total Transmission Plant				6,437,226,470	269,698,876	6,706,925,346	28,770,161	1,211,604	29,981,765
33	Total Operating Facilities				$ 7,364,353,640	314,398,180	7,678,751,820	31,567,361	$ 1,325,850	$ 32,893,211
34	Intangible Plant									
35	Intangible Plant - Software	13.00%			175,756,044	(5,529,616)	170,226,428	3,808,048	(119,808)	3,688,240
36	Intangible Cost - CIACs	10.00%			38,508,460	57,292	38,565,752	641,808	955	642,763
37	Intangible Cost - Leasehold Improvements				-	-	-	-	-	-
38	Intangible Cost - Leasehold Improvements - Fully Depreciated				-	-	-	-	-	-
39	Total Intangible Plant				214,264,504	(5,472,324)	208,792,180	4,449,856	(118,853)	4,331,003

NORTHERN NATURAL GAS COMPANY

Calculation of Depreciation Provision
for Nov 25 - Dec 25 Period

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	F/N	Depreciable Plant Balances 10/31/2025	Plant Additions	Depreciable Adjusted Plant Balances 12/31/2025	Depr. Provision for Nov 25 - Dec 25 Period On Base Period Plant	Depr. Provision for Nov 25 - Dec 25 Period On Test Period Additions	Total
	[a]	[b]	[c]		[d]	[e]	[f]=[d]+[e]	[g]	[h]	[i] = [g]+[h]
40	General Plant									
41	Structures & Improvements	2.75%			40,050,961	672,296	40,723,257	183,567	3,081	186,648
42	Office Computer Equipment	20.00%			16,569,001	-	16,569,001	552,300	-	552,300
43	Office Furniture & Equipment	10.00%			12,664,183	(1,913,122)	10,751,061	211,070	(31,885)	179,185
44	Tools, Shop & Garage Equip	10.00%			35,647,501	18,157	35,665,658	594,125	303	594,428
45	Laboratory Equipment	10.00%			2,220,184	-	2,220,184	37,003	-	37,003
46	Communication Equipment	10.00%			1,524,866	829,585	2,354,451	25,414	13,826	39,240
47	Transportation Equipment	10.00%			-	-	-	-	-	-
48	Transportation & Power Operated Equipment	10.00%			47,842,845	-	47,842,845	797,381	-	797,381
49	Miscellaneous Equipment	10.00%			887,179	-	887,179	14,786	-	14,786
50	Total General Plant	10.00%			157,406,720	(393,084)	157,013,636	2,415,646	(14,675)	2,400,971
51	Total Depreciable Plant				$ 7,736,024,864	308,532,772	8,044,557,636	38,432,863	$ 1,192,322	$ 39,625,185
52	Non-Depreciable Plant									
53	Land				10,351,730	817,672	11,169,402			
54	Plant Held for Future Use				6,625,032		6,625,032			
55	Transmission Recoverable Line Pack				4,898,155		4,898,155			
56	Organization Costs - Fully Amortized				4,841,691		4,841,691			
57	Total Non-Depreciable Plant				$ 26,716,608	817,672	27,534,280			
58	Fully Depreciated/Amortized Plant to Retire									
59	Mainline				15,618,784	-	15,618,784			
60	Land Rights Renewal				700,317	-	700,317			
61	Total Fully Depreciable Plant to Retire				16,319,101	-	16,319,101			
62	Total Gas Plant in Service				$ 7,779,060,573	309,350,444	8,088,411,017			

1/ Represents 9 months of ARO recovery recorded in FERC Account 108.

NORTHERN NATURAL GAS COMPANY

Depreciation and Amortization Expense
Test Period Ended December 31, 2025

Line No.	Particulars	Test Period Plant October 31, 2025: Depreciation Provision	Test Period Plant October 31, 2025: Negative Salvage Provision	Test Period Plant October 31, 2025: Total Depreciation Provision	Adjustments: Depreciation	Adjustments: Negative Salvage	Adjustments: Total Adjustment	End of Test Period Plant: Depreciation Provision	End of Test Period Plant: Negative Salvage Provision	End of Test Period Plant: Total Depreciation Provision	F/N
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	
1	Natural Gas Storage Plant										
2	Underground Storage Plant	9,951,214	-	9,951,214	15,070,014	5,421,199	20,491,213	25,021,228	5,421,199	30,442,427	
3	LNG Storage Plant	6,634,080	-	6,634,080	(101,869)	1,887,821	1,785,952	6,532,212	1,887,821	8,420,032	
4	Total Natural Gas Storage Plant	16,585,295	-	16,585,295	14,968,145	7,309,019	22,277,164	31,553,440	7,309,019	38,862,459	
5	Base Load LNG Terminal & Processing Plant	197,906	-	197,906	(8,570)	50,807	42,237	189,336	50,807	240,143	
6	Transmission Plant	165,486,015	7,134,946	172,620,961	84,516,268	71,002,160	155,518,428	250,002,283	78,137,107	328,139,389	
7	General Plant	14,493,877	-	14,493,877	(88,050)	-	(88,050)	14,405,828	-	14,405,828	
8	Intangible Plant	26,699,132	-	26,699,132	(713,121)	-	(713,121)	25,986,011	-	25,986,011	
9	Total Depreciation and Amortization Expense	$ 223,462,225	$ 7,134,946	$ 230,597,171	$ 98,674,672	$ 78,361,986	$ 177,036,658	$ 322,136,897	$ 85,496,932	$ 407,633,829	1/

1/ Column [j] ties to Schedule H-2 (1), column [k], line 60

NORTHERN NATURAL GAS COMPANY

Calculation of Test Period Depreciation and Amortization Expense
Test Period Ended December 31, 2025

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Annual Proposed Rate	Annual Proposed Negative Salvage	Depreciable Book Plant Balances 10/31/2025	Test Period Adjustments					Annual Depreciation Expense	Annual Negative Salvage	Total Annual Provision	F/N
							Plant Additions	Plant Transfer	Plant Retirements	Period Adjustments	Test Period Plant				
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k] = [f]+[j]	[l]=[k]*[d]	[m]=[k]*[e]	[n]=[l]+[m]	
1	Natural Gas Storage Plant														
2	Underground Storage														
5	Operating Plant	1.25%	0.00%	3.27%	0.75%	$ 661,743,152	$ 37,817,208	$ -	$ (1,703,549)	$ 36,113,659	$ 697,856,811	$ 22,819,918	$ 5,233,926	$ 28,053,844	
3	Storage Leaseholds and Rights	1.25%	0.00%	3.27%	0.75%	21,961,106	-	-	-	-	21,961,106	718,128	164,708	882,836	
4	Rights-of-way	1.25%	0.00%	3.27%	0.75%	1,782,481	1,226,085	-	-	1,226,085	3,008,566	98,380	22,564	120,944	
6	Shop, Communication, & Office Equipment	10.00%	0.00%	10.00%	0.00%	2,310,130	-	-	-	-	2,310,130	231,013	-	231,013	
7	Compressor Computer Control Systems	10.00%	0.00%	10.00%	0.00%	11,516,171	21,722	-	-	21,722	11,537,893	1,153,789	-	1,153,789	
8	Total Underground Storage					699,313,040	39,065,015	-	(1,703,549)	37,361,466	736,674,506	25,021,228	5,421,199	30,442,427	
9	LNG Storage														
10	Operating Plant	2.95%	0.00%	2.81%	0.83%	220,111,732	7,336,525	-	-	7,336,525	227,448,257	6,391,296	1,887,821	8,279,117	
11	Computer Control Systems	10.00%	0.00%	10.00%	0.00%	1,407,844	1,313	-	-	1,313	1,409,157	140,916	-	140,916	
12	Total Other Storage Plant					221,519,576	7,337,838	-	-	7,337,838	228,857,414	6,532,212	1,887,821	8,420,032	
13	Total Natural Gas Storage Plant					920,832,616	46,402,853	-	(1,703,549)	44,699,304	965,531,920	31,553,440	7,309,019	38,862,459	
14	Base Load LNG Terminal & Processing Plant														
15	LNG Processing Terminal Equipment	2.95%	0.00%	2.81%	0.83%	6,121,269	-	-	-	-	6,121,269	172,008	50,807	222,814	
16	LNG Transportation Equipment	10.00%	0.00%	10.00%	0.00%	-	-	-	-	-	-	-	-	-	
17	LNG Computers	10.00%	0.00%	10.00%	0.00%	173,285	-	-	-	-	173,285	17,329	-	17,329	
18	Total Base Load LNG Terminal & Processing Plant					6,294,554	-	-	-	-	6,294,554	189,336	50,807	240,143	
19	Transmission Plant														
20	Mainline	2.49%	0.10%	3.66%	1.16%	6,276,428,234	275,603,946	-	(10,560,593)	265,043,353	6,541,471,587	239,419,363	75,881,070	315,300,433	
21	Right of Way	2.49%	0.10%	3.66%	1.16%	82,583,163	817,158	-	-	817,158	83,400,321	3,052,452	967,444	4,019,895	
22	Land Rights Renewal- 2.63%	2.63%	0.00%	2.63%	0.00%	607,911	-	-	-	-	607,911	15,988	-	15,988	
23	Land Rights Renewal- 3.33%	3.33%	0.00%	3.33%	0.00%	4,405,176	-	-	-	-	4,405,176	146,692	-	146,692	
24	Land Rights Renewal- 4.17%	4.17%	0.00%	4.17%	0.00%	2,684,551	-	-	-	-	2,684,551	111,946	-	111,946	
25	Land Rights Renewal- 5.0%	5.00%	0.00%	5.00%	0.00%	3,594,770	-	-	-	-	3,594,770	179,738	-	179,738	
26	Land Rights Renewal-20%	20.00%	0.00%	20.00%	0.00%	-	-	-	-	-	-	-	-	-	
27	Compressor Control Equipment	10.00%	0.00%	10.00%	0.00%	62,039,590	2,604,994	-	-	2,604,994	64,644,584	6,464,458	-	6,464,458	
28	Communication Equipment-Radio	10.00%	0.00%	10.00%	0.00%	4,883,075	1,233,371	-	-	1,233,371	6,116,446	611,645	-	611,645	
29	Offshore - Negative Salvage, ARO				$ 1,288,592	-	-	-	-	-	-	-	1,288,592	1,288,592	
30	Total Transmission					6,437,226,470	280,259,469	-	(10,560,593)	269,698,876	6,706,925,346	250,002,283	78,137,107	328,139,389	
31	Total Transmission Plant					6,437,226,470	280,259,469	-	(10,560,593)	269,698,876	6,706,925,346	250,002,283	78,137,107	328,139,389	

NORTHERN NATURAL GAS COMPANY

Calculation of Test Period Depreciation and Amortization Expense
Test Period Ended December 31, 2025

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Annual Proposed Rate	Annual Proposed Negative Salvage	Depreciable Book Plant Balances 10/31/2025	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] = [f]+[j]	[l]=[k]*[d]	[m]=[k]*[e]	[n]=[l]+[m]	
32	Intangible Plant														
33	Intangible Plant - Other	13.00%	0.00%	13.00%	0.00%	175,756,044	8,627,021	-	(14,156,637)	(5,529,616)	170,226,428	22,129,436	-	22,129,436	
34	Intangible Cost - CIACs	10.00%	0.00%	10.00%	0.00%	38,508,460	57,292	-	-	57,292	38,565,752	3,856,575	-	3,856,575	
35	Intangible Cost - Leasehold Improvements	10.00%	0.00%	10.00%	0.00%	-	-	-	-	-	-	-	-	-	
36	Total Intangible Plant					214,264,504	8,684,313	-	(14,156,637)	(5,472,324)	208,792,180	25,986,011	-	25,986,011	
37	General Plant														
38	Structures & Improvements	2.75%	0.00%	2.75%	0.00%	40,050,961	672,296	-	-	672,296	40,723,257	1,119,890	-	1,119,890	
39	Office Computer Equipment	20.00%	0.00%	20.00%	0.00%	16,569,001	-	-	-	-	16,569,001	3,313,800	-	3,313,800	
40	Office Furniture and Equipment	10.00%	0.00%	10.00%	0.00%	12,664,183	542,228	-	(2,455,350)	(1,913,122)	10,751,061	1,075,106	-	1,075,106	
41	Tools, Shop & Garage Equip	10.00%	0.00%	10.00%	0.00%	35,647,501	18,157	-	-	18,157	35,665,658	3,566,566	-	3,566,566	
42	Laboratory Equipment	10.00%	0.00%	10.00%	0.00%	2,220,184	-	-	-	-	2,220,184	222,018	-	222,018	
43	Communication Equipment	10.00%	0.00%	10.00%	0.00%	1,524,866	829,585	-	-	829,585	2,354,451	235,445	-	235,445	
44	Transportation & Power Operated Equipment	10.00%	0.00%	10.00%	0.00%	47,842,845	-	-	-	-	47,842,845	4,784,285	-	4,784,285	
45	Miscellaneous Equipment	10.00%	0.00%	10.00%	0.00%	887,179	-	-	-	-	887,179	88,718	-	88,718	
46	Total General Plant					157,406,720	2,062,266	-	(2,455,350)	(393,084)	157,013,636	14,405,828	-	14,405,828	
47															
48	Total Depreciable Plant					7,736,024,864	337,408,901	-	(28,876,129)	308,532,772	8,044,557,636	322,136,897	85,496,932	407,633,829	
49	Non-Depreciable Plant														
50	Land					10,351,730	817,672	-	-	817,672	11,169,402				
51	Plant Held for Future Use - Mainline					6,625,032	-	-	-	-	6,625,032				
52	Plant Held for Future Use - Right of Way					-		-		-	-				
53	Transmission Recoverable Linepack					4,898,155	-	-	-	-	4,898,155				
54	Organization Costs - Fully Amortized					4,841,691	-	-	-	-	4,841,691				
55	Total Non-Depreciable Plant					26,716,608	817,672	-	-	817,672	27,534,280				
56	Fully Depreciated Plant to Retire														
57	Mainline					15,618,784	-	-	-	-	15,618,784				
58	Land Rights Renewal					700,317	-	-	-	-	700,317				
59	Total Fully Depreciable Plant to Retire					16,319,101	-	-	-	-	16,319,101				
60	Total Gas Plant in Service					$ 7,779,060,573	$ 338,226,573	$ -	$ (28,876,129)	$ 309,350,444	$ 8,088,411,017	$ 322,136,897	$ 85,496,932	$ 407,633,829	

NORTHERN NATURAL GAS COMPANY

Calculation of Base Period Depreciation and Amortization Expense
12-Month Period Ended October 31, 2025

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Adjusted Balance 10/31/2025	Annual Depreciation Expense	Annual Negative Salvage Provision	Total Annual Base Period Provision
	[a]	[b]	[c]	[d]	[e]=[d]*[b]	[f]=[d]*[c]	[g]=[e]+[f]
1	Natural Gas Storage Plant						
2	Underground Storage						
3	Operating Plant	1.25%	0.00%	661,743,152	8,271,789	-	8,271,789
4	Storage Leaseholds and Rights	1.25%	0.00%	21,961,106	274,514	-	274,514
5	Rights-of-way	1.25%	0.00%	1,782,481	22,281	-	22,281
6	Shop, Communication, & Office Equipment	10.00%	0.00%	2,310,130	231,013	-	231,013
7	Compressor Computer Control Systems	10.00%	0.00%	11,516,171	1,151,617	-	1,151,617
8	Total Underground Storage Plant			699,313,040	9,951,214	-	9,951,214
9	LNG Storage						
10	Operating Plant	2.95%	0.00%	220,111,732	6,493,296	-	6,493,296
11	Computer Control Systems	10.00%	0.00%	1,407,844	140,784	-	140,784
12	Total LNG Storage Plant			221,519,576	6,634,080	-	6,634,080
13	Total Natural Gas Storage Plant			920,832,616	16,585,295	-	16,585,295
14	Base Load LNG Terminal & Processing Plant						
15	LNG Processing Terminal Equipment	2.95%	0.00%	6,121,269	180,577	-	180,577
16	LNG Transportation Equipment	10.00%	0.00%	-	-	-	-
17	LNG Computers	10.00%	0.00%	173,285	17,329	-	17,329
18	Total Base Load LNG Terminal & Processing Plant			6,294,554	197,906	-	197,906

NORTHERN NATURAL GAS COMPANY

Calculation of Base Period Depreciation and Amortization Expense
12-Month Period Ended October 31, 2025

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Adjusted Balance 10/31/2025	Annual Depreciation Expense	Annual Negative Salvage Provision	Total Annual Base Period Provision
	[a]	[b]	[c]	[d]	[e]=[d]*[b]	[f]=[d]*[c]	[g]=[e]+[f]
19	Transmission Plant						
20	Mainline	2.49%	0.10%	6,276,428,234	156,283,063	6,276,428	162,559,491
21	Right of Way	2.49%	0.10%	82,583,163	2,056,321	82,583	2,138,904
22	Land Rights Renewal- 2.63%	2.63%	0.00%	607,911	15,988	-	15,988
23	Land Rights Renewal- 3.33%	3.33%	0.00%	4,405,176	146,692	-	146,692
24	Land Rights Renewal- 4.17%	4.17%	0.00%	2,684,551	111,946	-	111,946
25	Land Rights Renewal- 5.0%	5.00%	0.00%	3,594,770	179,738	-	179,738
26	Compressor Control Equipment	10.00%	0.00%	62,039,590	6,203,959	-	6,203,959
27	Communication Equipment-Radio	10.00%	0.00%	4,883,075	488,308	-	488,308
	Offshore - Negative Salvage, ARO		$ 775,935	-	-	775,935	775,935
28	Total Transmission			6,437,226,470	165,486,015	7,134,946	172,620,961
29	Total Transmission Plant			6,437,226,470	165,486,015	7,134,946	172,620,961
30	Total Operating Facilities			7,364,353,640	182,269,216	7,134,946	189,404,162
31	Intangible Plant						
32	Intangible Plant - Other	13.00%	0.00%	175,756,044	22,848,286	-	22,848,286
33	Intangible Cost - CIACs	10.00%	0.00%	38,508,460	3,850,846	-	3,850,846
34	Intangible Cost - Leasehold Improvements	10.00%	0.00%	-	-	-	-
35	Total Intangible Plant			214,264,504	26,699,132	-	26,699,132

NORTHERN NATURAL GAS COMPANY

Calculation of Base Period Depreciation and Amortization Expense
12-Month Period Ended October 31, 2025

Line No.	Particulars	Annual Rate Per Books	Annual Negative Salvage Rate	Adjusted Balance 10/31/2025	Annual Depreciation Expense	Annual Negative Salvage Provision	Total Annual Base Period Provision
	[a]	[b]	[c]	[d]	[e]=[d]*[b]	[f]=[d]*[c]	[g]=[e]+[f]
36	General Plant						
37	Structures & Improvements	2.75%	0.00%	40,050,961	1,101,401	-	1,101,401
38	Office Computer Equipment	20.00%	0.00%	16,569,001	3,313,800	-	3,313,800
39	Office Furniture and Equipment	10.00%	0.00%	12,664,183	1,266,418	-	1,266,418
40	Tools, Shop & Garage Equip	10.00%	0.00%	35,647,501	3,564,750	-	3,564,750
41	Laboratory Equipment	10.00%	0.00%	2,220,184	222,018	-	222,018
42	Communication Equipment	10.00%	0.00%	1,524,866	152,487	-	152,487
43	Transportation & Power Operated Equipment	10.00%	0.00%	47,842,845	4,784,285	-	4,784,285
44	Miscellaneous Equipment	10.00%	0.00%	887,179	88,718	-	88,718
45	Total General Plant			157,406,720	14,493,877	-	14,493,877
46	Total Depreciable Plant			7,736,024,864	223,462,225	7,134,946	230,597,171
47	Non-Depreciable Plant						
48	Land			10,351,730			
49	Plant Held for Future Use - Mainline			6,625,032			
50	Plant Held for Future Use - Right of Way			-			
51	Transmission Recoverable Line Pack			4,898,155			
52	Organization Costs - Fully Amortized			4,841,691			
53	Total Non-Depreciable Plant			26,716,608			
54	Fully Depreciated Plant to Retire						
55	Mainline			15,618,784			
56	Land Rights Renewal			700,317			
57	Total Fully Depreciable Plant to Retire			16,319,101			
58	Total Gas Plant in Service			$ 7,779,060,573	$ 223,462,225	$ 7,134,946	$ 230,597,171

NORTHERN NATURAL GAS COMPANY

Computation of Federal and State Income Taxes
Test Period Ended December 31, 2025

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	$ 88,958,779			
3	Allowance on Common Stock Equity		H-3, P. 2	446,487,757			
4	Total Return Allowance		B	535,446,536	68,603,066	466,843,469	1/
5	Eliminate Interest Expense (Line 2)		H-3, P. 2	(88,958,779)	(11,397,674)	(77,561,105)	1/
6	Taxable Portion of Return Allowance [Line 4 + Line 5]			446,487,757	57,205,392	389,282,364	
7	Adjustments:						
8	Amortization of under funded deferred income taxes		H-3[2]	-	-	-	
9	Amortization of Equity AFUDC			$4,186,388	536,373	3,650,015	
10	Total Adjustments			4,186,388	536,373	3,650,015	
11	Taxable Income After Income Taxes [Line 6 + Line 10]			450,674,145	57,741,765	392,932,379	
12	Add: Federal Income Tax	[26.58%	of line 11]	119,799,455			
13	Taxable Income Before Income Taxes			$ 570,473,600			
14	Federal Income Tax Applicable To:						
15	Common Stock Equity Component	[26.58%	of line 6]	118,686,618	15,206,497	103,480,121	2/
16	Other Tax Adjustments Component	[26.58%	of line 10]	1,112,837	142,580	970,257	2/
17	Total Federal Income Tax	[21.00%	of line 13]	119,799,455	15,349,077	104,450,378	2/
18	State Income Tax Applicable To:						
19	Common Stock Equity Component	[6.53%	of line 6 + 17]	36,958,849	4,735,282	32,223,567	2/
20	Other Tax Adjustments Component	[6.53%	of line 10]	273,225	35,006	238,219	2/
21	Total State Income Tax	[6.13%	of line 13+19+20]	37,232,074	4,770,288	32,461,786	2/
22	Total Federal and State Income Taxes			$ 157,031,529			

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, 2025

Line No.	Particulars	% of Rate Base	F/N	Amount
	[a]	[b]		[c]
1	Test Period Rate Base		1/	$ 5,246,108,039
2	Test Period Return Allowances by Components:			
3	Interest Expense	1.70%	2/	88,958,779
4	Allowance on Common Stock Equity	8.51%	2/	446,487,757
5	Total Return Allowance	10.21%	2/	535,446,536
6	Interest Expense Applicable to Investment			
7	in Rate Base [Line 3]			$ 88,958,779

1/ Statement B Line 15.

2/ Statement F- 2

NORTHERN NATURAL GAS COMPANY

State Income Tax Rate
Test Period Ended December 31, 2025

Line No.	Particulars	Total	Florida	Georgia	Illinois	Iowa	Kansas	Louisiana	Michigan	Minnesota	Nebraska	New Mexico	North Carolina	North Dakota	Oklahoma	Texas 4/	Wisconsin		F/N
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	(m)	(n)	(o)	(p)	(q)		
1	Taxable Income After Income Tax	$ 450,674,145																	1/
2	Add: Federal Income Tax	119,799,455																	1/
3	Total	$ 570,473,600																	
4	Taxable Income for Apportionment	$ 570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600	570,473,600		
5	Less Federal Income Tax Deduction		-	-	-	-	-	-	-	-	-	-	-	-	-	-			
6	Add Back State Income Taxes																		
7	Not Allowed as a Deduction:																		
8	Own State		879	-	144,088	-	5,735,231	-	329,799	11,472,588	-	192,194	-	-	966,909	-	1,575,641	-	
9	Other States		34,979,600	34,980,479	-	-	29,240,492	34,980,479	34,650,409	23,498,287	-	34,788,127	34,980,479	34,980,479	34,012,775	34,765,032	33,403,540	-	
10	Total for Apportionment		605,454,078	605,454,079	570,617,688	570,473,600	605,449,323	605,454,079	605,453,808	605,444,475	570,473,600	605,453,921	605,454,079	605,454,079	605,453,283	605,238,631	605,452,781	-	
11	Apportionment Factors		0.00264%	0.00000%	0.26580%	22.92616%	14.57717%	0.00000%	0.90786%	19.33575%	16.96933%	0.53803%	0.00000%	0.00000%	3.99250%	0.00000%	3.29420%		2/
12	Net Apportioned Taxable Income		15,975	-	1,516,721	130,787,689	88,257,399	-	5,496,646	117,067,223	96,805,546	3,257,529	-	-	24,172,722	-	19,944,826	-	
13	Less Amounts Taxed at Other Rates		-	-	-	100,000	50,000	-	-	-	-	-		50,000	-	-	-	-	
14	Amount Subject to State Tax Rate		15,975	-	1,516,721	130,687,689	88,207,399	-	5,496,646	117,067,223	96,805,546	3,257,529	-	(50,000)	24,172,722	-	19,944,826	-	
15	Tax Rate - %		5.5000%	5.3900%	9.5000%	7.1000%	6.5000%	5.5000%	6.0000%	9.8000%	5.2000%	5.9000%	2.2500%	4.3100%	4.0000%		7.9000%		3/
16	Subtotal [Line 14*Line 15]		$ 879	$ -	$ 144,088	$ 9,278,826	$ 5,733,481	$ -	$ 329,799	$ 11,472,588	$ 5,033,888	$ 192,194	$ -	$ (2,155)	$ 966,909	$ -	$ 1,575,641	$ -	
17	Tax on Line 13 Amounts				-	5,500	1,750	-	-	-	-	-		1,240	-	-	-	-	
18	Apportioned State Income Taxes	$ 34,950,991	$ 879	$ -	$ 144,088	$ 9,284,326	$ 5,735,231	$ -	$ 329,799	$ 11,472,588	$ 5,033,888	$ 192,194	$ -	$ -	$ 966,909	$ 215,447	$ 1,575,641	$ -	
19	Composite State Income Tax Rate [Line 18/Line 4]	6.1267%																	
20	Gross-Up State Income Taxes	$ 37,232,074																	

1/ From Statement H[3], Page 1, Lines 11 and 12.
2/ Apportionment data available is for the Year 2023
3/ State income tax rates available are for the Year 2025
4/ Texas income tax covered under "gross receipt" taxes.

Line No.	Particulars	Schedule Reference	Total Costs	Storage Costs	Transmission Costs
	(a)		(b)	(c)	(d)
1	O & M Expense	H-1	$ 430,862,695	$ 63,451,611	$ 367,411,084
2					
3	Depreciation and Amortization of Gas Plant in Service	H-2, B-2	392,227,860	42,063,726	350,164,134
4					
5	Taxes				
6	Federal Income Tax	H-3	119,799,455	15,349,077	104,450,378
7					
8	State Income Tax	H-3	37,232,074	4,770,288	32,461,786
9					
10	Taxes Other Than Income	H-4	99,820,206	13,019,129	86,801,077
11					
12	Return	B	535,446,535	68,603,066	466,843,469
13					
14	Other Operating Revenue	G-5	(616,873.43)	-	(616,873.43)
15					
16					
17	Total Overall Cost of Service		$ 1,614,771,952	$ 207,256,897	$ 1,407,515,055

Line No.	Particulars	Schedule 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	$	202,267,281
3	Variable Costs	Col. (b), L. 6		4,989,616
4				
5	Transmission Costs			
6	Fixed Costs -- Mileage	Col. (b), L. 11 + L. 12		1,255,255,594
7	Variable Costs -- Mileage	Col. (b), L. 14		35,250,252
8				
9	Other Non-Mileage			
10	Fixed Costs	Col. (b), L. 16		117,009,210
11	Total Classified Cost of Service		$	1,614,771,952
12				
13	Fixed Costs		$	1,574,532,084
14	Variable Costs			40,239,868
15	Total Cost of Service Allocated in Schedule I-1(a)		$	1,614,771,952

Line No.	Particulars (a)	Total Overall Cost of Service (b)	Operation & Maintenance Expenses (c)	Depreciation, Depletion & Amortization (d)	Taxes: Federal Income (e)	Taxes: State Income (f)	Taxes: Other than Income (g)	Return (h)	Other Operating Revenues (i)
1	Storage Costs:								
2	Fixed:								
3	Return and Related Income Taxes	$ 88,722,431	$ -	$ -	$ 15,349,077	$ 4,770,288	$ -	$ 68,603,066	$ -
4	Other Fixed	113,544,850	58,461,995	42,063,726	-	-	13,019,129	-	-
5	Variable:								
6	Other Variable	4,989,616	4,989,616	-	-	-	-	-	-
7	Total Storage Costs	$ 207,256,897	$ 63,451,611	$ 42,063,726	$ 15,349,077	$ 4,770,288	$ 13,019,129	$ 68,603,066	$ $ -
8									
9	Transmission Costs:								
10	Mileage -- Fixed:								
11	Return and Related Income Taxes	$ 603,755,633	$ -	$ -	$ 104,450,378	$ 32,461,786	$ -	$ 466,843,469	$ -
12	Other Mileage Fixed	651,499,961	215,151,622	350,164,134	-	-	86,801,077	-	(616,873)
13	Mileage -- Variable:								
14	Other Mileage Variable	35,250,252	35,250,252	-	-	-	-	-	-
15									
16	Other Non-Mileage Fixed Costs	117,009,210	117,009,210	-	-	-	-	-	-
17	Total Transmission Costs	$ 1,407,515,055	$ 367,411,084	$ 350,164,134	$ 104,450,378	$ 32,461,786	$ 86,801,077	$ 466,843,469	$ (616,873)
18									
19	Total Cost of Service	$ 1,614,771,952	$ 430,862,695	$ 392,227,860	$ 119,799,455	$ 37,232,074	$ 99,820,206	$ 535,446,535	$ (616,873)

Line No.	Particulars		Storage		Transmission Mileage		Transmission All Other		Total
	(a)		(b)		(c)		(d)		(e)
1	Total Classified Overall Fixed Cost of Service: 1/	$	202,267,281	$	1,255,255,594	$	117,009,210	$	1,574,532,084
2									
3	Less: Costs Assigned to Specific Services								
4	Transmission				-		-		-
5	Storage 2/		202,267,281						202,267,281
6									
7	Total Costs Assigned to Specific Services		202,267,281		-		-		202,267,281
8	Net Classified Overall								
9	Cost of Service	$	-	$	1,255,255,594	$	117,009,210	$	1,372,264,803
10									
11	1/ Fixed costs per Schedule I-1(a), Page 2, Line 13								
12	2/ Storage fixed costs per 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/	$ 4,989,616	$ 35,250,252	$ 40,239,868
2				
3	Less: Costs Assigned to Specific Services			
4				
5	Transmission		-	-
6				
7	Storage 2/	4,989,616		4,989,616
8				
9	Total Costs Assigned to Specific Rate Schedules & Services	$ 4,989,616	$ -	$ 4,989,616
10	Net Classified Overall			
11	Cost of Service	$ -	$ 35,250,252	$ 35,250,252
12				
13	1/ Variable costs per Schedule I-1(a), Page 2, Line 14			
14	2/ Variable Storage costs per Schedule I-1(a), Page 2, Line 3			

Line No.	Particulars (a)		Rate (b)	Volume (c)		Amount (d)
1	Underground Storage Service Revenue	1/				
2	Proposed FDD Rates:					
3	Reservation	$	4.7237	12,060,805	$	56,972,209
4	Capacity		0.9832	57,947,305		56,972,209
5	Injection		0.0228	68,955,337		1,572,445
6	Withdrawal	$	0.0228	68,955,337		1,572,445
7	Total FDD Revenue to Cost of Service				$	117,089,307
8						
9	Revenue Credits					
10	MBR Reservation Revenue				$	10,167,974
11	MBR Commodity Revenue					364,861
12	Discounted FDD Reservation Revenue					2,445,174
13	Total Revenue Credits for Storage	2/			$	12,978,009
14						
15	LNG Directly Assigned to Transmission					
16	Total Costs to Market Area Demand Rate				$	43,951,586
17	Total Costs to Market Area Commodity Rate					1,023,797
18	Total LNG Directly Assigned to Transmission	3/			$	44,975,384
19						
20	Operational Storage Allocation to Transmission					
21	Total Costs to Market Area Demand Rate				$	31,658,128
22	Total Cost to Field Area Demand Rate					100,000
23	Total Costs to Market Area Commodity Rate					456,069
24	Total Operational Storage Costs to Transmission	4/			$	32,214,198
25						
26	Total Storage Related Revenue to Cost of Service				$	207,256,897
27						
28	Classification of Storage Cost of Service					
29	Storage Demand				$	202,267,281
30	Storage Variable					4,989,616
31	Total Classified Storage Revenue				$	207,256,897
32						
33	1/ Schedule J-2, Page 6, Line 26					
34	2/ Schedule J-2, Page 6, Lines 14 - 16					
35	3/ Schedule I-a(1), Line 15					
36	4/ Schedule I-3(d), Line 30, Column (d)					

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)	$	65,771,604	$	10,139,062	$	55,632,542
3	Excluding Administrative and	(Lines 56 & 89)						
4	General							
5	Ratio - %			100.00%		15.42%		84.58%
6	Net Utility Plant (excluding Intangible Plant)							
7	Test Period Classified	B	$	6,071,265,150	$	777,869,269	$	5,293,395,881
8	Ratio - %	(Line 2 less 7)		100.00%		12.81%		87.19%
9	Kansas Nebraska Method							
10	KN Allocated A&G (See Page 2)	H-1	$	138,149,716	$	21,140,506	$	117,009,210
11	Ratio - % (See Page 2)			100.00%		15.30%		84.70%

NORTHERN NATURAL GAS COMPANY

Calculation of Kansas Nebraska Formula

Line No.	Particulars	Split Between Labor, Plant and Other: As Filed	As Adjusted	Labor Related	Plant Related	Total Lab & Plant	Calculation of Kansas Nebraska Ratio: Other	Labor Related	Plant Related	Total	Allocated A&G	Direct O&M	Total by Function
	[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]
1	910	-	-	-	-	-	-	-	-	-			
2	912	-	-	-	-	-	-	-	-	-			
3	913	-	-	-	-	-	-	-	-	-			
4	920	57,790,747	57,790,747	57,790,747	-	57,790,747	-	57,790,747	-	57,790,747			
5	921	18,363,332	18,363,332	18,363,332	-	18,363,332	-	18,363,332	-	18,363,332			
6	922-L	-	-	-	-	-	-	-	-	-			
7	922-O	9,174	9,174	-	-	-	9,174	-	-	9,174			
8	923-L	1,108,717	1,108,717	1,108,717	-	1,108,717	-	1,108,717	-	1,108,717			
9	923-O	20,056,345	20,056,345	-	-	-	20,056,345	-	-	20,056,345			
10	924	4,353,889	4,353,889	-	4,353,889	4,353,889	-	-	4,353,889	4,353,889			
11	925	2,973,887	2,973,887	2,973,887	-	2,973,887	-	2,973,887	-	2,973,887			
12	926	24,752,427	24,752,427	24,752,427	-	24,752,427	-	24,752,427	-	24,752,427			
13	928	2,026,800	2,026,800	-	-	-	2,026,800	-	-	2,026,800			
14	930.1	580,738	580,738				580,738						
15	930.2	5,216,656	5,216,656	-	-	-	5,216,656	-	-	5,216,656			
16	931	583,361	583,361	583,361	-	583,361	-	583,361	-	583,361			
17	932	11,639	11,639	-	-	-	11,639	-	-	11,639			
18	426.1	165,441	165,441	-	-	-	165,441	-	-	165,441			
19	426.5	156,563	156,563	-	-	-	156,563	-	-	156,563			
20		138,149,716	138,149,716	105,572,471	4,353,889	109,926,361	28,223,355	105,572,471	4,353,889	137,568,978			
21		Labor/Plant Ratio		96.04%	3.96%			96.04%	3.96%	100.00%			
22							Transmission:	84.58%	87.44%				
23		Labor and Plant Ratios for Storage and Transmission											
24			Labor		Plant		KN Trans:	81.23%	3.46%	84.70%	$ 117,009,210	$ 250,401,874	$ 367,411,084
25		Transmission Labor & Plant	55,632,542	84.58%	6,740,633,174	87.44%							
26		Storage labor & Plant	10,139,062	15.42%	968,556,430	12.56%	Storage:	15.42%	12.56%				
27		Total	$ 65,771,604	100.00%	$ 7,709,189,604	100.00%							
28							KN Stor:	14.80%	0.50%	15.30%	$ 21,140,506	$ 42,311,105	$ 63,451,611
29										100.00%			$ 430,862,695
													(Stmt A, Line 1)

Line No.	Particulars		Storage Plant		Transmission Plant		Totals
	(a)		(b)		(c)		(d)
1	Depreciation, Depletion and Amortization Expense 1/						
2	Storage:						
3	Fixed Costs	$	42,063,726			$	42,063,726
4							
5	Transmission Allocated on a Mileage Basis:						
6	Fixed Costs				350,164,134		350,164,134
7							
8	Total Depreciation, Depletion and Amortization Expense	$	42,063,726	$	350,164,134	$	392,227,860
9							
10							
11	1/ Per Schedules 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	$	11,655,431	$	1,361,122	$	2,575	$	13,019,129
5									
6	Transmission Allocated on a Mileage Basis:								
7	Fixed Costs		79,315,140		7,468,413		17,525		86,801,077
8									
9	Total Taxes - Other than Income	$	90,970,571	$	8,829,535	$	20,100	$	99,820,206
10			2/		3/		2/		
11									
12	1/ Per Statement H-4								
13	2/ Allocated to functions on a net utility plant basis, per Schedule I-1(d)								
14	3/ Allocated to functions on Direct Labor basis, per Schedule I-1(d)								

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	-	-	-	-	(616,873)	(616,873)
7							
8	Total Other Operating Revenues-Credit	$ -	$ -	$ -	$ -	$ (616,873)	$ (616,873) 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	$	37,321,488	$		$	21,140,506	$	58,461,995	
5	Variable Costs		4,989,616						4,989,616	
6										
7	Transmission:									
8	Fixed Costs -- Mileage				215,151,622				215,151,622	
9	Variable Costs -- Mileage				35,250,252				35,250,252	
10										
11	Transmission :									
12	Other Non-Mileage Fixed Costs						117,009,210		117,009,210	
13										
14	Total Other Operation & Maintenance Expenses	$	42,311,105	$	250,401,874	$	138,149,716	$	430,862,695	1/
15										
16	1/ Per Schedule H-1									

Line No.	Particulars	Total	Fixed	Variable
	(a)	(b)	(c)	(d)
1	Underground Storage Expenses:			
2	Operation:			
3	Supervision and Engineering	$ 295,790	$ 295,790	$ -
4	Well Expenses - Fuel	-	-	-
5	Compressor Station Expenses - Payroll	423,509	423,509	-
6	Compressor Station Expenses - Supplies & Exp.	1,599,054	-	1,599,054
7	Compressor Station Expenses - Fuel	-	-	-
8	Purification Expenses - Payroll	285,076	285,076	-
9	Purification Expenses - Supplies & Expenses	-	-	-
10	Storage Service Expenses	82,994	-	82,994
11	Other Operating Expenses	4,729,271	4,729,271	-
12	Total Operation	$ 7,415,694	$ 5,733,646	$ 1,682,048
13				
14	Maintenance:			
15	Supervision and Engineering	$ 845,730	$ 845,730	$ -
16	Compressor Station Equipment - Payroll	684,924	684,924	-
17	Compressor Station Equipment - Supplies & Exp.	1,558,298	-	1,558,298
18	Purification Expenses - Payroll	225,223	225,223	-
19	Purification Expenses - Supplies & Expenses	725,473	-	725,473
20	Other Maintenance Expenses	23,486,090	23,486,090	-
21	Total Maintenance	$ 27,525,737	$ 25,241,966	$ 2,283,771
22	Total Underground Storage Expenses	$ 34,941,432	$ 30,975,612	$ 3,965,819
23				
24	LNG Storage Expenses:			
25	Operation:			
26	Supervision and Engineering	$ 133,746	$ 133,746	$ -
27	Power	1,516,215	1,516,215	-
28	Other Operating Expenses	2,869,528	2,869,528	-
29	Total Operation	$ 4,519,489	$ 4,519,489	$ -
30				
31	Maintenance:			
32	Supervision and Engineering	$ 228,314	$ 228,314	$ -
33	Gas Holders - Payroll	51,137	51,137	-
34	Gas Holders - Supplies & Expenses	-	-	-
35	Compr., Measuring & Other Equip.-Payroll	87,222	87,222	-
36	Compr., Measuring & Other Equip.- Supplies & Expenses	1,019,377	-	1,019,377
37	Other Maintenance Expense	1,464,135	1,459,714	4,421
38	Total Maintenance	$ 2,850,185	$ 1,826,388	$ 1,023,797
39				
40	Total LNG Storage Expenses	$ 7,369,673	$ 6,345,876	$ 1,023,797
41				
42				
43				
44	Total Underground and LNG Storage Expense	$ 42,311,105	$ 37,321,488	$ 4,989,616
45				
46	Administrative and General Expenses:			
47	Underground Storage	$ 21,140,506	$ 21,140,506	$ -
48				
49	Total Natural Gas Storage Expenses	$ 63,451,611	$ 58,461,995	$ 4,989,616

Line No.	Particulars		Total		Fixed		Variable
	(a)		(b)		(c)		(d)
1	Transmission Expenses:						
2	Operation:						
3	Supervision & Engineering	$	3,520,784	$	3,520,784	$	-
4	Compressor Station Expenses						
5	Payroll		8,533,904		8,533,904		-
6	Supplies and Expenses		11,201,109		-		11,201,109
7	Transportation & Compression						
8	of Gas by Others		-		-		-
9	SPR Encroachment		-		-		
10	Other Operating Expenses		28,521,534		28,521,534		-
11	Other Gas Supply Expenses		-		-		-
12	Other Expenses		7,875,644		7,875,644		-
13	Total Operation	$	59,652,975	$	48,451,866	$	11,201,109
14							
15	Maintenance:						
16	Supervision & Engineering	$	2,328,026	$	2,328,026	$	-
17	Compressor Station Equipment						
18	Payroll		12,370,552		12,370,552		-
19	Supplies and Expenses		24,049,143		-		24,049,143
20	Other Maintenance Expenses		152,001,178		152,001,178		-
21	Total Maintenance	$	190,748,899	$	166,699,756	$	24,049,143
22							
23	Total Transmission Expenses	$	250,401,874	$	215,151,622	$	35,250,252
24							
25	Administrative and General Expenses:						
26	Transmission	$	117,009,210	$	117,009,210	$	-
27							
28	Total Transmission Expenses	$	367,411,084	$	332,160,832	$	35,250,252

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/	$	1,614,771,952	$	1,574,532,084	$	40,239,868
2	Less: Costs Assigned to Specific Rate Schedules & Services		207,256,897		202,267,281		4,989,616
3	Net Classified Cost of Service	$	1,407,515,055	$	1,372,264,803	$	35,250,252
4							
5	Allocation:						
6	Market Area	$	1,145,529,776	$	1,123,357,932	$	22,171,844
7	Field Area		261,985,279		248,906,872		13,078,407
8	Total	$	1,407,515,055	$	1,372,264,803	$	35,250,252
9					2/		3/
10							
11	1/ Schedule I-1(a), Page 2						
12	2/ Schedule I-3(a), Page 2						
13	3/ Schedule I-3(a), Page 3						

		Allocation of Costs				Allocation Percentages /2	
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/	$ 1,574,532,084	$ 202,267,281	$ 1,255,255,594	$ 117,009,210		
2	Less: Costs Assigned to Specific Rate Schedules & Services 1/	202,267,281	202,267,281	-	-		
3	Net Classified Cost of Service	$ 1,372,264,803	$ -	$ 1,255,255,594	$ 117,009,210		
4							
5	Allocation:						
6	Market Area	$ 1,123,357,932	$ -	$ 1,027,512,061	$ 95,845,871	0.818568	0.819131
7	Field Area	248,906,872	-	227,743,533	21,163,339	0.181432	0.180869
8	Total	$ 1,372,264,803	$ -	$ 1,255,255,594	$ 117,009,210	1.000000	1.000000
9							
10	1/ Schedule I-1(b), Page 1						
11	2/ Schedule I-3(b), Page 1						

		Allocation of Costs			Allocation Percentages 2/
Line No.	Particulars	Total Variable Costs 1/	Storage Variable Costs	Transmission Mileage Variable Costs	Transmission Mileage Variable Costs
	(a)	(b)	(c)	(d)	(e)
1	Total Classified Overall Cost of Service	$ 40,239,868	$ 4,989,616	$ 35,250,252	
2	Less: Costs Assigned to Specific Rate Schedules & Services	4,989,616	4,989,616	-	
3	Net Classified Cost of Service	$ 35,250,252	$ -	$ 35,250,252	
4					
5	Allocation:				
6	Market Area	$ 22,171,844	$ -	$ 22,171,844	62.90%
7	Field Area	13,078,407	-	13,078,407	37.10%
8	Total	$ 35,250,252	$ -	$ 35,250,252	100.00%
9					
10	1/ Schedule I-1(b), Page 2				
11	2/ Schedule I-3(b), Page 2				

NORTHERN NATURAL GAS COMPANY
Derivation of Fixed Cost Allocation Percentages

Line No.	Particulars	Allocation Factors 1/ Transmission Mileage Fixed Costs AMDCQ 2/ Miles	Allocation Factors 1/ All Other Fixed Costs AMDCQ 2/	Allocation Percentages Transmission Mileage Fixed Costs	Allocation Percentages All Other Fixed Costs
	(a)	(b)	(c)	(d)	(e)
1	Market Area	7,166,248,722	27,248,094	0.818568	0.819131
2					
3	Field Area	1,588,366,032	6,016,538	0.181432	0.180869
4					
5	Total	8,754,614,754	33,264,632	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	268,207,124	0.628984
2			
3	Field Area	158,206,221	0.371016
4			
5	Total	426,413,345	1.000000
6			
7	1/ Schedule I-3(c), Page 2; units are shown in 1,000s		

NORTHERN NATURAL GAS COMPANY
Development of Fixed Cost Allocation Factors

		For Allocation of Transmission Fixed Costs		
		Mileage Fixed Costs	All Other Fixed Costs	
Line No.	Particulars	AMDCQ Miles 1/	AMDCQ 2/	Average Miles of Haul 3/
	(a)	(b)	(c)	(d)
1	Allocation Factors:			
2				
3	Market Area	7,166,248,722	27,248,094	263
4				
5	Field Area	1,588,366,032	6,016,538	264
6				
7	Total	8,754,614,754	33,264,632	
8				

9 1/ Column (c) times Column (d)
10 2/ Schedule J-1, Page 1, Column (e)
11 3/ Based on Exhibit No. NNG-0014, Mileage Study Results for April 2024 to March 2025.

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	268,207,124	1,019,798,951	263
4					
5		Field Area	158,206,221	599,265,987	264
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-0014, Mileage Study Results for April 2024 to March 2025.			

Northern Natural Gas Company
Storage Cost Allocation

Docket No. RP25-989
Schedule I-3(d)

Line No.	Description		Total Storage			Storage Services			Operational Storage	
	(a)		(b)			(c)			(d)	
1	Allocation Basis:									
2	Deliverability		1,641,478	Dth		1,191,478	Dth		450,000	Dth
3	Capacity		78,694,838	Dth		68,694,838	Dth		10,000,000	Dth
4	Injections/Withdrawals		173,910,673	Dth		153,910,673	Dth		20,000,000	Dth
5										
6	Deliverability Allocation Factors:									
7	Deliverability		1.00000			0.72590			0.27410	
8	Capacity		1.00000			0.87290			0.12710	
9	Injections/Withdrawals		1.00000			0.88500			0.11500	
10										
11	Cost of Service									
12	Fixed Cost	$	202,267,281	1/						
13	Variable Cost		4,989,616	2/						
14	Total Cost of Service	$	207,256,897							
15										
	Less LNG Storage Cost Directly									
16	Assigned to Transmission:								4,000,000	Dth
17	Fixed Cost	$	43,951,586							
18	Variable Cost		1,023,797							
19	Total LNG Storage Cost	$	44,975,384							
20										
21	Total Underground Storage:									
22	Fixed Costs	$	158,315,694							
23	Variable Costs		3,965,819							
24	Total Underground Storage	$	162,281,514							
25										
26	Cost of Service Allocation:									
27	Deliverability	$	79,157,847	3/		57,460,681	5/		21,697,166	5/
28	Capacity		79,157,847	3/		69,096,885	5/		10,060,962	5/
29	Injections/Withdrawals		3,965,819	4/		3,509,750	5/		456,069	5/
30	Total Cost of Service	$	162,281,514		$	130,067,316		$	32,214,198	
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									

NORTHERN NATURAL GAS COMPANY

LNG Storage Cost of Service
Test Period Ended December 31, 2025

Line No.	Particulars [a]	F/N		Test Period 12/31/2025 [b]
	Cost of Service			
1	A&G Expenses	1/		$ 6,312,844
2	O & M Expenses	4/		7,369,673
3	Depreciation and Amortization of Gas Plant In Service			9,622,469
4	Amortization of Certain Reg Assets	2/		(426,460)
5	Income Taxes			
6	Federal Income at		21.00%	3,316,228
7	State Income at		6.13%	1,030,640
8	Taxes Other Than Income			
9	Payroll Taxes	3/		409,271
10	Franchise Taxes	2/		556
11	Fuel Use Tax			-
12	Ad Valorem	2/		2,518,202
13	Total Taxes Other Than Income			2,928,029
14	Return at		10.21%	14,821,961
15	Total Overall Cost of Service			$ 44,975,384
	Rate Base and Return Allowance			
16	Utility Plant			
17	Gas Plant in Service			$ 229,497,112
18	Regulatory Assets & Liabilities	2/		(7,931,597)
19	Sub-total			221,565,515
20	Classification of Intangible and General	2/		10,314,025
21	Total Classified Gas Plant in Service			231,879,540
22	Accumulated Provision for Depreciation and Amortization			61,435,409
23	Classification of Intangible and General	2/		4,675,823
24	Classified Accum. Provision for Depr. and Amort.			66,111,232
25	Net Utility Plant			165,768,308
26	Working Capital	2/		3,504,027
27	Total Rate Base Before Deductions			169,272,336
28	Less: Accumulated Deferred Income Taxes -	2/		(24,052,216)
29	Total Rate Base			145,220,120
30	Return Allowance		10.21%	
31	Interest Expense		1.70%	2,462,512
32	Allowance on Common Stock Equity		8.51%	12,359,449
33	Total Return Allowance			$ 14,821,961

NORTHERN NATURAL GAS COMPANY

LNG Storage Cost of Service
Test Period Ended December 31, 2025

Line No.	Particulars [a]	F/N			Test Period 12/31/2025 [b]
	Income Taxes				
34	Return Allowance				
35	Allowance on Common Stock Equity			$	12,359,449
36	Equity AFUDC Adjustment	2/			115,885
37	Taxable Income After Income Taxes				12,475,335
38	Income Tax Allowance				
39	Federal Income Tax Allowance		21.00%		3,316,228
40	State Income Tax Allowance		6.13%		1,030,640
41	Total Income Tax Allowance			$	4,346,868
	Basis for Allocation of General Costs				
42	Net LNG Plant (excluding Intangible Plant)				
43	Test Period Classified			$	168,061,703
44	Ratio - %				2.77%
45	LNG Operating Plant				
46	Test Period Classified			$	229,497,112
47	Ratio - %				2.98%
48	LNG Direct Labor				
49	Test Period O&M Payroll Expenses, excluding A&G			$	3,048,678
50	Ratio - %				4.64%
51	KN LNG				
52	KN labor (LNG Direct Labor Ratio * A&G Labor Ratio)				4.45%
53	KN plant (LNG Operating Plant Ratio * A&G Plant Ratio)				0.12%
54	Total KN LNG ratio - %				4.57%
55	Variable O&M Expenses for Materials and Supplies			$	1,023,797

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/ Variable O&M Expenses for Compressor supplies of $1,023,797

NORTHERN NATURAL GAS COMPANY
Comparison of Revenues with Allocated Costs

Docket No. RP25-989
Statement J

Line No.	Particulars	Test Period Revenues at Proposed Rates	Test Period Cost of Service	Revenue Excess (Deficiency)
	(a)	(b)	(c)	(d)
1	Transportation Revenue			
2	Rate Schedule TF	$ 407,056,130		
3	Rate Schedule TFX	1,041,411,782		
4	Rate Schedule GS-T	94,572		
5	Rate Schedule SMS	36,142,151		
6				
7				
8	Transportation Costs		$ 1,407,515,055 2/	
9	Plus Operational Storage Costs		32,214,198 3/	
10	Plus LNG Costs		44,975,384 4/	
11	Total Transportation	$ 1,484,704,634	$ 1,484,704,636	$ (1)
12				
13				
14	Storage Revenue			
15	Rate Schedule FDD	$ 122,517,281		
16	Rate Schedule IDD and PDD	7,550,000		
17	Storage Costs		$ 207,256,897 5/	
18	Less Operational Storage Costs		(32,214,198) 3/	
19	Less LNG Costs		(44,975,384) 4/	
20	Total Storage	$ 130,067,281	$ 130,067,316	$ (35)
21				
22	Total	$ 1,614,771,916 1/	$ 1,614,771,952 6/	$ (36)
23				
24				
25	1/ Statement G revenue for Test Period units at proposed rates, Col. (f)			
26	2/ Schedule I-1(a), Page 1, Line 17, Col. (d)			
27	3/ Schedule I-1(b), Page 3, Line 24, Col. (d)			
28	4/ Schedule I-1(b), Page 3, Line 18, Col. (d)			
29	5/ Schedule I-1(a), Page 1, Line 17, Col. (c)			
30	6/ Schedule I-1(a), Page 1, Line 17, Col. (b)			

NORTHERN NATURAL GAS COMPANY
Summary of Billing Determinants, Reservation Units and Discount Adjustment

Docket No. RP25-989
Schedule J-1

		Reservation Units - Dth			
Line No.	Description	Schedule G-2 Volumes 1/	Discount Adjustment	Imputed Units	Schedule J-2 Volumes (at Max Rate)
	(a)	(b)	(c)	(d)	(e)
1	Market Area:				
2	TF Base Summer	4,968,747	(1,799,882)	-	3,168,865
3	TF Base Winter	3,549,665	(1,264,700)	-	2,284,965
4	TF Variable Summer	4,977,735	(2,164,127)	-	2,813,608
5	TF Variable Winter	3,554,965	(1,557,660)	-	1,997,305
6	TF 5	2,531,120	(1,108,280)	-	1,422,840
7	TFX Summer	20,574,691	(13,210,273)	-	7,364,418
8	TFX Winter	21,445,680	(13,253,500)	-	8,192,180
9	GS-T	-	-	3,913	3,913
10	TI Summer	-	-	-	-
11	TI Winter	-	-	-	-
12	Total Market Area	61,602,603	(34,358,422)	3,913	27,248,094
13					
14	Field Area:				
15	TFX Summer	13,145,717	(9,688,899)	-	3,456,818
16	TFX Winter	9,790,526	(7,230,806)	-	2,559,720
17	TI Summer	-	-	-	-
18	TI Winter	-	-	-	-
19	Total Field Area	22,936,243	(16,919,705)	-	6,016,538
20					
21					
22	FDD/PDD/IDD:				
23	Reservation Fee 2/	11,890,572	(571,860)	742,073	12,060,785
24	Capacity Fee 2/	57,129,614	(2,747,533)	3,565,224	57,947,305
25					
26	SMS: 3/				
27	Market Area	3,706,567	-	-	3,706,567
28	Field Area	804,000	-	-	804,000
29	Total	4,510,567	-	-	4,510,567
30					

31 1/ Sourced from Sch. G-2_Data. This is the same workpaper that contains the billing determinants that are used to generate Schedule G-2
32 2/ Excludes FDD volumes related to market-based rate contracts, which revenues are credited to cost of service in Schedule J-2, Page 6
33 3/ SMS revenues are credited to cost of service in Schedule J-2, pages 1 and 4. Therefore, SMS billing determinants are not used in rate design

		Commodity Units - Dth		
Line No.	Description	Schedule G-2 Volumes 1/	Discount Adjustment	Schedule J-2 Volumes (at Max Rate)
	(a)	(b)	(c)	(d)
1	Market Area:			
2	TF	311,527,732	-	311,527,732
3	TFX	708,228,225	-	708,228,225
4	TI	-	-	-
5	GS-T	42,994	-	42,994
6	Total Market Area	1,019,798,951	-	1,019,798,951
7				
8	Field Area:			
9	TF	-	-	-
10	TFX	599,265,987	-	599,265,987
11	TI	-	-	-
12	Total Field Area	599,265,987	-	599,265,987
13				
14	Storage:			
15	FDD Injection 2/	57,129,615	-	57,129,615
16	FDD Withdrawal 2/	57,129,615	-	57,129,615
17	PDD Injection	6,923,268	-	6,923,268
18	PDD Withdrawal	6,080,110	-	6,080,110
19	IDD Injection	5,317,837	-	5,317,837
20	IDD Withdrawal	5,330,228	-	5,330,228
21	Storage Total	137,910,673	-	137,910,673
22				
23	SMS: 3/			
24	Market Area	20,816,730	-	20,816,730
25	Field Area	6,095,618	-	6,095,618
26	Total	26,912,348	-	26,912,348
27				
28				

29 1/ Sourced from Sch. G-2_Data. This is the same workpaper that contains the billing determinants that are used to generate Sch. G-2
30 2/ Excludes injec/withd volumes related to market-based rate contracts, which revenues are credited to cost of service in Sch. J-2, page 6
31 3/ SMS revenues are credited to cost of service in Sch. J-2, pages 2 and 5. Therefore, SMS volumes are not used in rate design

Line No.	Particulars (a)		AMDCQ (b)	Tier Relationship Factors (c)	Amount (d)	
1	Market Area Reservation Rate Costs:					
2	Total Transmission Fixed Costs	1/			$ 1,123,357,932	
3	less: Discounted Reservation Revenue	3/			(309,037,383)	
4	less: SMS Reservation Revenue Credits	2/			(29,239,883)	
5	plus: Operational Storage Fixed Costs	4/			31,658,128	
6	plus: LNG Storage Fixed Costs	5/			43,951,586	
7	Net Market Area Fixed Costs for Reservation Rates				$ 860,690,380	
8						
9	Market Area Billing Determinants:					
10	TF Base Summer		3,168,865	0.7500	2,376,649	
11	TF Base Winter		2,284,965	1.3500	3,084,703	
12	Annual TF Base	6/	5,453,830		5,461,352	
13						
14	TF Variable Summer		2,813,608	0.7500	2,110,206	
15	TF Variable Winter		1,997,305	1.8300	3,655,068	
16	Annual TF Variable	6/	4,810,913		5,765,274	
17						
18	TF5	6/	1,422,840	2.0000	2,845,680	
19						
20	TFX Summer		7,364,418	0.7500	5,523,314	
21	TFX Winter		8,192,180	2.0000	16,384,360	
22	Annual TFX	6/	15,556,598		21,907,674	
23						
24	GS-T Imputed Units	6/	3,913	1.0000	3,913	
25	TI Summer Imputed Units		-	1.0000	-	
26	TI Winter Imputed Units		-	1.0000	-	
27	Annual Units	6/	27,248,094		35,983,892	
28						
29					Updated	July 1 Filing
30					Unit	Unit
31	Market Area Reservation Rates:				Rate	Rate
32	Base Unit Rate				$ 23.919	23.870
33						
34	TF Base Summer Reservation Rate				$ 17.939	17.903
35	TF Base Winter Reservation Rate				$ 32.290	32.225
36						
37	TF Variable Summer Reservation Rate				$ 17.939	17.903
38	TF Variable Winter Reservation Rate				$ 43.771	43.682
39						
40	TF5 Reservation Rate				$ 47.838	47.740
41						
42	TFX Summer Reservation Rate				$ 17.939	17.903
43	TFX Winter Reservation Rate				$ 47.838	47.740
44						
45						
46	1/ Schedule I-3(a), Page 2, Line 6					
47	2/ SMS reservation units of 3,706,567 Dth, Schedule J-1, Page 1, Line 27, multiplied by SMS Reservation rate of $7.8726 = $29,180,296 as shown in					
48	Schedule J-2, pg. 1 - workpaper					
49	3/ The sum of discounted Market Area reservation revenue on Schedule G-2C					
50	4/ Schedule J-2, Page 6, Line 20					
51	5/ Schedule J-2, Page 6, Line 9					
52	6/ Schedule J-1, Page 1, Lines 2 through 9					

Line No.	Particulars (a)		Volumes (b)		Amount (c)		
1	Market Area Commodity Rate Costs:						
2	Total Transmission Variable Costs	1/			$ 22,171,844		
3	less: SMS Commodity Revenue Credits	2/			(432,988)		
4	plus: Operational Storage Variable Costs	3/			456,069		
5	plus: LNG Storage Variable Costs	4/			1,023,797		
6	Net Market Area Variable Costs for Commodity Rates				$ 23,218,722.55		
7							
8	Market Area Throughput Volumes:						
9	TF, TFX, TI, GS-T		1,019,798,951	5/			
10							
11	Market Area Commodity Rates:						
12							
13	TF/TFX Commodity Rate:						
14	TF/TFX Commodity Rate				$ 0.0228		
15							
16	Summer (April through October) TI Commodity Rate:						
17	TF Reservation Rate - $/Dth/Month		$ 17.9391	7/	Updated	July 1 Filing	
18	TF Reservation Rate - 100% Load Factor Rate		0.5901		Unit	Unit	
19	TF Commodity Rate		0.0228		Rate	Rate	
20	Summer TI Maximum Commodity Rate				$ 0.6129	0.6117	
21							
22	Summer TI Minimum Commodity Rate				$ 0.0228	0.0228	6/
23							
24	Winter (November through March) TI Maximum Commodity Rate:						
25	TF5 Reservation Rate - $/Dth/Month		$ 47.8375	8/			
26	TF5 Reservation Rate - 100% Load Factor Rate		1.5736				
27	TF Commodity Rate		0.0228				
28	Winter TI Maximum Commodity Rate				$ 1.5964	1.5932	
29							
30	Winter TI Minimum Commodity Rate				$ 0.0228	0.0228	6/
31							
32							
33	1/ Schedule I-3(a), Page 3, Line 6						
34	2/ SMS Commodity throughput of 20,816,730 Dth, Schedule J-1, Page 2, Line 24, multiplied by SMS Commodity rate						
35	of $0.0208 = $432,988 in Market Area SMS Commodity revenue.						
36	3/ Schedule J-2, Page 6, Line 22						
37	4/ Schedule J-2, Page 6, Line 10						
38	5/ Schedule J-1, Page 2, Line 6						
39	6/ The minimum TI rate is the TF/TFX commodity rate						
40	7/ Schedule J-2 , Page 1, Line 35						
41	8/ Schedule J-2, Page 1, Line 38						

Line No.	Particulars (a)		Updated Unit Rate (b)	July 1 Filing Unit Rate
1	GS-T Rate Design (Market Area)			
2				
3	Proposed Base Unit Market Demand Rate	$	23.919	23.870
4				
5	Reservation Portion of GS-T Rate (Line 3/ 30.4 Days)		0.7868	0.7852
6	Load Factor - Increases Reservation Component of GS-T by Same % as Market Reservation Rate		0.3614	0.3614
7	Rate @ 36.14% Load Factor ((Line 5) / (Line 6))		2.1769	2.1724
8				
9	Proposed TF/TFX Commodity Rate		0.0228	0.0228
10	Total Proposed Market Area GS-T Rate	$	2.1996	2.1952
11				
12	GS-T Rate Design (Field Area)			
13	Proposed Base Unit Field Demand Rate	$	22.975	22.907
14				
15	Reservation Portion of GS-T Rate (Line 13/ 30.4 Days)		0.7557	0.7535
16	Load Factor - Increases Reservation Component of GS-T by Same % as Field Reservation Rate		0.3877	0.3877
17	Rate @ 38.77% Load Factor ((Line 15) / (Line 16))		1.9493	1.9436
18				
19	Proposed Average Field Mileage Charge		0.0216	0.0216
20	Total Proposed Field Area GS-T Rate	$	1.9709	1.9652
21				
22	GS-T Rate Design (Field-to-Market)			
23	Total Proposed Market Area GS-T Rate	$	2.1996	2.1952
24	Total Proposed Field Area GS-T Rate		1.9709	1.9652
25	GS-T Field-to-Market Rate	$	4.1705	4.1604
26				
27	1/ Schedule J-2, Page 1, Line 30			
28	2/ Schedule J-2, Page 2, Line 14			
29	3/ Schedule J-2, Page 4, Line 14			
30	4/ Schedule J-2, Page 5, Line 8 times average mileage per 100 miles			

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/			$	248,906,872	
3	less: SMS Reservation Revenue Credits	2/				(6,342,491)	
4	less: Discounted Reservation Revenue	3/				(103,708,421)	
5	plus: Operational Storage Costs	4/				100,000	
6	Net Field Area Fixed Costs for Reservation Rates				$	138,955,959.75	
7							
8	Field Area Billing Determinants:						
9	TFF/TFX Summer		3,456,818	0.75		2,592,614	
10	TFF/TFX Winter		2,559,720	1.35		3,455,622	
11	Total Field Billing Determinants	5/	6,016,538			6,048,236	
12							
13	Field Area Reservation Rates:					Updated	July 1 Filing
14						Unit	Unit
15						Rate	Rate
16	Base Unit Rate				$	22.975	22.907
17							
18	TFF/TFX Field Summer Reservation Rate				$	17.231	17.180
19							
20	TFF/TFX Field Winter Reservation Rate				$	31.016	30.925
21							

22 1/ Schedule I-3(a), page 2, Line 7
23 2/ SMS reservation units of 804,000 Dth, Schedule J-1, page 1, Line 28, multiplied by SMS Reservation rate of $7.8726 = $6,329,565 as shown in
24 Schedule J-2, Pages 1 & 4 - workpaper
25 3/ The sum of discounted Field Area reservation revenue on Schedule G-2C
26 4/ Schedule J-2, Page 6, Line 21
27 5/ Schedule J-1, Page 1, Line 19

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/			$ 13,078,407
3	less: SMS Commodity Revenue Credits	2/			(126,789)
4	Net Field Area Variable Costs for Commodity Rates				12,951,618.47
5					
6	Dth Commodity Miles	3/		1,582,062,206	
7					
8	Firm Commodity Mileage Rate (Line 4/Line 6)				$ 0.0082
9					
10	TI Summer Rate:				
11	Maximum TFF/TFX Firm Reservation Rate		$ 17.2310		
12	TFF/TFX Rate /30.4/Field Mileage		0.2147		
13	Firm Commodity Mileage Rate		$ 0.0082		
14	Maximum TI Commodity Mileage Rate				$ 0.2229
15					
16					
17	TI Winter Rate:				
18	Maximum TFF/TFX Firm Reservation Rate		$ 31.0157		
19	TFF/TFX Rate /30.4/Field Mileage		0.3865		
20	Firm Commodity Mileage Rate		$ 0.0082		
21	Maximum TI Commodity Mileage Rate				$ 0.3946
22					
23	Minimum TI Commodity Mileage Rate	4/			$ 0.0082
24					
25					
26	1/ Schedule I-3(a), Page 3, Line 7				
27	2/ SMS Commodity throughput of 6,095,618, Schedule J-1, page 2, Line 25, multiplied by SMS Commodity rate				
28	of $0.0208 = $126,789 in Field Area SMS Commodity revenue.				
29	3/ Total Field Area commodity throughput in Schedule J-1, Page 2, Line 12 times average mileage per 100 miles				
30	4/ The minimum rate is the Firm Commodity Mileage Rate				

Line No.	Particulars (a)	Peak Day Withdrawal Dth (b)	Annual Cycle Volume-Dth (c)	Amount (d)	Unit Rate (e)	
1	Storage Rate Design Units	1,005,067	57,947,305			
2						
3	Total Cost of Service					
4	Fixed			$ 202,267,281 1/		
5	Variable			4,989,616 2/		
6	Cost of Service			$ 207,256,897		
7						
8	Less LNG Storage Cost Directly Assigned to Transmission:					
9	Fixed Cost			$ 43,951,586		
10	Variable Cost			1,023,797		
11	Total LNG Storage Cost			$ 44,975,384 3/		
12						
13	Less Revenue Credits:					
14	MBR Reservation Revenue			$ 10,167,974 4/		
15	MBR Commodity Revenue			364,861 4/		
16	Discounted FDD Reservation Revenue			2,445,174 5/		
17	Total Revenue Credits for Storage			$ 12,978,009		
18						
19	Less Operational Storage Allocated to Transmission:					
20	Fixed Cost Allocated to Market Area Reservation Rate			$ 31,658,128		
21	Fixed Cost Allocated to Field Area Reservation Rate			100,000		
22	Variable Cost Allocated to Market Area Commodity Rate			456,069		
23	Total Operational Storage Allocated to Transmission			$ 32,214,198 6/		
24						
25						
26	Net Cost of Service For FDD			$ 117,089,307		
27		Annualized			Updated	July 1 Filing
28		Billing	Annual	Allocated	Unit	Unit
29	FDD Rate Derivation	Units 7/	Cycle 8/	Cost	Rate	Rate
30	Reservation Rate	12,060,805		$ 56,972,209	$ 4.7237	4.8003
31	Capacity Rate		57,947,305	56,972,209	$ 0.9832	0.9991
32	Injection Rate		68,955,337	1,572,445	$ 0.0228	0.0228
33	Withdrawal Rate		68,955,337	1,572,445	$ 0.0228	0.0228
34			137,910,673	$ 117,089,307		
35						
36	IDD/PDD Rate Design					
37						
38	IDD/PDD Monthly Capacity Charge:					
39	FDD Reservation Charge @ 100% Load Factor				$ 0.1554	0.1579
40	FDD Capacity Rate per Month				$ 0.0819	0.0833
41	PDD/IDD Monthly Inventory Charge				$ 0.2373	0.2412
42						
43	PDD Capacity Charge				$ 0.9832	0.9991
44						
45	IDD/PDD Monthly Capacity Charge Minimum Rate				$ 0.0000	0.0000
46						
47	IDD/PDD Injection Rate				$ 0.0228	0.0228
48	IDD/PDD Withdrawal Rate				$ 0.0228	0.0228
49						
50	1/ Schedule I-3(d), Line 12					
51	2/ Schedule I-3(d), Line 13					
52	3/ Schedule I-3(d), Line 19					
53	4/ Market-based revenue (MBR) credit as agreed in 2020 Settlement in Docket No. RP19-1353. See Schedule J-2, Page 6 - MBR workpaper					
54	for computation of MBR reservation and commodity revenue credits					
55	5/ Revenue crediting of discounted FDD revenue					
56	6/ Schedule I-3(d), Page 1, Line 30, Column (d)					
57	7/ Line 1, Column (b) times 12					
58	8/ Line 1, Column (c)					

Market Area Reservation Rates - Schedule J-2, Page 1 Iterations Workpaper

Line No.	Market Area	Ref.			Calculation of Initial Rate (In $m)		Iteration No. 1		Iteration No. 2		Iteration No. 3		Iteration No. 4		Iteration No. 5		Final Results	
	[a]	[b]			[c]		[d]		[e]		[f]		[g]		[h]		[i]	
1	Total Fixed Costs	Sch I-3(a), pg 2 of 3			$ 1,123,357,932		$ 1,123,357,932		$ 1,123,357,932		$ 1,123,357,932		$ 1,123,357,932		$ 1,123,357,932		$ 1,123,357,932	
2	less: Disc. Rev Credit at Current Rates	Data Inputs Workpaper			$ (310,620,209)		$ (308,989,930)		$ (309,038,805)		$ (309,037,340)		$ (309,037,384)		$ (309,037,383)		$ (309,037,383)	
3	less: SMS Rev. Credit at Current Rates	Data Inputs Workpaper			$ (15,771,443)		$ (29,643,668)		$ (29,227,778)		$ (29,240,246)		$ (29,239,872)		$ (29,239,884)		$ (29,239,883)	
4	plus: Oper. Stg Costs	Sch J-2 pg 6 of 6			$ 31,658,128		$ 31,658,128		$ 31,658,128		$ 31,658,128		$ 31,658,128		$ 31,658,128		$ 31,658,128	
5	plus: LNG Stg Costs	Sch J-2 pg 6 of 6			$ 43,951,586		$ 43,951,586		$ 43,951,586		$ 43,951,586		$ 43,951,586		$ 43,951,586		$ 43,951,586	
6	Net Cost of Service:				$ 872,575,994		$ 860,334,048		$ 860,701,063		$ 860,690,060		$ 860,690,390		$ 860,690,380		$ 860,690,380	
7																		
8	Billing Determinants	Sch J-2 pg 1 of 6			35,983,892		35,983,892		35,983,892		35,983,892		35,983,892		35,983,892		35,983,892	
9																		
10	Base Unit Rate	line 6 / line 8			$ 24.2491		$ 23.9089		$ 23.9191		$ 23.9188		$ 23.9188		$ 23.9188		$ 23.9188	
11	Current Base Rate	Current Base Unit Rate			$ 12.9013		$ 12.9013		$ 12.9013		$ 12.9013		$ 12.9013		$ 12.9013		$ 12.9013	
12	Perc. Rate Increase				87.96%		85.32%		85.40%		85.40%		85.40%		85.40%		85.40%	
13																		
14				Current														SMS Variance
15	SMS Quantities 1/		SMS	Rate	Rev	Rate	Rev	Rate	Rev	Rate	Rev	Rate	Rev	Rate	Rev	Rate	Rev	by Contract
16	Contract 21385		360,000	$ 4.2550	$ 1,531,800	$ 7.9976	$ 2,879,139	$ 7.8854	$ 2,838,745	$ 7.8888	$ 2,839,956	$ 7.8887	$ 2,839,920	$ 7.8887	$ 2,839,921	$ 7.8887	$ 2,839,921	$ 1,308,121
17	Contract 108781		60,000	$ 4.2550	$ 255,300	$ 7.9976	$ 479,856	$ 7.8854	$ 473,124	$ 7.8888	$ 473,326	$ 7.8887	$ 473,320	$ 7.8887	$ 473,320	$ 7.8887	$ 473,320	$ 218,020
18	Contract 132454		12,000	$ 4.2550	$ 51,060	$ 7.9976	$ 95,971	$ 7.8854	$ 94,625	$ 7.8888	$ 94,665	$ 7.8887	$ 94,664	$ 7.8887	$ 94,664	$ 7.8887	$ 94,664	$ 43,604
19	Contract 135518		3,600	$ 4.2550	$ 15,318	$ 7.9976	$ 28,791	$ 7.8854	$ 28,387	$ 7.8888	$ 28,400	$ 7.8887	$ 28,399	$ 7.8887	$ 28,399	$ 7.8887	$ 28,399	$ 13,081
20			435,600		$ 1,853,478	$ 7.9976	$ 3,483,758	$ 7.8854	$ 3,434,882	$ 7.8888	$ 3,436,347	$ 7.8887	$ 3,436,303	$ 7.8887	$ 3,436,305	$ 7.8887	$ 3,436,305	$ 1,582,827
21																		
22	Change in SMS Revenue (Proposed vs. Current Rate)						$ 1,630,280		$ 1,581,404		$ 1,582,869		$ 1,582,825		$ 1,582,827		$ 1,582,827	
23																		
24				Current	SMS		SMS		SMS		SMS		SMS		SMS		SMS	
25	Redetermination of SMS Revenue Credit		Units	Rate	Credit	Rate	Credit	Rate	Credit	Rate	Credit	Rate	Credit	Rate	Credit	Rate	Credit	
26	SMS at Proposed Rates		(3,706,567)	$ 4.2550	$ (15,771,443)	$ 7.9976	$ (29,643,668)	$ 7.8854	$ (29,227,778)	$ 7.8888	$ (29,240,246)	$ 7.8887	$ (29,239,872)	$ 7.8887	$ (29,239,884)	$ 7.8887	$ (29,239,883)	
27																		
28							Disc. Rev.		Disc. Rev.		Disc. Rev.		Disc. Rev.		Disc. Rev.		Disc. Rev.	
29	Redetermination of Discounted Revenue Credit						Credit		Credit		Credit		Credit		Credit		Credit	
30	Discounted Revenue Credit	Line 2, column [c]					$ (310,620,209)		$ (310,620,209)		$ (310,620,209)		$ (310,620,209)		$ (310,620,209)		$ (310,620,209)	
31	Total Disc. Rev Adjustment - Rate Schedule TF	Line 17					$ 1,347,339		$ 1,306,945		$ 1,308,156		$ 1,308,120		$ 1,308,121		$ 1,308,121	
32	Total Disc. Rev Adjustment - Rate Schedule TFX						$ 282,941		$ 274,459		$ 274,713		$ 274,705		$ 274,705		$ 274,705	
33	Market Area - Adjusted Discount Revenue Credit						$ (308,989,930)		$ (309,038,805)		$ (309,037,340)		$ (309,037,384)		$ (309,037,383)		$ (309,037,383)	

1/ Represents the total SMS quantities under service aggreements with either an annual average discount rate or revenue cap provision. The increase in SMS revenue must be offset by a decrease in revenue for the discounted MDQ under these aggreements.

Field Area Reservation Rates - Schedule J-2, Page 4 Iterations Workpaper

Line No.	Field Area Costs:	Ref.			Calculation of Initial Rate (In $m)		Iteration No. 1		Final Results	
	[a]	[b]			[c]		[d]		[e]	
34	Total Fixed Costs	Sch I-3(a), pg 2 of 3			$ 248,906,872		$ 248,906,872		$ 248,906,872	
35	less: Disc. Rev Credit at Current Rates	Data Inputs Workpaper			$ (105,888,623)		$ (103,708,421)		$ (103,708,421)	
36	less: SMS Rev. Credit at Current Rates	Data Inputs Workpaper			$ (3,421,020)		$ (6,342,491)		$ (6,342,491)	
37	plus: Oper. Stg Costs	Sch J-2 pg 6 of 6			$ 100,000		$ 100,000		$ 100,000	
38	Net Cost of Service:				$ 139,697,228		$ 138,955,960		$ 138,955,960	
39										
40	Billing Determinants	Sch J-2 pg 4 of 6			6,048,236		6,048,236		6,048,236	
41										
42	Base Unit Rate	line 38 / line 40			$ 23.0970		$ 22.9750		$ 22.9750	
43	Current Base Unit Rate	Current Base Unit Rate			$ 9.9820		$ 9.9820		$ 9.9820	
44	Percentage Rate Increase				131.39%		130.16%		130.16%	
45										
46				Current						SMS Variance
47	SMS Quantities 2/		SMS	Rate	Rev	Rate	Rev	Rate	Rev	by Contract
48	Contract 121637		240,000	$ 4.2550	$ 1,021,200	$ 7.8887	$ 1,893,281	$ 7.8887	$ 1,893,281	$ 872,081
49	Contract 128691		360,000	$ 4.2550	$ 1,531,800	$ 7.8887	$ 2,839,921	$ 7.8887	$ 2,839,921	$ 1,308,121
50			600,000	$ 4.2550	$ 2,553,000	$ 7.8887	$ 4,733,202	$ 7.8887	$ 4,733,202	$ 2,180,202
51										
52	Change in SMS Revenue (Proposed vs. Current Rate)						$ 2,180,202		$ 2,180,202	
53										
54				Current	SMS		SMS		SMS	
55	Redetermination of SMS Revenue Credit		Units	Rate	Credit	Rate	Credit	Rate	Credit	
56	SMS at Proposed Rates		(804,000)	$ 4.2550	$ (3,421,020)	$ 7.8887	$ (6,342,491)	$ 7.8887	$ (6,342,491)	
57										
58							Disc. Rev.		Disc. Rev.	
59	Redetermination of Discounted Revenue Credit						Credit		Credit	
60	Discounted Revenue Credit	Line 35, column [c]					$ (105,888,623)		$ (105,888,623)	
61	Total Disc. Rev Adjustment	Line 52, coumn [d]					$ 2,180,202		$ 2,180,202	
62	Field Area - Adjusted Discount Revenue Credit						$ (103,708,421)		$ (103,708,421)	

2/ Represents the total SMS quantities under service aggreements with an annual average discount rate. The increase in SMS revenue must be offset by a decrease in revenues for the discounted MDQ under these aggreements.

Storage Services - Schedule J-2, Pg 6 Iterations Workpaper

Line No.	Particulars	Imputed Units at Current Rates			Imputed Units 1st Iteration		
1	**Imputation of Additional Units 1/**						
2		Units	Rate	Rev.	Units	Rate	Rev.
3	PDD Revenue			$ 6,250,000			$ 6,250,000
4	(less Injection/Withdrawal)	13,003,378	0.0232	$ 301,678	13,003,378	0.0228	$ 296,527
5	Net PDD Rev. for Capacity and Reservation			$ 5,948,321			$ 5,953,473
6							
7	IDD Revenue			$ 1,300,000			$ 1,300,000
8	(less Injection/Withdrawal)	10,648,065	0.0232	$ 247,035	10,648,065	0.0228	$ 242,816
9	Net IDD Rev. for Capacity and Reservation			$ 1,052,965			$ 1,057,184
10							
11		Imputed at	Current		Imputed at	Proposed	
12		Current Rates	Rate	Revenue	Proposed Rates	Rate	Revenue
13	Net PDD Rev. for Capacity and Reservation						
14	Reservation	919,512	3.2345	$ 2,974,161	644,726	$ 4.6171	$ 2,976,737
15	Capacity	4,418,601	0.6731	$ 2,974,161	3,097,646	$ 0.9610	$ 2,976,737
16				$ 5,948,321			$ 5,953,473
17	Net IDD Rev. for Capacity and Reservation						
18	Reservation	162,771	3.2345	$ 526,483	114,487	$ 4.6171	$ 528,592
19	Capacity	782,176	0.6731	$ 526,483	550,062	$ 0.9610	$ 528,592
20				$ 1,052,965			$ 1,057,184
21							
22	**Allocation of Underground Storage Costs**						
23							
24		Total Stg	Underg. Stg	Oper. Stg	Total Stg	Underg. Stg	Oper. Stg
25	Allocation Basis:						
26	Deliverability	1,669,846	1,219,846	450,000	1,642,908	1,192,908	450,000
27	Capacity	80,330,391	70,330,391	10,000,000	78,777,322	68,777,322	10,000,000
28							
29	Allocation Factors:						
30	Deliverability	100.00%	73.05%	26.95%	100.00%	72.61%	27.39%
31	Capacity	100.00%	87.55%	12.45%	100.00%	87.31%	12.69%
32							
33	Storage Fixed Cost of Service	###########			$ 202,267,281		
34	(less): LNG Fixed Costs to Transmission	$ 43,951,586			$ 43,951,586		
35	Net Storage Fixed Cost of Service	###########			$ 158,315,694		
36							
37	Fixed Cost of Service (Equitable Method)						
38		Total Stg	Underg. Stg	Oper. Stg	Total Stg	Underg. Stg	Oper. Stg
39	Deliverability	$ 79,157,847	$ 57,824,807	##########	$ 79,157,847	$ 57,476,513	##########
40	Capacity	$ 79,157,847	$ 69,302,695	$ 9,855,152	$ 79,157,847	$ 69,112,716	##########
41		###########	###########	##########	$ 158,315,694	###########	##########
42							
43	Less: Discounted FDD Revenue Credit		$ 2,445,174			$ 2,445,174	
44	Less: MBR Reservation Revenue Credit		$ 10,167,974			$ 10,167,974	
45	Net Underground Storage Cost of Service		###########			###########	
46							
47	Net Cost of Service For FDD						
48		Units	COS	Stg. Rates	Units	COS	Stg. Rates
49	Reservation Rate	12,401,219	$ 57,257,177	$ 4.6171	12,077,973	$ 56,988,040	$ 4.7183
50	Capacity Rate	59,582,858	$ 57,257,177	$ 0.9610	58,029,789	$ 56,988,040	$ 0.9820
51							

Line No.	Particulars	Imputed Units 2nd Iteration			Imputed Units 3rd Iteration		
1	**Imputation of Additional Units 1/**						
2		Units	Rate	Rev.	Units	Rate	Rev.
3	PDD Revenue			$ 6,250,000			$ 6,250,000
4	(less Injection/Withdrawal)	13,003,378	0.0228	$ 296,527	13,003,378	0.0228	$ 296,527
5	Net PDD Rev. for Capacity and Reservation			$ 5,953,473			$ 5,953,473
6							
7	IDD Revenue			$ 1,300,000			$ 1,300,000
8	(less Injection/Withdrawal)	10,648,065	0.0228	$ 242,816	10,648,065	0.0228	$ 242,816
9	Net IDD Rev. for Capacity and Reservation			$ 1,057,184			$ 1,057,184
10							
11		Imputed at	Proposed		Imputed at	Proposed	
12		Proposed Rates	Rate	Revenue	Proposed Rates	Rate	Revenue
13	Net PDD Rev. for Capacity and Reservation						
14	Reservation	630,886	$ 4.7183	$ 2,976,737	630,210	$ 4.7234	$ 2,976,737
15	Capacity	3,031,152	$ 0.9820	$ 2,976,737	3,027,903	$ 0.9831	$ 2,976,737
16				$ 5,953,473			$ 5,953,473
17	Net IDD Rev. for Capacity and Reservation						
18	Reservation	112,029	$ 4.7183	$ 528,592	111,909	$ 4.7234	$ 528,592
19	Capacity	538,255	$ 0.9820	$ 528,592	537,678	$ 0.9831	$ 528,592
20				$ 1,057,184			$ 1,057,184
21							
22	**Allocation of Underground Storage Costs**						
23							
24		Total Stg	Underg. Stg	Oper. Stg	Total Stg	Underg. Stg	Oper. Stg
25	Allocation Basis:						
26	Deliverability	1,641,550	1,191,550	450,000	1,641,484	1,191,484	450,000
27	Capacity	78,699,020	68,699,020	10,000,000	78,695,194	68,695,194	10,000,000
28							
29	Allocation Factors:						
30	Deliverability	100.00%	72.59%	27.41%	100.00%	72.59%	27.41%
31	Capacity	100.00%	87.29%	12.71%	100.00%	87.29%	12.71%
32							
33	Storage Fixed Cost of Service	$ 202,267,281			$ 202,267,281		
34	(less): LNG Fixed Costs to Transmission	$ 43,951,586			$ 43,951,586		
35	Net Storage Fixed Cost of Service	$ 158,315,694			$ 158,315,694		
36							
37	Fixed Cost of Service (Equitable Method)						
38		Total Stg	Underg. Stg	Oper. Stg	Total Stg	Underg. Stg	Oper. Stg
39	Deliverability	$ 79,157,847	$ 57,460,681	##########	$ 79,157,847	$ 57,460,681	##########
40	Capacity	$ 79,157,847	$ 69,096,885	##########	$ 79,157,847	$ 69,096,885	##########
41		$ 158,315,694	###########	##########	$ 158,315,694	###########	##########
42							
43	Less: Discounted FDD Revenue Credit		$ 2,445,174			$ 2,445,174	
44	Less: MBR Reservation Revenue Credit		$ 10,167,974			$ 10,167,974	
45	Net Underground Storage Cost of Service		###########			###########	
46							
47	Net Cost of Service For FDD						
48		Units	COS	Stg. Rates	Units	COS	Stg. Rates
49	Reservation Rate	12,061,675	$ 56,972,209	$ 4.7234	12,060,879	$ 56,972,209	$ 4.7237
50	Capacity Rate	57,951,487	$ 56,972,209	$ 0.9831	57,947,661	$ 56,972,209	$ 0.9832
51							

Line No.	Particulars	Imputed Units 4th Iteration			Imputed Units 5th Iteration		
1	**Imputation of Additional Units 1/**						
2		Units	Rate	Rev.	Units	Rate	Rev.
3	PDD Revenue			$ 6,250,000			$ 6,250,000
4	(less Injection/Withdrawal)	13,003,378	0.0228	$ 296,527	13,003,378	0.0228	$ 296,527
5	Net PDD Rev. for Capacity and Reservation			$ 5,953,473			$ 5,953,473
6							
7	IDD Revenue			$ 1,300,000			$ 1,300,000
8	(less Injection/Withdrawal)	10,648,065	0.0228	$ 242,816	10,648,065	0.0228	$ 242,816
9	Net IDD Rev. for Capacity and Reservation			$ 1,057,184			$ 1,057,184
10							
11		Imputed at	Proposed		Imputed at	Proposed	
12		Proposed Rates	Rate	Revenue	Proposed Rates	Rate	Revenue
13	Net PDD Rev. for Capacity and Reservation						
14	Reservation	630,168	$ 4.7237	$ 2,976,737	630,171	$ 4.7237	$ 2,976,737
15	Capacity	3,027,703	$ 0.9832	$ 2,976,737	3,027,600	$ 0.9832	$ 2,976,737
16				$ 5,953,473			$ 5,953,473
17	Net IDD Rev. for Capacity and Reservation						
18	Reservation	111,902	$ 4.7237	$ 528,592	111,902	$ 4.7237	$ 528,592
19	Capacity	537,642	$ 0.9832	$ 528,592	537,624	$ 0.9832	$ 528,592
20				$ 1,057,184			$ 1,057,184
21							
22	**Allocation of Underground Storage Costs**						
23							
24		Total Stg	Underg. Stg	Oper. Stg	Total Stg	Underg. Stg	Oper. Stg
25	Allocation Basis:						
26	Deliverability	1,641,480	1,191,480	450,000	1,641,478	1,191,478	450,000
27	Capacity	78,694,959	68,694,959	10,000,000	78,694,838	68,694,838	10,000,000
28							
29	Allocation Factors:						
30	Deliverability	100.00%	72.59%	27.41%	100.00%	72.59%	27.41%
31	Capacity	100.00%	87.29%	12.71%	100.00%	87.29%	12.71%
32							
33	Storage Fixed Cost of Service	$ 202,267,281			$ 202,267,281		
34	(less): LNG Fixed Costs to Transmission	$ 43,951,586			$ 43,951,586		
35	Net Storage Fixed Cost of Service	$ 158,315,694			$ 158,315,694		
36							
37	Fixed Cost of Service (Equitable Method)						
38		Total Stg	Underg. Stg	Oper. Stg	Total Stg	Underg. Stg	Oper. Stg
39	Deliverability	$ 79,157,847	$ 57,460,681	##########	$ 79,157,847	$ 57,460,681	##########
40	Capacity	$ 79,157,847	$ 69,096,885	##########	$ 79,157,847	$ 69,096,885	##########
41		$ 158,315,694	###########	##########	$ 158,315,694	###########	##########
42							
43	Less: Discounted FDD Revenue Credit		$ 2,445,174			$ 2,445,174	
44	Less: MBR Reservation Revenue Credit		$ 10,167,974			$ 10,167,974	
45	Net Underground Storage Cost of Service		###########			###########	
46							
47	Net Cost of Service For FDD						
48		Units	COS	Stg. Rates	Units	COS	Stg. Rates
49	Reservation Rate	12,060,830	$ 56,972,209	$ 4.7237	12,060,805	$ 56,972,209	$ 4.7237
50	Capacity Rate	57,947,426	$ 56,972,209	$ 0.9832	57,947,305	$ 56,972,209	$ 0.9832
51							

Line No.	Particulars	Imputed Units 6th Iteration			
1	**Imputation of Additional Units 1/**				
2		Units	Rate	Rev.	Rev. Increase
3	PDD Revenue			$ 6,250,000	Inj/With
4	(less Injection/Withdrawal)	13,003,378	0.0228	$ 296,527	PDD $ (5,152)
5	Net PDD Rev. for Capacity and Reservation			$ 5,953,473	
6					
7	IDD Revenue			$ 1,300,000	
8	(less Injection/Withdrawal)	10,648,065	0.0228	$ 242,816	IDD $ (4,219)
9	Net IDD Rev. for Capacity and Reservation			$ 1,057,184	
10					
11		Imputed at	Proposed		
12		Proposed Rates	Rate	Revenue	
13	Net PDD Rev. for Capacity and Reservation				
14	Reservation	630,171	$ 4.7237	$ 2,976,737	
15	Capacity	3,027,600	$ 0.9832	$ 2,976,737	
16				$ 5,953,473	
17	Net IDD Rev. for Capacity and Reservation				
18	Reservation	111,902	$ 4.7237	$ 528,592	
19	Capacity	537,624	$ 0.9832	$ 528,592	
20				$ 1,057,184	
21					
22	**Allocation of Underground Storage Costs**				
23					
24		Total Stg	Underg. Stg	Oper. Stg	
25	Allocation Basis:				
26	Deliverability	1,641,478	1,191,478	450,000	
27	Capacity	78,694,838	68,694,838	10,000,000	
28					
29	Allocation Factors:				
30	Deliverability	100.00%	72.59%	27.41%	
31	Capacity	100.00%	87.29%	12.71%	
32					
33	Storage Fixed Cost of Service	$ 202,267,281			
34	(less): LNG Fixed Costs to Transmission	$ 43,951,586			
35	Net Storage Fixed Cost of Service	$ 158,315,694			
36					
37	Fixed Cost of Service (Equitable Method)				
38		Total Stg	Underg. Stg	Oper. Stg	
39	Deliverability	$ 79,157,847	$ 57,460,681	##########	
40	Capacity	$ 79,157,847	$ 69,096,885	##########	
41		$ 158,315,694	###########	##########	
42					
43	Less: Discounted FDD Revenue Credit		$ 2,445,174		
44	Less: MBR Reservation Revenue Credit		$ 10,167,974		
45	Net Underground Storage Cost of Service		###########		
46					Check to
47	Net Cost of Service For FDD				Rates in
48		Units	COS	Stg. Rates	Sch J-2
49	Reservation Rate	12,060,805	$ 56,972,209	$ 4.7237	$ 4.7237
50	Capacity Rate	57,947,305	$ 56,972,209	$ 0.9832	$ 0.9832
51					

1 PDD & IDD contribute to the recovery of the cost of service for storage services. Therefore, Test Period revenues for PDD and IDD services are used to impute additional capacity and reservation units. With each iteration, the imputed units are added to the 65.1 bcf in line 27 for purposes of allocating costs between underground and operational storage, and calculating the new maximum capacity and reservation rates.