REDACTED

Northern Utilities, Inc.

New Hampshire Division

2021 / 2022 WINTER & SUMMER SEASON PROPOSED COST OF GAS ADJUSTMENT

WINTER RATES TO BE EFFECTIVE NOVEMBER 1, 2021

SUMMER RATES TO BE EFFECTIVE MAY 1, 2022

FILED SEPTEMBER 17, 2021

Northern Utilities, Inc.
New Hampshire Division
2021 / 2022 Annual Cost of Gas Filing
Winter and Summer Periods

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Winter Season

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Northern Utilities, Inc.
New Hampshire Division
2021 / 2022 Annual Cost of Gas Filing
Winter and Summer Periods

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Northern Utilities, Inc.
New Hampshire Division

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Northern Utilities, Inc.
New Hampshire Division

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New Hampshire Division

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Northern Utilities, Inc.
New Hampshire Division

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Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2021 - April 30, 2022

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$4,553,044	
Supply Costs:	$11,472,168	
Storage & Peaking Gas:		
Demand, Capacity:	$12,327,011	
Commodity Costs:	$7,733,349	
Interruptible Included Above	$0	
Inventory Finance Charge	$1,378	
Capacity Release, & Asset Management	($4,076,771)	
Re-entry Rate & Conversion Rate Revenues	$ (5,000)	
Total Anticipated Direct Cost of Gas		$32,005,179
ANTICIPATED INDIRECT COST OF GAS		
Adjustments:		
Prior Period Under/(Over) Collection	$189,294	
Interest	($42,086)	
Refunds	$0	
Interruptible Margins	$0	
Total Adjustments		$147,208
Working Capital:		
Total Anticipated Direct Cost of Gas	$32,005,179	
Working Capital Percentage	0.0892%	
Working Capital Allowance	$ 28,555	
Plus: Working Capital Reconciliation (Acct 173)	($5,834)	
Total Working Capital Allowance		$22,721
Bad Debt:		
Bad Debt Allowance	$137,320	
Plus: Bad Debt Reconciliation (Acct 173)	($61,950)	
Total Bad Debt Allowance		$75,370
Local Production and Storage Capacity		$476,106
Miscellaneous Overhead-79.87% Allocated to Winter Season		$463,606
Total Anticipated Indirect Cost of Gas		$1,185,012
Total Cost of Gas		$33,190,191

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Senior Vice President
Effective Date: November 1, 2021
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N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Fourth Revised Page No. 41
Superseding Third Revised Page No. 41

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 2022 - October 31, 2022

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$956,729	
Supply Costs:	$3,110,213	
Storage & Peaking Gas:		
Demand, Capacity:	$397,395	
Commodity Costs:	$21,467	
Interruptible Included Above	$0	
Inventory Finance Charge	$0	
Capacity Release & Asset Management	$0	
Re-entry Rate and Conversion Rate Revenues	$0	
Total Anticipated Direct Cost of Gas		$4,485,804
ANTICIPATED INDIRECT COST OF GAS		
Adjustments:		
Prior Period Under/(Over) Collection	$47,710	
Interest	($41,380)	
Refunds	$0	
Interruptible Margins	$0	
Total Adjustments		$6,330
Working Capital:		
Total Anticipated Direct Cost of Gas	$4,485,805	
Working Capital Percentage	0.0892%	
Working Capital Allowance	$4,002	
Plus: Working Capital Reconciliation (Acct 173)	($1,470)	
Total Working Capital Allowance		$2,532
Bad Debt:		
Bad Debt Allowance	$14,529	
Plus: Bad Debt Reconciliation (Acct 173)	($15,614)	
Total Bad Debt Allowance		($1,085)
Local Production and Storage Capacity		$0
Miscellaneous Overhead-20.13% Allocated to Summer Season		$116,849
Total Anticipated Indirect Cost of Gas		$124,627
Total Cost of Gas		$4,610,432

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N.H.P.U.C No. 12 Eighth Revised Page 42
NORTHERN UTILITIES, INC. Superseding Seventh Revised Page 42

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 2021 - April 30, 2022

(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$32,005,179		
Projected Prorated Sales (11/01/21 - 04/30/22)	35,339,329		
Direct Cost of Gas Rate		$0.9057	per therm
Demand Cost of Gas Rate	$12,798,284	$0.3622	per therm
Commodity Cost of Gas Rate	$19,206,895	$0.5435	per therm
Total Direct Cost of Gas Rate	$32,005,179	**$0.9057**	per therm
Total Anticipated Indirect Cost of Gas	$1,185,012		
Projected Prorated Sales (11/01/21 - 04/30/22)	35,339,329		
Indirect Cost of Gas		$0.0335	per therm
TOTAL PERIOD AVERAGE COST OF GAS		**$0.9392**	**per therm**

RESIDENTIAL COST OF GAS RATE -11/01/21	**COGwr**	**$0.9392**	**per therm**
	Maximum (COG+25%)	**$1.1740**	

COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/21	**COGwl**	**$0.8453**	**per therm**
	Maximum (COG+25%)	**$1.0566**	

C&I HLF DEMAND COSTS ALLOCATED PER SMBA	$668,845
PLUS: RESIDENTIAL DEMAND RELOCATION TO C&I HLF	$15,887
C&I HLF TOTAL ADJUSTED DEMAND COSTS	$684,732
C&I HLF PROJECTED PRORATED SALES (11/01/21 - 04/30/22)	2,692,919
DEMAND COST OF GAS RATE	**$0.2543**
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	$1,503,327
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF	($2,088)
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	$1,501,239
C&I HLF PROJECTED PRORATED SALES (11/01/21 - 04/30/22)	2,692,919
COMMODITY COST OF GAS RATE	**$0.5575**
INDIRECT COST OF GAS	**$0.0335**
TOTAL C&I HLF COST OF GAS RATE	**$0.8453**

COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/21	**COGwh**	**$0.9551**	**per therm**
	Maximum (COG+25%)	**$1.1939**	

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$5,898,495
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	$140,104
C&I LLF TOTAL ADJUSTED DEMAND COSTS	$6,038,599
C&I LLF PROJECTED PRORATED SALES (11/01/21 - 04/30/22)	15,871,915
DEMAND COST OF GAS RATE	**$0.3805**
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$8,600,676
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	($11,944)
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	$8,588,732
C&I LLF PROJECTED PRORATED SALES (11/01/21 - 04/30/22)	15,871,915
COMMODITY COST OF GAS RATE	**$0.5411**
INDIRECT COST OF GAS	**$0.0335**
TOTAL C&I LLF COST OF GAS RATE	**$0.9551**

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N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Tenth Revised Page No. 43
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CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: May 1, 2022 - October 31, 2022

(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$4,485,805		
Projected Prorated Sales (05/01/22 - 10/31/22)	8,907,030		
Direct Cost of Gas Rate		$0.5036	per therm
Demand Cost of Gas Rate	$1,354,125	$0.1520	per therm
Commodity Cost of Gas Rate	$3,131,680	$0.3516	per therm
Total Direct Cost of Gas Rate	$4,485,805	**$0.5036**	per therm
Total Anticipated Indirect Cost of Gas	$124,627		
Projected Prorated Sales (05/01/22 - 10/31/22)	8,907,030		
Indirect Cost of Gas		$0.0140	per therm
TOTAL PERIOD AVERAGE COST OF GAS		**$0.5176**	**per therm**

RESIDENTIAL COST OF GAS RATE -05/01/22	**COGwr**	**$0.5176**	**per therm**
	Maximum (COG+25%)	**$0.6470**	

COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/22	**COGwl**	**$0.4740**	**per therm**
	Maximum (COG+25%)	**$0.5925**	

C&I HLF DEMAND COSTS ALLOCATED PER SMBA	$205,468
PLUS: RESIDENTIAL DEMAND RELOCATION TO C&I HLF	$11,258
C&I HLF TOTAL ADJUSTED DEMAND COSTS	$216,726
C&I HLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	1,996,958
DEMAND COST OF GAS RATE	**$0.1085**
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	$701,906
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF	$64
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	$701,970
C&I HLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	1,996,958
COMMODITY COST OF GAS RATE	**$0.3515**
INDIRECT COST OF GAS	**$0.0140**
TOTAL C&I HLF COST OF GAS RATE	**$0.4740**

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/22	**COGwh**	**$0.5445**	**per therm**
	Maximum (COG+25%)	**$0.6806**	

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$549,002
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	$30,080
C&I LLF TOTAL ADJUSTED DEMAND COSTS	$579,082
C&I LLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	3,236,934
DEMAND COST OF GAS RATE	**$0.1789**
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$1,138,131
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	$104
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	$1,138,235
C&I LLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	3,236,934
COMMODITY COST OF GAS RATE	**$0.3516**
INDIRECT COST OF GAS	**$0.0140**
TOTAL C&I LLF COST OF GAS RATE	**$0.5445**

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Senior Vice President

Local Delivery Adjustment Clause

Rate Schedule	GAPRA	EEC	LRR	ERC	ITMC	RCE	RPC	LDAC
Residential Heating	$0.0060	$0.0449	$0.0066	$0.0056	$0.0000	$0.0000	$0.0000	$0.0631
Residential Non-Heating	$0.0060	$0.0449	$0.0066	$0.0056	$0.0000	$0.0000	$0.0000	$0.0631
Small C&I	$0.0060	$0.0238	$0.0006	$0.0056	$0.0000	$0.0000	$0.0000	$0.0360
Medium C&I	$0.0060	$0.0238	$0.0006	$0.0056	$0.0000	$0.0000	$0.0000	$0.0360
Large C&I	$0.0060	$0.0238	$0.0006	$0.0056	$0.0000	$0.0000	$0.0000	$0.0360
No Previous Sales Service								

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Title: Senior Vice President

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON RESIDENTIAL RATES

	Winter Season November 2021 - April 2022		Tariff Rates	Total Delivery Rates (Includes LDAC)		Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas	
Residential Heating	**Tariff Rate R 5:**						
	Monthly Customer Charge		$22.20		**$22.20**		**$22.20**
	First 50 therms		$0.6920	**$0.7551**		**$1.6943**	
	All usage over 50 therms		$0.6920	**$0.7551**		**$1.6943**	
	LDAC		**$0.0631**				
	Gas Cost Adjustment:						
	Cost of Gas		**$0.9392**				
Residential Heating	**Tariff Rate R 10:**						
Low Income	Monthly Customer Charge		$22.20		**$22.20**		**$22.20**
	First 50 therms		$0.6920	**$0.7551**		**$1.6943**	
	All usage over 50 therms		$0.6920	**$0.7551**		**$1.6943**	
	LDAC		**$0.0631**				
	Gas Cost Adjustment:						
	Cost of Gas		**$0.9392**				
45% Low Income Discount	Monthly Customer Charge		($9.99)		**($9.99)**		**($9.99)**
45% Low Income Discount	First 50 therms		($0.3114)	**($0.3114)**		**($0.7340)**	
45% Low Income Discount	All usage over 50 therms		($0.3114)	**($0.3114)**		**($0.7340)**	
No Discount	**LDAC**		$0.0000				
	Gas Cost Adjustment:						
45% Low Income Discount	Cost of Gas		($0.4226)				
Residential Non-Heating	**Tariff Rate R 6:**						
	Monthly Customer Charge		$22.20		**$22.20**		**$22.20**
	First 10 therms		$0.6470	**$0.7101**		**$1.6493**	
	All usage over 10 therms		$0.6470	**$0.7101**		**$1.6493**	
	LDAC		**$0.0631**				
	Gas Cost Adjustment:						
	Cost of Gas		**$0.9392**				

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NHPUC No. 12 - Gas
NORTHERN UTILITIES, INC.

Twelfth Revised Page 86
Superseding Eleventh Revised Page 86

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
SUMMER SEASON RESIDENTIAL RATES

	Summer Season May 2022 - October 2022	Tariff Rates	Total Delivery Rates (Includes LDAC)		Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas	
Residential Heating	**Tariff Rate R 5:**					
	Monthly Customer Charge	$22.20		**$22.20**		**$22.20**
	First 50 therms	$0.6099	**$0.6730**		**$1.1906**	
	All usage over 50 therms	$0.6099	**$0.6730**		**$1.1906**	
	LDAC	**$0.0631**				
	Gas Cost Adjustment:					
	Cost of Gas	**$0.5176**				
Residential Heating	**Tariff Rate R 10:**					
Low Income	Monthly Customer Charge	$22.20		**$22.20**		**$22.20**
	First 50 therms	$0.6099	**$0.6730**		**$1.1906**	
	All usage over 50 therms	$0.6099	**$0.6730**		**$1.1906**	
	LDAC	**$0.0631**				
	Gas Cost Adjustment:					
	Cost of Gas	**$0.5176**				
No Discount*	Monthly Customer Charge	$0.00		**$0.00**		**$0.00**
No Discount*	First 50 therms	$0.0000	**$0.0000**		**$0.0000**	
No Discount*	All usage over 50 therms	$0.0000	**$0.0000**		**$0.0000**	
No Discount	**LDAC**	$0.0000				
	Gas Cost Adjustment:					
No Discount*	Cost of Gas	$0.0000				
Residential Non-Heating	**Tariff Rate R 6:**					
	Monthly Customer Charge	$22.20		**$22.20**		**$22.20**
	First 10 therms	$0.6470	**$0.7101**		**$1.2277**	
	All usage over 10 therms	$0.6470	**$0.7101**		**$1.2277**	
	LDAC	**$0.0631**				
	Gas Cost Adjustment:					
	Cost of Gas	**$0.5176**				

*: Discount applicable to winter months November through April only.

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Title: **Senior Vice President**

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NORTHERN UTILITIES, INC. — **Superseding Eighth Revised Page 87**

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

WINTER SEASON C&I RATES

	Winter Season November 2021 - April 2022	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$75.09	**$75.09**	**$75.09**
	First 75 therms	$0.1865	**$0.2225**	**$1.1776**
	All usage over 75 therms	$0.1865	**$0.2225**	**$1.1776**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.9551**		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$75.09	**$75.09**	**$75.09**
	First 75 therms	$0.1865	**$0.2225**	**$1.0678**
	All usage over 75 therms	$0.1865	**$0.2225**	**$1.0678**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.8453**		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$222.64	**$222.64**	**$222.64**
	All usage	$0.2425	**$0.2785**	**$1.2336**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.9551**		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$222.64	**$222.64**	**$222.64**
	First 1,300 therms	$0.1712	**$0.2072**	**$1.0525**
	All usage over 1,300 therms	$0.1399	**$0.1759**	**$1.0212**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.8453**		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$1,335.81	**$1,335.81**	**$1,335.81**
	All usage	$0.1984	**$0.2344**	**$1.1895**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.9551**		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$1,335.81	**$1,335.81**	**$1,335.81**
	All usage	$0.1720	**$0.2080**	**$1.0533**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.8453**		

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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
SUMMER SEASON C&I RATES

	Summer Season May 2022 - October 2022	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$75.09	**$75.09**	**$75.09**
	First 75 therms	$0.1865	**$0.2225**	**$0.7670**
	All usage over 75 therms	$0.1865	**$0.2225**	**$0.7670**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.5445**		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$75.09	**$75.09**	**$75.09**
	First 75 therms	$0.1865	**$0.2225**	**$0.6965**
	All usage over 75 therms	$0.1865	**$0.2225**	**$0.6965**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.4740**		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$222.64	**$222.64**	**$222.64**
	All usage	$0.1895	**$0.2255**	**$0.7700**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.5445**		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$222.64	**$222.64**	**$222.64**
	First 1,000 therms	$0.1337	**$0.1697**	**$0.6437**
	All usage over 1,000 therms	$0.1087	**$0.1447**	**$0.6187**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.4740**		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$1,335.81	**$1,335.81**	**$1,335.81**
	All usage	$0.1206	**$0.1566**	**$0.7011**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.5445**		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$1,335.81	**$1,335.81**	**$1,335.81**
	All usage	$0.0792	**$0.1152**	**$0.5892**
	LDAC	**$0.0360**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.4740**		

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Title: Senior Vice President

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.71 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$ 71.85 per MMBtu** per MDPQ per month for November 2021 through April 2022. Provided on Page 6 of Attachment NUI-FXW-6.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Company Allowance Calculation: **1.25% -** Provided in Attachment NUI-FXW-3

IV. Supplier Services and Associated Fees:

SERVICE	PRICING
Pool Administration (required) **Non-Daily Metered Pools only**	• $0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• $0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• $1.50/customer/month billed @ marketer level
Customer Administration (required)	• $10/customer/switch billed @ marketer level

V. Meter Read Charge: $78.00 when customer phone line is not reporting daily data

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, 2021 through October 31, 2022.

	Commercial and Industrial	
	High Winter Use	Low Winter Use
Pipeline:	22.28%	60.95%
Storage:	32.31%	16.23%
Peaking:	45.41%	22.82%

VII. DELIVERY SERVICE TERMS AND CONDITIONS (continued)

Appendix D

Re-entry Surcharge and Conversion Surcharge (continued)

D. Information to be Filed with the Commission:

As part of the annual Cost of Gas filing, the Company shall file with the Commission a report showing the number of customers assessed the Re-entry Surcharge and the Conversion Surcharge and the amount of revenue received for each charge through the prior April 30. Pursuant to the Company's Cost of Gas Clause, the Company will apply such revenues as credits to the Company's New Hampshire Division Cost of Gas.

The following Re-entry Surcharge and Conversion Surcharge shall be applicable for the periods of November 1, 2021 through April 30, 2022 and May 1, 2022 through October 2022.

Effective Dates:	**November 1, 2021 – April 30, 2022**	**May 1, 2022 – October 30, 2022**
Re-entry Surcharge:	$0.000 per therm	$0.0000 per therm
Conversion Surcharge, Low Load Factor (G-40, G-41, G-42):	$0.0000 per therm	$0.0000 per therm
Conversion Surcharge, High Load Factor (G-50, G-51, G-52):	$0.5915 per therm	$0.4817 per therm

N.H.P.U.C No.12
NORTHERN UTILITIES, INC.

~~Third~~Fourth Revised Page 40
Superseding ~~Second~~Third Revised Page 40

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 20~~20~~21 - October 31, 20~~21~~22

(Col 1)	(Col 2)		(Col 3)	
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 4,596,721~~	$ 4,553,044		
Supply Costs:	~~$ 8,233,230~~	$ 11,472,168		
Storage & Peaking Gas:				
Demand, Capacity:	~~$ 11,702,910~~	$ 12,327,011		
Commodity Costs:	~~$ 2,618,320~~	$ 7,733,349		
Interruptible Included Above	~~$ -~~	$ -		
Inventory Finance Charge	~~$ 1,266~~	$ 1,378		
Capacity Release	~~$ (3,272,870)~~	$ (4,076,771)		
Re-entry Rate & Conversion Rate Revenues	~~$ (5,000)~~	$ (5,000)		
Total Anticipated Direct Cost of Gas			~~$ 23,874,576~~	$ 32,005,179
ANTICIPATED INDIRECT COST OF GAS				
Adjustments:				
Prior Period Under/(Over) Collection	~~$ 614,082~~	$ 189,294		
Interest	~~$ (44,016)~~	$ (42,086)		
Refunds	~~$ -~~	$ -		
Interruptible Margins	~~$ -~~	$ -		
Total Adjustments			~~$ 570,066~~	$ 147,208
Working Capital:				
Total Anticipated Direct Cost of Gas	~~$ 23,874,576~~	$ 32,005,179		
Working Capital Percentage	~~0.0892%~~	0.0892%		
Working Capital Allowance	~~$ 21,301~~	$ 28,555		
Plus: Working Capital Reconciliation (Acct 173	~~$ (35,910)~~	$ (5,834)		
Total Working Capital Allowance			~~$ (14,609)~~	$ 22,721
Bad Debt:				
Bad Debt Allowance	~~$ 156,687~~	$ 137,320		
Plus: Bad Debt Reconciliation (Acct 173)	~~$ (4,239)~~	$ (61,950)		
Total Bad Debt Allowance			~~$ 152,448~~	$ 75,370
Local Production and Storage Capacity			~~$ 476,106~~	$ 476,106
Miscellaneous Overhead-~~81.23~~79.87% Allocated to Winter Season			~~$ 471,532~~	$ 463,606
Total Anticipated Indirect Cost of Gas			~~$ 1,655,544~~	$ 1,185,012
Total Cost of Gas			~~$ 25,530,121~~	$ 33,190,191

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Senior Vice President

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NORTHERN UTILITIES, INC.

~~Third~~Fourth Revised Page 41
Superseding ~~Second~~Third Revised Page 41

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 20~~21~~22 - October 31, 20~~21~~22

(Col 1)	(Col 2)	(Col 2)	(Col 3)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$842,503~~	$956,729		
Supply Costs:	~~$2,140,506~~	$3,110,213		
Storage & Peaking Gas:				
Demand, Capacity:	~~$332,957~~	$397,395		
Commodity Costs:	~~$25,153~~	$21,467		
Interruptible Included Above	$0	$0		
Inventory Finance Charge	$0	$0		
Capacity Release & Asset Management	$0	$0		
Re-entry Rate & Conversion Rate Revenues	$0	$0		
Total Anticipated Direct Cost of Gas			~~$3,341,119~~	$4,485,804
ANTICIPATED INDIRECT COST OF GAS				
Adjustments:				
Prior Period Under/(Over) Collection	~~$141,851~~	$47,710		
Interest	~~($43,640)~~	($41,380)		
Refunds	$0	$0		
Interruptible Margins	$0	$0		
Total Adjustments			~~$98,211~~	$6,330
Working Capital:				
Total Anticipated Direct Cost of Gas	~~$3,341,119~~	$4,485,805		
Working Capital Percentage	~~0.0892%~~	0.089%		
Working Capital Allowance	~~$2,981~~	$4,002		
Plus: Working Capital Reconciliation (Acct 173)	~~($8,295)~~	($1,470)		
Total Working Capital Allowance			~~($5,314)~~	$2,532
Bad Debt:				
Bad Debt Allowance	~~$14,144~~	$14,529		
Plus: Bad Debt Reconciliation (Acct 173)	~~($979)~~	($15,614)		
Total Bad Debt Allowance			~~$13,166~~	($1,084)
Local Production and Storage Capacity			~~$0~~	$0
Miscellaneous Overhead-~~18.77~~20.13% Allocated to the Summer Season			~~$108,923~~	$116,849
Total Anticipated Indirect Cost of Gas			~~$214,984~~	$124,627
Total Cost of Gas			~~$3,556,103~~	$4,610,432

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Robert B. Hevert
Senior Vice President

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

~~Seventh~~ Eighth Revised Page 42
Superseding ~~Sixth~~ Seventh Revised Page 42

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: November 1, 20~~20~~21 - April 30, 20~~21~~22

(Col 1)	(Col 2)		(Col 3)		
Total Anticipated Direct Cost of Gas	~~$23,874,576~~	$32,005,179			
Projected Prorated Sales (11/01/~~20~~21- 04/30/~~21~~22)	~~34,897,412~~	35,339,329			
Direct Cost of Gas Rate			~~$0.6841~~	$0.9057	per therm
Demand Cost of Gas Rate	~~$13,021,761~~	$12,798,284	~~$0.3731~~	$0.3622	per therm
Commodity Cost of Gas Rate	~~$10,851,549~~	$19,206,895	~~$0.3110~~	$0.5435	per therm
Total Direct Cost of Gas Rate	~~$23,874,576~~	$32,005,179	**~~$0.6841~~**	**$0.9057**	per therm
Total Anticipated Indirect Cost of Gas	~~$1,655,544~~	$1,185,012			
Projected Prorated Sales (11/01/~~20~~21- 04/30/~~21~~22)	~~34,897,412~~	35,339,329			
Indirect Cost of Gas			~~$0.0474~~	$0.0335	per therm
TOTAL PERIOD AVERAGE COST OF GAS			**~~$0.7315~~**	**$0.9392**	**per therm**

RESIDENTIAL COST OF GAS RATE -11/01/~~20~~21	**COGwr**	**~~$0.7315~~**	**$0.9392**	**per therm**
	Maximum (COG+25%)	**~~$0.9144~~**	**$1.1740**	
COM/IND LOW WINTER USE COST OF GAS RATE -11/01/~~20~~21	**COGwl**	**~~$0.6465~~**	**$0.8453**	**per therm**
	Maximum (COG+25%)	**~~$0.8081~~**	**$1.0566**	

C&I HLF DEMAND COSTS ALLOCATED PER SMBA	~~$601,051~~	$668,845
PLUS: RESIDENTIAL DEMAND RELOCATION TO C&I HLF	~~$31,569~~	$15,887
C&I HLF TOTAL ADJUSTED DEMAND COSTS	~~$632,620~~	$684,732
C&I HLF PROJECTED PRORATED SALES (11/01/~~20~~21 - 04/30/~~21~~22)	~~2,277,711~~	2,692,919
DEMAND COST OF GAS RATE	**~~$0.2777~~**	**$0.2543**
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	~~$733,070~~	$1,503,327
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF	~~($940)~~	($2,088)
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	~~$732,130~~	$1,501,239
C&I HLF PROJECTED PRORATED SALES (11/01/~~20~~21 - 04/30/~~21~~22)	~~2,277,711~~	2,692,919
COMMODITY COST OF GAS RATE	**~~$0.3214~~**	**$0.5575**
INDIRECT COST OF GAS	**~~$0.0474~~**	**$0.0335**
TOTAL C&I HLF COST OF GAS RATE	**~~$0.6465~~**	**$0.8453**

COM/IND HIGH WINTER USE COST OF GAS RATE -11/01/~~20~~21	**COGwh**	**~~$0.7437~~**	**$0.9551**	**per therm**
	Maximum (COG+25%)	**~~$0.9296~~**	**$1.1939**	

C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	~~$5,855,245~~	$5,898,495
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	~~$307,534~~	$140,104
C&I LLF TOTAL ADJUSTED DEMAND COSTS	~~$6,162,780~~	$6,038,599
C&I HLF PROJECTED PRORATED SALES (11/01/~~20~~21 - 04/30/~~21~~22)	~~15,933,486~~	15,871,915
DEMAND COST OF GAS RATE	**~~$0.3868~~**	**$0.3805**
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	~~$4,937,736~~	$8,600,676
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	~~($6,330)~~	($11,944)
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	~~$4,931,406~~	$8,588,732
C&I HLF PROJECTED PRORATED SALES (11/01/~~20~~21 - 04/30/~~21~~22)	~~15,933,486~~	15,871,915
COMMODITY COST OF GAS RATE	**~~$0.3095~~**	**$0.5411**
INDIRECT COST OF GAS	**~~$0.0474~~**	**$0.0335**
TOTAL C&I LLF COST OF GAS RATE	**~~$0.7437~~**	**$0.9551**

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Senior Vice President

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

~~Ninth~~Tenth Revised Page No. 43
Superseding ~~Eighth~~Ninth Page No. 43

CALCULATION OF FIRM SALES COST OF GAS RATE

Period Covered: May 1, 202~~1~~2 - October 31, 202~~1~~2

(Col 1)	(Col 2)	(Col 2)	(Col 3)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$3,341,119~~	$4,485,805			
Projected Prorated Sales (05/01/202~~1~~2- 10/31/202~~1~~2)	~~8,061,210~~	8,907,030			
Direct Cost of Gas Rate			~~$0.4145~~	$0.5036	per therm
Demand Cost of Gas Rate	~~$1,175,460~~	$1,354,125	~~$0.1458~~	$0.1520	per therm
Commodity Cost of Gas Rate	~~$2,165,659~~	$3,131,680	~~$0.2687~~	$0.3516	per therm
Total Direct Cost of Gas Rate	~~$3,341,119~~	$4,485,805	~~**$0.4145**~~	**$0.5036**	per therm
Total Anticipated Indirect Cost of Gas	~~$214,984~~	$124,627			
Projected Prorated Sales (05/01/202~~1~~2- 10/31/202~~1~~2)	~~8,061,210~~	8,907,030			
Indirect Cost of Gas			~~$0.0267~~	$0.0140	per therm
TOTAL PERIOD AVERAGE COST OF GAS			~~**$0.4412**~~	**$0.5176**	**per therm**
~~**Period ending over-collection to be recovered - per April Report**~~	~~$450,141~~				
~~**Projected sales (05/01/21 - 10/31/21)**~~	~~8,061,210~~				
~~**Per unit change in Cost of Gas (05/01/21 - 10/31/21)**~~	~~$0.0558~~				

RESIDENTIAL COST OF GAS RATE -05/01/~~21~~22	**COGwr**	~~**$0.4412**~~	**$0.5176**	**per therm**
	Maximum (COG+25%)	~~**$0.5515**~~	**$0.6470**	
~~INITIAL RESIDENTIAL COST OF GAS RATE - 05/01/21~~		~~$0.4412~~		
~~CHANGE IN PER UNIT COST~~		~~$0.0558~~		
~~REVISED RESIDENTIAL COST OF GAS RATE - 05/01/21~~		~~$0.4970~~		

COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/~~21~~22	**COGwl**	~~**$0.3943**~~	**$0.4740**	**per therm**
	Maximum (COG+25%)	~~**$0.4929**~~	**$0.5925**	
~~INITIAL COM/IND LOW WINTER USE COST OF GAS RATE - 5/01/20~~		~~$0.3943~~		
~~CHANGE IN PER UNIT COST~~		~~$0.0558~~		
~~REVISED COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/21~~		~~$0.4501~~		
C&I HLF DEMAND COSTS ALLOCATED PER SMBA	$205,468			
PLUS: RESIDENTIAL DEMAND RELOCATION TO C&I HLF	$11,258			
C&I HLF TOTAL ADJUSTED DEMAND COSTS	$216,726			
C&I HLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	1,996,958			
DEMAND COST OF GAS RATE	**$0.1085**			
C&I HLF COMMODITY COSTS ALLOCATED PER SMBA	$701,906			
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I HLF	$64			
C&I HLF TOTAL ADJUSTED COMMODITY COSTS	$701,970			
C&I HLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	1,996,958			
COMMODITY COST OF GAS RATE	**$0.3515**			
INDIRECT COST OF GAS	**$0.0140**			
TOTAL C&I HLF COST OF GAS RATE	**$0.4740**			

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/~~21~~22	**COGwh**	~~**$0.4733**~~	**$0.5445**	**per therm**
	Maximum (COG+25%)	~~**$0.5916**~~	**$0.6806**	
~~INITIAL COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/21~~		~~$0.4733~~		
~~CHANGE IN PER UNIT COST~~		~~$0.0558~~		
~~REVISED COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/21~~		~~$0.5291~~		
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$549,002			
PLUS RESIDENTIAL DEMAND REALLOCATION TO C&I LLF	$30,080			
C&I LLF TOTAL ADJUSTED DEMAND COSTS	$579,082			
C&I LLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	3,236,934			
DEMAND COST OF GAS RATE	**$0.1789**			
C&I LLF COMMODITY COSTS ALLOCATED PER SMBA	$1,138,131			
PLUS: RESIDENTIAL COMMODITY REALLOCATION TO C&I LLF	$104			
C&I LLF TOTAL ADJUSTED COMMODITY COSTS	$1,138,235			
C&I LLF PROJECTED PRORATED SALES (05/01/22 - 10/31/22)	3,236,934			
COMMODITY COST OF GAS RATE	**$0.3516**			
INDIRECT COST OF GAS	**$0.0140**			
TOTAL C&I LLF COST OF GAS RATE	**$0.5445**			

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Northern Utilities, Inc.

Fifth ~~Fourth~~ Revised Page 62
Superseding *Fourth* ~~Third~~ Revised Page 62

Local Delivery Adjustment Clause

Rate Schedule	~~GAPRA~~	*GAPRA*	~~EEC~~	*EEC*	~~LRR~~	*LRR*	~~ERC~~	*ERC*	ITMC	RCE	RPC	LDAC	*LDAC*
Residential Heating	~~$0.0044~~	*$0.0060*	~~$0.0774~~	*$0.0449*	~~$0.0220~~	*$0.0066*	~~$0.0061~~	*$0.0056*	$0.0000	$0.0000	$0.0000	~~$0.1099~~	*$0.0631*
Residential Non-Heating	~~$0.0044~~	*$0.0060*	~~$0.0774~~	*$0.0449*	~~$0.0220~~	*$0.0066*	~~$0.0061~~	*$0.0056*	$0.0000	$0.0000	$0.0000	~~$0.1099~~	*$0.0631*
Small C&I	~~$0.0044~~	*$0.0060*	~~$0.0337~~	*$0.0238*	~~$0.0030~~	*$0.0006*	~~$0.0061~~	*$0.0056*	$0.0000	$0.0000	$0.0000	~~$0.0472~~	*$0.0360*
Medium C&I	~~$0.0044~~	*$0.0060*	~~$0.0337~~	*$0.0238*	~~$0.0030~~	*$0.0006*	~~$0.0061~~	*$0.0056*	$0.0000	$0.0000	$0.0000	~~$0.0472~~	*$0.0360*
Large C&I	~~$0.0044~~	*$0.0060*	~~$0.0337~~	*$0.0238*	~~$0.0030~~	*$0.0006*	~~$0.0061~~	*$0.0056*	$0.0000	$0.0000	$0.0000	~~$0.0472~~	*$0.0360*
No Previous Sales Service													

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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

WINTER SEASON RESIDENTIAL RATES

	Winter Season November 20~~20~~21 - April 20~~21~~22	Tariff Rates		Total Delivery Rates (Includes LDAC)		Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas	
Residential Heating	**Tariff Rate R 5:**						
	Monthly Customer Charge	$22.20			$22.20		$22.20
	First 50 therms	$0.6920		~~$0.8019~~	$0.7551	~~$1.5334~~	$1.6943
	All usage over 50 therms	$0.6920		~~$0.8019~~	$0.7551	~~$1.5334~~	$1.6943
	LDAC	~~$0.1099~~	$0.0631				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.7315~~	$0.9392				
Residential Heating	**Tariff Rate R 10:**						
Low income	Monthly Customer Charge	$22.20			$22.20		$22.20
	First 50 therms	$0.6920		~~$0.8019~~	$0.7551	~~$1.5334~~	$1.6943
	All usage over 50 therms	$0.6920		~~$0.8019~~	$0.7551	~~$1.5334~~	$1.6943
	LDAC	~~$0.1099~~	$0.0631				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.7315~~	$0.9392				
45% Low Income Discount	Monthly Customer Charge	($9.99)			($9.99)		($9.99)
45% Low Income Discount	First 50 therms	($0.3114)			($0.3114)		($0.7340)
45% Low Income Discount	All usage over 50 therms	($0.3114)			($0.3114)		($0.7340)
No Discount	**LDAC**	$0.0000					
	Gas Cost Adjustment:						
45% Low Income Discount	Cost of Gas		($0.4226)				
Residential Non-Heating	**Tariff Rate R 6:**						
	Monthly Customer Charge	$22.20			$22.20		$22.20
	First 10 therms	$0.6470		~~$0.7569~~	$0.7101	~~$1.4884~~	$1.6493
	All usage over 10 therms	$0.6470		~~$0.7569~~	$0.7101	~~$1.4884~~	$1.6493
	LDAC	~~$0.1099~~	$0.0631				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.7315~~	$0.9392				

Issued: ~~November 4, 2020~~September 17, 2021
Effective Date: With Service Rendered On and After ~~November 1, 2020~~ November 1, 2021
Authorized by NHPUC Order No. in Docket No. DG 21-, dated

Issued by: Robert B. Hevert
Title: Senior Vice President

NHPUC No. 12 - Gas
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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

SUMMER-SEASON RESIDENTIAL RATES

	Summer Season May 20~~21~~22- October 20~~21~~22	Tariff Rates		Total Delivery Rates (Includes LDAC)		Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas	
Residential Heating	**Tariff Rate R 5:**						
	Monthly Customer Charge	$22.20			$22.20		$22.20
	First 50 therms	$0.6099		~~$0.7198~~	$0.6730	~~$1.2168~~	$1.1906
	All usage over 50 therms	$0.6099		~~$0.7198~~	$0.6730	~~$1.2168~~	$1.1906
	LDAC	~~$0.1099~~	$0.0631				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.4970~~	$0.5176				
Residential Heating Low income	**Tariff Rate R 10:**						
	Monthly Customer Charge	$22.20			$22.20		$22.20
	First 50 therms	$0.6099		~~$0.7198~~	$0.6730	~~$1.2168~~	$1.1906
	All usage over 50 therms	$0.6099		~~$0.7198~~	$0.6730	~~$1.2168~~	$1.1906
	LDAC	~~$0.1099~~	$0.0631				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.4970~~	$0.5176				
No Discount*	Monthly Customer Charge	$0.0000			$0.0000		$0.0000
No Discount*	First 50 therms	$0.0000			$0.0000		$0.0000
No Discount*	All usage over 50 therms	$0.0000			$0.0000		$0.0000
No Discount	**LDAC**	$0.0000					
	Gas Cost Adjustment:						
No Discount*	Cost of Gas	$0.0000					
Residential Non-Heating	**Tariff Rate R 6:**						
	Monthly Customer Charge	$22.20			$22.20		$22.20
	First 10 therms	$0.6470		~~$0.7569~~	$0.7101	~~$1.2539~~	$1.2277
	All usage over 10 therms	$0.6470		~~$0.7569~~	$0.7101	~~$1.2539~~	$1.2277
	LDAC	~~$0.1099~~	$0.0631				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.4970~~	$0.5176				

*: Discount applicable to winter months November through April only.

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Title: **Senior Vice President**

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NORTHERN UTILITIES, INC.

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Superseding ~~Seventh~~Eighth Page 87

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON C&I RATES

	Winter Season November 20~~19~~21 - April 20~~20~~22	Tariff Rates		Total Delivery Rates (Includes LDAC)		Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas	
C&I Low Annual/High Winter	**Tariff Rate G 40:**						
	Monthly Customer Charge	$75.09			$75.09		$75.09
	First 75 therms	$0.1865		~~$0.2337~~	$0.2225	~~$0.9774~~	$1.1776
	All usage over 75 therms	$0.1865		~~$0.2337~~	$0.2225	~~$0.9774~~	$1.1776
	LDAC	~~$0.0472~~	$0.0360				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.7437~~	$0.9551				
C&I Low Annual/Low Winter	**Tariff Rate G 50:**						
	Monthly Customer Charge	$75.09			$75.09		$75.09
	First 75 therms	$0.1865		~~$0.2337~~	$0.2225	~~$0.8802~~	$1.0678
	All usage over 75 therms	$0.1865		~~$0.2337~~	$0.2225	~~$0.8802~~	$1.0678
	LDAC	~~$0.0472~~	$0.0360				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.6465~~	$0.8453				
C&I Medium Annual/High Winter	**Tariff Rate G 41:**						
	Monthly Customer Charge	$222.64			$222.64		$222.64
	All usage	$0.2425		~~$0.2897~~	$0.2785	~~$1.0334~~	$1.2336
	LDAC	~~$0.0472~~	$0.0360				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.7437~~	$0.9551				
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**						
	Monthly Customer Charge	$222.64			$222.64		$222.64
	First 1,300 therms	$0.1712		~~$0.2184~~	$0.2072	~~$0.8649~~	$1.0525
	All usage over 1,300 therms	$0.1399		~~$0.1871~~	$0.1759	~~$0.8336~~	$1.0212
	LDAC	~~$0.0472~~	$0.0360				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.6465~~	$0.8453				
C&I High Annual/High Winter	**Tariff Rate G 42:**						
	Monthly Customer Charge	$1,335.81			$1,335.81		$1,335.81
	All usage	$0.1984		~~$0.2456~~	$0.2344	~~$0.9893~~	$1.1895
	LDAC	~~$0.0472~~	$0.0360				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.7437~~	$0.9551				
C&I High Annual/Low Winter	**Tariff Rate G 52:**						
	Monthly Customer Charge	$1,335.81			$1,335.81		$1,335.81
	All usage	$0.1720		~~$0.2192~~	$0.2080	~~$0.8657~~	$1.0533
	LDAC	~~$0.0472~~	$0.0360				
	Gas Cost Adjustment:						
	Cost of Gas	~~$0.6465~~	$0.8453				

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NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

SUMMER SEASON C&I RATES

	Summer Season May 20~~21~~22- October 20~~21~~22	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$75.09	$75.09	$75.09
	First 75 therms	$0.1865	~~$0.2337~~ $0.2225	~~$0.7628~~ $0.7670
	All usage over 75 therms	$0.1865	~~$0.2337~~ $0.2225	~~$0.7628~~ $0.7670
	LDAC	~~$0.0472~~ $0.0360		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.5291~~ $0.5445		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$75.09	$75.09	$75.09
	First 75 therms	$0.1865	~~$0.2337~~ $0.2225	~~$0.6838~~ $0.6965
	All usage over 75 therms	$0.1865	~~$0.2337~~ $0.2225	~~$0.6838~~ $0.6965
	LDAC	~~$0.0472~~ $0.0360		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4501~~ $0.4740		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$222.64	$222.64	$222.64
	All usage	$0.1895	~~$0.2367~~ $0.2255	~~$0.7658~~ $0.7700
	LDAC	~~$0.0472~~ $0.0360		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.5291~~ $0.5445		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$222.64	$222.64	$222.64
	First 1,000 therms	$0.1337	~~$0.1809~~ $0.1697	~~$0.6310~~ $0.6437
	All usage over 1,000 therms	$0.1087	~~$0.1559~~ $0.1447	~~$0.6060~~ $0.6187
	LDAC	~~$0.0472~~ $0.0360		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4501~~ $0.4740		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$1,335.81	$1,335.81	$1,335.81
	All usage	$0.1206	~~$0.1678~~ $0.1566	~~$0.6969~~ $0.7011
	LDAC	~~$0.0472~~ $0.0360		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.5291~~ $0.5445		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$1,335.81	$1,335.81	$1,335.81
	All usage	$0.0792	~~$0.1264~~ $0.1152	~~$0.5765~~ $0.5892
	LDAC	~~$0.0472~~ $0.0360		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4501~~ $0.4740		

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Issued by: Robert B. Hevert
Title: Senior Vice President

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.71 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$ ~~64.53~~71.85 per MMBtu** per MDPQ per month for November ~~2020~~ 2021 through April ~~2021~~2022. Provided on Page 6 of ~~Schedule 21 FXW~~Attachment NUI-FXW-6.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Company Allowance Calculation: **1.~~30~~25% -** Provided in ~~Schedule 18 FXW~~Attachment NUI-FXW-3

IV. Supplier Services and Associated Fees:

SERVICE	PRICING
Pool Administration (required) **Non-Daily Metered Pools only**	• $0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• $0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• $1.50/customer/month billed @ marketer level
Customer Administration (required)	• $10/customer/switch billed @ marketer level

V. Meter Read Charge: $78 when customer phone line is not reporting daily data.

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VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Allocators

Capacity Allocators shall be calculated and filed with the Commission each year with the Winter Cost of Gas filing. The following Capacity Allocators shall be applicable for capacity assignments during the period of November 1, ~~2020~~ 2021 through October 31,~~2021~~2022.

Commercial and Industrial

	High Winter Use	Low Winter Use
Pipeline:	~~23.23~~22.82%	~~57.23~~60.95%
Storage:	~~31.91~~32.31%	~~17.78~~16.23%
Peaking:	~~44.86~~45.41%	~~24.99~~22.82%

Issued: September 17, ~~2020~~2021
Effective: November 1, ~~2020~~2021
Issued by: Robert B. Hevert
Senior Vice President
Authorized by NHPUC Order No. _______ in Docket No. DG ~~20~~21-_ __, dated __________.

VII. DELIVERY SERVICE TERMS AND CONDITIONS (continued)

Appendix D

Re-entry Surcharge and Conversion Surcharge (continued)

D. Information to be Filed with the Commission:

As part of the annual Cost of Gas filing, the Company shall file with the Commission a report showing the number of customers assessed the Re-entry Surcharge and the Conversion Surcharge and the amount of revenue received for each charge through the prior April 30. Pursuant to the Company's Cost of Gas Clause, the Company will apply such revenues as credits to the Company's New Hampshire Division Cost of Gas.

The following Re-entry Surcharge and Conversion Surcharge shall be applicable for the periods of November 1, ~~2020~~ 2021 through April 30, ~~2021~~ 2022 and May 1, ~~2021~~ 2022 through October ~~2021~~2022.

Effective Dates:	**November 1, 202~~0~~1 – April 30, 202~~1~~2**	**May 1, 202~~1~~2 – October 30, 202~~1~~2**
Re-entry Surcharge:	$0.~~0012~~ 0000 per therm	$0.~~0011~~ 0000 per therm
Conversion Surcharge, Low Load Factor (G-40, G-41, G-42):	$0.~~0012~~ 0000 per therm	$0.~~0011~~ 0000 per therm
Conversion Surcharge, High Load Factor (G-50, G-51, G-52):	$0.~~0984~~ 5915 per therm	$0.~~0011~~ 4817 per therm

NORTHERN UTILTIES, INC. - NEW HAMSHIRE DIVISION
2021 / 2022 Annual Cost of Gas Filing

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Attachment NUI-FXW-12	Contracts Ranked on a Per-Unit Cost Basis
Attachment NUI-FXW-13	Normal Year Sendout Volumes
Attachment NUI-FXW-14	Design Year Sendout Volumes
Attachment NUI-FXW-15	Normal Year Capacity Utilization
Attachment NUI-FXW-16	Design Year Capacity Utilization
Attachment NUI-FXW-17	Forecast of Upcoming Winter Period Design Day Report
Attachment NUI-FXW-18	New Hampshire 7 Day Cold Snap Analysis
Attachment NUI-FXW-19	Migration From Sales Service to Transportation Service
Attachment NUI-SED-1	Local Distribution Adjustment Charge (LDAC) Calculation
Attachment NUI-SED-2	Environmental Response Cost
Attachment NUI-SED-3	Typical Bill Impacts

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
NOVEMBER 2021 / OCTOBER 2022 ANNUAL PERIOD
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
CHRISTOPHER A. KAHL

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher A. Kahl. My business address is 6 Liberty Lane West, Hampton, New Hampshire.

Q. For whom do you work and in what capacity?

A. I am a Senior Regulatory Analyst for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation ("Unitil"). Unitil Service provides managerial, financial, regulatory and engineering services to the principal subsidiaries of Unitil. These subsidiaries are Fitchburg Gas and Electric Light Company d/b/a Unitil, Granite State Gas Transmission, Inc. ("Granite"), Northern Utilities, Inc. d/b/a Unitil ("Northern" or "the Company"), and Unitil Energy Systems, Inc. I am responsible for developing, providing and sponsoring certain reports, testimony and proposals filed with regulatory agencies.

Q. Please summarize your professional and educational background.

A. I have worked in the natural gas industry for over twenty-five years. Before joining Unitil in January 2011, I was employed as an Analyst with Columbia Gas of Massachusetts ("Columbia") where I had worked since 1997 in supply planning. Prior to working for Columbia, I was employed as an Analyst in the Rates and Regulatory Affairs Department of Algonquin Gas Transmission Company ("Algonquin") from 1993 to 1997. Prior to working for Algonquin, I was employed as a Senior Associate/Energy Consultant for DRI/McGraw-Hill. I received a Bachelor of Sciences degree and a Masters of Arts degree in Economics from Northeastern University.

Q. Have you previously testified before the New Hampshire Public Utilities Commission or for Unitil?

A. Yes, I have testified before the Commission in the 2021 / 2020 Annual Cost of Gas ("COG") proceeding, Docket No. DG 20-154 and the 2019 / 2020 Annual COG proceeding, Docket No. DG 19-154. I have testified in numerous other Cost of Gas proceedings as well.

Q. Please explain the purpose of your pre-filed direct testimony in this proceeding.

A. This proceeding reflects the annual COG filing and will present both the 2021 / 2022 Winter Season and 2022 Summer Season COG rates as well as various ancillary rates. I, Francis Wells, Manager of Gas Supply for Unitil Service, and Elena Demeris, Senior Regulatory Analyst for Unitil Service are sharing the responsibility of supporting the proposed New Hampshire Division 2021 / 2022 Annual COG and other proposed rate adjustments in this proceeding.

Mr. Wells is sponsoring the customer demand forecast and the resulting forecasted gas sendout and gas costs he developed for the Maine and New Hampshire Divisions. He is also providing the Capacity Allocation Percentages, the Peaking Demand Rate calculation and the Re-Entry Rate and Conversion Rate calculations.

Ms. Demeris is sponsoring the calculation of the 2021 / 2022 Local Distribution Adjustment Clause ("LDAC"), and the typical customer bill impacts resulting from the proposed 2021 / 2022 Winter Season and 2022 Summer Season COG rates.

My testimony presents and explains the New Hampshire Division's 2020 / 2021 Annual COG Reconciliation, the calculation of the 2021 / 2022 annual COG and the rates Northern proposes to charge customers for the November 1, 2021 to April 30, 2022 Winter Season, and for the May 1, 2022 to October 31, 2022 Summer Season. In addition, I will also discuss some of the proposed ancillary rates that are to be effective November 1, 2021 and May 1, 2022.

Q. Please provide a list of the Attachments that you have prepared in support of your testimony.

Before providing the list of attachments, I would like to point out that the filing has been reorganized in order for the Commissioners, Commission Staff, the Office of the Consumer Advocate, and any other interested parties to more easily tie the schedules to the testimony. Previously, the proposed ancillary rates and other supporting information were located in the rear section of the filing. The new format of the filing presents the schedules in a more sequential order, consistent with the order in which they are referenced in the testimony. All attachment numbers are preceded by the initials of the witness sponsoring the attachment. These attachments are now grouped with the attachments pertaining to the testimony of the witness thus allowing the reviewer to more easily match up testimony and attachments. In adopting this new format, the Company has not eliminated any of the schedules provided in previous filings. The Attachments that I have prepared in support of my testimony are listed below.

Attachment NUI-CAK-1	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Attachment NUI-CAK-2	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons
Attachment NUI-CAK-3	Division Sales and Sendout Forecast
Attachment NUI-CAK-4	Allocation of New Hampshire Demand Costs To New Hampshire Firm Sales Rate Classes
Attachment NUI-CAK-5	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Attachment NUI-CAK-6	New Hampshire Division Commodity Cost Analysis
Attachment NUI-CAK-7	Northern Utilities Inventory Activity
Attachment NUI-CAK-8	Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Attachment NUI-CAK-9	Calculation of High and Low Load Factor Rate Adjustments
Attachment NUI-CAK-10	2020 - 2021 Annual Reconciliation
Attachment NUI-CAK-11	Bad Debt Calculation
Attachment NUI-CAK-12	New Hampshire Division (Over) / Under-collection Balances and Interest Calculations
Attachment NUI-CAK-13	Summary of Cost of Gas Rate Calculations
Attachment NUI-CAK-14	Comparison of Proposed Rates to Current Rates
Attachment NUI-CAK-15	Supplier Balancing Charge
Attachment NUI-CAK-16	Prior Year Re-entry Rate and Conversion Rate Revenues
Attachment NUI-CAK-17	Short Term Debt Limit Calculation

II Summary

Q. Please Summarize Northern's proposed 2021 / 2022 Summer Period and Winter Period COG rates and describe how they compare to last year's rates.

A. Table 1 below provides Unitil's proposed 2021 / 2022 Winter Period COG rates and compares them to the average COG rates for the 2020 / 2021 Winter Period. As this table shows, Winter Period COG rates are higher than those in 2020 / 2021 by $0.2077 for residential customers and higher by $0.1988 and $0.2114 per therm for High and Low Load Factor Commercial / Industrial ("C / I") customers, respectively.

Table 1

Winter Period Cost of Gas Rates

Class	2021 / 2022 Proposed Rate per therm	2020 / 2021 Average Rate per therm	Percent Change From 2020/2021 Winter Period
Residential Non-Heat (R-5, R-6 & R-10)	$0.9392	$0.7315	28.39%
C & I - High Load Factor (G-50, G-51 & G-52)	$0.8453	$0.6465	30.75%
C & I - Low Load Factor (G-40, G-41 & G-42)	$0.9551	$0.7437	28.43%

Table 2 below provides Unitil's proposed 2021 / 2022 Summer Period COG rates and compares them to the average COG rates for the 2020 / 2021 Summer Period. As this table shows, the proposed COG rates are $0.0146 higher for Residential customers,

$0.0239 higher for High Load Factor C / I customers and $0.0154 higher for Low Load Factor C / I customers.

Table 2

Summer Period Cost of Gas Rates

Class	2021 / 2022 Proposed Rate per therm	2020 / 2021 Average Rate per therm	Percent Change From 2020 / 2021 Summer Period
Residential Non-Heat (R-5, R-6 & R-10)	$0.5176	$0. 4970	4.14%
C & I - High Load Factor (G-50, G-51 & G-52)	$0.4740	$0. 4501	5.31%
C & I - Low Load Factor (G-40, G-41 & G-42)	$0.5445	$0. 5291	2.91%

A summary of the calculation of these rates, and the components that make up these rates is provided in Attachment NUI-CAK-10. A more detailed comparison of 2021 / 2022 residential COG rates to 2021 / 2022 residential rates is provided in Attachment NUI-CAK-14. I will describe the reasons for the change in COG rates later in my testimony. Customer bill impacts resulting from the change in COG rates are discussed in the testimony of Ms. Demeris and are presented in Attachment1 NUI-SED-3.

II. COST OF GAS FACTOR

Q. Please provide an overview of how Northern's COG-related costs are allocated to the New Hampshire Division rate classes.

A. The allocation of Northern's costs to the New Hampshire Division rate classes is derived through three steps. They are as follows:

Step 1 – Allocate total Northern costs between the New Hampshire and Maine Divisions.

Step 2 - Allocate New Hampshire Division costs to the Winter and Summer Seasons.

Step 3 – Allocate New Hampshire Division seasonal costs to each rate class.

I will provide a detailed explanation of how these three steps are conducted.

A. Allocation of Northern's Demand-Related Costs to the Maine and New Hampshire Divisions

Q. Please explain how Northern's projected fixed costs, i.e. (a) pipeline reservation and gas supply demand charges, (b) underground storage capacity costs and (c) peaking resource capacity costs are allocated between Northern's Maine and New Hampshire Divisions.

A. Northern's total demand costs are allocated to the Maine and New Hampshire Divisions by application of the Modified Proportional Responsibility ("MPR") methodology. The MPR methodology allocates fixed gas costs to the Maine and New Hampshire Divisions in a two-step process: (1) costs, by resource type[1], are allocated to months by application of MPR allocation factors; and (2) the costs allocated to each month are then allocated to the Maine and New Hampshire Divisions based on the relative shares of Design Year

[1] Pipeline, storage and peaking.

demand[2] in that month. This MPR methodology was approved by the Commission pursuant to settlements in Docket Nos. 2005-087 and 2005-273.

As I will explain in more detail below, I used the MPR methodology to allocate Northern's projected total annual demand costs to the Maine and New Hampshire Divisions for the 2021 / 2022 Winter Season (November 2021 through April 2022) and for the 2022 Summer Season (May 2022 through October 2022).

Q. Please give an overview of the process you followed to derive the MPR allocator used to assign Northern's projected total demand costs for the 12-month period November 2021 through October 2022 to the Maine and New Hampshire Divisions.

A. I have prepared Attachment NUI-CAK-1 to explain how I calculated the MPR factors and how I used these factors to allocate Northern's total demand costs for November 2021 through October 2022 ("COG Period") to the Maine and New Hampshire Divisions. In this attachment, I distinguish between two types of demand costs; Capacity-related and Off-system Peaking demand costs. Capacity-related demand costs reflect the resource costs of Pipeline, Storage and On-system Peaking supplies, as well as credits for capacity release and asset management agreements, for both Sales Service and capacity assigned Delivery Service customers. Off-system Peaking demand costs reflect the costs

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2 For the MPR allocation process, Design Year demand is calculated as the actual demand to Maine and New Hampshire Division's firm sales and assigned capacity / non-grandfathered transportation customers for the period May 2020 through April 2021, adjusted to reflect design weather conditions from November through April and normal weather conditions from May through October.

associated with Northern's Off-system Peaking resources used for Sales Service customers only.

Attachment NUI-CAK-1 is arranged in the following six sections;

(1) Total Capacity-related demand costs, by type of resource (Pipeline, Storage, On-system Peaking, and other capacity related costs and credits), are summarized in Lines 1 through 14.

(2) Capacity-related demand costs for each resource type are allocated to each month in the COG Period according to MPR allocators that were developed specifically for each resource type, as shown on Lines 16 through 52, where the MPR allocators are based on design year sendout volumes for each resource type.

(3) Capacity-related demand costs that are allocated to each month in Section 2 are allocated to the Maine and New Hampshire Divisions according to design year total firm sendout as shown in Lines 53 through 96.

4) Off-system Peaking demand costs, shown on Line 97, are allocated to each month in the Winter Period according to MPR allocators that were developed based on the dispatch of Sales Service customer demand as shown in Lines 99 through 106.

5) Off-system Peaking demand costs that are allocated to each month in Section 4 are then allocated to the Maine and New Hampshire Divisions according to design year total Sales Service sendout as shown in Lines 108 through 123.

6) Total Demand costs for each division are then calculated by applying the ratio of each division's Capacity-related demand costs and Off-system Peaking demand costs to Northern's total costs as shown in Lines 124 through 137. From these calculations, the PR allocators are determined. As shown, for November 2021 through October 2022, the PR allocators are 59.01% for the Company's Maine Division and 40.99% for the New Hampshire Division.

I note the second column of Pages 2, 4 and 6 of Attachment NUI-CAK-1 describes the sources of data and explains the calculations included in Attachment NUI-CAK-1, on Pages 1, 3 and 5. Similar explanations are included in other attachments referenced in my testimony.

Q. Why are Off-system Peaking demand costs listed in steps 4 through 6 allocated separately from all other demands costs?

A. Northern no longer purchases Off-system Peaking supplies for capacity-assigned Delivery Service customers in either its Maine or New Hampshire Divisions[3]. Accordingly, these costs should not be included in the allocation of Capacity-related demand costs because the associated dispatch of these resources includes capacity-assigned (i.e. Sales Service plus capacity-assigned Delivery Service) load. A capacity resource, like the Company's Off-system Peaking Supplies, that reflects only the cost

[3] Northern ceased purchasing Off-system Peaking supplies for capacity assignment customers in the New Hampshire Division effective November 1, 2016.

associated with Sales Service customers, should be allocated between divisions based on the dispatch of Sales Service load only.

Q. Please explain how you allocated Northern's forecasted total Capacity-related demand costs to the months in the COG Period.

A. Lines 3 through 5 of Attachment NUI-CAK-1 show Northern's total projected demand costs for Pipeline, Storage, and On-system Peaking resources[4]. Also included are estimates of Northern's Capacity Release and Asset Management revenues, which I have summarized in Lines 8 and 9 of Attachment NUI-CAK-1.

The development of the MPR factors and the application of these factors to allocate Pipeline, Storage and On-system Peaking demand costs to each month are shown on Attachment NUI-CAK-1, Lines 20 through 25, Lines 36 through 43 and Lines 47 through 52, respectively. In addition, Lines 29 through 32 show the calculation of the Storage Injection Fees, by month. Storage Injection Fees represent capacity costs that comprise the portion of Northern's pipeline capacity that is used to transport gas to and from the underground storage fields. If the Company expects to incur such fees, they are added to the Storage demand costs, as shown on Line 42, and subtracted from the Pipeline demand costs, as shown on Line 57. However, as indicated, for the 2021 / 2022 Winter Season, storage injection fees are zero. This is because Northern is purchasing storage gas

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[4] The forecast of demand costs is provided in Schedule 20-FXW.

directly at the underground storage facility thereby eliminating the need for transportation to the facility and the associated transfer of costs.

Northern's fixed capacity costs that have been allocated to each month are summarized and consolidated on Lines 54 through 60. Lines 54, 55 and 56 repeat the Pipeline, Storage, and On-system Peaking capacity costs from Lines 25, 43, and 52. Line 57 shows the credit to Pipeline capacity costs that is related to the Storage Injection Fees that have been added to the Storage capacity costs[5]. In addition, 1/5 of total Capacity Release revenues are allocated evenly to each month from November through March, as shown on Line 58, and 1/6 of total Asset Management revenues are allocated evenly to each month from November through April, as shown on Line 59.

Q. How are the total Capacity-related Demand Costs and the Capacity Release and Asset Management revenues, which have been allocated to each month according to the process that you described above, allocated to the Maine and New Hampshire Divisions?

A. Northern's Total Capacity-related Demand Costs[6] and Capacity Release and Asset Management revenues allocated to each month are then allocated to the Maine and New Hampshire Divisions according to the design year total firm sendout for both divisions, which is shown in Lines 65 and 66 of Attachment NUI-CAK-1; the calculated percentages are provided in Lines 70 and 71. In accordance with Commission-approved

[5] As indicated, for the 2021 / 2022 Winter Season, the credit is zero due to purchases being made directly at the storage facility.
[6] Costs reflect pipeline, storage and on-system peaking resources.

settlements[7], the design-year firm sendout quantities for the COG Period as shown on Lines 65 and 66 are the sendout quantities required to serve the Maine and New Hampshire Divisions' firm sales and transportation customers that are subject to the assigned-capacity requirements under design winter conditions from May 2020 to April 2021.

Q. Is the same process used for allocating Capacity-related demand costs also used for Off-system Peaking demand costs?

A. Yes. Lines 101 through 106 of Attachment NUI-CAK-1 use the same process for allocating resource costs to each month as that used in Lines 47 through 52. Also, Lines 109 through 123 use the same process for applying monthly costs to divisional sendout as used in Lines 62 through 77. As shown in Lines 121 and 122, Off-system Peaking demand costs are allocated to each division based on the design winter dispatch of Sales Service customers only.

Q. Finally, how are the combined PR Allocators for both Capacity-related and Sales Service demands calculated?

A. The combined PR allocators are based on the percentage of total Capacity-related and Off-System Peaking PRs costs allocated to each division. Lines 125 and 130 of Attachment NUI-CAK-1 show the Capacity-related PR allocators while Lines 126 and 131 show the corresponding values for Off-system peaking PR allocators. Lines 127 and

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[7] These settlements were approved in Docket Nos. 2005-87 and 2005-273.

132 show the combined PR Allocators, 59.01% for Maine and 40.99% for New Hampshire, used to assign costs between divisions.

B. Allocation of New Hampshire Demand-Related Costs to Seasons

Q. Please explain how the projected annual demand-related costs that are allocated to the New Hampshire Division are then assigned to be recovered in the 2021 / 2022 Winter Season and the 2022 Summer Season.

A. Northern allocates costs between the seasons as well as among customer classes through the Simplified Market Based Allocation ("SMBA") method. I have prepared Attachment NUI-CAK-2 to show detailed support for the allocation of New Hampshire Division Sales Service demand costs to months, and then to seasons utilizing the SMBA method.

Lines 2 through 4 of Attachment NUI-CAK-2 summarize the Pipeline and Storage and On-system Peaking demand costs that are allocated to the New Hampshire Division, as determined in Attachment NUI-CAK-1. Lines 12 through 22 of Attachment NUI-CAK-2 show the calculation of Net Demand Costs for firm sales customers, which is Total Demand Costs allocated to the New Hampshire Division less the capacity assignment revenues from New Hampshire Division transportation customers. The Winter and Summer Season rates that will be charged to New Hampshire Division firm sales customers from November 2021 through October 2022 will recover: (1) the Net Pipeline

Demand costs shown on Line 19; (2) the Net Storage costs shown on Line 20; and (3) the On-system Peaking demand costs shown on Line 21 of Attachment NUI-CAK-2.[8]

Lines 26 through 40 of Attachment NUI-CAK-2 show the calculation of pipeline demand costs for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use demand costs.[9] The Base Use that is shown on Line 31 of Attachment NUI-CAK-2 is the average projected daily use in July and August 2022[10] for all firm sales classes. The Base Pipeline Use Demand cost that is shown on Line 39 of Attachment NUI-CAK-2 is calculated by multiplying Firm Sales Base Use, shown on Line 31, times the weighted average annual cost of pipeline capacity, as shown on Line 35 of Attachment NUI-CAK-2. Line 40 shows the Remaining Pipeline Use Net Pipeline Demand costs for sales customers, which is the difference between total net Pipeline and Product Demand costs and Base Pipeline Use demand costs.

Lines 44 through 49 of Attachment NUI-CAK-2 show the calculation of the Proportional Responsibility ("PR") allocator that is used to allocate (a) Remaining Use Net Pipeline Demand costs and (b) Storage and On-system Peaking costs related to Firm Sales customers for twelve months, November 2021 through October 2022. Lines 51 through 55 show the calculation of the PR factor that is used to allocate (c) Capacity Release and Asset Management revenues, (d) Interruptible margins and Re-entry Rate and Conversion

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8 These direct demand costs are adjusted by Outage Replacement expenses (Line 75); Capacity Release and Asset Management revenues (Line 77); Interruptible margins (Line 78); and Re-Entry Rate and Conversion Rate Credits (Line 79).

9 This separation is necessary because the SMBA allocation methodology allocates Base Use demand costs to seasons on a different basis than Remaining Use demand costs.

10 Average Projected Daily demand by class in July and August is shown in Attachment NUI-CAK-3, Line 48.

Rate revenues and (e) Off-system Peaking Supplies to the Winter Season months, November 2021 through April 2022. These PR factors are summarized by type of capacity cost at lines 60 through 65. Line 60 of Attachment NUI-CAK-2 shows that 1/12th of the net annual Base Use pipeline demand costs is allocated to each month, and Lines 69 through 79 show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the "All Months" and "Peak Months Only" allocation factors.

As shown on Line 80 of Attachment NUI-CAK-2, $12,798,284 of total direct demand costs are allocated to the 2021 / 2022 Winter Season, and $1,354,125 is allocated to the 2022 Summer Season.

Q. Please explain the annual Outage Replacement expense of $44,367 listed on Line 75 of Attachment NUI-CAK-2.

A. The Outage Replacement expense listed on Line 75 pertains to two separate occurrences of requiring replacement supplies to maintain service to Northern's customers during a pipeline outage. The first outage occurred in in June 2020 and the second outage occurred in June 2021.

Q. Please provide additional information on the first pipeline outage.

A. The first pipeline outage was due to upstream construction involving the addition of a new compressor to the Eliot Compressor Station as part of Portland Natural Gas Transmission

System's (PNGTS) Portland Xpress Project (PXP)[11]. In Northern's 2020-2021 COG filing, the Company requested, and was allowed, recovery of $119, 666[12] for the fixed cost portion of acquiring compressed natural gas ("CNG") to maintain service. However, the Company had also incurred an additional $18,105 of expenses it did not include in the 2020-2021 COG filing. As result, Northern is proposing to collect the New Hampshire Division's share of the remaining charges in this filing. Of the remaining amount, the portion allocated to the New Hampshire division, $7,575, is based on the PR Allocator in effect at the time of the outage (41.84%). An itemized list of the additional expenses is provided on page 1 of Confidential Attachment NUI-CAK-2A.

Q. Please provide additional information on the second pipeline outage.

A. The second outage was due to work at the Westbrook gate station for the PNGTS[13] WXP project. As with the work on the Eliot Compressor Station, this project required the shut-down of a portion of Northern's system. In this case, all gas flowing onto Northern's system from both PNGTS and Maritimes and Northeast Pipeline was shut down and required the acquisition of a replacement supply on this portion of Northern's system. The total demand cost for the replacement supply was $90,000[14]. Of this amount, the portion allocated to the New Hampshire division, $36,792, is based on the PR Allocator in effect at

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[11] Northern's distribution system in Eliot is fed by a single pipeline interconnection and the construction of the compressor station required the station to shut down thereby necessitating CNG supply in order to maintain service to that portion of its system.
[12] Total CNG demand costs were $286,008 of which 41.84% were assigned to the New Hampshire division.
[13] Portland Natural Gas Transmission System
[14] The invoice for this demand cost is provided on page 2 of Confidential Attachment CAK-2A.

the time of the outage (40.88%). The expenses associated with this outage is discussed in greater detail in Mr. Wells' testimony.

C. Allocation of New Hampshire Winter and Summer Season Demand Costs to Customer Classes

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Winter and Summer Seasons are allocated to each sales rate class.

A. The New Hampshire Division sales service Base Use demand-related costs for each month are allocated to each Sales Service rate class based on that class's pro rata share of total forecasted firm sendout to sales customers under normal weather conditions in that month. The Remaining Use demand-related costs for each month are allocated to each Sales Service rate class based on that class's pro rata share of total forecasted firm sales design day, temperature-sensitive demand.

I have prepared Attachment NUI-CAK-3 to show the calculation of the factors that are used to allocate New Hampshire Division Sales Service Winter and Summer Season Base Use demand-related costs for each month to each sales service rate class. The firm sales forecast, shown on Lines 1 to 16, and the firm sendout forecast by class, shown on Lines 18 to 33, are used to determine: daily Base Use, shown on Lines 35 to 48; Base Use sendout, shown on Lines 49 to 64; and Remaining Use sendout, shown on Lines 66 to 80. The Base and Remaining Use sendout values for each class are used to allocate the seasonal demand costs to the New Hampshire Division firm sales classes.

I have prepared Attachment NUI-CAK-4 to show the allocation of Winter and Summer Season New Hampshire Division Net Demand costs to each firm sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Winter Season and Summer Season month as shown in Attachment NUI-CAK-2, Lines 69 through 79, and (b) the rate class allocators as shown Attachment NUI-CAK-3, Lines 49 to 80. The Base Use Sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Attachment NUI-CAK-4. The Remaining Use Design Day allocators, which are used to allocate all other demand-related costs and credits to firm Sales Service rate classes, are shown on Lines 39 through 48.

The following table shows the location in Attachment NUI-CAK-4 of the Net Demand-related costs and credits by component allocated to each firm sales rate class:

Demand Cost Component	Attachment NUI-CAK-4
Base Capacity	Lines 24 through 37
Remaining Pipeline Capacity	Lines 50 through 66
Peaking and Storage Demand	Lines 68 through 84
Off-system Peaking Demand & Outage Expense	Lines 86 through 102
Capacity Release & Asset Mgmt. Revenues	Lines 105 through 121
Interruptible, Re-entry & Conversion Revenues	Lines 123 through 139
Total Non-Base Capacity Costs	Lines 141 through 155
Total Capacity Costs	Lines 157 through 175

D. Allocation of Variable Costs

Q. Please provide a description of Variable costs, and explain how Variable costs are allocated to Northern's Maine and New Hampshire Divisions.

A. Variable costs include commodity costs and variable pipeline and storage costs[15] for firm sales. Mr. Wells prepared a forecast of Northern's variable gas costs by month, which is provided in Attachment NUI-FXW-8. These variable gas costs have been allocated between the Maine and New Hampshire Divisions based on each Division's percentage of monthly firm normal sendout. I have prepared Attachment NUI-CAK-5 to show the allocation of the 2021 / 2022 Winter and Summer Season variable gas costs between the Maine and New Hampshire Divisions.

Q. Please explain Attachment NUI-CAK-5.

A. Lines 1 through 10 of Attachment NUI-CAK-5 show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 12, 20 and 21 of Attachment NUI-CAK-5. This Attachment also shows projected Off-system Sales revenues on Line 22. The pipeline commodity costs shown on Lines 12 and 19 are based on projected NYMEX prices as of September 14, 2021. The total variable gas costs for firm Sales Service, on Lines 24 and 36, are allocated to the Maine and New Hampshire Divisions based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 40, 41, 45 and 46. Attachment NUI-CAK-5 also shows the allocation of Commodity costs to the two Divisions, (Maine Division: Lines 51 through 57; New Hampshire Division: Lines 59 through 65). Finally,

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15 Variable costs include pipeline usage/commodity charges, pipeline fuel retention, storage commodity injection and withdrawal charges, and storage fuel retention.

Attachment NUI-CAK-5 shows the inventory finance costs for underground storage and LNG resources (Lines 82 to 84), the allocation of these costs to the Maine and New Hampshire Divisions (Lines 87 to 89), and the allocation of New Hampshire Division's allocated share of annual inventory finance costs to the Winter Season, using the firm sales remaining sendout allocators (Lines 98 to 100).

I have prepared Attachment NUI-CAK-6 to summarize the New Hampshire Division variable gas costs that were determined in Attachment NUI-CAK-5. This attachment also shows the calculation of base and remaining commodity costs.

Q. Please explain how you calculated the inventory finance costs for underground storage and LNG resources that are included in Attachment NUI-CAK-5.

A. The allocation of inventory finance charges to the Company's Maine and New Hampshire Divisions are shown on Lines 87 and 88 of Attachment NUI-CAK-5. These inventory finance costs, as shown on Lines 82 and 83 were calculated based on forecasted inventory activity calculations which are shown in Attachment NUI-CAK-7.

Q. Please explain how the New Hampshire Division variable gas costs for sales customers are allocated to each firm sales class.

A. I have prepared Attachment NUI-CAK-8 to show the allocation of New Hampshire Division variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the Base Sendout allocators by rate class. Lines 22 to 35 show the allocation of the monthly New Hampshire Division Base Commodity costs[16] to each rate class. Lines 37 to 56 show the calculation of the Remaining Sendout allocators by rate class. Lines 57 to 70 show the allocation of the monthly New Hampshire Division Remaining Commodity costs[17] to each rate class. A summary of all commodity costs allocated to the New Hampshire Division's firm sales classes is shown on Lines 71 to 84.

E. Adjustments

Q. Once direct demand and commodity costs are determined for the rate classes, are any adjustments made?

A. Yes. Since Residential COG rates are based on the average cost of gas (total seasonal cost of gas divided by total seasonal demand), and the High and Low Load Factor Commercial and Industrial ("C&I") COG rates are determined through the SMBA method, an adjustment to C&I COG rates is required in order to properly recover all costs. Attachment NUI-CAK-9 adjusts C&I COG rates in order to account for differences between the average cost and SMBA methodologies. This adjustment is based on the difference in total projected costs that would be assigned to Residential customers under the two methodologies, and applies the difference to the C&I customer classes based on their percentage of total allocated C&I demand and commodity costs.

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16 New Hampshire Division Base Commodity costs by month are shown in Attachment NUI-CAK-6, Line 34.
17 New Hampshire Division Remaining Commodity costs by month are shown in –Attachment NUI-CAK-6, Line 35.

F. Refunds

Q. Are there any refunds included in this filing?

A. Yes there is a small refund of $11,075 from Maritimes for interruptible service plus interest. The refund was included in the August 2021 invoice from Maritimes.

G. Indirect Costs and Miscellaneous Charges / Credits

Q. Please explain the 2020 / 2021 Annual COG Reconciliation.

A. The 2020 / 2021 Annual COG Reconciliation is provided as Attachment NUI-CAK-10. As Page 1 of this Attachment indicates, the projected October 31, 2020 annual ending balance is an under-collection of $237,004. As shown on Page 1 of this Attachment, the allocation of the ending balance between seasons is based on the portion of projected sales that occur in each season. Similar allocations are provided for Working Capital (Attachment A) and Bad Debt (Attachment B) of this Annual Reconciliation.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2021 / 2022 Winter Season and 2022 Summer Season COGs?

A. To develop its bad debt projections, Northern forecasts 12 months of customer write-offs for both supply and distribution service. This forecast is based on actual experience and any recent unexpected increases or decreases in the number of customer write-offs. As shown on Line 14 of Attachment NUI-CAK-11, for the twelve months ended December 31, 2022, Northern projects annual Bad Debt expense to be $400,000. The projected annual Bad Debt expense was then allocated to supply (38%) and distribution (62%) services based on the actual Bad Debt experience of these components over the 12-months ended July 31, 2021. This is shown on Lines 7 and 5, respectively, of Attachment NUI-CAK-11. The annual Bad Debt expense forecast allocated to supply was then allocated further to the 2021 / 2022 Winter Season (90%) and 2022 Summer Season (10%) based on the allocation of direct demand costs between the Winter and Summer seasons. This breakout establishes the Winter Season Bad Debt of $137,320 (Line 16) and a Summer Season Bad Debt expense of $14,529, (Line 17). I have also included these expenses at lines 36 and 144 in Attachment NUI-CAK-13.

Q. How were Northern's Working Capital Costs derived?

The Working Capital Costs were based on a formula approved in Northern's 2017 base rate proceeding, Docket No. DG 17-070. This formula derives the working capital percentage by dividing the supply related net lag of 10.02 days by 365 days and then multiplying the result by the prime interest rate. Based on the current prime rate of 3.25%, the Working Capital Percentage is 0.0892%. This percentage, when multiplied by each season's forecasted Direct Cost of Gas, yields a 2021 / 2022 Winter Season Working Capital Cost of $28,555 and a 2022 Summer Season Working Capital Cost of $4,002. These amounts are included in Attachment NUI-CAK-13 at lines 29 and 138.

Q. Please explain the costs related to the Company's local production and storage facilities, and Other Administrative and General ("A&G") expenses that are included in the Winter Season COG.

A. Northern's local production and storage costs were set at $476,106 in the Company's most recent base rate case proceeding, Docket No. DG 17-070, and are recovered solely in the Winter Season. Also in the last base rate case proceeding, A&G expenses were set at $580,455. Of this amount, $463,606 is recovered from sales customers in the Winter Season and $116,849 is recovered in the Summer Season. These amounts are included in Attachment NUI-CAK-13 on lines 40, 42 and 150 respectively.

Q. Please explain the calculation of the Winter and Summer interest expense.

A. Interest expense is calculated in Attachment NUI-CAK-12 (Line 100) and is based on the latest prime rate and expected costs and revenues during the Winter and Summer seasons. Winter and Summer period interest expense is also shown on Attachment NUI-CAK-13, on Lines 21 and 130 respectively

H. <u>Cost of Gas Factor</u>

Q. Please explain the calculation of the proposed New Hampshire Division COG Factors or Rates for the 2021 / 2022 Winter Season and the 2022 Summer Season.

A. Attachment NUI-CAK-13, which is similar to the Company's COG tariff Pages 40 through 43, has been prepared to explain the calculation of the proposed 2021 / 2022 Winter and 2022 Summer COG Factors. Attachment NUI-CAK-13 shows the calculation of the Winter and Summer Season COGs for each of Northern's three COG Rate Groups: (1) Residential classes R-5, R-6 and R-10; (2) C&I Low Winter use classes G-50, G-51 and G-52; and (3) C&I High Winter use classes G-40, G-41 and G-42.

As shown on Page 3 of the Attachment, the 2021 / 2022 Winter Season projected Average COG is $0.9392 per therm (Line 66), which is the sum of the average Total Direct COG, $0.9057 per therm (Line 59) and the average Indirect COG, $0.0335 per therm (Line 63). As shown of Page 7 of the Attachment, the 2022 Summer Season, the projected Average COG is $0.5176 per therm (Line 175), which is the sum of the average Total Direct COG, $0.5036 per therm (Line 168) and the average Indirect COG, $0.0140 per therm (Line 172).

Also shown on the Attachment are the proposed Residential COG Factors for the 2021 / 2022 Winter Period (Line 68) and the 2022 Summer Period (Line 177), the proposed C&I Low Winter Use COG Factors for the 2021 / 2022 Winter Period (Line 72) and 2022 Summer Period (Line 181), and the proposed C&I High Winter Use COG Factors the Winter 2021 / 2022 Winter Period (Line 92) and 2022 Summer Period (Line 201).

Q. Please explain the calculation of the Working Capital allowances for the 2021 / 2022 Winter Season.

The total Working Capital allowance, $22,721 as shown on Line 33 of Attachment NUI-CAK-13 is the sum of the current period working capital allowance (Line 29) plus the prior seasonal allocation of Working Capital reconciliation balance (Line 31).

Q. Please explain the calculation of the Bad Debt allowance for 2021 / 2022 Winter Season.

A. The Bad Debt allowance, $75,370 (Line 38), is the sum of the current period bad debt allowance (Line 36) plus the seasonal allocation of the Bad Debt reconciliation balance (Line 37).

Q. Please explain the calculation of the 2022 Summer Season Working Capital allowances.

The total Working Capital allowance, $2,532 as shown on Line 141 of Attachment NUI-CAK-13 is the sum of the current period working capital allowance (Line 138) plus the prior seasonal allocations of Working Capital reconciliation balance (Line 139).

Q. Please explain the calculation of the Bad Debt allowance for 2022 Summer Season.

A. The Bad Debt allowance, ($1,085) (Line 146), is the sum of the current period bad debt allowances (Line 144), plus the seasonal allocations of the Bad Debt reconciliation balance (Line 145).

Q. Is Northern proposing any credits to the COG for transportation customers returning to Sales Service?

A. Northern is projecting a combined total of $5,000 in revenues associated with the Re-entry Rate and Conversion Rate. This amount is included in Attachment NUI-CAK-13 at Line 14.

I. Summary Analyses

Q. How does the proposed average 2021 / 2022 Winter Season Residential COG rate compare to the average 2020 / 2021 Winter Season Residential COG rate?

A. Attachment NUI-CAK-14 compares the proposed 2021 / 2022 Winter Season Residential COG rate to the average 2020 / 2021 Winter Season Residential COG rate. As this Attachment indicates, there were no adjustments to COG rates during the 2020 / 2021 Winter Period. This Attachment also shows that the proposed 2021 / 2022 Winter Season COG rate, \$0.9392 per therm, is about \$0.2077 per therm higher than the average 2020 / 2021 Winter Season COG rate, \$0.7315 per therm. The increase is due to a significant increase in commodity costs. The impact of higher commodity costs is partially offset by an increase projected sales, and a smaller reconciliation under-collection compared to the prior year. Commodity costs are higher due to large increases in NYMEX prices. The change in costs and projected sales for Residential customers is also applicable to C&I customers.

Q. How does the proposed 2022 Summer Season Residential COG rate compare to the filed 2021 Summer Season COG rate?

A. Attachment NUI-CAK-14 also compares the proposed 2022 Summer Season Residential COG rate to the average 2021 Summer Season Residential COG rate. As this Attachment indicates, the proposed 2022 Summer Season average COG rate, \$0.5176 per therm, is \$0.0206 per therm higher than the 2021 Summer Season Average COG, \$0.4970 per therm. As with the Winter COG rate, commodity costs are higher than last year. However, this is offset by significantly higher projected sales and a lower reconciliation under-collection compared to the prior year. This change in costs and projected sales for Residential customers is also applicable to C&I customers.

Q. Why is the variance in the Winter Season larger than in the Summer Season?

A. Seasonal variances can differ for a number of reasons. For the 2020 / 2021 annual COG period, material increases in NYMEX prices have boosted pipeline supply costs as well as peaking supply costs including LNG. This has resulted in increased commodity costs in both the Summer and Winter Periods. However, when compared to the 2021 / 2022 Winter period, the 2022 Summer Period has a larger year-over-year increase in forecasted sales. This increase in sales helps to offset the increase in costs. In addition, 2021 Summer COG rates increased this past April which reduced the cost differential between the 2022 and 2021 summer COG prices.

III. ANCILLARY CHARGES & SUPPORTING INFORMATION

Q. What ancillary charges and schedules have you updated for this filing?

A. I have provided updates to four ancillary charges / schedules and supporting information to four separate schedules. First, I have updated the Supplier Balancing Charge to be effective November 1, 2021. The proposed charge remains unchanged at $0.71 per MMBtu. I have prepared Attachment NUI-CAK-15 to support the updated Supplier Balancing Charge calculation. Second, I have updated the On-system Peaking Demand charge to be effective November 1, 2021 through April 30, 2022. The proposed charge is $71.85 per Dth. Support for this charge is provided by Mr. Wells in Attachment NUI-FXW-5. Both the Supplier Balancing Charge and On-system Peaking Demand Charge are included in Tariff Page No. 141, Appendix A.

Third, I have updated Tariff Page 156 which updates the capacity allocation percentages for all non-exempt Delivery Service customers for the period November 1, 2021 through

October 31, 2022. The calculations supporting the capacity allocators are provided by Mr. Wells in Attachment NUI-FXW-7.

Lastly, I have updated the Re-entry Rates and Conversion Rates to be effective November 1, 2021 through April 30, 2022, and May 1, 2022 through October 31, 2022. For both High and Low Load Factor C&I customers the Re-entry Rate is $0.0000 per therm in both the Winter and Summer Seasons. In the Winter Season, the proposed Conversion Rate is $0.5915 per therm for High Load Factor customers and $0.4817 per therm for Low Load Factor C&I customers. In the Summer Season, the Conversion Rate is $0.0000 per therm for both High and Low Load Factor customers. These rates appear on Tariff Page No. 158, Appendix D. Support for these rates is provided by Mr. Wells in Attachment NUI-FXW-11.

Q. Are there any additional schedules that are included in this filing?

A. Yes, Attachments NUI-CAK-16 and NUI-CAK-17 have not been discussed in my testimony. Attachment NUI-CAK-16 provides the historical revenues from the Re-entry Rate and Conversion Rate Surcharges that are applied to transportation customers returning to the Company's Sales Service. Attachment NUI-CAK-17 determines Northern's short-term debt limit calculation for the period November 2021 through October 2022.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2021 / 2022 Winter Season COG rates if it receives any new or updated information on gas supplier or transportation rates?

A. If requested by Commission Staff, the Company will file a revised calculation of its 2021 / 2022 Winter and Summer Season COG rates to reflect updated gas and pipeline transportation cost projections as well as any other cost information a few weeks prior to the effective date of the Winter Season, November 1, 2021. In addition, the Company will file proposed changes to the approved 2021 / 2022 Winter Season COG rates when the projected end-of-season variance exceeds 2% of the target projected cost of gas. As mentioned above, Attachment NUI-CAK-12 projects Northern's monthly COG over/under collections, balances and interest. Northern will update this schedule each month with actual costs and updated NYMEX prices in order to determine the variance between the latest projected end-of-season balances and the target end-of-season balances established in this COG filing. As indicated on Line 94 on that Attachment, Northern projects a target balance over collection of $5,157,224[18] on April 30, 2022. This target balance will be updated in December to adjust for the actual balance effective November 1, 2021. If, during the upcoming Winter Season, the Company's monthly projected April 30, 2022 ending balance varies from the target balance by 2% or more of total target projected gas costs, then the Company will file to adjust the 2021 / 2022 Winter Season COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2021 / 2022 Winter Season COG rates.

[18] This over-collection is projected to be near $0 by October 31, 2021.

Lastly, the Company will also file proposed changes to the approved 2022 Summer Season COG when the projected annual variance exceeds 4% of the target projected gas costs. If, during the upcoming Summer Season, the Company's updated projected October 31, 2021 ending balance varies from the target Annual COG period balance by 4% or more of total Summer Period projected gas costs, and a rate change will help to lower the annual reconciliation balance, it will then file to change the 2022 Summer COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2022 Summer Period COG.

Q. Does this conclude your testimony?

A. Yes it does.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL PERIOD 2021-2022
COST OF GAS FILING

PREFILED TESTIMONY OF
FRANCIS X. WELLS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton, NH.

Q. What is your relationship with Northern Utilities, Inc.?

A. I am employed by Unitil Service Corp. (the “Service Company”) as Manager of Energy Planning. The Service Company provides professional services to Northern Utilities, Inc.

Q. Please briefly describe your educational and business experience.

A. I earned my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined the Service Company in September 1996 and have worked primarily in the Energy Contracts department. My primary responsibilities involve gas supply planning and acquisition.

Q. Have you previously testified before the New Hampshire Public Utilities Commission (“Commission”)?

A. Yes. I have testified as Northern’s gas supply witness before the Commission in Northern’s Cost of Gas (“COG”) proceedings.

Q. Please summarize your prepared direct testimony in this proceeding.

A. The purpose of my testimony is to present and support Northern's gas supply cost forecast, which was used for the calculation of the proposed COG.

The 2021-2022 fixed, annual demand cost estimates are 1% higher than the fixed, annual demand cost estimates provided for the prior 2020-2021 Winter Period COG filing. The major reasons for this increase include the projected increased Canadian pipeline demand costs due to less favorable exchange rates, higher Granite demand costs and higher peaking supply demand costs, partially offset by higher Asset Management Agreement revenue. Estimated average delivered commodity rates for the 2021-2022 Winter Period are 74% higher than the average delivered commodity rates estimated for the 2020-2021 Winter Period COG. The major reason for this increase is higher NYMEX supply costs and higher delivered supply costs, including baseload and peaking supplies added to the portfolio due to higher projected demands. Estimated average delivery commodity rates for the 2022 Summer Period are 31% higher than the average delivered commodity rates estimated for the 2021 Summer Period COG. Higher NYMEX supply costs are the major reason for this increase.

Northern projects combined sales service and delivery service distribution deliveries to be 9,169,707 Dth in the New Hampshire Division for the 2021-2022 Annual Period, which is 5.9% higher than the 2020-2021 Annual Period weather-normalized distribution deliveries and 9.6% higher than the 2019-2020 Annual Period weather-normalized distribution deliveries. The increase in the forecast reflects the recovery from the use per customer impacts of the COVID-19 pandemic on the economy by the beginning of 2022 and expected usage increases from two large customers from the prior year. Of the 9,169,707 Dth of projected distribution system deliveries, Northern projects that 4,424,636 Dth will be supplied by the Company through Sales Service. In order to supply 4,424,636 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,480,645 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 127,737 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,608,382 Dth for the upcoming Winter Period. The details behind these estimates are contained in Attachments NUI-FXW -1 and -2.

Northern's portfolio has 142,844 Dth maximum daily quantity of Pipeline, Storage and Peaking Capacity (each of these Capacity terms as defined in the Company's New Hampshire Division Delivery Service Terms and Conditions), assuming that the Atlantic Bridge project is placed into service. I review the portfolio in more detail in the body of my testimony.

I project Northern's total company (including both the Maine and New Hampshire Divisions) demand cost for the November 2021 through October 2022 gas year to be $46,657,517. (*See* Attachment NUI-FXW-5). Mr. Chris Kahl, who is also testifying in this proceeding, presents the allocation of the total annual demand cost to Northern's New Hampshire Division and the portion of that allocation of annual demand costs to be recovered in the Winter COG rate. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $5,012,735. (*See* Attachment NUI-FXW-6). I also discuss the updated Capacity Allocators and Capacity Ratio pursuant to the New Hampshire Division capacity assignment program, which are provided as Attachment NUI-FXW-7.

I project that Northern's total company (including both the Maine and New Hampshire Divisions) commodity cost to provide sales service during the 2021-2022 Winter Period will be $53,379,334 at an average rate equal to $5.339 per Dth. (*See* Attachment NUI-FXW-8). 2022 Summer Period commodity cost to provide sales service during the 2022

Summer period are projected to be $10,424,440 at an average rate equal to $3.470 per Dth.

I provide the proposed Re-entry Rate, applicable to Capacity Assigned Delivery Service customers who switch to Northern's Sales Service, and the proposed Conversion Rates, applicable to Capacity Exempt Delivery Service customers who switch to Northern's Sales Service. I also provide the supporting calculations for these proposed rates. These calculations are provided in Attachment NUI-FXW-11.

Finally, I discuss the outage replacement supply costs that were incurred by the Company in June 2021 due to an outage of the PNGTS-MNUS interconnect that was necessitated due to construction on the PNGTS system. This resulted in approximately $207,000 in gas supply cost, which the Company seeks recovery through the COG.

II. SALES AND SENDOUT FORECAST

Q. Please describe the Company's forecasts sales.

A. The sales forecast has been updated in light of the pandemic and its effects on the economy. Historically, for the residential, regular general, and large rate classes, the sales forecast is developed by independently forecasting meter growth, base usage per meter, and a weather-driven usage per meter assuming 'normal' weather (average degree days during over the last 20 years) for the forecast period. Also forecasted is the Company's meter read cycle. In addition, Business Development personnel are consulted for comments on significant usage changes for the Company's large customers. The forecast seeks to limit subjectivity and typically relies on historical trends. However, average usage per C&I customer has declined as a result of the deterioration of the economic environment caused by the unprecedented COVID-19 crisis. Consequently, historical usage per customer levels are unlikely to be illustrative of future sales over the short to medium terms. The sales forecast assumes that usage per customer will return to pre-pandemic levels at the beginning of 2022. This timing decision reflects an apparent consensus among macroeconomic forecasts reviewed by the Company. The forecast assumes a recovery for usage per customer back to pre-pandemic levels at a linear rate through the beginning of 2022.

Q. Please provide the forecast distribution deliveries, meter counts and use-per-meter figures utilized in this COG filing and a comparison of this forecast to weather normalized data for prior periods.

A. I have prepared Table 1, below, which provides a summary of the company's forecast of total billed distribution deliveries (Dth) for the upcoming 2021-2022 Annual Period.

Table 1. 2021-2022 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years

Month	2021-2022 Forecast[1]	2020-2021 Actual[2]	2021-2022 minus 2020-2021	Percent Change	2019-2020 Actual[2]	2021-2022 minus 2019-2020	Percent Change
Nov	742,238	706,201	36,038	5.1%	710,939	31,300	4.4%
Dec	1,012,081	974,136	37,945	3.9%	967,728	44,354	4.6%
Jan	1,300,722	1,195,414	105,308	8.8%	1,190,671	110,051	9.2%
Feb	1,335,467	1,256,408	79,058	6.3%	1,255,585	79,881	6.4%
Mar	1,107,637	1,052,431	55,206	5.2%	1,023,935	83,702	8.2%
Apr	877,111	812,809	64,303	7.9%	739,593	137,518	18.6%
May	631,324	583,125	48,199	8.3%	565,494	65,830	11.6%
Jun	446,553	426,376	20,177	4.7%	396,103	50,450	12.7%
Jul	401,291	384,587	16,704	4.3%	347,265	54,026	15.6%
Aug	401,013	385,149	15,864	4.1%	330,714	70,300	21.3%
Sep	408,450	392,793	15,657	4.0%	386,921	21,529	5.6%
Oct	505,819	486,861	18,958	3.9%	452,419	53,400	11.8%
Winter	6,375,256	5,997,398	377,858	6.3%	5,888,450	486,806	8.3%
Summer	2,794,451	2,658,891	135,560	5.1%	2,478,916	315,536	12.7%
Annual	9,169,707	8,656,289	513,418	5.9%	8,367,366	802,341	9.6%

Forecast distribution deliveries are projected to increase 5.9% compared to the 2020-2021 weather-normalized actual sales. Page 1 of Attachment NUI-FXW-1 shows that the increase in sales is explained by a 2.3% projected increase in meter counts and a 3.6% increase in projected use per customer. The increase in use per customer is explained by the continued recovery in use per customer explained above.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2021-2022 Annual Period in Attachment NUI-FXW-1. Page 1 of Attachment NUI-FXW-1 provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2021-2022 Winter Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2020-2021 and 2019-2020 Winter Periods. The changes in the distribution deliveries from the prior period are presented in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Attachment NUI-FXW-1 provides a calculation of the use-per-meter, which has been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. How does the Company allocate total distribution deliveries between Sales Service and Delivery Service deliveries?

A. For each rate class, the Company calculated the percentage of total distribution deliveries that were attributable to Sales Service for the 12-month period May 2020 through April 2021. These percentages were used to estimate the percentage of billed sales that would be supplied by the Company under Sales Service. Delivery Service sales were allocated between Capacity Assigned and Capacity Exempt based on monthly percentage of weather-normalized deliveries by rate class over the same 12-month period.

Q. Please summarize the Company's forecast of sales service deliveries and city-gate receipts required to meet the projected sales service deliveries.

A. I have prepared Table 2, below, which provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries, Company Managed Deliveries and City-Gate Receipts[1] for the upcoming Winter Period.

Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary

Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	Company Managed Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-21	904,460	471,318	23,850	501,134
Dec-21	1,138,582	672,045	25,927	706,478
Jan-22	1,311,721	788,030	30,414	828,419
Feb-22	1,165,490	677,460	22,901	708,937
Mar-22	1,079,498	579,426	24,645	611,406
Apr-22	775,504	345,654	0	350,029
May-22	525,996	190,761	0	193,176
Jun-22	421,906	125,725	0	127,316
Jul-22	410,447	107,420	0	108,780
Aug-22	419,208	109,042	0	110,423
Sep-22	428,956	120,812	0	122,341
Oct-22	587,938	236,943	0	239,943
Winter	6,375,256	3,533,933	127,737	3,706,403
Summer	2,794,451	890,703	0	901,979
Annual	9,169,707	4,424,636	127,737	4,608,382

The detailed calculations can be found in Attachment NUI-FXW-2. On Pages 1 and 2 of Attachment NUI-FXW-2, I present calendar month and billed sales service deliveries by rate class. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the New Hampshire Division. An annual summary of the impact of migration by rate class can be found in Attachment NUI-FXW-19.

On Page 3 of Attachment NUI-FXW-2, I present my calculations of the city-gate receipts. First, I estimated Company Gas Allowance by multiplying the forecast Sales Service Deliveries and the Company Gas Allowance percentage. Company Gas Allowance includes both Company Use and Lost and Unaccounted For. The Company Gas

[1] When I use the term "City-Gate Receipts", I refer to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, and Maritimes and Northeast, L.L.C and the Company's LNG facility.

Allowance Percentage was based on the recent history of actual data, which are presented in Attachment NUI-FXW-3. Finally, I added Northern's projection of Company Managed Sales pursuant to the New Hampshire Division's capacity assignment program.

Q. What are Company Managed Sales?

A. Company Managed Sales are a form of Capacity Assignment. Capacity Assignment is a means of transferring the demand cost responsibility for capacity contracts from Northern to the retail marketers on its system. Whenever a retail marketer enrolls a customer, who is "capacity assigned," the retail marketer assumes cost and benefits of a pro-rated portion of the capacity contracts entered into by Northern, subject to the capacity assignment provisions of each division. These capacity contracts can include interstate pipeline contracts, underground storage contracts and on-site peaking facilities. Such transfer may be achieved by releasing capacity directly to the retail marketer ("Capacity Release"), who may then purchase their own supplies and utilize the released contracts to deliver supplies to their customers. Pursuant to Northern's Delivery Service Terms and Conditions for its New Hampshire Division, all upstream pipeline and underground storage capacity that delivers to Northern's system is assigned via Capacity Release except for upstream pipeline and storage capacity resources that require the Bay State Exchange Agreement. These excepted pipeline and storage resources are assigned via Company Managed Supply. On-system peaking capacity, such as Northern's Lewiston LNG plant, is also assigned via Company Managed Supply. Under the Company Managed Supply form of capacity assignment, Northern bills the retail marketer for a pro-rated portion of these capacity resources at their respective actual costs and offers a city-gate delivered supply service. Such city-gate supplies are priced in accordance with the capacity assignment provisions of each division. Such arrangements are known as “Company Managed Sales.”

Q. Please explain the process used to project Company Managed Sales.

A. Company Managed resources include pipeline (specifically Iroquois Receipts and Algonquin Receipts capacity paths) and on-system peaking resources (Lewiston LNG plant). The maximum daily volume of each Company Managed resource was estimated based on current capacity assigned transportation customer data. Northern allows marketers to nominate their peaking Company Managed resources on a daily basis. In addition, marketers are required to purchase pipeline baseload supplies that are associated with the Company Managed pipeline resources. The Company Managed Sales forecast assumes that marketers will utilize all Pipeline and Peaking Company-managed supply available to them under the capacity assignment program.

III. NORTHERN’S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its Sales Service customers and meet Company Managed Supply obligations.

A. I have prepared Table 3, below, which provides an overview of the sources of supply available to Northern through its portfolio of contracts, including transportation contracts, storage contracts, baseload and peaking supply contracts and an exchange agreement with Bay State Gas Company.

Table 3. Northern Capacity Summary (Dth/Day)

Pipeline Capacity Paths	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
PXP Dawn Hub	9,965
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	40,586
Storage Capacity Paths	
Tennessee Firm Storage	2,644
Dawn Hub Storage	39,863
Total Storage Capacity	42,507
Peaking Capacity Paths	
LNG - On-System	6,500
PNGTS Delivered Baseload (Dec-Feb)	2,491
Peaking Contract 1	39,860
Peaking Contract 2	9,965
Additional Granite Capacity	935
Total Peaking Capacity	59,751
Total Design Day Capacity	142,844

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2021-2022 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above.

Table 3 can also be found on page 1 of Attachment NUI-FXW-4. Subsequent pages of Attachment NUI-FXW-4 include capacity path diagram and capacity path detail for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern Capacity listed for each source of supply.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Maritimes & Northeast Pipelines, L.L.C. ("MNUS" or "Maritimes"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited

("TransCanada"), Enbridge Gas, Inc. ("Enbridge" or "Union")[2], Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P. ("Iroquois") and Texas Eastern Transmission System, L.P. ("Texas Eastern" or "TETCO"). The gas supply portfolio also includes long-term storage contracts with Enbridge and Tennessee. Northern's gas supply portfolio for 2021-2022 includes a multi-year peaking contract ("Peaking Contract 1"), a PNGTS Delivered Baseload supply and a single-year peaking contact ("Peaking Contract 2"). The multi-year peaking supply arrangement was procured through a Request-For-Proposals ("RFP") and has a delivery period November through March for 4 years beginning November 2019. The PNGTS Delivered Baseload supply has a delivery period from December through February for the 2021-2022 Winter Period. Peaking Contract 2 has a delivery period from November through March for the 2021-2022 Winter Period. These shorter-term peaking supplies were procured via an RFP process that concluded in August 2021. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which Northern relies on to produce 6,500 Dth per day with a storage capacity of approximately 12,000 Dth of LNG. Also through an RFP Northern has procured an LNG Contract for up to 3,000 Dth per day with an annual contract quantity of up to 75,000 Dth beginning November 2021 and ending October 2022 in order to supply this facility. The gas supply portfolio includes an exchange agreement with Bay State Gas Company ("BSG Exchange" or "Bay State Exchange Agreement"), which is needed to bring the Iroquois Receipts, Leidy Hub Supply and Transco Zone 6, non-NY capacity path supplies into

[2] Enbridge Gas, Inc. was formed on January 1, 2019 with the amalgamation of Enbridge Gas Distribution and Union Gas Limited.

Northern's system, as the delivery points on these capacity paths are on the Bay State Gas Company system.

The portfolio I used to project gas supply costs for the 2021-2022 winter season includes the Portland XPress ("PXP") and Atlantic Bridge ("AB") projects. These supply sources are relatively new to the portfolio, having been added to the portfolio since the last COG filing.

The capacity path diagrams and capacity path details in Attachment NUI-FXW-4 show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, in order to move natural gas supplies from the sources of supply listed in Table 3 to Northern's distribution system. Each of these contractual arrangements represents a segment in one or more capacity paths. The capacity path diagrams show how each segment in the path is interconnected within the path. The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

Q. Please describe the Company's process for procuring its gas supply commodity supplies.

A. Northern's practice is to secure most of its gas supply and asset management services through an annual RFP for terms beginning April 1 and running through March 31 each year. In March Northern completed its annual RFP for the delivery period of April 1, 2020 through March 31, 2021. Northern has entered into asset management agreements for the PXP Dawn Hub, Atlantic Bridge Ramapo, Iroquois Receipts, Algonquin Receipts, Niagara, Tennessee Zone 0/L and Dawn Hub Storage capacity paths. Northern also entered into baseload supply agreements through this RFP. Northern has also completed its RFP process for LNG supplies for the upcoming winter.

Q. Please describe any changes in Northern's portfolio for the upcoming 2021-2022 Winter compared to the portfolio relied upon for the 2020-2021 Winter.

A. The 2021-2022 Winter Portfolio includes the short-term peaking supplies referenced above, 2,500 Dth per Day of PNGTS Delivered Baseload (Dec – Feb) and Peaking Contract 2, which has a maximum daily volume of 10,000 Dth and a seasonal quantity of 300,000 Dth. These additional short-term peaking supplies were procured to assure that Northern has sufficient supplies to meet it projected Design Winter demands for its Sales Service customers.

Q. Please provide an update on the PXP and AB projects.

A. All facilities required for both PXP and AB projects have been constructed and placed into service. Northern has fully executed service agreements for transportation capacity anticipated in the related precedent agreements.

The AB project is currently subject to additional process established by an Order Establishing Briefing issued by the FERC on February 19, 2021 in Docket No. CP16-9 ("Briefing Order"). FERC's Briefing Order states that in response to a request for rehearing of its September 24, 2020 order authorizing Algonquin Gas Transmission, LLC ("Algonquin") to place the Weymouth Compressor Station into service and "numerous other pleadings expressing safety concerns regarding the operation of the project," the FERC has determined that "concerns raised regarding the operation of the project warrant further consideration by the Commission." The Briefing Order specifically requests parties to address whether it is consistent with the Natural Gas Act to allow the Weymouth Compressor Station to remain in service, whether the Commission should reconsider the current operation of the Weymouth Compressor Station in light of changed circumstances, whether the FERC should impose additional mitigation measures on Weymouth Compressor Station and what the consequences would be if the FERC reversed or stayed the Authorization Order. The Briefing Order does permit Weymouth Compressor Station to remain in service while the Commission considers these issues.

Initial and Reply Briefs have been filed pursuant to the Briefing Order. FERC has not issued any substantive order related to the Briefing Order at this time. The Briefing Order, itself, has been challenged in federal court with Algonquin challenging the FERC's authority to consider any changes to its authority to modify the operation of the Weymouth Compressor Station.

Northern's supply plan and corresponding estimated cost of gas supply assumes continued operation of the Weymouth Compressor Station, which is necessary to ship supplies from the Algonquin system into the Maritimes system for ultimate delivery to Northern.

IV. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Kahl to calculate the 2021-2022 Winter COG.

A. I have provided Mr. Kahl the following cost estimates for the period beginning November 2021 through October 2022, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities
- New Hampshire Division Capacity Assignment program demand revenues

- Northern's commodity costs

The allocation of Northern's supply costs to the New Hampshire Division was performed by Mr. Kahl. The figures I present in my testimony relate to total company costs, inclusive of both the Maine and New Hampshire Divisions.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 4, below, titled, "Estimated Gas Supply Demand Costs."

Table 4. Estimated Gas Supply Demand Costs
November 1, 2021 through October 31, 2022

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 17,953,274	Att NUI-FXW-4, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 22,032,867	Att NUI-FXW-4, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 2,959,638	Att NUI-FXW-4, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 2,216,171	Att NUI-FXW-4, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 11,397,667	Att NUI-FXW-4, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (9,902,100)	Att NUI-FXW-4, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 46,657,517	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Attachment NUI-FXW-5. Page 1 of Attachment NUI-FXW-5 provides the summary data presented here in Table 4. On page 2 of Attachment NUI-FXW-5, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 3 of Attachment NUI-FXW-5, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 4 and 5 of Attachment NUI-FXW-5 provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of Attachment NUI-FXW-5, I forecast the capacity release and asset management revenue the Company expects to receive. Asset Management Revenue associated with the AB capacity will offset by the one-time acquisition fee Northern paid to gain assignment of the AB precedent agreement until such time as AMA revenue or other non-core service revenues derived from use of the Atlantic Bridge capacity exceed the one-time acquisition fee. Support for the transportation, storage and supply demand rates used in Attachment NUI-FXW-5 are found in the Attachment NUI-FXW-10, Supplier Prices.

Q. How does 2021-2022 Winter COG forecasted annual demand cost compare with the 2020-2021 Winter COG forecasted annual demand cost?

A. 2020-2021 Winter COG forecasted annual demand costs were equal to $46,230,726. 2021-2022 Winter COG forecasted annual demand costs are equal to $46,657,517, reflecting an increase in forecasted annual demand costs equal to $426,791 or 1%.

This majority of the change in projected demand cost is explained by the following.

1. <u>Increase in projected pipeline and storage demand contract costs by $ $1,490,882.</u> The increase reflects a lower exchange rate for demand costs related to Union and TransCanada pipeline charges (combined $1,231,726) and higher Granite demand costs due to the increase in Granites' rates set forth in Granite's limited Section 4 FERC filing ($341,738). These increases are offset by decreases in Tennessee and Texas Eastern demand costs due to lower filed rates (combined decrease equal to $79,845).
2. <u>Increase in projected Peaking Supply Contract demand costs by $288,500.</u> The increase in Peaking Supply Contract demand costs reflects higher LNG demand costs due to higher demand prices bid via the RFP for LNG supply conducted by Northern. Northern has elected a lower volume of LNG supply to partially offset this increase.
3. <u>These increases are partially offset by an increase in projected Asset Management Agreement revenue credits by $1,352,591.</u> Higher AMA revenue reflects the results of Northern's annual request-for-proposals process, reflecting higher overall value obtained through asset management agreements.

Q. Please provide Northern's forecast of Capacity Assignment Demand Revenues for the New Hampshire Division.

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed calculations of the demand revenues from capacity assignment in Attachment NUI-FXW-6. On page 1 of Attachment NUI-FXW-6, I present a summary of the Company's forecast of New Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Attachment NUI-FXW-6, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Attachment NUI-FXW-6. The 2021-2022 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $5,012,735.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2021 through April 2021?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 6 of Attachment NUI-FXW-6. The proposed Peaking Service Demand Charge is equal to $71.85 per Dth, as shown in Attachment NUI-FXW-6 and presented in the proposed revised Appendix A to the Delivery Service Terms and Conditions. Please note that the Peaking Service Demand Charge applies only to capacity assignment pertaining to the on-system LNG plant.

Q. Please provide the Capacity Allocation Factors to be used for Capacity Assignment under the current New Hampshire Division Delivery Service tariff for effect November 1, 2021.

A. The Capacity Allocation Factors are provided in the proposed tariff sheet, Appendix C to the New Hampshire Division's Delivery Service Terms and Conditions. My calculations are provided in Attachment NUI-FXW-7. These Capacity Allocation Factors reflect a Capacity Ratio equal to 0.958, which is equal to Total Design Day Capacity of 142,844 Dth divided by the Total Design Day Planning Load (inclusive of both Maine and New Hampshire) of 149,082 Dth.

Q. Please describe Northern's process for forecasting commodity costs.

A. I base the Company's commodity cost forecast on Northern's projected city-gate receipts for sales service customers, which I calculated in Attachment NUI-FXW-2, and the supply sources available to Northern, which I presented in Attachment NUI-FXW-3. I forecast supply prices at each supply source, utilizing NYMEX natural gas contract price data and a forecast of the adder to NYMEX for the price of supply at each supply source available to Northern through its portfolio. To the extent that Northern's supply contract for a particular supply source provides for a fixed adder to the NYMEX Last Day Settlement, the contract prices are used to forecast the adder. If Northern's supply contract for a particular supply source does not provide for a fixed adder to the NYMEX Last Day Settlement, an estimate of the adder is based on the basis futures prices, through the Intercontinental Exchange ("ICE"). I also forecast variable fuel retention factors and rates for Northern's transportation and storage contracts. Then, I utilized the Sendout® natural gas supply cost model to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.

Q. Please present the Company's commodity cost forecast for the 2021-2022 Annual Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter and Summer Period in Tables 5 and 6, respectively.

Table 5. Winter Period Estimated Delivered City-Gate Commodity Costs and Volumes November 2021 through April 2022			
Supply Source	Winter Period Delivered City-Gate Costs	Winter Period Delivered City-Gate Volumes	Winter Period Delivered Cost per Dth
Pipeline Resources	$ 32,159,520	5,861,225	$ 5.487
Storage Resources	$ 10,403,958	3,348,512	$ 3.107
Peaking Resources	$ 10,815,857	787,782	$ 13.730
Total Commodity Costs	$ 53,379,334	9,997,519	$ 5.339

Table 6. Summer Period Estimated Delivered City-Gate Commodity Costs and Volumes May 2022 through October 2022			
Supply Source	Summer Period Delivered City-Gate Costs	Summer Period Delivered City-Gate Volumes	Summer Period Delivered Cost per Dth
Pipeline Resources	$ 10,352,007	2,993,295	$ 3.458
Storage Resources	$ -	-	
Peaking Resources	$ 72,433	11,040	$ 6.561
Total Commodity Costs	$ 10,424,440	3,004,335	$ 3.470

In summary, Winter Period net projected delivered commodity costs equal approximately $53.4 million at an average delivered rate of $5.339 per Dth, and Summer Period net projected delivered commodity costs equal approximately $10.4 million at an average delivered rate of $3.470 per Dth. In support of this forecast, I prepared Attachment NUI-FXW-8 to show the monthly forecasted commodity cost by supply option. Page 1 of Attachment NUI-FXW-8 provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Attachment NUI-FXW-8 provides monthly delivered volumes (Dth) by supply source. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources. Attachment NUI-FXW-12 provides a summary Winter and Summer Periods ranked by average delivered commodity cost.

The detailed calculations of the delivered commodity cost are found in Attachment NUI-FXW-9. For each supply source, I have provided the detailed monthly calculations for supply cost, fuel losses and variable transportation charges, which will be incurred by

Northern in order to deliver its supplies to Northern's city-gates for ultimate consumption by our customers. Support of the supply prices and variable transportation charges found in Attachment NUI-FXW-9 are found in the Attachment NUI-FXW-10, Supplier Prices.

Q. How do forecasted commodity costs for the 2021-2022 Winter Period (November through April) commodity costs compare with the forecasted commodity costs presented for the 2020-2021 Winter Period COG?

A. As show in Table 5, above, the 2021-2022 Winter Period COG forecasted commodity costs are equal to $53,379,334 at an average delivered rate of $5.339 per Dth. The 2020-2021 Winter Period COG forecasted commodity costs were equal to $27,501,662 at an average delivered rate of $3.066 per Dth. Overall, 2021-2022 forecasted Winter Period commodity costs are 94% higher than 2020-2021 forecasted Winter Period costs due primarily to a 74% increase in projected average unit cost. The 2021-2022 projected delivered volume is 11% higher than was projected in 2020-2021. Projected NYMEX prices are 62% at the time of this 2021-2022 Annual Period COG filing (averaging $5.08 per Dth), compared to projected NYMEX prices at the time of last year's 2020-2021 Annual Period COG filing (averaging $3.15 per Dth). The Company's unit cost forecast reflects these higher NYMEX prices. The projected average unit cost also reflects an increase in must-take delivered supplies, specifically the short-term PNGTS Delivered Baseload supplies and Peaking Contract 2 supplies discussed previously in my testimony. The Company secured these incremental delivered supplies in order to 1.) assure its ability to meet Design Winter demand requirements of the Company as the Company projects an 11% increase in normal sendout requirements and 2.) replace the reduced LNG Contract volume, as the new LNG contract will have an annual contract quantity equal to 75,000 Dth rather than 125,000 Dth contracted for during the 2020-2021 Winter Period.

Q. How do forecasted commodity costs for the 2022 Summer Period (May through October) commodity costs compare with the forecasted commodity costs presented for the 2021 Summer Period COG?

A. As show in Table 6, above, the 2022 Summer Period COG forecasted commodity costs are equal to $10,424,440 at an average delivered rate of $3.470 per Dth. The 2021 Summer Period COG forecasted commodity costs were equal to $6,290,994 at an average delivered rate of $2.652 per Dth. Overall, 2022 forecasted Summer Period commodity costs at the time of this 2021-2022 Annual Period COG Filing are 66% higher than 2021 forecasted Summer Period costs at the time of last year's 2020-2021 Annual Period COG Filing due to a 31% increase in projected average unit cost and a 27% increase in projected delivered volumes. Projected NYMEX prices are 37% higher for the 2022 Summer Period (averaging $3.86 per Dth), compared to projected NYMEX for the 2021 Summer Period (averaging $2.82 per Dth). The Company's unit cost forecast reflects these higher NYMEX prices.

Q. Please provide a summary of capacity utilization by supply source projected for the upcoming year.

A. Please refer to Attachments NUI-FXW-13, -14, -15 and -16. Attachment NUI-FXW-13 provides monthly supply volumes for Northern's normal year weather scenario. The data in Attachment NUI-FXW-13 is also found in Attachment NUI-FXW-8. Attachment NUI-FXW-14 provides monthly supply volumes for Northern's design cold year weather scenario. Attachment NUI-FXW-15 calculates the capacity utilization of all supply resources under the normal weather scenario. Attachment NUI-FXW-16 calculates the capacity utilization of all supply resources under the design cold weather scenario.

Q. Please provide Northern's Design Day Report for the upcoming Winter Period.

A. Northern's Design Day Report is found in Attachment NUI-FXW-17.

Q. Please provide Northern's 7-Day Cold Snap Analysis for the upcoming Winter Period.

A. Northern's 7-Day Cold Snap Analysis is found in Attachment NUI-FXW-18.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2021 through October 2022.

A. These results are based upon the Company's Sendout® analysis, which I provided to Mr. Kahl, and are the basis for his calculations in Attachment NUI-CAK-7.

V. PROPOSED RE-ENTRY AND CONVERSION SURCHARGES

Q. Please describe the Re-entry Surcharge and the Conversion Surcharge.

A. The Re-entry Surcharge is applicable to all Capacity Assigned Delivery Service customers, who switch from a retail marketer to Northern's Sales Service and the Conversion Surcharge is applicable to all Capacity Exempt Delivery Service customers, who switch from a retail marketer to Northern's Sales Service. I have prepared proposed updated Re-entry and Conversion Surcharges to be effective for the 2021-2022 Winter Period. Customers electing to migrate and purchase their supply from Northern shall be required to continue purchasing Northern's Sales Service until April 30, 2022. After this time, such customers may elect to either switch to a retail marketer or continue purchasing Sales Service from Northern under the normal cost of gas rates.

Q. Please provide the proposed Re-entry Surcharge and the proposed Conversion Surcharge.

A. Proposed Appendix D to the Delivery Service Terms and Conditions, provides the Re-entry Surcharge and the Conversion Surcharge. The Re-entry Surcharge and Conversion Surcharge will be applied as a surcharge in addition to the normal cost of gas rates. These surcharges shall only be applicable to customers switching from Delivery Service to Sales Service.

Q. Please provide your calculations for the Re-entry Surcharge and the Conversion Surcharges.

A. Please refer to Attachment NUI-FXW-11. Page 1 shows the Re-entry Surcharge and Conversion Surcharge calculations. The Re-entry surcharge reflects the removal of any prior period credits, such as an over-recovery due to incumbent Sales Service Customers. The Conversion Surcharge reflects the removal of prior period credits due to incumbent Sales Service customers plus the incremental cost to serve the customers, based on estimated incremental commodity prices. Conversion customers will have a floor price equal to the COG for Low Load Factor customers, removing prior period credits.

Page 2 is the Incremental Commodity Price Worksheet. Pages 3 through 9 are the Load Shape Price Factor Worksheet. Page 10 is the projected city-gate sendout forecast of Delivery Service loads that are not currently subject to Capacity Assignment.

VI. OUTAGE REPLACEMENT SUPPLY EXPENSES

Q. Did Northern incur unexpected gas supply costs this past summer?

A. Yes, Northern incurred $90,000 in incremental supply demand costs and $117,200 in incremental supply commodity costs to provide replacement supply service to firm customers during a pipeline outage from June 17, 2021 through June 23, 2021 during the construction of PNGTS' Westbrook Xpress Project (WXP) (collectively the "Outage

Replacement Supply Costs"). The WXP construction involved adding a new compressor to the Westbrook Compressor Station. During the outage, supplies were unable to move from north of the Westbrook interconnect between PNGTS and Maritimes ("the PNGTS-MNUS interconnect") onto the Joint Facilities, where the Westbrook, Eliot and Newington receipt points to Granite are located. During this time, deliveries on the Joint Facilities could not be sourced from either Dawn Hub via PNGTS or Canaport via Maritimes, requiring supply to Northern to be dependent upon its Atlantic Bridge capacity via the Weymouth Compressor Station, which had been experiencing both operational and regulatory challenges. As a result, Northern purchased incremental supplies to supplement its portfolio and assure continuity of service during the WXP outage. Fortunately, there was no interruption of Atlantic Bridge supplies during the WXP outage, but the outage replacement supplies procured by the Company were needed to protect against the uncertainty posed by Atlantic Bridge's operational and regulatory history.

Q. Does this conclude your testimony?

A. Yes it does.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
NOVEMBER 2021/OCTOBER 2022 ANNUAL COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
S. ELENA DEMERIS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is S. Elena Demeris. My business address is 6 Liberty Lane West, Hampton, New Hampshire.

Q. For whom do you work and in what capacity?

A. I am a Senior Regulatory Analyst for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's principal subsidiaries Fitchburg Gas and Electric Light Company, d/b/a Unitil ("FG&E"), Granite State Gas Transmission, Inc. ("Granite"), Northern Utilities, Inc. d/b/a Unitil ("Northern"), and Unitil Energy Systems, Inc. ("UES") (together "Unitil"). In this capacity I am responsible for preparing regulatory filings, pricing research, regulatory analysis, tariff administration, revenue requirements calculations, customer research, and other analytical services.

Q. Please summarize your professional and educational background.

A. In 1996, I graduated from the University of Massachusetts - Lowell with a Bachelor's of Science Degree in Civil Engineering. In 2005, I earned a Master's Degree in Business Administration and in 2006 a Master's Degree in Finance from Southern New Hampshire University. I joined Unitil in July 1998 in the regulatory/rate department.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to introduce and describe Northern's (or "the Company") proposed changes to its Local Delivery Adjustment Charges ("LDAC"). Northern is proposing changes to its LDAC for effect November 1, 2021 for the following components: Gas Assistance Program and Regulatory Assessment ("GAPRA"), Energy Efficiency Charge (EEC), Environmental Response Cost ("ERC") Rate, and Lost Revenue Rate ("LRR"). Northern is not proposing to change the following LDAC components: Interruptible Transportation Margin (ITM), Rate Case Expense (RCE) Factor and Reconciliation of Permanent Changes (RPC) in Distribution Rates. My testimony also discusses the impact the proposed cost of gas (COG) and LDAC rate changes have on customer bills during the 2021-2022 Winter and 2022 Summer Seasons.

Q. What are the Company's proposed LDAC surcharges?

A. The Company is submitting for approval a proposed LDAC of $0.0631 per therm for the Residential Class and $0.0360 per therm for the Commercial/Industrial (C&I) Class effective November 1, 2021 through October 31, 2022. The proposed rates are included on the Fifth Revised Tariff Page 62, superseding the Fourth Revised Tariff Page 62.

Q. Please describe the purpose of the GAPRA.

A. The purpose of this rate is to allow the Company to recover revenue discounts associated with customers participating in the Gas Assistance Program and Regulatory Assessment

(GAPRA), as well as the associated administrative costs of that program, pursuant to the Commission's Order in Docket No. DG 05-076. The Commission's Order in Docket DG 20-013 renamed the RLIA effective November 1, 2020. The order also modified the program to apply a 45% discount to both distribution and supply rates, excluding the LDAC, and to apply the discounts during the winter period only. These changes are reflected in Attachment NUI-SED-1 GAPRA. This rate also recovers the non-distribution (or COG) portion of the annual NHPUC Regulatory Assessment (RA) to the Company. The GAPRA rate is charged on all sales and delivery only services billed under the Company's rate schedules. In Docket DG 21-123, currently pending before the Commission, the Company proposed a reconciling mechanism, the Regulatory Cost Adjustment Mechanism (RCAM), to recover excess property tax expense. If approved, the RCAM would also include the Regulatory Assessment, removing that cost component from the GAPRA.

Q. Please describe the proposed change to the GAPRA rate.

A. Northern is proposing to increase the GAPRA rate from $0.0044 to $0.0060 per therm effective November 1, 2021.

Q. Could you describe the derivation of the proposed GAPRA rate?

A. The GAPRA rate is derived by estimating the Company's Gas Assistance Program and Regulatory Assessment costs from November 1, 2021 through October 31, 2022, the Regulatory Assessment costs from July 1, 2021 through June 30, 2022, and the total account ending balance as of October 31, 2021, based on actual data through July, 2021 and estimated data from August 1, 2021 to October 31, 2021. As shown on Attachment NUI-SED-1 GAPRA, Page 1 of 3, Line 16, total estimated costs are $471,152. Lines 1-7 provide the derivation of the average per customer subsidy. The estimated 2022 NHPUC Regulatory Assessment collected in the LDAC, $116,230, is shown on Page 1 of 3, Line 15, and is based on the NHPUC invoice dated August 19, 2020. As of this filing the Company has not received an invoice for the 2022 Assessment. Page 3 of 3 of the schedule shows the assignment of the NHPUC annual Regulatory Assessment to distribution and non-distribution costs. The $368,964 assigned to distribution represents the amount established in the Company's last base rate case proceeding in Docket No. DG 17-070. The remainder is assigned to the GAPRA and LDAC.

Lastly, the projected October 31, 2021 ending balance of the GAPRA is an under-collection of $26,008, and is derived as shown on Attachment NUI-SED-1 GAPRA, Page 2 of 3. The total amount of these three factors, $471,152, is shown on Page 1 of 3, line 16, of Attachment NUI-SED-1 GAPRA, and is divided by estimated weather-normalized firm therm sales billed to customers for the twelve-months ended October 31, 2022 to derive the proposed GAPRA charge of $0.0060 per therm shown on Page 1 of 3, line 22.

Q. Does the proposed rate exceed the program cost or bill impact thresholds established in Order No. 26,397, issued August 27, 2020 in Docket DG 20-013?

A. No, it does not. The thresholds established in Order No. 26,397 are (1) GAP overall program costs exceed one percent of a utility's gross (annual) revenue; and (2) GAP overall program costs exceed one percent of the typical residential heating customer's total annual bill. (1) Projected gross revenue, based on the 2021 Y-T-D average $/therm times the November 2021 – October 2022 therm sales forecast of 78,231,768 results in an estimated gross revenue of $66,410,948. GAPRA projected program subsidies represent 0.50% of the estimated gross revenue. Total program costs, including the assessment, represent 0.67% of the estimated gross revenue. (2) As shown on Attachment NUI-SED-3, Page 1 of 10, the typical residential heating customer's annual bill for the November 2021 – October 2022 period is $1,409.96. Of that amount $4.29 or 0.30% is attributable to the GAPRA.

Q. What is the purpose of the EEC Rate?

The purpose of the EEC rate is to recover from customers, excluding those with Special Contracts, Energy Efficiency (EE) program costs and performance incentives.

Q. What are the changes being proposed to the EEC?

A. The Company is proposing to decrease the EEC rate for the Residential Customer Class from $0.0774 per therm to $0.0449 per therm, and decrease the charge for the C&I Customer Class from $0.0337 per therm to $0.0238 per therm effective November 1, 2021.

Q. Please describe the reason for these proposed changes to and the derivation of the EEC rate.

A. The proposed changes to the EEC rate reflect 2020 program budgets. In its last filing Northern set EEC rates based on the 2021-2023 3-year plan filed in DE 20-092. In an Order issued December 29, 2020 in DE 20-092, the Commission approved extension of the 2020 program budgets until an order in the proceeding is issued. Spending levels in 2021 and the proposed November 2021-October 2022 rate period remain at 2020 budget levels. The budgets for the Residential and C&I customer classes are provided in Attachment NUI-SED-1 EEC, Page 1 of 4. They include estimated monthly costs for the remainder of the 2021 rate year (August 2021 – October 2021, and estimated costs for the 2022 rate year (November 2021 – October 2022). The proposed changes to the EEC rate are impacted by an expected over-collection in the November 1, 2021 beginning balance of the Residential class and an expected over-collection in the November 1, 2021 beginning balance of the C&I class. The derivation of the EEC rate is provided in Attachment NUI-SED-1 EEC, Page 2 of 4. As shown, it is derived by customer class and includes an annual Reconciliation Adjustment of program costs, Performance Incentives and an adjustment for Low-Income Discounts. Supporting information regarding the development of the proposed EEC for the Residential Classes is provided in Attachment NUI-SED-1 EEC, Page 3 of 4, and Page 4 of 4 provides the support for the proposed C&I Class.

Q. Please explain the purpose of the LRR?

A. The purpose of the LRR is to recover lost distribution revenue related to the Company's Energy Efficiency programs. This rate mechanism was established in accordance with

Order No. 25,932 in Docket No. DE 15-137 approving a Settlement Agreement which provides for the implementation of a Lost Revenue Rate adjustment mechanism.

Q. What changes are being proposed to the LRR?

A. The Company is proposing to decrease the LRR rate for the Residential Customer Class from $0.0220 per therm to $0.0066 per therm, and decrease the charge for the C&I Customer Class from $0.0030 per therm to $0.0006 per therm effective November 1, 2021. On August 2, 2021 Northern filed a rate case with the Commission, Docket No. DG 21-104. In its filing Northern proposed to transition to decoupling beginning August 1, 2022. As part of that transition Northern will stop accruing lost revenue July 31, 2022. See DG 21-104, Exhibit CGDN-1, pages 59-61 [Bates 000111-00113], attached here as Appendix 1, for your convenience.

Q. Please explain the calculation of the proposed LRR?

A. The calculation of the LRR is provided on Attachment NUI-SED-1 LRR. As shown on Page 1, the LRR for the Residential and C&I Classes is derived by adding projected annual lost distribution revenue over the period November 1, 2020 through July 31, 2022, the expected October 31, 2021 reconciliation ending balance and the projected interest on monthly over/under collections, and dividing this total by forecast annual therm throughput, by class. Pages 2 and 2a provide the projected customer class monthly reconciliation of costs and revenue for the period November 2020 through October 2022. Note that November 2020 through October 2021 has been recast to reflect adjusted savings as discussed above and in Appendix 1. Beginning monthly balances are shown on Lines 2 and 21 for the Residential and C&I classes, respectively, and ending monthly balances are shown on Lines 19 and 39, respectively. Pages 3 and 3a provides the calculation of estimated lost distribution revenue based on estimated customer class therm savings. The savings calculations shown on Pages 3 and 3a of Attachment NUI-SED-1 LRR reflect the transition to decoupling discussed in Appendix 1. Page 4 provides further detail for the estimated savings that are used in the calculation of lost revenue on Page 3. Page 5 provides the calculation of the Company's average distribution rates by sector, excluding Customer Charges. These average distribution rates are derived by taking seasonal averages of total volumetric revenue divided by total Winter and Summer Season therms, by class.

Q. Please explain the purpose of Northern's ERC.

A. The purpose of the ERC is to recover expenditures associated with remediation of former manufactured gas plants. The ERC is applied to all gas sales and delivery service billed under the Company's sales and delivery service rate schedules. The costs submitted for recovery through the ERC recovery mechanism are presented in the ERC Filing submitted in this docket under separate cover. The environmental investigation and remediation costs that underlie these expenses are the result of efforts by the Company to respond to its legal obligations at a site located in Rochester, New Hampshire. In total, the Company has incurred environmental remediation costs of $118,256 from July 2020 through June 2021. A summary sheet and detailed backup spreadsheets supporting 2020-2021 costs are provided in the ERC Filing.

Q. Please describe the change to Northern's ERC rate that is proposed for effect November 1, 2021.

A. The current ERC rate is $0.0061 per therm. Northern proposes to decrease this rate to $0.0056 per therm.

Q. Please explain the calculation of the proposed ERC rate.

A. As stated above, during the period July 1, 2020 through June 30, 2021, ERC expenses totaled $118,256. Northern is allowed to recover one-seventh of the actual response costs incurred by the Company in a twelve-month period ending June 30 of each year until fully amortized over seven years, plus any insurance and third-party expenses for the year. Due to the amortization of these costs, the ERC rate in this filing includes the current year ($118,256 divided by 7, or $16,894) and six prior years of unamortized amounts. Any insurance and third-party recoveries or other credits for the year are used to reduce the unamortized balance. The total ERC cost to be recovered, $432,594, is shown in the following table and on Page 1, Line 13, of Attachment NUI-SED-2 ERC (this schedule is also Schedule 1 submitted by the Company in the Environmental Response Cost filing).

1/7 ERC costs incurred July 2020 – June 2021	$16,894
1/7 ERC costs incurred July 2019 – June 2020	$11,024
1/7/ ERC costs incurred July 2018 – June 2019	$29,051
1/7/ ERC costs incurred July 2017 – June 2018	$40,449
1/7th ERC costs incurred July 2016 - June 2017	$7,736
1/7th ERC costs incurred July 2015 - June 2016	$311,412
1/7th ERC costs incurred July 2014 - June 2015	$16,028
Total	**$432,594**

In addition, the ERC rate includes the prior period reconciliation of ERC costs. The October 31, 2021 ending balance is estimated to be an under collection of $3,446, as shown on Attachment NUI-SED-1 ERC Page 2 of 2. Total ERC costs to be recovered for the period of November 2021 through October 2022 are $436,040. Dividing the recoverable ERC costs by projected total annual sales of 78,231,768 therms results in an ERC rate of $0.0056 per therm. This calculation is illustrated in Attachment NUI-SED-2 ERC, Page 1 of 2.

Q. Does the proposed LDAC include a credit for Interruptible Transportation Margins?

A. No. The Company did not provide Interruptible Transportation service during the past year, has not provided this service for many years and does not expect to provide any in the upcoming year. Therefore, Northern has not credited any actual or expected interruptible margins back to customers.

Q. Have you prepared typical bill analyses showing the impacts of the proposed COG and LDAC rate changes for effect on November 1, 2021 for typical Residential heating customers over the upcoming Winter Season?

A. Yes, Attachment NUI-SED-3, page 1 provides the analyses. It shows that a typical Residential heating customer consuming 581 therms during the 2021/2022 Winter Season will expect a bill of $1,118.29. This is an increase of $93.55, or 9.1% compared to the 2020/2021 Winter Season bill with the same consumption.

Q. Have you prepared typical bill analyses showing the impacts of the proposed COG and LDAC for effect on May 1, 2022 for typical Residential heating gas customers over the next Summer Season?

A. Yes, Attachment NUI-SED-3, page 6 provides this analysis. It shows that a typical residential heating customer consuming 133 therms during the 2022 Summer Season will expect a bill of $291.67. This is a decrease of $3.49, or -1.2% compared to the 2021 Summer Season bill with the same consumption.

Q. Does this conclude your testimony?

A. Yes, it does.

in the area to further support the economics of the expansion. Furthermore, the pipelines installed in Epping have sufficient capacity to serve other communities should the Company continue to expand its distribution network.

VII. TRANSITION TO DECOUPLING

Q. How will the Company transition from Lost Base Revenue Recovery as part of the Lost Revenue Rate ("LRR") to Decoupling?

A. At the start of the proposed decoupling period of August 1, 2022, the Company will stop accruing Lost Base Revenue ("LBR") associated with Energy Efficiency savings. Up until that time, the Company will continue to collect and accrue LBR associated with the 2020 energy efficiency savings, the 2021 energy efficiency savings and the 2022 energy efficiency savings through July 31, 2022, assuming a start date of decoupling of August 1, 2022. Table 3 below outlines how the transition will work based on the proposed temporary rates, permanent rates and decoupling start period of August 1, 2022 timeline. The Company is not proposing any change to the LRR at this time and instead will make all required changes, including reconciliations in subsequent LRR filings as appropriate.

Table 3: Transition from LBR to Decoupling

October 1, 2021 (Temporary Rates Effective)
Stop accruing lost revenue associated with the 2017 savings
Stop accruing lost revenue associated with the 2018 savings
Stop accruing lost revenue associated with the 2019 savings
Continue accruing lost revenue associated with the 2020 savings*
Continue accruing lost revenue associated with the 2021 savings
January 1, 2022 to August 1, 2022
Continue accruing lost revenue associated with the 2020 savings*
Continue accruing lost revenue associated with the 2021 savings
Continue accruing lost revenue associated with the 2022 savings
August 1, 2022 (Permanent Rates Effective - Begin Decoupling)
Stop accruing lost revenue associated with the 2020 savings*
Stop accruing lost revenue associated with the 2021 savings
Stop accruing lost revenue associated with the 2022 savings
*Taking into account timing of the month of installtion for the 2020 measures

Q. Why will the Company continue to accrue lost revenue associated with the 2020 measures if 2020 was the test year?

A. The Company needs to continue to recover lost revenue associated with the savings reduction not reflected in the 2020 test year. For example, for a measure that was installed in December 2020 that is estimated to save 120 therms annually, the impact on the 2020 test year sales would only reflect a reduction of 10 therms kWh (120 / 12 months * 1 month). The remaining 110 therms of savings would be realized in 2021, so it is necessary to continue to recover lost revenue associated with the 2020 savings, taking into account the month that savings were realized in 2020. Table 4 below shows an illustrative example of how the calculation would work based on the 145,178 therms of actual annual 2020 savings installed in 2020. The 2020 test year would reflect a reduction in sales of 65,169 therms with the remaining reduction of 80,008 therms of savings reduction occurring in 2021.

Table 4: Illustrative 2020 Savings Annualization

	Northern Utilities, Inc.													
	2020 Residential Installed Therm Savings													
	Savings Annualization													
Line	Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Annual Savings
	Col. A	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	**Monthly Residential Therm Savings***	**-**	**16,204**	**15,242**	**7,355**	**918**	**4,876**	**3,827**	**30,944**	**14,644**	**24,534**	**7,203**	**19,430**	**145,176**
2														
3	**Monthly Residential Therms Savings**													
4	January 2020	-	-	-	-	-	-	-	-	-	-	-	-	-
5	February 2020		1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	14,853
6	March 2020			1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	12,702
7	April 2020				613	613	613	613	613	613	613	613	613	5,516
8	May 2020					76	76	76	76	76	76	76	76	612
9	June 2020						406	406	406	406	406	406	406	2,844
10	July 2020							319	319	319	319	319	319	1,913
11	August 2020								2,579	2,579	2,579	2,579	2,579	12,893
12	September 2020									1,220	1,220	1,220	1,220	4,881
13	October 2020										2,044	2,044	2,044	6,133
14	November 2020											600	600	1,201
15	December 2020												1,619	1,619
16	**Total 2020 Therm Savings Realized in 2020**	**-**	**1,350**	**2,621**	**3,233**	**3,310**	**3,716**	**4,035**	**6,614**	**7,834**	**9,879**	**10,479**	**12,098**	**65,169**
17														
18	**2020 Residential Therm Savings Realized in 2021**	**-**	**1,350**	**2,540**	**1,839**	**306**	**2,031**	**1,913**	**18,051**	**9,762**	**18,400**	**6,003**	**17,811**	**80,008**
	*Per DE 17-136 Northern Utilities, Inc 2020 Energy Efficiency Revised Annual Report filed on June 29, 2021 Page 1 of 18(Revised)													

VIII. PROPOSED TARIFF CHANGES

Q. Please summarize the proposed tariff changes presented in the Company's filing.

A. The Company's proposed tariff changes reflect: (1) the proposed rates, as presented in the prefiled testimony of Ron Amen and John Taylor; (2) the proposed Revenue Decoupling Adjustment Clause as presented in the prefiled testimony of Timothy Lyons; (3) proposed changes to the Company's proposed RCAM tariff, which is a component of the LDAC; (4) proposed Temporary Rate surcharge; and (5) changes to the Company's delivery service terms and conditions as supported by Mark Lambert.

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

Total Fixed Capacity Costs To Be Allocated

	NUI Total	
Pipeline Demand	$ 17,953,274	
Storage Demand	$ 24,992,506	
On-system Peaking Demand	$ 3,992,171	
Subtotal Demand	$ 46,937,950	
Capacity Release (Credit)	$ -	
Asset Management (Credit)	$ (9,902,100)	
Total Net Demand Costs	$ 37,035,850	
Off-System Peaking Demand	$ 9,621,667	PR Allocation on Page 5
Total Demand Costs	$ 46,657,516	

Proportional Responsibility (PR) Allocators

Allocation of Product and Pipeline Demand Costs (including Injections) to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Pipeline Sendout	1,251,924	1,257,820	1,257,819	1,207,638	1,484,768	1,216,238	692,758	427,492	407,061	428,105	513,700	888,799	11,034,123
Rank	4	2	3	6	1	5	8	11	12	10	9	7	
% Max Month	84.32%	84.71%	84.71%	81.34%	100.00%	81.91%	46.66%	28.79%	27.42%	28.83%	34.60%	59.86%	
PR	0.60%	0.00%	0.13%	3.58%	15.29%	0.12%	1.51%	0.13%	2.28%	0.00%	0.64%	1.89%	26.16%
CumPR	10.74%	10.88%	10.88%	10.03%	26.16%	10.14%	4.56%	2.41%	2.28%	2.41%	3.05%	6.45%	100.00%
Product and Pipeline Demand Costs	$ 1,928,863	$ 1,952,631	$ 1,952,625	$ 1,800,189	$ 4,696,796	$ 1,820,988	$ 819,006	$ 432,629	$ 410,169	$ 433,369	$ 548,367	$1,157,641	$ 17,953,274

Allocation of Storage Injection Fees to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Storage Injection Volume	-	-	-	-	-	-	-	-	-	-	-	-	-
Design Year Pipeline Sendout	1,251,924	1,257,820	1,257,819	1,207,638	1,484,768	1,216,238	692,758	427,492	407,061	428,105	513,700	888,799	11,034,123
% of Deliveries Injected	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Allocation of Storage Demand Costs to Months

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Storage	384,599	949,630	1,116,303	1,034,206	647,868	-	-	-	-	-	-	-	4,132,606
Rank	5	3	1	2	4	6	6	6	6	6	6	6	
% Max Month	34.45%	85.07%	100.00%	92.65%	58.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
PR	6.89%	9.01%	7.35%	3.79%	5.90%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	32.94%
CumPR	6.89%	21.80%	32.94%	25.59%	12.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Storage Demand Costs	$ 1,722,128	$ 5,447,705	$ 8,232,513	$ 6,394,467	$ 3,195,692	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,992,506
Plus Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	$ 1,722,128	$ 5,447,705	$ 8,232,513	$ 6,394,467	$ 3,195,692	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,992,506

Allocation of All Peaking Demand Costs Excluding Off-System Peaking

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
Design Year Peaking Volumes	1,795	79,083	112,600	79,389	13,513	1,794	1,860	1,800	1,860	1,860	1,800	1,860	299,213
Rank	11	3	1	2	4	12	8	10	7	6	9	5	
% Max Month	1.59%	70.23%	100.00%	70.51%	12.00%	1.59%	1.65%	1.60%	1.65%	1.65%	1.60%	1.65%	
PR	0.00%	19.41%	29.49%	0.14%	2.59%	0.13%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	51.77%
CumPR	0.13%	22.14%	51.77%	22.27%	2.73%	0.13%	0.14%	0.13%	0.14%	0.14%	0.13%	0.14%	100.00%
Peaking Demand Costs	$ 5,304	$ 883,785	$ 2,066,699	$ 889,215	$ 108,876	$ 5,300	$ 5,587	$ 5,321	$ 5,587	$ 5,587	$ 5,321	$ 5,587	$ 3,992,171

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

LN		
1		
2		`
3	Pipeline Demand	NUI-FXW-5, PG 1, LN 1
4	Storage Demand	NUI-FXW-5, PG 1, LN 2 + 3
5	On-system Peaking Demand	NUI-FXW-5, PG 1, LN 4 + 5
6	Subtotal Demand	Sum LN 3 : LN 5
7		
8	Capacity Release (Credit)	NUI-FXW-5, PG 6
9	Asset Management (Credit)	NUI-FXW-5, PG 6
10	Total Net Demand Costs	Sum LN 6 : LN 9
11		
12	Off-System Peaking Demand	NUI-FXW-5, PG 5
13		
14	Total Demand Costs	LN 10 + LN 12
15		
16	**Proportional Responsibility (PR) Allocators**	
17		
18	**Allocation of Product and Pipeline Demand Costs (including Injections) to Months**	
19		
20	Design Year Pipeline Sendout	Company Analysis
21	Rank	LN 20 Ranking
22	% Max Month	LN 20 / LN 20 MAX
23	PR	The difference between LN 22 for the month and LN 22 for next highest rank
24	CumPR	Cumulative Values, LN 23
25	Product and Pipeline Demand Costs	LN 24 * LN 3
26		
27	**Allocation of Storage Injection Fees to Months**	
28		
29	Storage Injection Volume	Company Analysis
30	Design Year Pipeline Sendout	LN 20
31	% of Deliveries Injected	LN 29 / Sum (LN 29 : LN 30)
32	Injection Fees	LN 31 * LN 25
33		
34	**Allocation of Storage Demand Costs to Months**	
35		
36	Design Year Storage	Company Analysis
37	Rank	LN 36 Ranking
38	% Max Month	LN 36 / LN 36 MAX
39	PR	The difference between LN 38 for the month and LN 38 for next highest rank
40	CumPR	Cumulative Values, LN 39
41	Storage Demand Costs	LN 40 * LN 4
42	Plus Injection Fees	LN 32
43	TOTAL	LN 41 + LN 42
44		
45	**Allocation of All Peaking Demand Costs Excluding Off-System Peaking**	
46		
47	Design Year Peaking Volumes	Company Analysis
48	Rank	LN 47 Ranking
49	% Max Month	LN 47 / LN 47 MAX
50	PR	The difference between LN 49 for the month and LN 49 for next highest rank
51	CumPR	Cumulative Values, LN 50
52	Peaking Demand Costs	LN 51 * LN 5

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual
Pipeline & Product Demand	$ 1,928,863	$ 1,952,631	$ 1,952,625	$ 1,800,189	$ 4,696,796	$ 1,820,988	$ 819,006	$ 432,629	$ 410,169	$ 433,369	$ 548,367	$1,157,641	$ 17,953,274
Storage Incld Inj Fees	$ 1,722,128	$ 5,447,705	$ 8,232,513	$ 6,394,467	$ 3,195,692	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,992,506
On-system Peaking	$ 5,304	$ 883,785	$ 2,066,699	$ 889,215	$ 108,876	$ 5,300	$ 5,587	$ 5,321	$ 5,587	$ 5,587	$ 5,321	$ 5,587	$ 3,992,171
Less Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Capacity Release	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Asset Mgmt	$ (1,650,350)	$ (1,650,350)	$ (1,650,350)	$ (1,650,350)	$ (1,650,350)	$(1,650,350)	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,902,100)
Total Demand	$ 2,005,945	$ 6,633,771	$ 10,601,487	$ 7,433,521	$ 6,351,014	$ 175,938	$ 824,593	$ 437,950	$ 415,757	$ 438,956	$ 553,689	$1,163,229	$ 37,035,850

Capacity Cost Allocator based on Design Year Firm Sendout

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual
Therms													
Maine	953,078	1,363,286	1,655,363	1,470,818	1,299,001	742,868	427,912	252,221	240,495	254,997	306,067	513,458	9,479,564
New Hampshire	685,239	1,007,317	1,192,761	1,033,962	885,575	475,164	266,707	177,072	168,426	174,968	209,433	377,201	6,653,824
Total	1,638,317	2,370,603	2,848,124	2,504,780	2,184,576	1,218,032	694,618	429,292	408,921	429,965	515,500	890,659	16,133,388

Percentage of Total	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual
Maine	58.17%	57.51%	58.12%	58.72%	59.46%	60.99%	61.60%	58.75%	58.81%	59.31%	59.37%	57.65%	58.49%
New Hampshire	41.83%	42.49%	41.88%	41.28%	40.54%	39.01%	38.40%	41.25%	41.19%	40.69%	40.63%	42.35%	41.51%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Allocation of Demand Costs by Division

Maine	$1,166,942	$3,814,947	$6,161,708	$4,364,996	$3,776,464	$107,303	$507,981	$257,307	$244,515	$260,330	$328,741	$670,593	$21,661,828
New Hampshire	$839,002	$2,818,823	$4,439,780	$3,068,525	$2,574,550	$68,635	$316,612	$180,643	$171,242	$178,627	$224,948	$492,636	$15,374,022
Total	$ 2,005,945	$ 6,633,771	$ 10,601,487	$ 7,433,521	$ 6,351,014	$ 175,938	$ 824,593	$ 437,950	$ 415,757	$ 438,956	$ 553,689	$ 1,163,229	$ 37,035,850

Detailed Allocation of Demand Costs by Division

Maine	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
Pipeline & Product Demand	$ 1,122,101	$ 1,122,918	$ 1,134,888	$ 1,057,079	$ 2,792,827	$ 1,110,606	$ 504,539	$ 254,181	$ 241,229	$ 257,016	$ 325,582	$ 667,372	$ 10,590,338	58.99%
Storage Incld Injection Fees	$ 1,001,834	$ 3,132,865	$ 4,784,832	$ 3,754,859	$ 1,900,235	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,574,625	58.32%
On-system Peaking	$ 3,085	$ 508,247	$ 1,201,190	$ 522,151	$ 64,740	$ 3,233	$ 3,442	$ 3,126	$ 3,286	$ 3,314	$ 3,159	$ 3,221	$ 2,322,194	58.17%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Capacity Release (Credit)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Asset Management (Credit)	$ (960,078)	$ (949,083)	$ (959,203)	$ (969,093)	$ (981,337)	$ (1,006,536)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,825,329)	58.83%
Total Allocated Demand	$ 1,166,942	$ 3,814,947	$ 6,161,708	$ 4,364,996	$ 3,776,464	$ 107,303	$ 507,981	$ 257,307	$ 244,515	$ 260,330	$ 328,741	$ 670,593	$ 21,661,828	58.49%

New Hampshire	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
Pipeline & Product Demand	$ 806,762	$ 829,712	$ 817,737	$ 743,110	$ 1,903,969	$ 710,382	$ 314,467	$ 178,448	$ 168,940	$ 176,353	$ 222,786	$ 490,270	$ 7,362,936	41.01%
Storage Incld Injection Fees	$ 720,294	$ 2,314,840	$ 3,447,681	$ 2,639,608	$ 1,295,457	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,417,880	41.68%
On-system Peaking	$ 2,218	$ 375,538	$ 865,510	$ 367,064	$ 44,136	$ 2,068	$ 2,145	$ 2,195	$ 2,301	$ 2,274	$ 2,162	$ 2,366	$ 1,669,977	41.83%
Less: Injection Fees	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Capacity Release	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Asset Management	$ (690,272)	$ (701,267)	$ (691,147)	$ (681,257)	$ (669,013)	$ (643,814)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,076,771)	41.17%
Total Allocated Demand	$ 839,002	$ 2,818,823	$ 4,439,780	$ 3,068,525	$ 2,574,550	$ 68,635	$ 316,612	$ 180,643	$ 171,242	$ 178,627	$ 224,948	$ 492,636	$ 15,374,022	41.51%

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

53		
54	Pipeline & Product Demand	LN 25
55	Storage	LN 43
56	Peaking	LN 52
57	Less: Injection Fees	-(LN 32)
58	Less: Capacity Release	-(LN 8 / 5)
59	Less: Asset Management	-(LN 9 / 6)
60	Total Demand	Sum (LN 54 : LN 59)
61		
62	**Capacity Cost Allocator based on Design Year Firm Sendout**	
63		
64	**Therms**	
65	Maine	Company Analysis
66	New Hampshire	Company Analysis
67	Total	LN 65 + LN 66
68		
69	**Percentage of Total**	
70	Maine	LN 65 / LN 67
71	New Hampshire	LN 66 / LN 67
72	Total	LN 70 + LN 71
73		
74	**Allocation of Demand Costs by Division**	
75	Maine	LN 60 * LN 70
76	New Hampshire	LN 60 * LN 71
77	Total	LN 75 + LN 76
78		
79	**Detailed Allocation of Demand Costs by Division**	
80	**Maine**	
81	Pipeline & Product Demand	LN 54 * LN 70
82	Storage	LN 55 * LN 70
83	Peaking	LN 56 * LN 70
84	Injection Fees	LN 57 * LN 70
85	Capacity Release (Credit)	LN 58 * LN 70
86	Asset Management (Credit)	LN 59 * LN 70
87	**Total Allocated Demand**	Sum (LN 81 : LN 86)
88		
89	**New Hampshire**	
90	Pipeline & Product Demand	LN 54 * LN 71
91	Storage	LN 55 * LN 71
92	Peaking	LN 56 * LN 71
93	Injection Fees	LN 57 * LN 71
94	Capacity Release	LN 58 * LN 71
95	Asset Management (Credit)	LN 59 * LN 71
96	**Total Allocated Demand**	Sum (LN 90 : LN 95)

Northern Utilities
Simplified Market Based Allocator (MBA) Calculations
ALLOCATION OF NORTHERN FIXED CAPACITY COSTS BETWEEN ME & NH DIVISIONS

97 **Off-System Peaking Demand Costs** $ 9,621,667

98

99 **Allocation of Off-system Peaking Demand Costs to Months**

Line		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
100		Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Annual
101	Design Year Peaking Volumes	-	84,071	361,402	183,548	38,427	-	-	-	-	-	-	-	667,448
102	Rank	5	3	1	2	4	5	5	5	5	5	5	5	
103	% Max Month	0.00%	23.26%	100.00%	50.79%	10.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
104	PR	0.00%	4.21%	49.21%	13.76%	2.66%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	69.84%
105	CumPR	0.00%	6.87%	69.84%	20.63%	2.66%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
106	Peaking Demand Costs	$ -	$ 660,823	$ 6,720,056	$ 1,985,025	$ 255,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,621,667

107

108 **Capacity Cost Allocator based on Design Year Sales**

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual
110	**Therms**													
111	Maine	769,970	1,118,218	1,373,487	1,222,295	1,075,734	602,565	335,601	186,167	184,179	197,150	232,899	397,265	7,695,530
112	New Hampshire	473,924	746,005	884,060	759,575	635,070	312,572	164,969	91,875	82,497	87,972	108,619	227,211	4,574,349
113	Total	1,243,894	1,864,223	2,257,548	1,981,870	1,710,804	915,137	500,570	278,043	266,676	285,122	341,518	624,476	12,269,879

114

Line	Percentage of Total	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Annual
116	Maine	61.90%	59.98%	60.84%	61.67%	62.88%	65.84%	67.04%	66.96%	69.06%	69.15%	68.20%	63.62%	61.01%
117	New Hampshire	38.10%	40.02%	39.16%	38.33%	37.12%	34.16%	32.96%	33.04%	30.94%	30.85%	31.80%	36.38%	38.99%
118	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

119

120 **Allocation of Off-System Peaking Demand Costs by Division**

Line														
121	Maine	$0	$396,382	$4,088,469	$1,224,241	$160,821	$0	$0	$0	$0	$0	$0	$0	$5,869,912
122	New Hampshire	$0	$264,441	$2,631,588	$760,784	$94,942	$0	$0	$0	$0	$0	$0	$0	$3,751,755
123	Total	$ -	$ 660,823	$ 6,720,056	$ 1,985,025	$ 255,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,621,667

Total Weighted Average MPR Factor

Line	Maine	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
125	Total Pipeline, Storage & On-system	$ 1,166,942	$ 3,814,947	$ 6,161,708	$ 4,364,996	$ 3,776,464	$ 107,303	$ 507,981	$ 257,307	$ 244,515	$ 260,330	$ 328,741	$ 670,593	$ 21,661,828	58.49%
126	Total Off-system Peaking	$0	$396,382	$4,088,469	$1,224,241	$160,821	$0	$0	$0	$0	$0	$0	$0	$ 5,869,912	61.01%
127	Total Demand Cost Allocation	$ 1,166,942	$ 4,211,329	$ 10,250,176	$ 5,589,237	$ 3,937,285	$ 107,303	$ 507,981	$ 257,307	$ 244,515	$ 260,330	$ 328,741	$ 670,593	$ 27,531,741	**59.01%**

128

Line	New Hampshire	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	
130	Total Pipeline, Storage & On-system	$ 839,002	$ 2,818,823	$ 4,439,780	$ 3,068,525	$ 2,574,550	$ 68,635	$ 316,612	$ 180,643	$ 171,242	$ 178,627	$ 224,948	$ 492,636	$ 15,374,022	41.51%
131	Total Off-system Peaking	$0	$264,441	$2,631,588	$760,784	$94,942	$0	$0	$0	$0	$0	$0	$0	$ 3,751,755	38.99%
132	Total Demand Cost Allocation	$ 839,002	$ 3,083,265	$ 7,071,367	$ 3,829,309	$ 2,669,492	$ 68,635	$ 316,612	$ 180,643	$ 171,242	$ 178,627	$ 224,948	$ 492,636	$ 19,125,776	**40.99%**

133

Line	Total Northern	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual
135	Total Pipeline, Storage & On-system	$ 2,005,945	$ 6,633,771	$ 10,601,487	$ 7,433,521	$ 6,351,014	$ 175,938	$ 824,593	$ 437,950	$ 415,757	$ 438,956	$ 553,689	$ 1,163,229	$ 37,035,850
136	Total Off-system Peaking	$ -	$ 660,823	$ 6,720,056	$ 1,985,025	$ 255,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,621,667
137	Total Demand Cost Allocation	$ 2,005,945	$ 7,294,594	$ 17,321,544	$ 9,418,546	$ 6,606,777	$ 175,938	$ 824,593	$ 437,950	$ 415,757	$ 438,956	$ 553,689	$ 1,163,229	$ 46,657,517

97	**Off-System Peaking Demand Costs**	LN 12
98		
99	**Allocation of Off-system Peaking Demand Costs to Months**	
100		
101	Design Year Peaking Volumes	Company Analysis
102	Rank	LN 101 Ranking
103	% Max Month	LN 101 / LN 101 MAX
104	PR	The difference between LN 103 for the month and LN 103 for next highest rank
105	CumPR	Cumulative Values, LN 104
106	Peaking Demand Costs	LN 105 * LN 97
107		
108	**Capacity Cost Allocator based on Design Year Sales**	
109		
110	**Therms**	
111	Maine	Company Analysis
112	New Hampshire	Company Analysis
113	Total	LN 111 + LN 112
114		
115	**Percentage of Total**	
116	Maine	LN 111 / LN 113
117	New Hampshire	LN 112 / LN 113
118	Total	LN 116 + LN 117
119		
120	**Allocation of Off-System Peaking Demand Costs by Division**	
121	Maine	LN 106 * LN 116
122	New Hampshire	LN 106 * LN 117
123	Total	LN 121 + LN 122

Total Weighted Average MPR Factor

124	**Maine**	
125	Total Pipeline, Storage & On-system	LN 87
126	Total Off-system Peaking	LN 121
127	Total Demand Cost Allocation	LN 125 + LN 126
128		
129	**New Hampshire**	
130	Total Pipeline, Storage & On-system	LN 96
131	Total Off-system Peaking	LN 122
132	Total Demand Cost Allocation	LN 130 + Ln 131
133		
134	**Total Northern**	
135	Total Pipeline, Storage & On-system	LN 125 + LN 130
136	Total Off-system Peaking	LN 126 + LN 131
137	Total Demand Cost Allocation	LN 127 + LN 132

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH Division Total Annual Demand Cost Allocation

1	**Resource**	**Costs**
2	Pipeline & Product Demand	$ 7,362,936
3	Storage	$ 10,417,880
4	On-system Peaking	$ 1,669,977
5	Total Gross Demand Cost	$ 19,450,793
6		
7	Capacity Assignment Demand Revenue Estimate	$ 5,012,735
8	NH Total Pipeline, Storage & Peaking Demand Cost	$ 19,450,793
9	Capacity Assignment as % of Total Gross Demand Cost	25.77%
10		
11		**Costs**
12	Pipeline & Product Demand	$ 1,897,529
13	Storage	$ 2,684,830
14	On-system Peaking	$ 430,376
15	Total Capacity Assignment Credit	$ 5,012,735
16		
17	NH Net Annual Demand Cost (Less Capacity Assignment)	
18		**Costs**
19	Pipeline & Product Demand	$ 5,465,407
20	Storage	$ 7,733,050
21	On-system Peaking	$ 1,239,601
22	Total Net Demand Cost (Less Capacity Assignment)	$ 14,438,058
23		
24	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND COSTS**	
25		MMBtu/day
26	Pipeline MDQ	16,645
27	Less 25.77% NH Transp. Capacity Assignment	(4,290)
28	Net Pipeline MDQ	12,355
29		
30	Net Pipeline MDQ	12,355
31	Less: Firm Sales Base Use	3,536
32	Remaining Pipeline MDQ	8,820
33		
34		**Unit Cost**
35	Pipeline Unit Cost	$442.35
36		
37		**Costs**
38	Pipeline & Product Demand	$ 5,465,407
39	Less: Base Pipeline Use	$ 1,563,940
40	Remaining Pipeline Use	$ 3,901,466

1	**Resource**	
2	Pipeline & Product Demand	Attachment NUI-CAK-1, LN 90 + Attachment NUI-CAK-1, LN 93
3	Storage	Attachment NUI-CAK-1, LN 91
4	On-system Peaking	Attachment NUI-CAK-1, LN 92
5	Total Gross Demand Cost	Sum (LN 2 : LN 4)
6		
7	Capacity Assignment Demand Revenue Estimate	Attachment NUI-FXW-6, Page 1
8	NH Total Pipeline, Storage & Peaking Demand Cost	LN 5
9	Capacity Assignment as % of Total Gross Demand Cost	LN 7 / LN 8
10		
11		
12	Pipeline & Product Demand	LN 2 * LN 9
13	Storage	LN 3 * LN 9
14	On-system Peaking	LN 4 * LN 9
15	Total Capacity Assignment Credit	Sum (LN 12 : LN 14)
16		
17	NH Net Annual Demand Cost (Less Capacity Assignment)	
18		
19	Pipeline & Product Demand	LN 2 - LN 12
20	Storage	LN 3 - LN 13
21	On-system Peaking	LN 4 - LN 14
22	Total Net Demand Cost (Less Capacity Assignment)	LN 5 - LN 15
23		
24	**DEVELOPMENT OF BASE AND REMAINING PIPELINE DEMAND (**	
25		
26	Pipeline MDQ	Company Analysis
27	Less 25.77% NH Transp. Capacity Assignment	-(LN 26) * LN 9
28	Net Pipeline MDQ	Sum (LN 26 : LN 27)
29		
30	Net Pipeline MDQ	LN 28
31	Less: Firm Sales Base Use	Attachment NUI-CAK-3, LN 48 / 10
32	Remaining Pipeline MDQ	LN 30 - LN 31
33		
34		
35	Pipeline Unit Cost	LN 19 / LN 30
36		
37		
38	Pipeline & Product Demand	LN 19
39	Less: Base Pipeline Use	LN 35 * LN 31
40	Remaining Pipeline Use	LN 38 - LN 39

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

41	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR ALLOCATORS)**						
42	(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)						
43							
44	**All Months**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
45	Remaining Load for All Months	3,712,185	5,709,500	6,884,032	5,870,407	4,771,592	2,439,637
46	Rank	5	3	1	2	4	6
47	% Max Month	53.92%	82.94%	100.00%	85.28%	69.31%	35.44%
48	PR	3.70%	4.54%	14.72%	1.17%	3.85%	2.75%
49	CumPR	8.87%	17.25%	33.15%	18.42%	12.71%	5.17%
50							
51	**Peak Months Only**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
52	Remaining Load for Peak Months Only	3,712,185	5,709,500	6,884,032	5,870,407	4,771,592	2,439,637
53	Rank	5	3	1	2	4	6
54	% Max Month	53.92%	82.94%	100.00%	85.28%	69.31%	35.44%
55	PR	3.70%	4.54%	14.72%	1.17%	3.85%	5.91%
56	CumPR	9.60%	17.99%	33.89%	19.16%	13.45%	5.91%
57							
58	**DEMAND COST PR ALLOCATORS**						
59		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
60	Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
61	Pipeline - Remaining	8.87%	17.25%	33.15%	18.42%	12.71%	5.17%
62	Storage & Peaking	8.87%	17.25%	33.15%	18.42%	12.71%	5.17%
63	Capacity Release	9.60%	17.99%	33.89%	19.16%	13.45%	5.91%
64	Off-system Peaking	9.29%	17.64%	34.66%	18.93%	13.70%	5.79%
65	Interr. Margins & Off Sys Sales	9.60%	17.99%	33.89%	19.16%	13.45%	5.91%
66							
67	**DEMAND COSTS ALLOCATED TO MONTHS**						
68		**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**
69	Pipeline - Base	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328
70	Pipeline - Remaining	$ 345,883	$ 673,169	$ 1,293,229	$ 718,765	$ 495,985	$ 201,641
71	Total Pipeline	$ 476,211	$ 803,497	$ 1,423,557	$ 849,094	$ 626,313	$ 331,970
72							
73	Storage & On-system Peaking	$ 795,466	$ 1,548,164	$ 2,974,187	$ 1,653,027	$ 1,140,674	$ 463,738
74	Off-system Peaking	$348,528	$661,712	$1,300,321	$710,247	$513,808	$217,139
75	Outage Replacement	$ 3,933	$ 7,655	$ 14,707	$ 8,174	$ 5,640	$ 2,293
76	Less Credits to Demand Cost						
77	Cap Rel Margins & Asset Mgt Credits	$ 391,517	$ 733,509	$ 1,381,430	$ 781,155	$ 548,364	$ 240,795
78	Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -
79	Conversion Rate and Re-entry Rate Credits	$ 480	$ 900	$ 1,694	$ 958	$ 673	$ 295
80	Total Direct Demand Costs	$ 1,232,141	$ 2,286,619	$ 4,329,647	$ 2,438,429	$ 1,737,398	$ 774,050
81							
82	Indirect Demand Costs/(Credits)						
83	Miscellaneous Overhead						
84	Local Production & Storage						
85	Subtotal						

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR /ALLOCATORS)
(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)

All Months	May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer
Remaining Load for All Months	835,747	214,153	0	8,214	162,755	1,303,416	31,911,637	29,387,353	2,524,285
Rank	8	9	12	11	10	7			
% Max Month	12.14%	3.11%	0.00%	0.12%	2.36%	18.93%			
PR	1.13%	0.08%	0.00%	0.01%	0.22%	0.97%	33.15%		
CumPR	1.45%	0.32%	0.00%	0.01%	0.24%	2.42%	100.00%	95.57%	4.43%

Peak Months Only	Annual	Winter	Summer
Remaining Load for Peak Months Only	29,387,353	29,387,353	
Rank			
% Max Month			
PR	33.89%		
CumPR	100.00%	100.00%	0.00%

DEMAND COST PR ALLOCATORS

	May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer
Pipeline - Base	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	100.00%	50.00%	50.00%
Pipeline - Remaining	1.45%	0.32%	0.00%	0.01%	0.24%	2.42%	100.00%	95.57%	4.43%
Storage & Peaking	1.45%	0.32%	0.00%	0.01%	0.24%	2.42%	100.00%	95.57%	4.43%
Capacity Release	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
Off-system Peaking	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%
Interr. Margins & Off Sys Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%

DEMAND COSTS ALLOCATED TO MONTHS

	May	Jun	Jul	Aug	Sep	Oct	Annual	Winter	Summer	Winter	Summer
Pipeline - Base	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 1,563,940	$ 781,970	$ 781,970	50.00%	50.00%
Pipeline - Remaining	$ 56,454	$ 12,418	$ -	$ 423	$ 9,182	$ 94,318	$ 3,901,466	$ 3,728,672	$ 172,794	95.57%	4.43%
Total Pipeline	$ 186,782	$ 142,747	$ 130,328	$ 130,752	$ 139,510	$ 224,646	$ 5,465,407	$ 4,510,642	$ 954,764	82.53%	17.47%
Storage & On-system Peaking	$ 129,833	$ 28,560	$ -	$ 973	$ 21,116	$ 216,913	$ 8,972,651	$ 8,575,256	$ 397,395	95.57%	4.43%
Off-system Peaking	$0	$0	$0	$0	$0	$0	$ 3,751,755	$ 3,751,755	$ -	100.00%	0.00%
Outage Replacement	$ 642	$ 141	$ -	$ 5	$ 104	$ 1,073	$ 44,367	$ 42,402	$ 1,965		
Less Credits to Demand Cost											
Cap Rel Margins & Asset Mgt Credits	$ -	$ -	$ -	$ -	$ -	$ -	$4,076,771	$ 4,076,771	$ -	100.00%	0.00%
Interruptible Margins	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Conversion Rate and Re-entry Rate Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,000	$ 5,000	$ -		
Total Direct Demand Costs	$ 317,257	$ 171,448	$ 130,328	$ 131,730	$ 160,731	$ 442,631	$ 14,152,409	$ 12,798,284	$ 1,354,125	90.43%	9.57%

Indirect Demand Costs/(Credits)	Annual	Winter	Summer	Winter	Summer
Miscellaneous Overhead	$ 580,455	$ 463,606	$ 116,849	79.87%	20.13%
Local Production & Storage	$ 476,106	$ 476,106	$ -	100.00%	0.00%
Subtotal	$ 1,056,561	$ 939,712	$ 116,849	88.94%	11.06%

Northern Utilities - NEW HAMPSHIRE DIVISION
Simplified Market Based Allocator (SMBA) Calculations
DEMAND COSTS

41	**NH DIVISION MONTHLY PROPORTIONAL RESPONSIBILITY (PR /ALLOCATORS)**	
42	(Based on NH Firm Sales Sendout for Remaining Temperature Sensitive Load)	
43		
44	**All Months**	
45	Remaining Load for All Months	Attachment NUI-CAK-3, LN 80
46	Rank	Rank LN 45
47	% Max Month	LN 45 / MAX Month LN 45
48	PR	The difference between LN 47 for the month and LN 47 for next highest rank
49	CumPR	Cumulative Values, LN 48
50		
51	**Peak Months Only**	
52	Remaining Load for Peak Months Only	LN 45
53	Rank	Rank LN 52
54	% Max Month	LN 52 / MAX Month LN 52
55	PR	The difference between LN 54 for the month and LN 54 for next highest rank
56	CumPR	Cumulative Values, LN 55
57		
58	**DEMAND COST PR ALLOCATORS**	
59		
60	Pipeline - Base	1/12
61	Pipeline - Remaining	LN 49
62	Storage & Peaking	LN 49
63	Capacity Release	LN 56
64	Off-system Peaking	LN 56
65	Interr. Margins & Off Sys Sales	LN 56
66		
67	**DEMAND COSTS ALLOCATED TO MONTHS**	
68		
69	Pipeline - Base	LN 39 * LN 60
70	Pipeline - Remaining	LN 40 * LN 61
71	Total Pipeline	LN 69 + LN 70
72		
73	Storage & On-system Peaking	LN 62 * (Sum LN 20 : LN 21)
74	Off-system Peaking	Attachment NUI-CAK-1, LN 122,* LN 64
75	Outage Replacement	Attachment NUI-CAK-2A
76	Less Credits to Demand Cost	
77	Cap Rel Margins & Asset Mgt Credits	Attachment NUI-CAK-1, LN 95 * LN 63
78	Interruptible Margins	
79	Conversion Rate and Re-entry Rate Credits	Company Analysis
80	Total Direct Demand Costs	LN 71 + LN 73 + LN 74 - (Sum LN 76 : LN 79)
81		
82	Indirect Demand Costs/(Credits)	
83	Miscellaneous Overhead	Company Analysis
84	Local Production & Storage	Company Analysis
85	Subtotal	LN 83 + LN 84

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-CAK-2A
Page 1 of 1 **REDACTED**

Eliot Outage Cost Detail

Denotes Confidential Data

Month	Vendor Code	Expense
	Costs Recovered in 2020-2021 COG	
May 2020	[redacted]	
May 2020		
May 2020		
May 2020		
May 2020		
June 2020		
June 2020		
June 2020		
June 2020		
June 2020		
June 2020		
June 2020		
June 2020		
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July 2020		
July 2020		
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July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
July 2020		
Total		**$286,008**

Additional Costs
June 2020 Outage Costs

Month	Vendor Code	Expense	Allocated % to New Hampshire Division	
August 2020	[redacted]			
August 2020				
August 2020				
August 2020				
August 2020				
Total		**$18,105**	41.84%	$7,575

Westbrook Outage

June 2021 Outage Costs

Jun-21	[redacted]		40.88%	$36,792
Total				$44,367

REDACTED

[redacted]

Invoice

To: Northern Utilities
6 Liberty Lane West
Hampton, NH 03842

Invoice Number: NU001
Invoice Date: 26 May 21
Due Date: 1 Jun 21

DESCRIPTION	AMOUNT	TOTAL
Reservation Charge		$ 90,000.00
	Total Due	**$ 90,000.00**

Invoice amounts and all payments to be made in United States dollars.

Please wire payments to

[redacted]

Northern Utilities - NEW HAMPSHIRE DIVISION
2021 - 2022 Period

	Forecasted Normal Sales By Class- Therms														
Line	Calendar Month Firm Sales Volumes														
No.	Normal Winter	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Annual**	**Winter**	**Summer**
1	Res Heat	2,214,836	3,176,763	3,717,973	3,190,785	2,720,227	1,601,139	774,136	505,683	427,329	433,379	480,902	970,020	20,213,169	16,621,722	3,591,447
2	Res General	20,357	29,198	34,173	29,327	25,002	14,716	17,608	11,502	9,720	9,858	10,939	22,064	234,465	152,774	81,691
3	**Total Residential**	**2,235,193**	**3,205,961**	**3,752,145**	**3,220,112**	**2,745,230**	**1,615,855**	**791,744**	**517,185**	**437,049**	**443,237**	**491,840**	**992,084**	**20,447,634**	**16,774,496**	**3,673,138**
4	G50 Low Annual-Low Winter	118,323	169,711	198,624	170,460	145,322	85,537	146,159	95,474	80,681	81,823	90,796	183,143	1,566,054	887,978	678,076
5	G40 Low Annual-High Winter	1,128,570	1,618,720	1,894,493	1,625,865	1,386,092	815,860	293,304	191,593	161,906	164,199	182,204	367,521	9,830,327	8,469,600	1,360,727
6	G51 Med Annual-Low Winter	196,136	281,320	329,247	282,562	240,891	141,790	219,962	143,684	121,421	123,140	136,643	275,620	2,492,415	1,471,945	1,020,469
7	G41 Med Annual-High Winter	828,952	1,188,975	1,391,535	1,194,223	1,018,107	599,262	310,158	202,602	171,210	173,634	192,674	388,639	7,659,971	6,221,055	1,438,916
8	G52 High Annual-Low Winter	53,899	52,129	58,595	56,625	58,318	53,429	52,740	45,879	48,194	49,987	48,339	53,274	631,408	332,996	298,412
9	G42 High Annual-High Winter	152,111	203,629	255,657	224,755	200,301	144,806	93,544	60,828	53,739	54,403	65,622	109,154	1,618,550	1,181,259	437,291
10	**Total C&I**	**2,477,990**	**3,514,485**	**4,128,152**	**3,554,490**	**3,049,031**	**1,840,685**	**1,115,867**	**740,061**	**637,150**	**647,185**	**716,278**	**1,377,351**	**23,798,725**	**18,564,833**	**5,233,892**
11	**Total Sales**	**4,713,183**	**6,720,446**	**7,880,297**	**6,774,602**	**5,794,261**	**3,456,540**	**1,907,611**	**1,257,246**	**1,074,199**	**1,090,422**	**1,208,118**	**2,369,434**	**44,246,359**	**35,339,329**	**8,907,030**
12																
13	Residential Heat & Non Heat	2,235,193	3,205,961	3,752,145	3,220,112	2,745,230	1,615,855	791,744	517,185	437,049	443,237	491,840	992,084	20,447,634	16,774,496	3,673,138
14	SALES HLF CLASSES	368,357	503,160	586,466	509,647	444,531	280,756	418,861	285,038	250,296	254,950	275,778	512,036	4,689,876	2,692,919	1,996,958
15	SALES LLF CLASSES	2,109,633	3,011,324	3,541,686	3,044,843	2,604,500	1,559,929	697,006	455,024	386,854	392,235	440,500	865,314	19,108,849	15,871,915	3,236,934
16	**Total Firm Sales**	**4,713,183**	**6,720,446**	**7,880,297**	**6,774,602**	**5,794,261**	**3,456,540**	**1,907,611**	**1,257,246**	**1,074,199**	**1,090,422**	**1,208,118**	**2,369,434**	**44,246,359**	**35,339,329**	**8,907,030**
17																
18	**ESTIMATED SENDOUT BY CLASS - Therms**															
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)															
20	Normal Winter	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Annual**	**Winter**	**SUMMER**
21	Res Heat	2,242,870	3,216,973	3,765,033	3,231,172	2,754,659	1,621,405	783,934	512,083	432,738	438,865	486,989	982,298	20,469,017	16,832,111	3,636,906
22	Res General	20,615	29,568	34,605	29,699	25,319	14,903	17,831	11,648	9,843	9,982	11,077	22,343	237,433	154,708	82,725
23	G50 Low Annual-Low Winter	119,820	171,859	201,138	172,618	147,161	86,620	148,009	96,683	81,702	82,859	91,945	185,461	1,585,876	899,217	686,659
24	G40 Low Annual-High Winter	1,142,855	1,639,209	1,918,473	1,646,444	1,403,637	826,187	297,017	194,018	163,956	166,277	184,510	372,173	9,954,754	8,576,804	1,377,950
25	G51 Med Annual-Low Winter	198,619	284,881	333,414	286,138	243,940	143,584	222,746	145,503	122,958	124,699	138,372	279,109	2,523,962	1,490,576	1,033,386
26	G41 Med Annual-High Winter	839,445	1,204,025	1,409,149	1,209,339	1,030,993	606,847	314,084	205,167	173,377	175,832	195,112	393,558	7,756,927	6,299,798	1,457,129
27	G52 High Annual-Low Winter	54,581	52,789	59,336	57,342	59,056	54,106	53,407	46,460	48,804	50,619	48,951	53,948	639,400	337,210	302,189
28	G42 High Annual-High Winter	154,036	206,207	258,893	227,600	202,837	146,639	94,728	61,598	54,419	55,092	66,453	110,536	1,639,037	1,196,211	442,826
29	**Subtotal**															
30	Residential	2,263,485	3,246,541	3,799,638	3,260,870	2,779,977	1,636,308	801,765	523,731	442,581	448,847	498,066	1,004,641	20,706,450	16,986,819	3,719,631
31	SALES HLF CLASSES	373,020	509,529	593,889	516,098	450,158	284,310	424,162	288,645	253,464	258,177	279,268	518,517	4,749,238	2,727,004	2,022,234
32	SALES LLF CLASSES	2,136,335	3,049,440	3,586,515	3,083,383	2,637,466	1,579,674	705,829	460,783	391,751	397,200	446,076	876,267	19,350,718	16,072,813	3,277,905
33	**Total Firm Sales**	4,772,840	6,805,510	7,980,042	6,860,351	5,867,601	3,500,291	1,931,757	1,273,159	1,087,795	1,104,224	1,223,410	2,399,425	44,806,406	35,786,636	9,019,770

Northern Utilities - NEW HAMPSHIRE DIVISION
2021 - 2022 Period

Line No.	Forecasted Normal Sales By Class- Therms Calendar Month Firm Sales Volumes Firm Sales	
1	Res Heat	(Attachment NUI-FXW-2, Page 1) * 10
2	Res General	(Attachment NUI-FXW-2, Page 1) * 10
3	**Total Residential**	Sum LN 1 : LN 2
4	G50 Low Annual-Low Winter	(Attachment NUI-FXW-2, Page 1) * 10
5	G40 Low Annual-High Winter	(Attachment NUI-FXW-2, Page 1) * 10
6	G51 Med Annual-Low Winter	(Attachment NUI-FXW-2, Page 1) * 10
7	G41 Med Annual-High Winter	(Attachment NUI-FXW-2, Page 1) * 10
8	G52 High Annual-Low Winter	(Attachment NUI-FXW-2, Page 1) * 10
9	G42 High Annual-High Winter	(Attachment NUI-FXW-2, Page 1) * 10
10	**Total C&I**	Sum LN 4 : LN 9
11	**Total Sales**	LN 3 + LN 10
12		
13	Residential Heat & Non Heat	LN 3
14	SALES HLF CLASSES	LN 4 + LN 6 + LN 8
15	SALES LLF CLASSES	LN 5 + LN 7 + LN 9
16	**Total Firm Sales**	Sum LN 13 : LN 15
17		
18	**ESTIMATED SENDOUT BY CLASS - Therms**	
19	Calendar Month Sendout Volumes (Includes Loss & Unaccounted For)	Unaccounted For)
20	Normal Winter	
21	Res Heat	LN 1 x Adj factor (Attachment NUI-FXW-2, Page 4)
22	Res General	LN 2 x Adj factor (Attachment NUI-FXW-2, Page 4)
23	G50 Low Annual-Low Winter	LN 4 x Adj factor (Attachment NUI-FXW-2, Page 4)
24	G40 Low Annual-High Winter	LN 5 x Adj factor (Attachment NUI-FXW-2, Page 4)
25	G51 Med Annual-Low Winter	LN 6 x Adj factor (Attachment NUI-FXW-2, Page 4)
26	G41 Med Annual-High Winter	LN 7 x Adj factor (Attachment NUI-FXW-2, Page 4)
27	G52 High Annual-Low Winter	LN 8 x Adj factor (Attachment NUI-FXW-2, Page 4)
28	G42 High Annual-High Winter	LN 9 x Adj factor (Attachment NUI-FXW-2, Page 4)
29	**Subtotal**	
30	Residential	LN 21 + LN 22
31	SALES HLF CLASSES	LN 23 + LN 25 + LN 27
32	SALES LLF CLASSES	LN 24 + LN 26 + LN 28
33	**Total Firm Sales**	Sum LN 30 : LN 32

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	**DAILY BASE GAS ENTITLEMENT - Therms/day**	
36	Res Heat	14,058
37	Res General	320
38	G50 Low Annual-Low Winter	2,654
39	G40 Low Annual-High Winter	5,326
40	G51 Med Annual-Low Winter	3,994
41	G41 Med Annual-High Winter	5,632
42	G52 High Annual-Low Winter	1,604
43	G42 High Annual-High Winter	1,766
44	**Subtotal**	
45	Residential	14,378
46	SALES HLF CLASSES	8,252
47	SALES LLF CLASSES	12,725
48	**Total Firm Sales**	**35,355**

49	**BASE SENDOUT BY CLASS - Therms**															
50	Days per Month	30	31	31	28	31	30	31	30	31	31	30	31			
51		**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Annual**	**Winter**	**SUMMER**
52	Res Heat	421,743	435,801	435,801	393,627	435,801	421,743	435,801	421,743	432,738	435,801	421,743	435,801	5,128,145	2,544,517	2,583,628
53	Res General	9,593	9,913	9,913	8,953	9,913	9,593	9,913	9,593	9,843	9,913	9,593	9,913	116,644	57,877	58,767
54	G50 Low Annual-Low Winter	79,626	82,281	82,281	74,318	82,281	79,626	82,281	79,626	81,702	82,281	79,626	82,281	968,209	480,412	487,797
55	G40 Low Annual-High Winter	159,790	165,116	165,116	149,137	165,116	159,790	165,116	159,790	163,956	165,116	159,790	165,116	1,942,950	964,066	978,884
56	G51 Med Annual-Low Winter	119,834	123,828	123,828	111,845	123,828	119,834	123,828	119,834	122,958	123,828	119,834	123,828	1,457,105	722,996	734,109
57	G41 Med Annual-High Winter	168,972	174,604	174,604	157,707	174,604	168,972	174,604	168,972	173,377	174,604	168,972	174,604	2,054,595	1,019,463	1,035,133
58	G52 High Annual-Low Winter	48,108	49,712	49,712	44,901	49,712	48,108	49,712	46,460	48,804	49,712	48,108	49,712	582,759	290,252	292,507
59	G42 High Annual-High Winter	52,989	54,755	54,755	49,456	54,755	52,989	54,755	52,989	54,419	54,755	52,989	54,755	644,362	319,700	324,662
60	**Subtotal**															
61	Residential	431,336	445,714	445,714	402,580	445,714	431,336	445,714	431,336	442,581	445,714	431,336	445,714	5,244,789	2,602,394	2,642,395
62	SALES HLF CLASSES	247,568	255,820	255,820	231,063	255,820	247,568	255,820	245,920	253,464	255,820	247,568	255,820	3,008,073	1,493,660	1,514,413
63	SALES LLF CLASSES	381,751	394,476	394,476	356,301	394,476	381,751	394,476	381,751	391,751	394,476	381,751	394,476	4,641,907	2,303,228	2,338,679
64	**Total Firm Sales**	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486
65																
66	**REMAINING SENDOUT BY CLASS - Therms**															
67		**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Annual**	**Winter**	**SUMMER**
68	Res Heat	1,821,127	2,781,171	3,329,231	2,837,545	2,318,857	1,199,662	348,133	90,340	-	3,064	65,245	546,496	15,340,872	14,287,594	1,053,279
69	Res General	11,022	19,655	24,693	20,745	15,406	5,310	7,919	2,055	-	70	1,484	12,431	120,789	96,831	23,958
70	G50 Low Annual-Low Winter	40,194	89,579	118,858	98,300	64,881	6,994	65,729	17,056	-	578	12,319	103,180	617,667	418,805	198,862
71	G40 Low Annual-High Winter	983,065	1,474,093	1,753,357	1,497,307	1,238,520	666,397	131,900	34,228	-	1,161	24,720	207,056	8,011,804	7,612,738	399,066
72	G51 Med Annual-Low Winter	78,785	161,053	209,586	174,293	120,112	23,751	98,918	25,669	-	870	18,539	155,281	1,066,858	767,580	299,277
73	G41 Med Annual-High Winter	670,473	1,029,421	1,234,544	1,051,632	856,389	437,876	139,480	36,195	-	1,227	26,141	218,954	5,702,332	5,280,335	421,997
74	G52 High Annual-Low Winter	6,473	3,077	9,625	12,441	9,344	5,998	3,695	-	-	908	843	4,236	56,640	46,958	9,682
75	G42 High Annual-High Winter	101,047	151,451	204,138	178,143	148,081	93,650	39,973	8,610	-	336	13,464	55,781	994,676	876,512	118,164
76	**Subtotal**															
77	Residential	1,832,149	2,800,827	3,353,924	2,858,290	2,334,263	1,204,972	356,051	92,395	-	3,133	66,730	558,927	15,461,661	14,384,425	1,077,236
78	SALES HLF CLASSES	125,452	253,709	338,069	285,035	194,337	36,742	168,342	42,726	-	2,356	31,700	262,697	1,741,165	1,233,344	507,822
79	SALES LLF CLASSES	1,754,585	2,654,964	3,192,039	2,727,082	2,242,991	1,197,923	311,353	79,032	-	2,725	64,325	481,791	14,708,811	13,769,585	939,227
80	**Total Firm Sales**	3,712,185	5,709,500	6,884,032	5,870,407	4,771,592	2,439,637	835,747	214,153	-	8,214	162,755	1,303,416	31,911,637	29,387,353	2,524,285

Northern Utilities - NEW HAMPSHIRE DIVISION
Sendout by Class - Allocation between Base & Remaining Sendout

34		
35	DAILY BASE GAS ENTITLEMENT - Therms/day	
36	Res Heat	Avg (LN 21 Jul : LN 21 Aug) / 31 days
37	Res General	Avg (LN 22 Jul : LN 22 Aug) / 31 days
38	G50 Low Annual-Low Winter	Avg (LN 23 Jul : LN 23 Aug) / 31 days
39	G40 Low Annual-High Winter	Avg (LN 24 Jul : LN 24 Aug) / 31 days
40	G51 Med Annual-Low Winter	Avg (LN 25 Jul : LN 25 Aug) / 31 days
41	G41 Med Annual-High Winter	Avg (LN 26 Jul : LN 26 Aug) / 31 days
42	G52 High Annual-Low Winter	Avg (LN 27 Jul : LN 27 Aug) / 31 days
43	G42 High Annual-High Winter	Avg (LN 28 Jul : LN 28 Aug) / 31 days
44	**Subtotal**	
45	Residential	LN 36 + LN 37
46	SALES HLF CLASSES	LN 38 + LN 40 + LN 42
47	SALES LLF CLASSES	LN 39 + LN 41 + LN 43
48	**Total Firm Sales**	Sum LN 45 : LN 47
49	**BASE SENDOUT BY CLASS - Therms**	
50	Days per Month	
51		
52	Res Heat	MIN(LN 36 * LN 50, LN 21)
53	Res General	MIN(LN 37 * LN 50, LN 22)
54	G50 Low Annual-Low Winter	MIN(LN 38 * LN 50, LN 23)
55	G40 Low Annual-High Winter	MIN(LN 39 * LN 50, LN 24)
56	G51 Med Annual-Low Winter	MIN(LN 40 * LN 50, LN 25)
57	G41 Med Annual-High Winter	MIN(LN 41 * LN 50, LN 26)
58	G52 High Annual-Low Winter	MIN(LN 42 * LN 50, LN 27)
59	G42 High Annual-High Winter	MIN(LN 43 * LN 50, LN 28)
60	**Subtotal**	
61	Residential	LN 52 + LN 53
62	SALES HLF CLASSES	LN 54 + LN 56 + LN 58
63	SALES LLF CLASSES	LN 55 + LN 57 + LN 59
64	**Total Firm Sales**	Sum LN 61 : LN 63
65		
66	REMAINING SENDOUT BY CLASS - Therms	
67		
68	Res Heat	LN 21 - LN 52
69	Res General	LN 22 - LN 53
70	G50 Low Annual-Low Winter	LN 23 - LN 54
71	G40 Low Annual-High Winter	LN 24 - LN 55
72	G51 Med Annual-Low Winter	LN 25 - LN 56
73	G41 Med Annual-High Winter	LN 26 - LN 57
74	G52 High Annual-Low Winter	LN 27 - LN 58
75	G42 High Annual-High Winter	LN 28 - LN 59
76	**Subtotal**	
77	Residential	LN 68 + LN 69
78	SALES HLF CLASSES	LN 70 + LN 72 + LN 74
79	SALES LLF CLASSES	LN 71 + LN 73 + LN 75
80	**Total Firm Sales**	Sum LN 77 : LN 79

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Demand Costs to Customer Classes

Base Capacity Costs

1	**BASE SENDOUT BY CLASS**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Annual**	**Winter**	**SUMMER**
2	**Total Therms**															
3	Res Heat	421,743	435,801	435,801	393,627	435,801	421,743	435,801	421,743	432,738	435,801	421,743	435,801	5,128,145	2,544,517	2,583,628
4	Res General	9,593	9,913	9,913	8,953	9,913	9,593	9,913	9,593	9,843	9,913	9,593	9,913	116,644	57,877	58,767
5	G50 Low Annual-Low Winter	79,626	82,281	82,281	74,318	82,281	79,626	82,281	79,626	81,702	82,281	79,626	82,281	968,209	480,412	487,797
6	G40 Low Annual-High Winter	159,790	165,116	165,116	149,137	165,116	159,790	165,116	159,790	163,956	165,116	159,790	165,116	1,942,950	964,066	978,884
7	G51 Med Annual-Low Winter	119,834	123,828	123,828	111,845	123,828	119,834	123,828	119,834	122,958	123,828	119,834	123,828	1,457,105	722,996	734,109
8	G41 Med Annual-High Winter	168,972	174,604	174,604	157,707	174,604	168,972	174,604	168,972	173,377	174,604	168,972	174,604	2,054,595	1,019,463	1,035,133
9	G52 High Annual-Low Winter	48,108	49,712	49,712	44,901	49,712	48,108	49,712	46,460	48,804	49,712	48,108	49,712	582,759	290,252	292,507
10	G42 High Annual-High Winter	52,989	54,755	54,755	49,456	54,755	52,989	54,755	52,989	54,419	54,755	52,989	54,755	644,362	319,700	324,662
11	Total Firm Sales	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486
12																
13	**% of Total**															
14	Res Heat	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.82%	39.78%	39.76%	39.76%	39.76%			
15	Res General	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.91%	0.90%	0.90%	0.90%	0.90%			
16	G50 Low Annual-Low Winter	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.52%	7.51%	7.51%	7.51%	7.51%			
17	G40 Low Annual-High Winter	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.09%	15.07%	15.07%	15.07%	15.07%			
18	G51 Med Annual-Low Winter	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.32%	11.30%	11.30%	11.30%	11.30%			
19	G41 Med Annual-High Winter	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.96%	15.94%	15.93%	15.93%	15.93%			
20	G52 High Annual-Low Winter	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.39%	4.49%	4.54%	4.54%	4.54%			
21	G42 High Annual-High Winter	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%			
22	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			
23																
24	**PIPELINE BASE DEMAND COSTS**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Annual**	**Winter**	**SUMMER**
25	TOTAL PIPELINE BASE DEMAND COST	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 130,328	$ 1,563,940	$ 781,970	$ 781,970
26	Res Heat	$ 51,822	$ 51,822	$ 51,822	$ 51,822	$ 51,822	$ 51,822	$ 51,822	$ 51,903	$ 51,846	$ 51,822	$ 51,822	$ 51,822	$ 621,967	$ 310,931	$ 311,036
27	Res General	$ 1,179	$ 1,179	$ 1,179	$ 1,179	$ 1,179	$ 1,179	$ 1,179	$ 1,181	$ 1,179	$ 1,179	$ 1,179	$ 1,179	$ 14,147	$ 7,072	$ 7,075
28	G50 Low Annual-Low Winter	$ 9,784	$ 9,784	$ 9,784	$ 9,784	$ 9,784	$ 9,784	$ 9,784	$ 9,799	$ 9,789	$ 9,784	$ 9,784	$ 9,784	$ 117,429	$ 58,705	$ 58,725
29	G40 Low Annual-High Winter	$ 19,634	$ 19,634	$ 19,634	$ 19,634	$ 19,634	$ 19,634	$ 19,634	$ 19,665	$ 19,643	$ 19,634	$ 19,634	$ 19,634	$ 235,651	$ 117,805	$ 117,845
30	G51 Med Annual-Low Winter	$ 14,725	$ 14,725	$ 14,725	$ 14,725	$ 14,725	$ 14,725	$ 14,725	$ 14,748	$ 14,731	$ 14,725	$ 14,725	$ 14,725	$ 176,725	$ 88,348	$ 88,377
31	G41 Med Annual-High Winter	$ 20,762	$ 20,762	$ 20,762	$ 20,762	$ 20,762	$ 20,762	$ 20,762	$ 20,795	$ 20,772	$ 20,762	$ 20,762	$ 20,762	$ 249,192	$ 124,575	$ 124,617
32	G52 High Annual-Low Winter	$ 5,911	$ 5,911	$ 5,911	$ 5,911	$ 5,911	$ 5,911	$ 5,911	$ 5,718	$ 5,847	$ 5,911	$ 5,911	$ 5,911	$ 70,678	$ 35,468	$ 35,210
33	G42 High Annual-High Winter	$ 6,511	$ 6,511	$ 6,511	$ 6,511	$ 6,511	$ 6,511	$ 6,511	$ 6,521	$ 6,520	$ 6,511	$ 6,511	$ 6,511	$ 78,151	$ 39,066	$ 39,085
34																
35	Residential	$ 53,001	$ 53,001	$ 53,001	$ 53,001	$ 53,001	$ 53,001	$ 53,001	$ 53,083	$ 53,025	$ 53,001	$ 53,001	$ 53,001	$ 636,114	$ 318,004	$ 318,111
36	SALES HLF CLASSES	$ 30,420	$ 30,420	$ 30,420	$ 30,420	$ 30,420	$ 30,420	$ 30,420	$ 30,265	$ 30,367	$ 30,420	$ 30,420	$ 30,420	$ 364,832	$ 182,520	$ 182,312
37	SALES LLF CLASSES	$ 46,908	$ 46,908	$ 46,908	$ 46,908	$ 46,908	$ 46,908	$ 46,908	$ 46,981	$ 46,936	$ 46,908	$ 46,908	$ 46,908	$ 562,994	$ 281,446	$ 281,547
38																

Northern Utilities - NEW HAMPSHII
Allocation of Demand Costs to Cus

Base Capacity Costs

1	**BASE SENDOUT BY CLASS**	
2	**Total Therms**	
3	Res Heat	Attachment NUI-CAK-3, LN 52
4	Res General	Attachment NUI-CAK-3, LN 53
5	G50 Low Annual-Low Winter	Attachment NUI-CAK-3, LN 54
6	G40 Low Annual-High Winter	Attachment NUI-CAK-3, LN 55
7	G51 Med Annual-Low Winter	Attachment NUI-CAK-3, LN 56
8	G41 Med Annual-High Winter	Attachment NUI-CAK-3, LN 57
9	G52 High Annual-Low Winter	Attachment NUI-CAK-3, LN 58
10	G42 High Annual-High Winter	Attachment NUI-CAK-3, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12		
13	**% of Total**	
14	Res Heat	LN 3 / LN 11
15	Res General	LN 4 / LN 11
16	G50 Low Annual-Low Winter	LN 5 / LN 11
17	G40 Low Annual-High Winter	LN 6 / LN 11
18	G51 Med Annual-Low Winter	LN 7 / LN 11
19	G41 Med Annual-High Winter	LN 8 / LN 11
20	G52 High Annual-Low Winter	LN 9 / LN 11
21	G42 High Annual-High Winter	LN 10 / LN 11
22	Total Firm Sales	LN 11 / LN 11
23		
24	**PIPELINE BASE DEMAND COSTS**	
25	TOTAL PIPELINE BASE DEMAND COST	Attachment NUI-CAK-2, LN 69
26	Res Heat	LN 25 * LN 14
27	Res General	LN 25 * LN 15
28	G50 Low Annual-Low Winter	LN 25 * LN 16
29	G40 Low Annual-High Winter	LN 25 * LN 17
30	G51 Med Annual-Low Winter	LN 25 * LN 18
31	G41 Med Annual-High Winter	LN 25 * LN 19
32	G52 High Annual-Low Winter	LN 25 * LN 20
33	G42 High Annual-High Winter	LN 25 * LN 21
34		
35	Residential	LN 26 + LN 27
36	SALES HLF CLASSES	LN 28 + LN 30 + LN 32
37	SALES LLF CLASSES	LN 29 + LN 31 + LN 33
38		

Remaining Capacity Costs

	Column A Design Day Demand (MMBtu)	Column B Avg Daily Base Use Load (MMBtu)	Column C Remaining Design Day Demand (MMBtu)	Column D % of Total Remaining Design Day Demand
Res Heat	24,141	1,406	22,735	48.80%
Res General	222	32	190	0.41%
G50 Low Annual-Low Winter	905	265	640	1.37%
G40 Low Annual-High Winter	11,858	533	11,325	24.31%
G51 Med Annual-Low Winter	1,441	399	1,041	2.23%
G41 Med Annual-High Winter	9,240	563	8,677	18.62%
G52 High Annual-Low Winter	365	160	205	0.44%
G42 High Annual-High Winter	1,952	177	1,776	3.81%
TOTAL	50,124	3,536	46,588	100.00%

REMAINING PIPELINE DEMAND

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
NH DIVISION TOTAL - REMAINING PIPELI	$ 345,883	$ 673,169	$ 1,293,229	$ 718,765	$ 495,985	$ 201,641	$ 56,454	$ 12,418	$ -	$ 423	$ 9,182	$ 94,318	$ 3,901,466	$ 3,728,672	$ 172,794
Res Heat	$ 168,790	$ 328,505	$ 631,093	$ 350,756	$ 242,040	$ 98,401	$ 27,549	$ 6,060	$ -	$ 207	$ 4,481	$ 46,027	$ 1,903,907	$ 1,819,584	$ 84,323
Res General	$ 1,411	$ 2,745	$ 5,274	$ 2,931	$ 2,023	$ 822	$ 230	$ 51	$ -	$ 2	$ 37	$ 385	$ 15,911	$ 15,207	$ 705
G50 Low Annual-Low Winter	$ 4,750	$ 9,244	$ 17,759	$ 9,870	$ 6,811	$ 2,769	$ 775	$ 171	$ -	$ 6	$ 126	$ 1,295	$ 53,576	$ 51,203	$ 2,373
G40 Low Annual-High Winter	$ 84,082	$ 163,643	$ 314,376	$ 174,727	$ 120,571	$ 49,018	$ 13,724	$ 3,019	$ -	$ 103	$ 2,232	$ 22,928	$ 948,422	$ 906,417	$ 42,005
G51 Med Annual-Low Winter	$ 7,730	$ 15,044	$ 28,902	$ 16,063	$ 11,084	$ 4,506	$ 1,262	$ 278	$ -	$ 9	$ 205	$ 2,108	$ 87,191	$ 83,330	$ 3,862
G41 Med Annual-High Winter	$ 64,418	$ 125,372	$ 240,853	$ 133,864	$ 92,373	$ 37,554	$ 10,514	$ 2,313	$ -	$ 79	$ 1,710	$ 17,566	$ 726,617	$ 694,435	$ 32,182
G52 High Annual-Low Winter	$ 1,519	$ 2,956	$ 5,679	$ 3,156	$ 2,178	$ 886	$ 248	$ 55	$ -	$ 2	$ 40	$ 414	$ 17,133	$ 16,375	$ 759
G42 High Annual-High Winter	$ 13,184	$ 25,659	$ 49,293	$ 27,397	$ 18,905	$ 7,686	$ 2,152	$ 473	$ -	$ 16	$ 350	$ 3,595	$ 148,709	$ 142,123	$ 6,586
TOTAL	$ 345,883	$ 673,169	$ 1,293,229	$ 718,765	$ 495,985	$ 201,641	$ 56,454	$ 12,418	$ -	$ 423	$ 9,182	$ 94,318	$ 3,901,466	$ 3,728,672	$ 172,794
Residential	$ 170,201	$ 331,250	$ 636,367	$ 353,687	$ 244,062	$ 99,223	$ 27,779	$ 6,111	$ -	$ 208	$ 4,518	$ 46,411	$ 1,919,818	$ 1,834,790	$ 85,028
SALES HLF CLASSES	$ 13,999	$ 27,245	$ 52,340	$ 29,090	$ 20,074	$ 8,161	$ 2,285	$ 503	$ -	$ 17	$ 372	$ 3,817	$ 157,900	$ 150,907	$ 6,993
SALES LLF CLASSES	$ 161,683	$ 314,674	$ 604,522	$ 335,988	$ 231,849	$ 94,258	$ 26,389	$ 5,805	$ -	$ 198	$ 4,292	$ 44,089	$ 1,823,748	$ 1,742,975	$ 80,773

STORAGE AND ON-SYSTEM PEAKING DEMAND

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
NH DIVISION TOTAL - PEAKING & STORA	$ 795,466	$ 1,548,164	$ 2,974,187	$ 1,653,027	$ 1,140,674	$ 463,738	$ 129,833	$ 28,560	$ -	$ 973	$ 21,116	$ 216,913	$ 8,972,651	$ 8,575,256	$ 397,395
Res Heat	$ 388,186	$ 755,501	$ 1,451,397	$ 806,674	$ 556,646	$ 226,303	$ 63,358	$ 13,937	$ -	$ 475	$ 10,305	$ 105,853	$ 4,378,634	$ 4,184,706	$ 193,928
Res General	$ 3,244	$ 6,314	$ 12,130	$ 6,741	$ 4,652	$ 1,891	$ 529	$ 116	$ -	$ 4	$ 86	$ 885	$ 36,593	$ 34,972	$ 1,621
G50 Low Annual-Low Winter	$ 10,923	$ 21,260	$ 40,842	$ 22,700	$ 15,664	$ 6,368	$ 1,783	$ 392	$ -	$ 13	$ 290	$ 2,979	$ 123,214	$ 117,757	$ 5,457
G40 Low Annual-High Winter	$ 193,373	$ 376,349	$ 723,006	$ 401,840	$ 277,291	$ 112,732	$ 31,562	$ 6,943	$ -	$ 237	$ 5,133	$ 52,730	$ 2,181,195	$ 2,084,591	$ 96,604
G51 Med Annual-Low Winter	$ 17,777	$ 34,599	$ 66,468	$ 36,942	$ 25,492	$ 10,364	$ 2,902	$ 638	$ -	$ 22	$ 472	$ 4,848	$ 200,524	$ 191,643	$ 8,881
G41 Med Annual-High Winter	$ 148,149	$ 288,333	$ 553,918	$ 307,863	$ 212,441	$ 86,368	$ 24,180	$ 5,319	$ -	$ 181	$ 3,933	$ 40,398	$ 1,671,084	$ 1,597,073	$ 74,012
G52 High Annual-Low Winter	$ 3,493	$ 6,799	$ 13,061	$ 7,259	$ 5,009	$ 2,037	$ 570	$ 125	$ -	$ 4	$ 93	$ 953	$ 39,404	$ 37,658	$ 1,745
G42 High Annual-High Winter	$ 30,320	$ 59,010	$ 113,365	$ 63,007	$ 43,478	$ 17,676	$ 4,949	$ 1,089	$ -	$ 37	$ 805	$ 8,268	$ 342,003	$ 326,856	$ 15,147
TOTAL	$ 795,466	$ 1,548,164	$ 2,974,187	$ 1,653,027	$ 1,140,674	$ 463,738	$ 129,833	$ 28,560	$ -	$ 973	$ 21,116	$ 216,913	$ 8,972,651	$ 8,575,256	$ 397,395
Residential	$ 391,430	$ 761,814	$ 1,463,526	$ 813,415	$ 561,298	$ 228,194	$ 63,888	$ 14,054	$ -	$ 479	$ 10,391	$ 106,738	$ 4,415,227	$ 4,219,678	$ 195,549
SALES HLF CLASSES	$ 32,194	$ 62,657	$ 120,372	$ 66,901	$ 46,165	$ 18,768	$ 5,255	$ 1,156	$ -	$ 39	$ 855	$ 8,779	$ 363,142	$ 347,058	$ 16,083
SALES LLF CLASSES	$ 371,842	$ 723,692	$ 1,390,289	$ 772,711	$ 533,210	$ 216,775	$ 60,691	$ 13,350	$ -	$ 455	$ 9,871	$ 101,396	$ 4,194,282	$ 4,008,519	$ 185,763

Off-SYSTEM PEAKING DEMAND & OUTAGE REPLACEMENT

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
NH DIVISION - OFF-SYSTEM PEAKING	$ 352,462	$ 669,367	$ 1,315,028	$ 718,421	$ 519,448	$ 219,432	$ 642	$ 141	$ -	$ 5	$ 104	$ 1,073	$ 3,796,122	$ 3,794,157	$ 1,965
Res Heat	$ 172,000	$ 326,650	$ 641,731	$ 350,588	$ 253,489	$ 107,082	$ 313	$ 69	$ -	$ 2	$ 51	$ 523	$ 1,852,499	$ 1,851,540	$ 959
Res General	$ 1,437	$ 2,730	$ 5,363	$ 2,930	$ 2,118	$ 895	$ 3	$ 1	$ -	$ 0	$ 0	$ 4	$ 15,482	$ 15,474	$ 8
G50 Low Annual-Low Winter	$ 4,840	$ 9,192	$ 18,058	$ 9,865	$ 7,133	$ 3,013	$ 9	$ 2	$ -	$ 0	$ 1	$ 15	$ 52,129	$ 52,102	$ 27
G40 Low Annual-High Winter	$ 85,681	$ 162,719	$ 319,675	$ 174,644	$ 126,274	$ 53,343	$ 156	$ 34	$ -	$ 1	$ 25	$ 261	$ 922,813	$ 922,336	$ 478
G51 Med Annual-Low Winter	$ 7,877	$ 14,959	$ 29,389	$ 16,056	$ 11,609	$ 4,904	$ 14	$ 3	$ -	$ 0	$ 2	$ 24	$ 84,837	$ 84,793	$ 44
G41 Med Annual-High Winter	$ 65,643	$ 124,664	$ 244,913	$ 133,800	$ 96,743	$ 40,867	$ 120	$ 26	$ -	$ 1	$ 19	$ 200	$ 706,997	$ 706,631	$ 366
G52 High Annual-Low Winter	$ 1,548	$ 2,940	$ 5,775	$ 3,155	$ 2,281	$ 964	$ 3	$ 1	$ -	$ 0	$ 0	$ 5	$ 16,671	$ 16,662	$ 9
G42 High Annual-High Winter	$ 13,434	$ 25,514	$ 50,124	$ 27,383	$ 19,799	$ 8,364	$ 24	$ 5	$ -	$ 0	$ 4	$ 41	$ 144,694	$ 144,619	$ 75
TOTAL	$ 352,462	$ 669,367	$ 1,315,028	$ 718,421	$ 519,448	$ 219,432	$ 642	$ 141	$ -	$ 5	$ 104	$ 1,073	$ 3,796,122	$ 3,794,157	$ 1,965
Residential	$ 173,438	$ 329,379	$ 647,094	$ 353,518	$ 255,608	$ 107,977	$ 316	$ 69	$ -	$ 2	$ 51	$ 528	$ 1,867,981	$ 1,867,014	$ 967
SALES HLF CLASSES	$ 15,702	$ 29,821	$ 58,585	$ 32,006	$ 23,142	$ 9,776	$ 29	$ 6	$ -	$ 0	$ 5	$ 48	$ 169,119	$ 169,031	$ 88
SALES LLF CLASSES	$ 336,759	$ 639,546	$ 1,256,443	$ 686,415	$ 496,306	$ 209,656	$ 613	$ 135	$ -	$ 5	$ 100	$ 1,025	$ 3,627,003	$ 3,625,126	$ 1,877

Remaining Capacity Costs

39		
40	Res Heat	Company Analysis
41	Res General	Company Analysis
42	G50 Low Annual-Low Winter	Company Analysis
43	G40 Low Annual-High Winter	Company Analysis
44	G51 Med Annual-Low Winter	Company Analysis
45	G41 Med Annual-High Winter	Company Analysis
46	G52 High Annual-Low Winter	Company Analysis
47	G42 High Annual-High Winter	Company Analysis
48	TOTAL	Sum LN 40 : LN 47
49		
50	**REMAINING PIPELINE DEMAND**	
51		
52	NH DIVISION TOTAL - REMAINING PIPELI	Attachment NUI-CAK-2, LN 70
53		
54	Res Heat	LN 40 Col D * LN 52
55	Res General	LN 41 Col D * LN 52
56	G50 Low Annual-Low Winter	LN 42 Col D * LN 52
57	G40 Low Annual-High Winter	LN 43 Col D * LN 52
58	G51 Med Annual-Low Winter	LN 44 Col D * LN 52
59	G41 Med Annual-High Winter	LN 45 Col D * LN 52
60	G52 High Annual-Low Winter	LN 46 Col D * LN 52
61	G42 High Annual-High Winter	LN 47 Col D * LN 52
62	TOTAL	Sum LN 54 : LN 61
63		
64	Residential	LN 54 + LN 55
65	SALES HLF CLASSES	LN 56 + LN 58 + LN 60
66	SALES LLF CLASSES	LN 57 + LN 59 + LN 61
67		
68	**STORAGE AND ON-SYSTEM PEAKING DE**	**EMAND**
69		
70	NH DIVISION TOTAL - PEAKING & STORA	Attachment NUI-CAK-2, LN 73
71		
72	Res Heat	LN 40 Col D * LN 70
73	Res General	LN 41 Col D * LN 70
74	G50 Low Annual-Low Winter	LN 42 Col D * LN 70
75	G40 Low Annual-High Winter	LN 43 Col D * LN 70
76	G51 Med Annual-Low Winter	LN 44 Col D * LN 70
77	G41 Med Annual-High Winter	LN 45 Col D * LN 70
78	G52 High Annual-Low Winter	LN 46 Col D * LN 70
79	G42 High Annual-High Winter	LN 47 Col D * LN 70
80	TOTAL	Sum LN 72 : LN 79
81		
82	Residential	LN 72 + LN 73
83	SALES HLF CLASSES	LN 74 + LN 76 + LN 78
84	SALES LLF CLASSES	LN 75 + LN 77 + LN 79
85		
86	**Off-SYSTEM PEAKING DEMAND & OUTA(**	
87		
88	NH DIVISION - OFF-SYSTEM PEAKING	Attachment NUI-CAK-2, LN 74
89		
90	Res Heat	LN 40 Col D * LN 88
91	Res General	LN 41 Col D * LN 88
92	G50 Low Annual-Low Winter	LN 42 Col D * LN 88
93	G40 Low Annual-High Winter	LN 43 Col D * LN 88
94	G51 Med Annual-Low Winter	LN 44 Col D * LN 88
95	G41 Med Annual-High Winter	LN 45 Col D * LN 88
96	G52 High Annual-Low Winter	LN 46 Col D * LN 88
97	G42 High Annual-High Winter	LN 47 Col D * LN 88
98	TOTAL	Sum LN 90 : LN 97
99		
100	Residential	LN 90 + LN 91
101	SALES HLF CLASSES	LN 92 + LN 94 + LN 96
102	SALES LLF CLASSES	LN 93 + LN 95 + LN 97
103		
104		

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-CAK-4
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105 **CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
106		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
107	NH DIVISION - MONTHLY CAP. RELEASE	$ (391,517)	$ (733,509)	$ (1,381,430)	$ (781,155)	$ (548,364)	$ (240,795)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,076,771)	$ (4,076,771)	$ -
108																
109	Res Heat	$ (191,060)	$ (357,951)	$ (674,135)	$ (381,202)	$ (267,601)	$ (117,507)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,989,455)	$ (1,989,455)	$ -
110	Res General	$ (1,597)	$ (2,991)	$ (5,634)	$ (3,186)	$ (2,236)	$ (982)	$ -	$ -	$ -	$ -	$ -	$ -	$ (16,626)	$ (16,626)	$ -
111	G50 Low Annual-Low Winter	$ (5,376)	$ (10,073)	$ (18,970)	$ (10,727)	$ (7,530)	$ (3,307)	$ -	$ -	$ -	$ -	$ -	$ -	$ (55,983)	$ (55,983)	$ -
112	G40 Low Annual-High Winter	$ (95,175)	$ (178,312)	$ (335,817)	$ (189,894)	$ (133,304)	$ (58,536)	$ -	$ -	$ -	$ -	$ -	$ -	$ (991,037)	$ (991,037)	$ -
113	G51 Med Annual-Low Winter	$ (8,750)	$ (16,393)	$ (30,873)	$ (17,458)	$ (12,255)	$ (5,381)	$ -	$ -	$ -	$ -	$ -	$ -	$ (91,109)	$ (91,109)	$ -
114	G41 Med Annual-High Winter	$ (72,917)	$ (136,610)	$ (257,280)	$ (145,484)	$ (102,128)	$ (44,846)	$ -	$ -	$ -	$ -	$ -	$ -	$ (759,266)	$ (759,266)	$ -
115	G52 High Annual-Low Winter	$ (1,719)	$ (3,221)	$ (6,067)	$ (3,430)	$ (2,408)	$ (1,057)	$ -	$ -	$ -	$ -	$ -	$ -	$ (17,903)	$ (17,903)	$ -
116	G42 High Annual-High Winter	$ (14,923)	$ (27,959)	$ (52,655)	$ (29,775)	$ (20,902)	$ (9,178)	$ -	$ -	$ -	$ -	$ -	$ -	$ (155,391)	$ (155,391)	$ -
117	TOTAL	$ (391,517)	$ (733,509)	$ (1,381,430)	$ (781,155)	$ (548,364)	$ (240,795)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,076,771)	$ (4,076,771)	$ -
118																
119	Residential	$ (192,656)	$ (360,942)	$ (679,769)	$ (384,388)	$ (269,837)	$ (118,489)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,006,081)	$ (2,006,081)	$ -
120	SALES HLF CLASSES	$ (15,846)	$ (29,687)	$ (55,909)	$ (31,615)	$ (22,193)	$ (9,745)	$ -	$ -	$ -	$ -	$ -	$ -	$ (164,995)	$ (164,995)	$ -
121	SALES LLF CLASSES	$ (183,015)	$ (342,880)	$ (645,752)	$ (365,152)	$ (256,334)	$ (112,560)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,905,694)	$ (1,905,694)	$ -

122

123 **MISCELLANEOUS CREDITS BY CLASS (Includes Re-entry Rate & Conversion Rate Revenues)**

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
124		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
125	NH DIVISION - MISCELLANEOUS CREDIT	$ (480)	$ (900)	$ (1,694)	$ (958)	$ (673)	$ (295)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,000)	$ (5,000)	$ -
126																
127	Res Heat	$ (234)	$ (439)	$ (827)	$ (468)	$ (328)	$ (144)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,440)	$ (2,440)	$ -
128	Res General	$ (2)	$ (4)	$ (7)	$ (4)	$ (3)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ (20)	$ (20)	$ -
129	G50 Low Annual-Low Winter	$ (7)	$ (12)	$ (23)	$ (13)	$ (9)	$ (4)	$ -	$ -	$ -	$ -	$ -	$ -	$ (69)	$ (69)	$ -
130	G40 Low Annual-High Winter	$ (117)	$ (219)	$ (412)	$ (233)	$ (163)	$ (72)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,215)	$ (1,215)	$ -
131	G51 Med Annual-Low Winter	$ (11)	$ (20)	$ (38)	$ (21)	$ (15)	$ (7)	$ -	$ -	$ -	$ -	$ -	$ -	$ (112)	$ (112)	$ -
132	G41 Med Annual-High Winter	$ (89)	$ (168)	$ (316)	$ (178)	$ (125)	$ (55)	$ -	$ -	$ -	$ -	$ -	$ -	$ (931)	$ (931)	$ -
133	G52 High Annual-Low Winter	$ (2)	$ (4)	$ (7)	$ (4)	$ (3)	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ (22)	$ (22)	$ -
134	G42 High Annual-High Winter	$ (18)	$ (34)	$ (65)	$ (37)	$ (26)	$ (11)	$ -	$ -	$ -	$ -	$ -	$ -	$ (191)	$ (191)	$ -
135	TOTAL	$ (480)	$ (900)	$ (1,694)	$ (958)	$ (673)	$ (295)	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,000)	$ (5,000)	$ -
136																
137	Residential	$ (236)	$ (443)	$ (834)	$ (471)	$ (331)	$ (145)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,460)	$ (2,460)	$ -
138	SALES HLF CLASSES	$ (21)	$ (40)	$ (75)	$ (43)	$ (30)	$ (13)	$ -	$ -	$ -	$ -	$ -	$ -	$ (223)	$ (223)	$ -
139	SALES LLF CLASSES	$ (459)	$ (860)	$ (1,619)	$ (915)	$ (643)	$ (282)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,777)	$ (4,777)	$ -

140

141 **TOTAL NON-BASE CAPACITY COSTS**

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
142		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
143	Res Heat	$ 537,682	$ 1,052,265	$ 2,049,258	$ 1,126,348	$ 784,247	$ 314,135	$ 91,221	$ 20,066	$ -	$ 684	$ 14,836	$ 152,403	$ 6,143,145	$ 5,863,935	$ 279,210
144	Res General	$ 4,493	$ 8,794	$ 17,126	$ 9,413	$ 6,554	$ 2,625	$ 762	$ 168	$ -	$ 6	$ 124	$ 1,274	$ 51,339	$ 49,006	$ 2,333
145	G50 Low Annual-Low Winter	$ 15,130	$ 29,611	$ 57,666	$ 31,695	$ 22,069	$ 8,840	$ 2,567	$ 565	$ -	$ 19	$ 417	$ 4,289	$ 172,867	$ 165,010	$ 7,857
146	G40 Low Annual-High Winter	$ 267,844	$ 524,181	$ 1,020,828	$ 561,085	$ 390,669	$ 156,485	$ 45,441	$ 9,996	$ -	$ 341	$ 7,391	$ 75,919	$ 3,060,177	$ 2,921,090	$ 139,087
147	G51 Med Annual-Low Winter	$ 24,624	$ 48,190	$ 93,848	$ 51,582	$ 35,915	$ 14,386	$ 4,178	$ 919	$ -	$ 31	$ 679	$ 6,979	$ 281,332	$ 268,545	$ 12,787
148	G41 Med Annual-High Winter	$ 205,204	$ 401,592	$ 782,089	$ 429,865	$ 299,304	$ 119,888	$ 34,814	$ 7,658	$ -	$ 261	$ 5,662	$ 58,164	$ 2,344,501	$ 2,237,942	$ 106,559
149	G52 High Annual-Low Winter	$ 4,839	$ 9,469	$ 18,441	$ 10,136	$ 7,057	$ 2,827	$ 821	$ 181	$ -	$ 6	$ 134	$ 1,371	$ 55,283	$ 52,770	$ 2,513
150	G42 High Annual-High Winter	$ 41,997	$ 82,190	$ 160,062	$ 87,976	$ 61,255	$ 24,536	$ 7,125	$ 1,567	$ -	$ 53	$ 1,159	$ 11,904	$ 479,824	$ 458,016	$ 21,808
151	TOTAL	$ 1,101,813	$ 2,156,291	$ 4,199,319	$ 2,308,101	$ 1,607,070	$ 643,721	$ 186,929	$ 41,119	$ -	$ 1,401	$ 30,402	$ 312,303	$ 12,588,468	$ 12,016,314	$ 572,154
152																
153	Residential	$ 542,176	$ 1,061,059	$ 2,066,384	$ 1,135,761	$ 790,801	$ 316,760	$ 91,983	$ 20,234	$ -	$ 690	$ 14,960	$ 153,677	$ 6,194,484	$ 5,912,941	$ 281,544
154	SALES HLF CLASSES	$ 44,593	$ 87,270	$ 169,955	$ 93,414	$ 65,041	$ 26,053	$ 7,565	$ 1,664	$ -	$ 57	$ 1,230	$ 12,640	$ 509,482	$ 486,325	$ 23,156
155	SALES LLF CLASSES	$ 515,045	$ 1,007,962	$ 1,962,979	$ 1,078,926	$ 751,228	$ 300,909	$ 87,380	$ 19,221	$ -	$ 655	$ 14,212	$ 145,987	$ 5,884,503	$ 5,617,048	$ 267,455

156

157 **TOTAL CAPACITY COSTS**

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
158		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	SUMMER
159	Res Heat	$ 589,504	$ 1,104,087	$ 2,101,080	$ 1,178,170	$ 836,068	$ 365,956	$ 143,043	$ 71,969	$ 51,846	$ 52,506	$ 66,658	$ 204,225	$ 6,765,112	$ 6,174,866	$ 590,246
160	Res General	$ 5,672	$ 9,973	$ 18,305	$ 10,592	$ 7,733	$ 3,804	$ 1,941	$ 1,348	$ 1,179	$ 1,184	$ 1,303	$ 2,452	$ 65,486	$ 56,078	$ 9,408
161	G50 Low Annual-Low Winter	$ 24,914	$ 39,395	$ 67,450	$ 41,479	$ 31,853	$ 18,624	$ 12,351	$ 10,364	$ 9,789	$ 9,803	$ 10,202	$ 14,073	$ 290,296	$ 223,715	$ 66,581
162	G40 Low Annual-High Winter	$ 287,478	$ 543,815	$ 1,040,462	$ 580,719	$ 410,303	$ 176,119	$ 65,075	$ 29,661	$ 19,643	$ 19,975	$ 27,025	$ 95,553	$ 3,295,828	$ 3,038,896	$ 256,932
163	G51 Med Annual-Low Winter	$ 39,348	$ 62,914	$ 108,573	$ 66,307	$ 50,640	$ 29,111	$ 18,902	$ 15,666	$ 14,731	$ 14,756	$ 15,404	$ 21,704	$ 458,057	$ 356,893	$ 101,164
164	G41 Med Annual-High Winter	$ 225,966	$ 422,354	$ 802,852	$ 450,628	$ 320,066	$ 140,650	$ 55,576	$ 28,453	$ 20,772	$ 21,023	$ 26,425	$ 78,926	$ 2,593,693	$ 2,362,517	$ 231,176
165	G52 High Annual-Low Winter	$ 10,750	$ 15,381	$ 24,353	$ 16,047	$ 12,969	$ 8,738	$ 6,732	$ 5,898	$ 5,847	$ 5,917	$ 6,045	$ 7,283	$ 125,961	$ 88,238	$ 37,723
166	G42 High Annual-High Winter	$ 48,508	$ 88,701	$ 166,573	$ 94,487	$ 67,766	$ 31,047	$ 13,636	$ 8,088	$ 6,520	$ 6,564	$ 7,670	$ 18,415	$ 557,975	$ 497,082	$ 60,893
167	TOTAL	$ 1,232,141	$ 2,286,619	$ 4,329,647	$ 2,438,429	$ 1,737,398	$ 774,050	$ 317,257	$ 171,448	$ 130,328	$ 131,730	$ 160,731	$ 442,631	$ 14,152,409	$ 12,798,284	$ 1,354,125
168																
169	Residential	$ 595,176	$ 1,114,060	$ 2,119,385	$ 1,188,762	$ 843,801	$ 369,760	$ 144,984	$ 73,317	$ 53,025	$ 53,690	$ 67,961	$ 206,677	$ 6,830,599	$ 6,230,944	$ 599,654
170	SALES HLF CLASSES	$ 75,013	$ 117,690	$ 200,375	$ 123,834	$ 95,461	$ 56,473	$ 37,985	$ 31,929	$ 30,367	$ 30,477	$ 31,650	$ 43,060	$ 874,314	$ 668,845	$ 205,468
171	SALES LLF CLASSES	$ 561,952	$ 1,054,870	$ 2,009,887	$ 1,125,834	$ 798,136	$ 347,816	$ 134,288	$ 66,202	$ 46,936	$ 47,563	$ 61,119	$ 192,894	$ 6,447,496	$ 5,898,495	$ 549,002
172																
173	% ALLOCATION BETWEEN SALES HLF AND LLF															
174	SALES HLF CLASSES														10.18%	27.23%
175	SALES LLF CLASSES														89.82%	72.77%

105	**CAPACITY RELEASE MARGINS & ASSET MANAGEMENT CREDIT BY CLASS**	
106		
107	NH DIVISION - MONTHLY CAP. RELEASE	Attachment NUI-CAK-2, LN 77
108		
109	Res Heat	LN 40 Col D * LN 107
110	Res General	LN 41 Col D * LN 107
111	G50 Low Annual-Low Winter	LN 42 Col D * LN 107
112	G40 Low Annual-High Winter	LN 43 Col D * LN 107
113	G51 Med Annual-Low Winter	LN 44 Col D * LN 107
114	G41 Med Annual-High Winter	LN 45 Col D * LN 107
115	G52 High Annual-Low Winter	LN 46 Col D * LN 107
116	G42 High Annual-High Winter	LN 47 Col D * LN 107
117	TOTAL	Sum LN 109 : LN 116
118		
119	Residential	LN 109 + LN 110
120	SALES HLF CLASSES	LN 111 + LN 113 + LN 115
121	SALES LLF CLASSES	LN 112 + LN 114 + LN 116
122		
123	**MISCELLANEOUS CREDITS BY CLASS (I**	**Includes Re-entry Rate & Conversion Ra**
124		
125	NH DIVISION - MISCELLANEOUS CREDIT	Attachment NUI-CAK-2, LN 78 + LN 79
126		
127	Res Heat	LN 40 Col D * LN 125
128	Res General	LN 41 Col D * LN 125
129	G50 Low Annual-Low Winter	LN 42 Col D * LN 125
130	G40 Low Annual-High Winter	LN 43 Col D * LN 125
131	G51 Med Annual-Low Winter	LN 44 Col D * LN 125
132	G41 Med Annual-High Winter	LN 45 Col D * LN 125
133	G52 High Annual-Low Winter	LN 46 Col D * LN 125
134	G42 High Annual-High Winter	LN 47 Col D * LN 125
135	TOTAL	Sum LN 127 : LN 134
136		
137	Residential	LN 127 + LN 128
138	SALES HLF CLASSES	LN 129 + LN 131 + LN 133
139	SALES LLF CLASSES	LN 130 + LN 132 + LN 134
140		
141	**TOTAL NON-BASE CAPACITY COSTS**	
142		
143	Res Heat	Sum of Ln 54, 72, 90, 109, 127
144	Res General	Sum of Ln 55, 73, 91, 110, 128
145	G50 Low Annual-Low Winter	Sum of Ln 56, 74, 92, 111, 129
146	G40 Low Annual-High Winter	Sum of Ln 57, 75, 93, 112, 130
147	G51 Med Annual-Low Winter	Sum of Ln 58, 76, 94, 113, 131
148	G41 Med Annual-High Winter	Sum of Ln 59, 77, 95, 114, 132
149	G52 High Annual-Low Winter	Sum of Ln 60, 78, 96, 115, 133
150	G42 High Annual-High Winter	Sum of Ln 61, 79, 97, 116, 134
151	TOTAL	Sum LN 143 : LN 150
152		
153	Residential	LN 143 + LN 144
154	SALES HLF CLASSES	LN 145 + LN 147 + LN 149
155	SALES LLF CLASSES	LN 146 + LN 148 + LN 150
156		
157	**TOTAL CAPACITY COSTS**	
158		
159	Res Heat	LN 143 + LN 26
160	Res General	LN 144 + LN 27
161	G50 Low Annual-Low Winter	LN 145 + LN 28
162	G40 Low Annual-High Winter	LN 146 + LN 29
163	G51 Med Annual-Low Winter	LN 147 + LN 30
164	G41 Med Annual-High Winter	LN 148 + LN 31
165	G52 High Annual-Low Winter	LN 149 + LN 32
166	G42 High Annual-High Winter	LN 150 + LN 33
167	TOTAL	Sum LN 159 : LN 166
168		
169	Residential	LN 159 + LN 160
170	SALES HLF CLASSES	LN 161 + LN 163 + LN 165
171	SALES LLF CLASSES	LN 162 + LN 164 + LN 166
172		
173	% ALLOCATION BETWEEN SALES HLF A	
174	SALES HLF CLASSES	LN 170 / (LN170 + LN 171)
175	SALES LLF CLASSES	LN 171 / (LN 170 + LN 171)

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
1	**Supply Volumes - MMBtu**															
2	Total Pipeline	982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	8,854,520	5,861,225	2,993,295
3	Total Storage	334,018	731,204	814,153	870,348	598,789	0	0	0	0	0	0	0	3,348,512	3,348,512	0
4	Total Peaking	1,794	132,447	416,567	168,774	66,406	1,794	1,860	1,800	1,860	1,860	1,800	1,860	798,822	787,782	11,040
5	Total Off-system Sales													0	0	
6	Subtotal	1,317,939	1,842,583	2,157,613	1,885,708	1,688,286	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854	9,997,519	3,004,335
7	Less Interruptible - Maine	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Less Interruptible - New Hampshire	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total Firm Supply	1,317,939	1,842,583	2,157,613	1,885,708	1,688,286	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854	9,997,519	3,004,335
10	Total Firm Pipeline Sendout	982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	8,854,520	5,861,225	2,993,295
11	**Variable Costs**															
12	Base Pipeline Costs Modeled in Sendout™	$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274	$ 42,511,526	$ 32,159,520	$ 10,352,007
13	NYMEX Price Used for Forecast	$5.305	$5.398	$5.465	$5.370	$5.013	$3.939	$3.810	$3.839	$3.871	$3.879	$3.863	$3.890			
14	NYMEX Price Used for Update	$5.305	$5.398	$5.465	$5.370	$5.013	$3.939	$3.810	$3.839	$3.871	$3.879	$3.863	$3.890			
15	Increase/(Decrease) NYMEX Price	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00			
16	Increase/(Decrease) in Pipeline Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
17	Total Updated Pipeline Costs	$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274	$ 42,511,526	$ 32,159,520	$ 10,352,007
18															$ -	
19	Total Pipeline	$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274	$ 42,511,526	$ 32,159,520	$ 10,352,007
20	Total Storage	$ 1,044,295	$ 2,265,206	$ 2,524,545	$ 2,702,360	$ 1,867,551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,403,958	$ 10,403,958	$ -
21	Total Peaking	$ 9,526	$ 2,091,388	$ 4,553,220	$ 2,865,280	$ 1,286,222	$ 10,221	$ 10,555	$ 11,094	$ 11,464	$ 11,464	$ 13,455	$ 14,402	$ 10,888,290	$ 10,815,857	$ 72,433
22	Total Off-sytem Sales	$ -				$ -								$ -	$ -	
23																
24	Subtotal	$ 6,302,351	$10,091,778	$ 13,140,440	$ 11,023,635	$ 8,590,113	$ 4,231,017	$ 2,207,586	$ 1,486,950	$ 1,384,547	$ 1,394,443	$ 1,424,238	$ 2,526,676	$ 63,803,774	$ 53,379,334	$ 10,424,440
25																
26	Interruptible Cost Estimate															
27	Variable Pipeline Costs	$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274	$ 42,511,526	$ 32,159,520	$ 10,352,007
28	Average Supply Cost ($/MMBtu)	$ 5.344	$ 5.859	$ 6.541	$ 6.445	$ 5.314	$ 3.825	$ 3.521	$ 3.452	$ 3.469	$ 3.448	$ 3.311	$ 3.495			
29	Interruptible Cost - Maine	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Interruptible Cost - New Hampshire	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31																
32	Total Pipeline	$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274	$ 42,511,526	$ 32,159,520	$ 10,352,007
33	Total Storage	$ 1,044,295	$ 2,265,206	$ 2,524,545	$ 2,702,360	$ 1,867,551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,403,958	$ 10,403,958	$ -
34	Total Peaking	$ 9,526	$ 2,091,388	$ 4,553,220	$ 2,865,280	$ 1,286,222	$ 10,221	$ 10,555	$ 11,094	$ 11,464	$ 11,464	$ 13,455	$ 14,402	$ 10,888,290	$ 10,815,857	$ 72,433
35	Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -							$ -	$ -	
36	Total Firm Sales Variable Costs	$ 6,302,351	$10,091,778	$ 13,140,440	$ 11,023,635	$ 8,590,113	$ 4,231,017	$ 2,207,586	$ 1,486,950	$ 1,384,547	$ 1,394,443	$ 1,424,238	$ 2,526,676	$ 63,803,774	$ 53,379,334	$ 10,424,440

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

1	**Supply Volumes - MMBtu**	
2	Total Pipeline	Attachment NUI-FXW-8, Page 2
3	Total Storage	Attachment NUI-FXW-8, Page 2
4	Total Peaking	Attachment NUI-FXW-8, Page 2
5	Total Off-system Sales	NA
6	Subtotal	SUM LN 2: LN 6
7	Less Interruptible - Maine	Company Analysis
8	Less Interruptible - New Hampshire	Company Analysis
9	Total Firm Supply	LN 7 - LN 8 - LN 9
10	Total Firm Pipeline Sendout	LN 2 + LN 3- LN 8 - LN 9
11	**Variable Costs**	
12	Pipeline Costs Modeled in Sendout™	Attachment NUI-FXW-8, Page 1
13	NYMEX Price Used for Forecast	Attachment NUI-FXW10, Page 1
14	NYMEX Price Used for Update	Attachment NUI-FXW10, Page 1
15	Increase/(Decrease) NYMEX Price	LN 13 - LN 14
16	Increase/(Decrease) in Pipeline Costs	LN 2 * LN 15
17	Total Updated Pipeline Costs	LN 12 + LN 16
18		
19	Total Pipeline Baseload	LN 17
20	Total Storage	Attachment NUI-FXW-8, Page 1
21	Total Peaking	Attachment NUI-FXW-8, Page 1
22	Total Off-sytem Sales	NA
23		
24	Subtotal	Sum LN 19 : LN 22
25		
26	Interruptible Cost Estimate	Company Analysis
27	Variable Pipeline Costs Excld Hedges	LN 17
28	Average Supply Cost ($/MMBtu)	LN 27 / LN 2
29	Interruptible Cost - Maine	LN 28 * LN 7
30	Interruptible Cost - New Hampshire	LN 28 * LN 8
31		
32	Firm Sales Pipeline Commodity	LN 19 - LN 29 - LN 30
33	Total Storage	LN 20
34	Total Peaking	LN 21
35	Off-system Sales	LN 22
36	Total Firm Sales Variable Costs	SUM LN 32 : LN 35

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

Commodity Allocation Factors

Firm Sales Sendout for Normal Winter, MMBtu

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
Maine	840,656	1,162,033	1,359,609	1,199,672	1,101,525	755,361	432,603	302,023	288,888	292,515	305,552	480,776	8,521,213	6,418,856	2,102,357
New Hampshire	477,284	680,551	798,004	686,035	586,760	350,029	193,176	127,316	108,780	110,422	122,341	239,943	4,480,641	3,578,664	901,977
Total	1,317,940	1,842,584	2,157,613	1,885,708	1,688,285	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	13,001,854	9,997,520	3,004,334
Percentage of Total															
Maine	63.79%	63.07%	63.01%	63.62%	65.25%	68.33%	69.13%	70.35%	72.65%	72.60%	71.41%	66.71%	65.54%	64.20%	69.98%
New Hampshire	36.21%	36.93%	36.99%	36.38%	34.75%	31.67%	30.87%	29.65%	27.35%	27.40%	28.59%	33.29%	34.46%	35.80%	30.02%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Commodity Allocation by Jurisdiction

	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
Maine															
Total Pipeline	$ 3,347,806	$ 3,616,916	$ 3,820,363	$ 3,471,061	$ 3,546,951	$ 2,884,253	$ 1,518,815	$ 1,038,207	$ 997,484	$ 1,003,983	$ 1,007,419	$ 1,675,884	$ 27,929,145	$ 20,687,352	$ 7,241,793
Storage	$ 666,110	$ 1,428,561	$ 1,590,829	$ 1,719,221	$ 1,218,487	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,623,208	$ 6,623,208	$ -
Peaking	$ 6,076	$ 1,318,942	$ 2,869,188	$ 1,822,868	$ 839,198	$ 6,984	$ 7,297	$ 7,804	$ 8,328	$ 8,322	$ 9,608	$ 9,607	$ 6,914,224	$ 6,863,258	$ 50,966
Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Maine Commodity Costs	$ 4,019,993	$ 6,364,420	$ 8,280,380	$ 7,013,150	$ 5,604,637	$ 2,891,238	$ 1,526,112	$ 1,046,011	$ 1,005,812	$ 1,012,305	$ 1,017,028	$ 1,685,492	$ 41,466,577	$ 34,173,818	$ 7,292,759
Maine Inventory Finance Costs	$ 335	$ 522	$ 640	$ 561	$ 485	$ 284	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,827	$ 2,827	$ -
Total Maine Variable Costs	$ 4,020,328	$ 6,364,941	$ 8,281,020	$ 7,013,711	$ 5,605,122	$ 2,891,522	$ 1,526,112	$ 1,046,011	$ 1,005,812	$ 1,012,305	$ 1,017,028	$ 1,685,492	$ 41,469,404	$ 34,176,644	$ 7,292,759
New Hampshire															
Total Pipeline	$ 1,900,723	$ 2,118,268	$ 2,242,311	$ 1,984,934	$ 1,889,389	$ 1,336,543	$ 678,216	$ 437,649	$ 375,599	$ 378,996	$ 403,363	$ 836,389	$ 14,582,381	$ 11,472,168	$ 3,110,213
Storage	$ 378,185	$ 836,645	$ 933,716	$ 983,140	$ 649,063	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,780,749	$ 3,780,749	$ -
Peaking	$ 3,450	$ 772,446	$ 1,684,032	$ 1,042,411	$ 447,024	$ 3,237	$ 3,258	$ 3,290	$ 3,136	$ 3,142	$ 3,847	$ 4,795	$ 3,974,066	$ 3,952,599	$ 21,467
Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total New Hampshire Commodity Costs	$ 2,282,359	$ 3,727,358	$ 4,860,059	$ 4,010,484	$ 2,985,476	$ 1,339,779	$ 681,474	$ 440,939	$ 378,735	$ 382,138	$ 407,210	$ 841,184	$ 22,337,197	$ 19,205,516	$ 3,131,680
New Hampshire Inventory Finance Costs	$ 174	$ 268	$ 323	$ 275	$ 224	$ 114	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,378	$ 1,378	$ -
Total New Hampshire Variable Costs	$ 2,282,533	$ 3,727,626	$ 4,860,382	$ 4,010,760	$ 2,985,700	$ 1,339,894	$ 681,474	$ 440,939	$ 378,735	$ 382,138	$ 407,210	$ 841,184	$ 22,338,575	$ 19,206,895	$ 3,131,680
Northern Utilities															
Total Pipeline	$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274	$ 42,511,526	$ 32,159,520	$ 10,352,007
Storage	$ 1,044,295	$ 2,265,206	$ 2,524,545	$ 2,702,360	$ 1,867,551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,403,958	$ 10,403,958	$ -
Peaking	$ 9,526	$ 2,091,388	$ 4,553,220	$ 2,865,280	$ 1,286,222	$ 10,221	$ 10,555	$ 11,094	$ 11,464	$ 11,464	$ 13,455	$ 14,402	$ 10,888,290	$ 10,815,857	$ 72,433
Off-system Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Northern Commodity Costs	$ 6,302,351	$10,091,778	$ 13,140,440	$ 11,023,635	$ 8,590,113	$ 4,231,017	$ 2,207,586	$ 1,486,950	$ 1,384,547	$ 1,394,443	$ 1,424,238	$ 2,526,676	$ 63,803,774	$ 53,379,334	$ 10,424,440
Northern Inventory Finance Costs	$ 509	$ 789	$ 963	$ 836	$ 709	$ 398	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,205	$ 4,205	$ -
Total Northern Variable Costs	$ 6,302,860	$10,092,567	$ 13,141,403	$ 11,024,471	$ 8,590,822	$ 4,231,415	$ 2,207,586	$ 1,486,950	$ 1,384,547	$ 1,394,443	$ 1,424,238	$ 2,526,676	$ 63,807,979	$ 53,383,539	$ 10,424,440

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

37	**Commodity Allocation Factors**	
38	Firm Sales Sendout for Normal Winter, MMBtu	
39		
40	Maine	Company Analysis
41	New Hampshire	NUI-CAK-3, LN 33/10
42	Total	LN 40 + LN 41
43		
44	**Percentage of Total**	
45	Maine	LN 40 / LN 42
46	New Hampshire	LN 41 / LN 42
47	Total	LN 45 + LN 46
48		
49	**Commodity Allocation by Jurisdiction**	
50	**Maine**	
51	Firm Sales Pipeline Commodity	LN 32 * LN 45
52	Storage	LN 33 * LN 45
53	Peaking	LN 34 * LN 45
54	Off-system Sales	LN 35 * LN 45
55	Total Maine Commodity Costs	SUM LN 51 : LN 54
56	Maine Inventory Finance Costs	LN 95
57	Total Maine Variable Costs	LN 55 + LN 56
58	**New Hampshire**	
59	Firm Sales Pipeline Commodity Excld Hedge	LN 32 * LN 46
60	Storage	LN 33 * LN 46
61	Peaking	LN 34 * LN 46
62	Off-system Sales	LN 35 * LN 46
63	Total New Hampshire Commodity Costs	SUM LN 59 : LN 62
64	New Hampshire Inventory Finance Costs	LN 100
65	Total New Hampshire Variable Costs	LN 63 + LN 64
66	**Northern Utilities**	
67	Firm Sales Pipeline Commodity Excld Hedge	LN 51 + LN 59
68	Storage	LN 52 + LN 60
69	Peaking	LN 53 + LN 61
70	Off-system Sales	LN 54 + LN 62
71	Total Northern Commodity Costs	LN 55 + LN 63
72	Northern Inventory Finance Costs	LN 56 + LN 64
73	Total Northern Variable Costs	LN 57 + LN 65
74		

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

75 **Northern Utilities**
76 **Simplified Market Based Allocator (MBA) Calculations**
77 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**

Line	Col A	Col B	Col C	Col D	Col E	Col F	Col G	Col H	Col I	Col J	Col K	Col L	Col M	Col N	Col O	Col P
78																
80																
81	**Inventory Finance Charge**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Annual**	**Winter**	**Summer**
82	Storage	$ 606	$ 509	$ 314	$ 130	$ 21	$ -	$ 72	$ 145	$ 214	$ 354	$ 489	$ 618	$ 3,470		$ 1,891
83	Peaking	$ 64	$ 53	$ 43	$ 33	$ 29	$ 52	$ 74	$ 77	$ 74	$ 61	$ 76	$ 99	$ 735		$ 461
84	Total	$ 670	$ 562	$ 357	$ 162	$ 50	$ 52	$ 146	$ 222	$ 288	$ 415	$ 565	$ 717	$ 4,205		$ 2,352
85																
86	**Inventory Finance Charge Allocation by Jurisdiction**															
87	Maine	$ 427	$ 354	$ 225	$ 103	$ 33	$ 35	$ 101	$ 156	$ 209	$ 302	$ 403	$ 478	$ 2,827		$ 1,649
88	New Hampshire	$ 243	$ 208	$ 132	$ 59	$ 17	$ 16	$ 45	$ 66	$ 79	$ 114	$ 161	$ 239	$ 1,378		$ 703
89	Total	$ 670	$ 562	$ 357	$ 162	$ 50	$ 52	$ 146	$ 222	$ 288	$ 415	$ 565	$ 717	$ 4,205		$ 2,352
90																
91	**Inventory Finance Charge Allocation by Month**															
92	**Maine**															
93	Firm Sales Normal Remaining Sendout	559,332	871,331	1,068,907	937,104	810,824	474,037	0	0	0	0	0	0	0	4,721,535	0
94	Monthly % Sendout of Total Winter	11.85%	18.45%	22.64%	19.85%	17.17%	10.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
95	ME Allocated Inventory Finance Charge	$ 335	$ 522	$ 640	$ 561	$ 485	$ 284	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,827	$ -
96																
97	**New Hampshire**															
98	Firm Sales Normal Remaining Sendout	371,219	570,950	688,403	587,041	477,159	243,964	0	0	0	0	0	0	0	2,938,735	0
99	Monthly % Sendout of Total Winter	12.63%	19.43%	23.43%	19.98%	16.24%	8.30%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
100	NH Allocated Inventory Finance Charge	$ 174	$ 268	$ 323	$ 275	$ 224	$ 114	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,378	$ -

Northern Utilities
ALLOCATION OF COMMODITY COSTS BETWEEN ME & NH DIVISIONS

75 **Northern Utilities**
76 **Simplified Market Based Allocator (MBA) Calculations**
77 **ALLOCATION OF NORTHERN INVENTORY FINANCE CHARGE**
78
79
80

81	**Inventory Finance Charge**	
82	Storage	Attachment NUI-CAK-7 - 'Carrying Costs'
83	Peaking	Attachment NUI-CAK-7 - 'Carrying Costs'
84	Total	SUM LN 82 : LN 83
85		
86	**Inventory Finance Charge Allocation by Jurisdiction**	
87	Maine	LN 45 * LN 84
88	New Hampshire	LN 46 * LN 84
89	Total	SUM LN 87 : LN 88
90		
91	**Inventory Finance Charge Allocation by Month**	
92	**Maine**	
93	Firm Sales Remaining Sendout	Attachment NUI-CAK-3, LN 80/10
94	Monthly % Sendout of Total Winter	LN 93 / LN 93 COL O
95	ME Allocated Inventory Finance Charge	LN 94 * LN 87 COL N
96		
97	**New Hampshire**	
98	Firm Sales Remaining Sendout	Attachment NUI-CAK-3, LN 80/10
99	Monthly % Sendout of Total Winter	LN 98 / LN 98 COL O
100	NH Allocated Inventory Finance Charge	LN 99 * LN 88 COL N

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
	Supply Volumes - Therms															
1	New Hampshire Sales Pipeline	3,556,713	3,615,649	3,428,159	3,079,946	3,555,734	3,494,609	1,926,016	1,267,821	1,082,707	1,099,128	1,218,262	2,393,235	29,717,980	20,730,811	8,987,169
2	New Hampshire Sales Storage	1,209,626	2,700,672	3,011,188	3,166,394	2,081,078	0	0	0	0	0	0	0	12,168,959	12,168,959	0
3	New Hampshire Sales Peaking	6,497	489,187	1,540,696	614,012	230,792	5,681	5,742	5,338	5,088	5,097	5,146	6,192	2,919,468	2,886,865	32,603
4	Total New Hampshire Firm Sales Sendout	4,772,837	6,805,508	7,980,043	6,860,353	5,867,604	3,500,290	1,931,758	1,273,159	1,087,795	1,104,225	1,223,408	2,399,427	44,806,406	35,786,634	9,019,772
5																
6	New Hampshire Interruptible Sendout (Pipeline)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7																
8	Total Firm Sendout	4,772,837	6,805,508	7,980,043	6,860,353	5,867,604	3,500,290	1,931,758	1,273,159	1,087,795	1,104,225	1,223,408	2,399,427	44,806,406	35,786,634	9,019,772
9	Total Firm Sales	4,713,183	6,720,446	7,880,297	6,774,602	5,794,261	3,456,540	1,907,611	1,257,246	1,074,199	1,090,422	1,208,118	2,369,434	44,246,359	35,339,329	8,907,030
10	Difference (LAUF & Company Use)	59,654	85,062	99,746	85,751	73,343	43,750	24,147	15,913	13,597	13,803	15,291	29,993	560,047	447,305	112,742
11	Percent Difference	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
12																
13	**Variable Costs**															
14	New Hampshire Sales Pipeline	$ 1,900,723	$ 2,118,268	$ 2,242,311	$ 1,984,934	$ 1,889,389	$ 1,336,543	$ 678,216	$ 437,649	$ 375,599	$ 378,996	$ 403,363	$ 836,389	$ 14,582,381	$ 11,472,168	$ 3,110,213
15	New Hampshire Total Storage	$ 378,185	$ 836,645	$ 933,716	$ 983,140	$ 649,063	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,780,749	$ 3,780,749	$ -
16	New Hampshire Total Peaking	$ 3,450	$ 772,446	$ 1,684,032	$ 1,042,411	$ 447,024	$ 3,237	$ 3,258	$ 3,290	$ 3,136	$ 3,142	$ 3,847	$ 4,795	$ 3,974,066	$ 3,952,599	$ 21,467
17	New Hampshire Inventory Finance Charge	$ 174	$ 268	$ 323	$ 275	$ 224	$ 114	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,378	$ 1,378	$ -
18	Total New Hampshire Sales Variable Costs	$ 2,282,533	$ 3,727,626	$ 4,860,382	$ 4,010,760	$ 2,985,700	$ 1,339,894	$ 681,474	$ 440,939	$ 378,735	$ 382,138	$ 407,210	$ 841,184	$ 22,338,575	$ 19,206,895	$ 3,131,680
19														$ -	$ -	$ -
20	New Hampshire Interruptible Commodity Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Total New Hampshire Commodity Costs	$ 2,282,533	$ 3,727,626	$ 4,860,382	$ 4,010,760	$ 2,985,700	$ 1,339,894	$ 681,474	$ 440,939	$ 378,735	$ 382,138	$ 407,210	$ 841,184	$ 22,338,575	$ 19,206,895	$ 3,131,680
22																
23	**Supply Cost/Therm**															
24	New Hampshire Sales Pipeline	$ 0.534	$ 0.586	$ 0.654	$ 0.644	$ 0.531	$ 0.382	$ 0.352	$ 0.345	$ 0.347	$ 0.345	$ 0.331	$ 0.349	$ 0.491	$ 0.553	$ 0.346
25	New Hampshire Storage Excld Inventory Finance Costs	$ 0.313	$ 0.310	$ 0.310	$ 0.310	$ 0.312	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.311	$ 0.311	$ -
26	New Hampshire Peaking Excld Inventory Finance Costs	$ 0.531	$ 1.579	$ 1.093	$ 1.698	$ 1.937	$ 0.570	$ 0.567	$ 0.616	$ 0.616	$ 0.616	$ 0.748	$ 0.774	$ 1.361	$ 1.369	$ 0.658
27	New Hampshire Inventory Finance Costs per Dth Stor and Peak	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.020	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.000	$ 0.000	$ -
28	Weighted Average Cost per Dth Sendout	$ 0.478	$ 0.548	$ 0.609	$ 0.585	$ 0.509	$ 0.383	$ 0.353	$ 0.346	$ 0.348	$ 0.346	$ 0.333	$ 0.351	$ 0.499	$ 0.537	$ 0.347
29																
30	New Hampshire Interruptible Cost / Therm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31																
32	**Commodity Costs**															
33	Base Commodity, therms	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486
34	Base Commodity Cost	$ 566,819	$ 642,109	$ 716,885	$ 637,990	$ 582,380	$ 405,656	$ 385,942	$ 365,567	$ 377,364	$ 377,921	$ 351,180	$ 383,034	$ 5,792,848	$ 3,551,839	$ 2,241,009
35	Remaining Commodity	$ 1,715,714	$ 3,085,517	$ 4,143,497	$ 3,372,770	$ 2,403,320	$ 934,237	$ 295,532	$ 75,372	$ 1,371	$ 4,217	$ 56,030	$ 458,150	$ 16,545,727	$ 15,655,056	$ 890,671
36	Total Commodity	$ 2,282,533	$ 3,727,626	$ 4,860,382	$ 4,010,760	$ 2,985,700	$ 1,339,894	$ 681,474	$ 440,939	$ 378,735	$ 382,138	$ 407,210	$ 841,184	$ 22,338,575	$ 19,206,895	$ 3,131,680

Northern Utilities - NEW HAMPSHIRE DIVISION
COMMODITY COSTS

	Supply Volumes - Therms	
1	New Hampshire Sales Pipeline	Attachment NUI-CAK-5, LN 2 * LN 46 * 10
2	New Hampshire Sales Storage	Attachment NUI-CAK-5, LN 3 * LN 46 * 10
3	New Hampshire Sales Peaking	Attachment NUI-CAK-5, LN 4 * LN 46 * 10
4	Total New Hampshire Firm Sales Sendout	Sum LN 1 : LN 3
5		
6	New Hampshire Interruptible Sendout (Pipeline)	Attachment NUI-CAK-5, LN 8 * 10
7		
8	Total Firm Sendout	LN 4
9	Total Firm Sales	Attachment NUI-CAK-3, LN 11
10	Difference (LAUF & Company Use)	LN 8 - LN 9
11	Percent Difference	LN 10 / LN 8
12		
13	**Variable Costs**	
14	New Hampshire Sales Pipeline Commodity	Attachment NUI-CAK-5, LN 59
15	New Hampshire Total Storage	Attachment NUI-CAK-5, LN 60
16	New Hampshire Total Peaking	Attachment NUI-CAK-5, LN 61
17	New Hampshire Inventory Finance Charge	Attachment NUI-CAK-5, LN 64
18	Total New Hampshire Sales Variable Costs	Sum LN 14 : LN 17
19		
20	New Hampshire Interruptible Commodity Costs	Attachment NUI-CAK-5, LN 30
21	Total New Hampshire Commodity Costs	LN 18 + LN 20
22		
23	**Supply Cost/Therm**	
24	New Hampshire Sales Pipeline Commodity	LN 14 / LN 1
25	New Hampshire Storage Excld Inventory Finance Costs	LN 15 / LN 2
26	New Hampshire Peaking Excld Inventory Finance Costs	LN 16 / LN 3
27	New Hampshire Inventory Finance Costs per Dth Stor and Peak	LN 17 / Sum (LN 2 : LN 3)
28	Weighted Average Cost per Dth Sendout	LN 18 / LN 8
29		
30	New Hampshire Interruptible Cost / Therm	LN 20 / LN 6
31		
32	**Commodity Costs**	
33	Base Commodity, therms	Attachment NUI-CAK-3, LN 64
34	Base Commodity Cost	Min (LN 24 * LN 33), LN 18
35	Remaining Commodity	LN 21 - LN 34
36	Total Commodity	LN 34 + LN 35

REDACTED

Northern Utilities, Inc.
Storage Inventory and Activity Costs

Denotes Confidential Information

Tennessee Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding	Withdrawn Value plus Charges
Nov-21	210,132	-	-	210,132	559,161	$ 2.66	NA	$ -	$ 2.66	$ -	$ 559,161	1.30%	$ 606	$ 559,161	$ -
Dec-21	210,132	-	67,442	142,690	$ 559,161	$ 2.66	NA	$ -	$ 2.66	$ 179,463	$ 379,699	1.30%	$ 509	$ 379,699	$ 179,463
Jan-22	142,690	-	67,442	75,248	$ 379,699	$ 2.66	NA	$ -	$ 2.66	$ 179,463	$ 200,236	1.30%	$ 314	$ 200,236	$ 179,463
Feb-22	75,248	-	60,580	14,668	$ 200,236	$ 2.66	NA	$ -	$ 2.66	$ 161,204	$ 39,032	1.30%	$ 130	$ 39,032	$ 161,204
Mar-22	14,668	-	14,668	-	$ 39,032	$ 2.66	NA	$ -	$ 2.66	$ 39,032	$ -	1.30%	$ 21	$ -	$ 39,032
Apr-22	-	-	-	-	$ -	NA	NA	$ -	$ -	$ -	$ -	1.30%	$ -	$ -	$ -
May-22	-	42,727	-	42,727	$ -	NA	$ 3.13	$ 133,552	$ -	$ -	$ 133,552	1.30%	$ 72	$ 133,552	$ -
Jun-22	42,727	-	-	42,727	$ 133,552	$ 3.13	NA	$ -	$ 3.13	$ -	$ 133,552	1.30%	$ 145	$ 133,552	$ -
Jul-22	42,727	40,601	-	83,328	$ 133,552	$ 3.13	$ 3.14	$ 127,441	$ 3.13	$ -	$ 260,992	1.30%	$ 214	$ 260,992	$ -
Aug-22	83,328	42,727	-	126,055	$ 260,992	$ 3.13	$ 3.08	$ 131,423	$ 3.11	$ -	$ 392,415	1.30%	$ 354	$ 392,414	$ -
Sep-22	126,055	41,349	-	167,405	$ 392,415	$ 3.11	$ 2.83	$ 117,181	$ 3.04	$ -	$ 509,596	1.30%	$ 489	$ 509,595	$ -
Oct-22	167,405	42,727	-	210,132	$ 509,596	$ 3.04	$ 2.84	$ 121,256	$ 3.00	$ -	$ 630,852	1.30%	$ 618	$ 630,851	$ -

Union Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding	Withdrawn Value plus Charges
Nov-21	3,241,066	-	344,586	2,896,480	$ 9,716,716	$ 3.00	NA	$ -	$ 3.00	$ 1,033,068	$ 8,683,648			$ 8,683,648	$ 1,033,068
Dec-21	2,896,480	-	685,851	2,210,629	$ 8,683,648	$ 3.00	NA	$ -	$ 3.00	$ 2,056,182	$ 6,627,466			$ 6,627,466	$ 2,056,182
Jan-22	2,210,629	-	771,425	1,439,204	$ 6,627,466	$ 3.00	NA	$ -	$ 3.00	$ 2,312,733	$ 4,314,733			$ 4,314,733	$ 2,312,733
Feb-22	1,439,204	-	836,366	602,838	$ 4,314,733	$ 3.00	NA	$ -	$ 3.00	$ 2,507,425	$ 1,807,308			$ 1,807,308	$ 2,507,425
Mar-22	602,838	-	602,838	-	$ 1,807,308	$ 3.00	NA	$ -	$ 3.00	$ 1,807,308	$ -			$ -	$ 1,807,308
Apr-22	-	-	-	-	$ -	#DIV/0!	NA	$ -	#DIV/0!		$ -			$ -	$ -
May-22	-	749,027	-	749,027	$ -	#DIV/0!	$ 3.66	$2,741,099	$ 3.66		$ 2,741,099			$ 2,741,099	$ -
Jun-22	749,027	724,865	-	1,473,891	$ 2,741,099	$ 3.66	$ 3.67	$2,662,881	$ 3.67		$ 5,403,980			$ 5,403,980	$ -
Jul-22	1,473,891	-	-	1,473,891	$ 5,403,980	$ 3.67	NA	$ -	$ 3.67		$ 5,403,980			$ 5,403,980	$ -
Aug-22	1,473,891	293,283	-	1,767,175	$ 5,403,980	$ 3.67	$ 3.68	$1,078,004	$ 3.67		$ 6,481,984			$ 6,481,984	$ -
Sep-22	1,767,175	724,865	-	2,492,039	$ 6,481,984	$ 3.67	$ 3.66	$2,656,322	$ 3.67		$ 9,138,306			$ 9,138,306	$ -
Oct-22	2,492,039	749,027	-	3,241,066	$ 9,138,306	$ 3.67	$ -	$2,752,370	$ 3.67		$ 11,890,676			$ 11,890,676	$ -

LNG Storage

Month	Beginning Inventory Volume	Injections	Withdrawals	Ending Inventory Volume	Beginning Inventory Cost	Beginning Inventory Rate	Injection Rate	Injected Value	Withdrawal Rate	Withdrawn Value	Ending Inventory Value	Interest Rate	Carrying Costs	Ending Inventory Value Excluding	Withdrawn Value plus Charges
Nov-21	12,000	-	1,794	10,206	[redacted]										
Dec-21	10,206	-	1,854	8,352											
Jan-22	8,352	-	1,854	6,498											
Feb-22	6,498	-	1,674	4,824											
Mar-22	4,824	1,830	1,854	4,800											
Apr-22	4,800	8,994	1,794	12,000											
May-22	12,000	1,860	1,860	12,000											
Jun-22	12,000	1,800	1,800	12,000											
Jul-22	12,000	-	1,860	10,140											
Aug-22	10,140	-	1,860	8,280											
Sep-22	8,280	5,520	1,800	12,000											
Oct-22	12,000	1,860	1,860	12,000											

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-CAK-8
Page 1 of 4

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
1	**BASE SENDOUT BY CLASS**															
2	**Total Therms**															
3	Res Heat	421,743	435,801	435,801	393,627	435,801	421,743	435,801	421,743	432,738	435,801	421,743	435,801	5,128,145	2,544,517	2,583,628
4	Res General	9,593	9,913	9,913	8,953	9,913	9,593	9,913	9,593	9,843	9,913	9,593	9,913	116,644	57,877	58,767
5	G50 Low Annual-Low Winter	79,626	82,281	82,281	74,318	82,281	79,626	82,281	79,626	81,702	82,281	79,626	82,281	968,209	480,412	487,797
6	G40 Low Annual-High Winter	159,790	165,116	165,116	149,137	165,116	159,790	165,116	159,790	163,956	165,116	159,790	165,116	1,942,950	964,066	978,884
7	G51 Med Annual-Low Winter	119,834	123,828	123,828	111,845	123,828	119,834	123,828	119,834	122,958	123,828	119,834	123,828	1,457,105	722,996	734,109
8	G41 Med Annual-High Winter	168,972	174,604	174,604	157,707	174,604	168,972	174,604	168,972	173,377	174,604	168,972	174,604	2,054,595	1,019,463	1,035,133
9	G52 High Annual-Low Winter	48,108	49,712	49,712	44,901	49,712	48,108	49,712	46,460	48,804	49,712	48,108	49,712	582,759	290,252	292,507
10	G42 High Annual-High Winter	52,989	54,755	54,755	49,456	54,755	52,989	54,755	52,989	54,419	54,755	52,989	54,755	644,362	319,700	324,662
11	Total Firm Sales	1,060,655	1,096,010	1,096,010	989,944	1,096,010	1,060,655	1,096,010	1,059,006	1,087,795	1,096,010	1,060,655	1,096,010	12,894,769	6,399,283	6,495,486
12	**% of Total**															
13	Res Heat	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.76%	39.82%	39.78%	39.76%	39.76%	39.76%			
14	Res General	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.91%	0.90%	0.90%	0.90%	0.90%			
15	G50 Low Annual-Low Winter	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.51%	7.52%	7.51%	7.51%	7.51%	7.51%			
16	G40 Low Annual-High Winter	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.07%	15.09%	15.07%	15.07%	15.07%	15.07%			
17	G51 Med Annual-Low Winter	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.30%	11.32%	11.30%	11.30%	11.30%	11.30%			
18	G41 Med Annual-High Winter	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.93%	15.96%	15.94%	15.93%	15.93%	15.93%			
19	G52 High Annual-Low Winter	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.54%	4.39%	4.49%	4.54%	4.54%	4.54%			
20	G42 High Annual-High Winter	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%			
21	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			

22	**BASE COMMODITY COSTS**	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
23	TOTAL BASE COMMODITY	$ 566,819	$ 642,109	$ 716,885	$ 637,990	$ 582,380	$ 405,656	$ 385,942	$ 365,567	$ 377,364	$ 377,921	$ 351,180	$ 383,034	$ 5,792,848	$ 3,551,839	$ 2,241,009
24	Res Heat	$ 225,381	$ 255,319	$ 285,052	$ 253,681	$ 231,569	$ 161,299	$ 153,460	$ 145,585	$ 150,120	$ 150,271	$ 139,638	$ 152,304	$ 2,303,679	$ 1,412,301	$ 891,378
25	Res General	$ 5,127	$ 5,807	$ 6,484	$ 5,770	$ 5,267	$ 3,669	$ 3,491	$ 3,311	$ 3,415	$ 3,418	$ 3,176	$ 3,464	$ 52,399	$ 32,124	$ 20,275
26	G50 Low Annual-Low Winter	$ 42,553	$ 48,205	$ 53,819	$ 47,896	$ 43,721	$ 30,454	$ 28,974	$ 27,487	$ 28,343	$ 28,372	$ 26,364	$ 28,755	$ 434,942	$ 266,647	$ 168,295
27	G40 Low Annual-High Winter	$ 85,392	$ 96,735	$ 108,000	$ 96,115	$ 87,737	$ 61,113	$ 58,143	$ 55,159	$ 56,877	$ 56,935	$ 52,906	$ 57,705	$ 872,817	$ 535,092	$ 337,725
28	G51 Med Annual-Low Winter	$ 64,040	$ 72,546	$ 80,994	$ 72,081	$ 65,798	$ 45,831	$ 43,604	$ 41,366	$ 42,655	$ 42,698	$ 39,677	$ 43,276	$ 654,565	$ 401,289	$ 253,275
29	G41 Med Annual-High Winter	$ 90,299	$ 102,294	$ 114,206	$ 101,637	$ 92,778	$ 64,625	$ 61,484	$ 58,329	$ 60,146	$ 60,206	$ 55,946	$ 61,021	$ 922,971	$ 565,840	$ 357,132
30	G52 High Annual-Low Winter	$ 25,709	$ 29,124	$ 32,516	$ 28,937	$ 26,415	$ 18,399	$ 17,505	$ 16,038	$ 16,931	$ 17,141	$ 15,928	$ 17,373	$ 262,017	$ 161,101	$ 100,917
31	G42 High Annual-High Winter	$ 28,317	$ 32,079	$ 35,815	$ 31,873	$ 29,095	$ 20,266	$ 19,281	$ 18,292	$ 18,878	$ 18,880	$ 17,544	$ 19,136	$ 289,457	$ 177,445	$ 112,012
32																
33	Residential	$ 230,508	$ 261,126	$ 291,535	$ 259,451	$ 236,836	$ 164,968	$ 156,951	$ 148,896	$ 153,534	$ 153,689	$ 142,814	$ 155,768	$ 2,356,079	$ 1,444,425	$ 911,654
34	SALES HLF CLASSES	$ 132,301	$ 149,875	$ 167,329	$ 148,914	$ 135,934	$ 94,684	$ 90,083	$ 84,891	$ 87,928	$ 88,211	$ 81,969	$ 89,404	$ 1,351,524	$ 829,037	$ 522,487
35	SALES LLF CLASSES	$ 204,009	$ 231,108	$ 258,021	$ 229,625	$ 209,610	$ 146,004	$ 138,908	$ 131,780	$ 135,901	$ 136,021	$ 126,397	$ 137,862	$ 2,085,246	$ 1,278,377	$ 806,869

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Base Commodity Costs

1	**BASE SENDOUT BY CLASS**	
2	**Total Therms**	
3	Res Heat	Attachment NUI-CAK-3, LN 52
4	Res General	Attachment NUI-CAK-3, LN 53
5	G50 Low Annual-Low Winter	Attachment NUI-CAK-3, LN 54
6	G40 Low Annual-High Winter	Attachment NUI-CAK-3, LN 55
7	G51 Med Annual-Low Winter	Attachment NUI-CAK-3, LN 56
8	G41 Med Annual-High Winter	Attachment NUI-CAK-3, LN 57
9	G52 High Annual-Low Winter	Attachment NUI-CAK-3, LN 58
10	G42 High Annual-High Winter	Attachment NUI-CAK-3, LN 59
11	Total Firm Sales	Sum LN 3 : LN 10
12	**% of Total**	
13	Res Heat	LN 3 / LN 11
14	Res General	LN 4 / LN 11
15	G50 Low Annual-Low Winter	LN 5 / LN 11
16	G40 Low Annual-High Winter	LN 6 / LN 11
17	G51 Med Annual-Low Winter	LN 7 / LN 11
18	G41 Med Annual-High Winter	LN 8 / LN 11
19	G52 High Annual-Low Winter	LN 9 / LN 11
20	G42 High Annual-High Winter	LN 10 / LN 11
21	Total Firm Sales	Sum LN 13 : LN 20

22	**BASE COMMODITY COSTS**	
23	TOTAL BASE COMMODITY	Attachment NUI-CAK-6, LN 34
24	Res Heat	LN 23 * LN 13
25	Res General	LN 23 * LN 14
26	G50 Low Annual-Low Winter	LN 23 * LN 15
27	G40 Low Annual-High Winter	LN 23 * LN 16
28	G51 Med Annual-Low Winter	LN 23 * LN 17
29	G41 Med Annual-High Winter	LN 23 * LN 18
30	G52 High Annual-Low Winter	LN 23 * LN 19
31	G42 High Annual-High Winter	LN 23 * LN 20
32		
33	Residential	LN 24 + LN 25
34	SALES HLF CLASSES	LN 26 + LN 28 + LN 30
35	SALES LLF CLASSES	LN 27 + LN 29 + LN 31

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

	REMAINING SENDOUT BY CLASS	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
36	**REMAINING SENDOUT BY CLASS**															
37	**Total Therms**															
38	Res Heat	1,821,127	2,781,171	3,329,231	2,837,545	2,318,857	1,199,662	348,133	90,340	-	3,064	65,245	546,496	15,340,872	14,287,594	1,053,279
39	Res General	11,022	19,655	24,693	20,745	15,406	5,310	7,919	2,055	-	70	1,484	12,431	120,789	96,831	23,958
40	G50 Low Annual-Low Winter	40,194	89,579	118,858	98,300	64,881	6,994	65,729	17,056	-	578	12,319	103,180	617,667	418,805	198,862
41	G40 Low Annual-High Winter	983,065	1,474,093	1,753,357	1,497,307	1,238,520	666,397	131,900	34,228	-	1,161	24,720	207,056	8,011,804	7,612,738	399,066
42	G51 Med Annual-Low Winter	78,785	161,053	209,586	174,293	120,112	23,751	98,918	25,669	-	870	18,539	155,281	1,066,858	767,580	299,277
43	G41 Med Annual-High Winter	670,473	1,029,421	1,234,544	1,051,632	856,389	437,876	139,480	36,195	-	1,227	26,141	218,954	5,702,332	5,280,335	421,997
44	G52 High Annual-Low Winter	6,473	3,077	9,625	12,441	9,344	5,998	3,695	-	-	908	843	4,236	56,640	46,958	9,682
45	G42 High Annual-High Winter	101,047	151,451	204,138	178,143	148,081	93,650	39,973	8,610	-	336	13,464	55,781	994,676	876,512	118,164
46	Total Firm Sales	3,712,185	5,709,500	6,884,032	5,870,407	4,771,592	2,439,637	835,747	214,153	-	8,214	162,755	1,303,416	31,911,637	29,387,353	2,524,285
47	**% of Total**															
48	Res Heat	49.06%	48.71%	48.36%	48.34%	48.60%	49.17%	41.66%	42.18%	37.30%	37.30%	40.09%	41.93%			
49	Res General	0.30%	0.34%	0.36%	0.35%	0.32%	0.22%	0.95%	0.96%	0.85%	0.85%	0.91%	0.95%			
50	G50 Low Annual-Low Winter	1.08%	1.57%	1.73%	1.67%	1.36%	0.29%	7.86%	7.96%	7.04%	7.04%	7.57%	7.92%			
51	G40 Low Annual-High Winter	26.48%	25.82%	25.47%	25.51%	25.96%	27.32%	15.78%	15.98%	14.13%	14.13%	15.19%	15.89%			
52	G51 Med Annual-Low Winter	2.12%	2.82%	3.04%	2.97%	2.52%	0.97%	11.84%	11.99%	10.60%	10.60%	11.39%	11.91%			
53	G41 Med Annual-High Winter	18.06%	18.03%	17.93%	17.91%	17.95%	17.95%	16.69%	16.90%	14.94%	14.94%	16.06%	16.80%			
54	G52 High Annual-Low Winter	0.17%	0.05%	0.14%	0.21%	0.20%	0.25%	0.44%	0.00%	11.05%	11.05%	0.52%	0.33%			
55	G42 High Annual-High Winter	2.72%	2.65%	2.97%	3.03%	3.10%	3.84%	4.78%	4.02%	4.10%	4.10%	8.27%	4.28%			
56	Total Firm Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%			

57	REMAINING COMMODITY COSTS	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
58	REMAINING COMMODITY	$ 1,715,714	$ 3,085,517	$ 4,143,497	$ 3,372,770	$ 2,403,320	$ 934,237	$ 295,532	$ 75,372	$ 1,371	$ 4,217	$ 56,030	$ 458,150	$ 16,545,727	$ 15,655,056	$ 890,671
59	Res Heat	$ 841,696	$ 1,502,995	$ 2,003,864	$ 1,630,276	$ 1,167,945	$ 459,400	$ 123,105	$ 31,796	$ 511	$ 1,573	$ 22,462	$ 192,093	$ 7,977,716	$ 7,606,177	$ 371,539
60	Res General	$ 5,094	$ 10,622	$ 14,862	$ 11,919	$ 7,760	$ 2,033	$ 2,800	$ 723	$ 12	$ 36	$ 511	$ 4,369	$ 60,741	$ 52,290	$ 8,451
61	G50 Low Annual-Low Winter	$ 18,577	$ 48,410	$ 71,540	$ 56,477	$ 32,679	$ 2,678	$ 23,243	$ 6,003	$ 97	$ 297	$ 4,241	$ 36,268	$ 300,509	$ 230,361	$ 70,148
62	G40 Low Annual-High Winter	$ 454,357	$ 796,626	$ 1,055,345	$ 860,259	$ 623,809	$ 255,191	$ 46,642	$ 12,047	$ 194	$ 596	$ 8,510	$ 72,780	$ 4,186,356	$ 4,045,587	$ 140,769
63	G51 Med Annual-Low Winter	$ 36,413	$ 87,036	$ 126,150	$ 100,138	$ 60,497	$ 9,095	$ 34,979	$ 9,034	$ 145	$ 447	$ 6,382	$ 54,581	$ 524,898	$ 419,329	$ 105,569
64	G41 Med Annual-High Winter	$ 309,882	$ 556,317	$ 743,072	$ 604,202	$ 431,340	$ 167,681	$ 49,322	$ 12,739	$ 205	$ 630	$ 8,999	$ 76,962	$ 2,961,352	$ 2,812,494	$ 148,857
65	G52 High Annual-Low Winter	$ 2,992	$ 1,663	$ 5,793	$ 7,148	$ 4,707	$ 2,297	$ 1,307	$ -	$ 151	$ 466	$ 290	$ 1,489	$ 28,302	$ 24,599	$ 3,703
66	G42 High Annual-High Winter	$ 46,702	$ 81,847	$ 122,871	$ 102,350	$ 74,585	$ 35,862	$ 14,135	$ 3,030	$ 56	$ 173	$ 4,635	$ 19,607	$ 505,853	$ 464,217	$ 41,636
67																
68	Residential	$ 846,791	$ 1,513,617	$ 2,018,726	$ 1,642,195	$ 1,175,705	$ 461,433	$ 125,905	$ 32,519	$ 523	$ 1,608	$ 22,972	$ 196,462	$ 8,038,457	$ 7,658,467	$ 379,990
69	SALES HLF CLASSES	$ 57,982	$ 137,109	$ 203,484	$ 163,763	$ 97,882	$ 14,070	$ 59,528	$ 15,037	$ 393	$ 1,210	$ 10,913	$ 92,338	$ 853,710	$ 674,290	$ 179,420
70	SALES LLF CLASSES	$ 810,942	$ 1,434,791	$ 1,921,288	$ 1,566,811	$ 1,129,733	$ 458,734	$ 110,099	$ 27,816	$ 455	$ 1,399	$ 22,145	$ 169,349	$ 7,653,561	$ 7,322,299	$ 331,262

Total Commodity Costs

71	TOTAL COMMODITY COSTS	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Annual	Winter	Summer
72	TOTAL COMMODITY	$ 2,282,533	$ 3,727,626	$ 4,860,382	$ 4,010,760	$ 2,985,700	$ 1,339,894	$ 681,474	$ 440,939	$ 378,735	$ 382,138	$ 407,210	$ 841,184	$ 22,338,575	$ 19,206,895	$ 3,131,680
73	Res Heat	$ 1,067,078	$ 1,758,314	$ 2,288,915	$ 1,883,957	$ 1,399,514	$ 620,699	$ 276,565	$ 177,381	$ 150,631	$ 151,844	$ 162,100	$ 344,397	$ 10,281,395	$ 9,018,478	$ 1,262,917
74	Res General	$ 10,221	$ 16,430	$ 21,346	$ 17,689	$ 13,027	$ 5,702	$ 6,291	$ 4,035	$ 3,426	$ 3,454	$ 3,687	$ 7,834	$ 113,141	$ 84,415	$ 28,726
75	G50 Low Annual-Low Winter	$ 61,130	$ 96,615	$ 125,359	$ 104,373	$ 76,400	$ 33,132	$ 52,216	$ 33,490	$ 28,440	$ 28,669	$ 30,605	$ 65,023	$ 735,451	$ 497,008	$ 238,443
76	G40 Low Annual-High Winter	$ 539,750	$ 893,361	$ 1,163,345	$ 956,374	$ 711,546	$ 316,304	$ 104,785	$ 67,206	$ 57,071	$ 57,530	$ 61,416	$ 130,485	$ 5,059,173	$ 4,580,679	$ 478,494
77	G51 Med Annual-Low Winter	$ 100,453	$ 159,582	$ 207,144	$ 172,219	$ 126,295	$ 54,927	$ 78,583	$ 50,401	$ 42,800	$ 43,145	$ 46,059	$ 97,857	$ 1,179,463	$ 820,619	$ 358,844
78	G41 Med Annual-High Winter	$ 400,181	$ 658,611	$ 857,278	$ 705,840	$ 524,118	$ 232,305	$ 110,806	$ 71,068	$ 60,350	$ 60,836	$ 64,945	$ 137,983	$ 3,884,323	$ 3,378,334	$ 505,989
79	G52 High Annual-Low Winter	$ 28,701	$ 30,787	$ 38,309	$ 36,085	$ 31,122	$ 20,696	$ 18,812	$ 16,038	$ 17,082	$ 17,607	$ 16,219	$ 18,862	$ 290,320	$ 185,700	$ 104,620
80	G42 High Annual-High Winter	$ 75,020	$ 113,926	$ 158,685	$ 134,223	$ 103,679	$ 56,129	$ 33,416	$ 21,322	$ 18,934	$ 19,053	$ 22,180	$ 38,743	$ 795,310	$ 641,662	$ 153,648
81																
82	Residential	$ 1,077,298	$ 1,774,744	$ 2,310,261	$ 1,901,646	$ 1,412,541	$ 626,401	$ 282,856	$ 181,415	$ 154,057	$ 155,298	$ 165,787	$ 352,231	$ 10,394,536	$ 9,102,892	$ 1,291,644
83	SALES HLF CLASSES	$ 190,283	$ 286,984	$ 370,812	$ 312,677	$ 233,816	$ 108,754	$ 149,611	$ 99,928	$ 88,322	$ 89,420	$ 92,882	$ 181,742	$ 2,205,233	$ 1,503,327	$ 701,906
84	SALES LLF CLASSES	$ 1,014,951	$ 1,665,899	$ 2,179,309	$ 1,796,437	$ 1,339,343	$ 604,738	$ 249,007	$ 159,595	$ 136,356	$ 137,420	$ 148,541	$ 307,211	$ 9,738,806	$ 8,600,676	$ 1,138,131
85																
86	% ALLOCATION BETWEEN HLF & LLF															
87	HLF CLASSES%														14.88%	38.15%
88	LLF CLASSES %														85.12%	61.85%

Northern Utilities - NEW HAMPSHIRE DIVISION
Allocation of Commodity Costs to Customer Classes

Remaining Commodity Costs

36	**REMAINING SENDOUT BY CLASS**	
37	**Total Therms**	
38	Res Heat	Attachment NUI-CAK-3, LN 68
39	Res General	Attachment NUI-CAK-3, LN 69
40	G50 Low Annual-Low Winter	Attachment NUI-CAK-3, LN 70
41	G40 Low Annual-High Winter	Attachment NUI-CAK-3, LN 71
42	G51 Med Annual-Low Winter	Attachment NUI-CAK-3, LN 72
43	G41 Med Annual-High Winter	Attachment NUI-CAK-3, LN 73
44	G52 High Annual-Low Winter	Attachment NUI-CAK-3, LN 74
45	G42 High Annual-High Winter	Attachment NUI-CAK-3, LN 75
46	Total Firm Sales	Sum LN 38 : LN 45
47	**% of Total**	
48	Res Heat	LN 38 / LN 46
49	Res General	LN 39 / LN 46
50	G50 Low Annual-Low Winter	LN 40 / LN 46
51	G40 Low Annual-High Winter	LN 41 / LN 46
52	G51 Med Annual-Low Winter	LN 42 / LN 46
53	G41 Med Annual-High Winter	LN 43 / LN 46
54	G52 High Annual-Low Winter	LN 44 / LN 46
55	G42 High Annual-High Winter	LN 45 / LN 46
56	Total Firm Sales	Sum LN 62 : LN 69

57	**REMAINING COMMODITY COSTS**	
58	REMAINING COMMODITY	Attachment NUI-CAK-6, LN 35
59	Res Heat	LN 58 * LN 48
60	Res General	LN 58 * LN 49
61	G50 Low Annual-Low Winter	LN 58 * LN 50
62	G40 Low Annual-High Winter	LN 58 * LN 51
63	G51 Med Annual-Low Winter	LN 58 * LN 52
64	G41 Med Annual-High Winter	LN 58 * LN 53
65	G52 High Annual-Low Winter	LN 58 * LN 54
66	G42 High Annual-High Winter	LN 58 * LN 55
67		
68	Residential	LN 59 + LN 60
69	SALES HLF CLASSES	LN 61 + LN 63 + LN 65
70	SALES LLF CLASSES	LN 62 + LN 64 + LN 66

Total Commodity Costs

71	**TOTAL COMMODITY COSTS**	
72	TOTAL COMMODITY	Attachment NUI-CAK-6, LN 36
73	Res Heat	LN 24 + LN 59
74	Res General	LN 25 + LN 60
75	G50 Low Annual-Low Winter	LN 26 + LN 61
76	G40 Low Annual-High Winter	LN 27 + LN 62
77	G51 Med Annual-Low Winter	LN 28 + LN 63
78	G41 Med Annual-High Winter	LN 29 + LN 64
79	G52 High Annual-Low Winter	LN 30 + LN 65
80	G42 High Annual-High Winter	LN 31 + LN 66
81		
82	Residential	LN 73 + LN 74
83	SALES HLF CLASSES	LN 75 + LN 77 + LN 79
84	SALES LLF CLASSES	LN 76 + LN 78 + LN 80

Northern Utilities - NEW HAMPSHIRE DIVISION
Supporting Detail to Proposed Tariff Sheets
Demand and Commodity Cost Reallocation to HLF and LLF Customers

		Winter	Summer	Annual	
1	Demand	$ 12,798,284	$ 1,354,125	$ 14,152,409	Attachment NUI-CAK-2, LN 80
2	Commodity	$ 19,206,895	$ 3,131,680	$ 22,338,575	Attachment NUI-CAK-6, LN 36
3	Total	$ 32,005,179	$ 4,485,805	$ 36,490,984	LN 1 + LN 2
4					
5	Forecasted Firm Sales (Therms)	35,339,329	8,907,030	44,246,359	Attachment NUI-CAK-3, LN 11
6	Forecasted Residential Sales (Therms)	16,774,496	3,673,138	20,447,634	Attachment NUI-CAK-3, LN 3
7	Average Residential Rate:	**Winter**	**Summer**	**Annual**	
8	Average Demand Rate	$0.3622	$0.1520		LN 1 / LN 5
9	Average Commodity Rate	$0.5435	$0.3516		LN 2 / LN 5
10	Average Rate	$0.9057	$0.5036		LN 3 / LN 5
11					
12	**Residential Reallocation:**	**Winter**	**Summer**	**Annual**	
13	Demand Costs Allocated To Residential per SMBA	$ 6,230,944	$ 599,654	$ 6,830,599	Attachment NUI-CAK-4, LN 169
14	Demand Costs Allocated To Residential per Avg Res. Rate	$ 6,074,953	$ 558,317	$ 6,633,270	LN 8 * LN 6
15	**Demand Reallocation:**	$ 155,991	$ 41,337	$ 197,329	LN 13 - LN 14
16	**HLF Allocation**	$ 15,887	$ 11,258	$ 27,144	LN 15 * LN 20
17	**LLF Allocation**	$ 140,104	$ 30,080	$ 170,184	LN 15 * LN 21
18					
19	**SMBA Capacity Cost Allocation (%)**				
20	HLF	10.18%	27.23%		Attachment NUI-CAK-4, LN 174
21	LLF	89.82%	72.77%		Attachment NUI-CAK-4, LN 175
22					
23	Commodity Costs Allocated To Residential per SMBA	$ 9,102,892	$ 1,291,644	$ 10,394,536	Attachment NUI-CAK-8, LN 82
24	Commodity Costs Allocated To Residential per Avg Res. Rate	$ 9,116,924	$ 1,291,475	$ 10,408,399	LN 9 * LN 6
25	**Commodity Reallocation:**	$ (14,032)	$ 168	$ (13,864)	LN 23 - LN 24
26	**HLF Allocation**	$ (2,088)	$ 64	$ (2,024)	LN 25 * LN 30
27	**LLF Allocation**	$ (11,944)	$ 104	$ (11,840)	LN 25 * LN 31
28					
29	**SMBA Commodity Cost Allocation (%)**				
30	HLF	14.88%	38.15%		Attachment NUI-CAK-8, LN 87
31	LLF	85.12%	61.85%		Attachment NUI-CAK-8, LN 88

ATTACHMENT NUI-CAK-10
FORM III
Schedule 1

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
SCHEDULE 1: SUMMARY OF ANNUAL BALANCE
August 2020 - October 2021

	AMOUNT	
Annual Beginning Balance	$ (1,320,875)	FORM III SCHEDULE 2
Less: Reported Collections	$ (28,156,245)	FORM III SCHEDULE 3
Add: Cost of Firm Gas Allowable	$ 29,800,471	FORM III SCHEDULE 4
Add: Interest	$ (86,346)	FORM III SCHEDULE 2
Annual Ending Balance	$ 237,004	

Allocation of Reconciliation Balance to 2021 / 2022 Winter Season and 2022 Summer Season

Winter Season Sales (DTHs)	3,533,933	Attachment NUI-CAK-3
Summer Season Sales(DTHs)	890,703	Attachment NUI-CAK-3
Winter Season Sales Percentage	79.87%	
Summer Season Sales Percentage	20.13%	
Reconciliation Allocated to Winter Season	$ 189,294	
Reconciliation Allocated to Summer Season	$ 47,710	

Attachment NUI-CAK-10
FORM III
Schedule 2

NORTHERN UTILTIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
SCHEDULE 2: ADJUSTMENTS TO REPORTED SUMMER, WINTER AND ANNUAL ACCOUNTS
August 2020 - October 2021
Acct 191

													Estimated			
	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Inital Account Beginning Balance	$(1,456,073)															
Adjustment (1)	$ 135,198															
Adjusted Beginning Balance	$(1,320,875)	$ (485,746)	$ 339,439	$ 1,191,118	$ 526,216	$ (611,235)	$ (2,346,307)	$ (4,200,362)	$ (5,426,903)	$ (5,377,699)	$ (5,051,942)	$ (3,950,322)	$ (3,091,269)	$ (2,005,967)	$ (892,006)	
Plus: Cost of Firm Gas (Schedule 4)	$ 952,706	$ 1,122,305	$ 1,339,833	$ 2,199,518	$ 3,098,711	$ 3,453,314	$ 2,894,144	$ 2,832,065	$ 2,250,229	$ 1,380,129	$ 1,396,231	$ 1,434,047	$ 1,578,420	$ 1,647,240	$ 2,221,580	$ 29,800,471
Less: Reported Collections (Schedule 3)	$ (115,133)	$ (296,923)	$ (490,224)	$ (2,866,742)	$ (4,236,047)	$ (5,184,385)	$ (4,739,347)	$ (4,045,586)	$ (2,186,413)	$ (1,040,267)	$ (282,437)	$ (565,472)	$ (486,225)	$ (529,360)	$ (1,091,684)	$ (28,156,245)
Annual Account Ending Balance	$ (483,303)	$ 339,637	$ 1,189,048	$ 523,894	$ (611,120)	$ (2,342,307)	$ (4,191,509)	$ (5,413,884)	$ (5,363,088)	$ (5,037,838)	$ (3,938,148)	$ (3,081,746)	$ (1,999,073)	$ (888,087)	$ 237,890	
Month's Average Balance	$ (902,089)	$ (73,054)	$ 764,244	$ 857,506	$ (42,452)	$ (1,476,771)	$ (3,268,908)	$ (4,807,123)	$ (5,394,995)	$ (5,207,768)	$ (4,495,045)	$ (3,516,034)	$ (2,545,171)	$ (1,447,027)	$ (327,058)	
Interest Rate (Prime Rate)	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
Interest Applied	$ (2,443)	$ (198)	$ 2,070	$ 2,322	$ (115)	$ (4,000)	$ (8,853)	$ (13,019)	$ (14,611)	$ (14,104)	$ (12,174)	$ (9,523)	$ (6,893)	$ (3,919)	$ (886)	$ (86,346)
						$ (5,184,385)	$ (4,739,347)	$ (4,045,586)	$ (2,186,413)	$ (1,040,267)	$ (282,437)	$ (565,472)				
Annual Account Ending Balance w/int	$ (485,746)	$ 339,439	$ 1,191,118	$ 526,216	$ (611,235)	$ (2,346,307)	$ (4,200,362)	$ (5,426,903)	$ (5,377,699)	$ (5,051,942)	$ (3,950,322)	$ (3,091,269)	$ (2,005,967)	$ (892,006)	$ 237,004	

(1) Reflects Fuel Tax Recovery Expense of $10,540 plus ATV charges, plus interest, not included in 2019 - 2020 reconciliation.

Attachment NUI-CAK-10
FORM III
Schedule 3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
SCHEDULE 3: REVENUE BACKUP TO REPORTED COLLECTIONS
August 2020 - October 2021

													Estimated[1]			
	Aug-20	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
Accrued Revenue	$ 750	$ 58,413	$ 91,519	$ 1,393,390	$ 573,281	$ 519,878	$ (551,300)	$ (920,779)	$ (316,069)	$ (377,411)	$ (295,234)	$ (9,813)				
Billed Revenue	$ 114,383	$ 238,510	$ 398,705	$ 1,473,353	$ 3,662,766	$ 4,664,508	$ 5,290,646	$ 4,966,366	$ 2,502,482	$ 1,417,678	$ 577,671	$ 575,285				
Calendarized Revenue	$ 115,133	$ 296,923	$ 490,224	$ 2,866,742	$ 4,236,047	$ 5,184,385	$ 4,739,347	$ 4,045,586	$ 2,186,413	$ 1,040,267	$ 282,437	$ 565,472	$ 486,225	$ 529,360	$ 1,091,684	$ 28,156,245

FORM III
Schedule 4
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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS
August 2020 - October 2021

													----------------------Estimated[1]	--------------------		
Commodity Costs	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
Citadel Energy	$ -	$ -	$ -	$ -	$ -	$ 520,615	$ -	$ 529,757	$ -	$ -	$ -	$ -				**$ 1,050,372**
DTE Energy	$ -	$ -	$ 4,127	$ -	$ 50,816	$ 54,195	$ -	$ -	$ -	$ 40,041	$ 46,569	$ 46,489				**$ 242,236**
Emera Energy Services Corp.	$ 138,318	$ 146,938	$ -	$ 357,389	$ 459,390	$ 537,322	$ 1,213,306	$ 851,263	$ 769,661	$ 598,860	$ 392,823	$ 111,700				**$ 5,576,969**
Repsol	$ -	$ -	$ 70,001	$ 35,263	$ 4,391	$ 56,283	$ 138,332	$ 223,237	$ 208,848	$ 42,548	$ 46,448	$ 44,812				**$ 870,163**
Shell	$ 4,347	$ -	$ 20,756	$ -	$ 218,166	$ 390,904	$ 386,594	$ 370,884	$ 319,651	$ -						**$ 1,711,302**
Southwestern	$ 20,228	$ 24,699	$ 39,336	$ 31,237	$ -	$ -	$ -	$ -	$ -	$ -						**$ 115,499**
Xpress	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,692				**$ 37,692**
Subtotal - Commodity	$ 162,893	$ 171,636	$ 134,219	$ 423,889	$ 732,763	$ 1,559,319	$ 1,738,232	$ 1,975,140	$ 1,298,160	$ 681,449	$ 485,840	$ 240,692				**$ 9,604,231**
Transportation																
Granite	$ 74	$ 126	$ 202	$ 199	$ 418	$ 537	$ 418	$ 344	$ 239	$ 167	$ 77	$ 98				**$ 2,898**
Emera	$ 69	$ 88	$ 105	$ 230	$ 310	$ 470	$ 677	$ 619	$ 354	$ 534	$ 308	$ 58				**$ 3,822**
Emera Energy Services	$ -	$ -	$ -	$ -	$ 833	$ 1,342	$ 2,177	$ 4,269	$ 1,473	$ 49	$ 29					**$ 10,171**
Maritimes	$ -	$ -	$ 70	$ 2,653	$ 31,276	$ 11,040	$ 5,102	$ 1,258	-			$ 170				**$ 51,569**
Tennessee	$ 2,104	$ 1,951	$ 2,097	$ 2,115	$ 2,322	$ 2,491	$ 2,587	$ 2,303	$ 1,844	$ 2,098	$ 2,128	$ 2,054				**$ 26,094**
Subtotal - Commodity Transportation	$ 2,247	$ 2,165	$ 2,474	$ 5,197	$ 35,159	$ 15,880	$ 10,961	$ 8,792	$ 3,910	$ 2,848	$ 2,542	$ 2,380				**$ 94,554**
Commodity Cost Estimates	$ 169,403	$ 262,672	$ 449,643	$ 767,504	$ 1,574,848	$ 1,748,786	$ 1,983,661	$ 1,274,326	$ 683,787	$ 488,305	$ 240,436	$ 293,016				**$ 9,936,386**
Commodity Cost Reversals	$ (124,887)	$ (169,403)	$ (262,672)	$ (449,643)	$ (767,504)	$ (1,574,848)	$ (1,748,786)	$ (1,983,661)	$ (1,274,326)	$ (683,787)	$ (488,305)	$ (240,436)				**$ (9,768,258)**
Subtotal - Estimates	$ 44,516	$ 93,269	$ 186,971	$ 317,861	$ 807,344	$ 173,938	$ 234,875	$ (709,335)	$ (590,539)	$ (195,483)	$ (247,869)	$ 52,580				**$ 20,397,684**
Subtotal - Supply	$ 209,656	$ 267,070	$ 323,665	$ 746,947	$ 1,575,265	$ 1,749,136	$ 1,984,069	$ 1,274,597	$ 711,532	$ 488,814	$ 240,513	$ 295,651				**$ 9,866,914**
Withdrawal - Underground Storage	$ 2,269	$ 3,687	$ (5,892)	$ 234,557	$ 359,574	$ 642,651	$ 604,645	$ 208,998	$ 685	$ (529)	$ (49)	$ (131)				**$ 2,050,464**
ATV Reconciliation Charges	$ (3,132)	$ (2,611)	$ (7,580)	$ (27,268)	$ (74,639)	$ (94,725)	$ (24,705)	$ 9,067	$ 12,743	$ -	$ -	$ -				**$ (212,850)**
Off System Sales	$ -	$ -	$ -	$ -	$ (2,936)	$ -	$ (205,410)	$ (1,025,807)	$ (22,267)	$ -	$ -	$ (9,889)				**$ (1,266,309)**
Net OBA Adjustment	$ 184	$ (588)	$ 623	$ 1,852	$ (392)	$ 791	$ (2,621)	$ (5,475)	$ (7,362)	$ (102)	$ (24)	$ (328)				**$ (13,442)**
Company Managed	$ -	$ -	$ -	$ -	$ -	$ -	$ (151,764)	$ (200,336)	$ -	$ (87,953)	$ -	$ -				**$ (440,053)**
LNG Withdrawal / Boiloff	$ 2,841	$ 3,146	$ 2,017	$ 1,161	$ 2,132	$ 8,966	$ 32,062	$ 16,943	$ 2,069	$ 1,772	$ 1,498	$ 1,916				**$ 76,523**
Supplier Balancing	$ (72,711)	$ -	$ (19,710)	$ -	$ (15,065)	$ -	$ 76,839	$ 202,849	$ -	$ 1,841	$ 8,024	$ 48,543				**$ 230,610**
Inventory Finance Charge	$ 59	$ 79	$ 99	$ 120	$ 128	$ 108	$ 62	$ 41	$ 35	$ 58	$ 73	$ 105				**$ 967**
Subtotal - Other Commodity	$ (70,490)	$ 3,712	$ (30,442)	$ 210,421	$ 268,802	$ 557,792	$ 329,109	$ (793,719)	$ (14,098)	$ (84,912)	$ 9,520	$ 40,216				**$ 425,911**
Sales for Resale Estimates	$ -	$ -	$ -	$ (72,377)	$ (82,322)	$ (300,945)	$ (1,130,405)	$ (109,591)	$ -	$ -	$ (9,889)	$ -				**$ (1,705,530)**
Sales for Resale Reversals	$ -	$ -	$ -	$ -	$ 72,377	$ 82,322	$ 300,945	$ 1,130,405	$ 109,591	$ -	$ -	$ 9,889				**$ 1,705,530**
Subtotal - Estimates	$ -	$ -	$ -	$ (72,377)	$ (9,945)	$ (218,622)	$ (829,460)	$ 1,020,814	$ 109,591	$ -	$ (9,889)	$ 9,889				**$ -**
Total Commodity Costs	$ 139,166	$ 270,783	$ 293,222	$ 884,990	$ 1,834,122	$ 2,088,305	$ 1,483,717	$ 1,501,692	$ 807,025	$ 403,902	$ 240,145	$ 345,756	$ 434,808	$ 446,066	$ 918,281	**$ 12,091,979**

(1) Monthly estimates provided in Table 2 of Northern 's August 2021 Monthly Cost of Gas Report, submitted in DG 20-154 on August 19, 2021. Estimates updated for September 7, 2021 NYMEX prices

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
SCHEDULE 4: PURCHASED GAS COSTS
August 2020 - October 2021

													Estimated[1]			
Demand Costs	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
Pipeline Reservation																
Alberta Northeast	$ 3,705	$ 5,577	$ 3,761	$ 4,174	$ 3,542	$ 3,633	$ 3,850	$ 3,290	$ 3,632	$ 3,518	$ 3,977	$ 4,983				$ 47,641
Algonquin	$ 14,212	$ 14,212	$ 36,001	$ 19,388	$ 19,186	$ 19,185	$ 19,172	$ 147,029	$ 189,691	$ 189,784	$ 189,784	$ 189,784				$ 1,047,432
Emera	$ 275,583	$ 289,367	$ 258,980	$ 256,915	$ 316,636	$ 349,666	$ 428,894	$ 429,584	$ 414,581	$ 447,016	$ 439,044	$ 429,653				$ 4,335,918
Granite State	$ 144,287	$ 144,287	$ 144,287	$ 280,644	$ 280,644	$ 280,644	$ 280,644	$ 280,644	$ 280,644	$ 179,428	$ 179,428	$ 179,428				$ 2,655,007
Iroquois	$ 14,390	$ 14,390	$ 14,390	$ 14,390	$ 14,060	$ 14,060	$ 14,060	$ 14,060	$ 14,060	$ 14,060	$ 14,060	$ 14,060				$ 170,041
Maritimes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,769	$ 41,033	$ 41,033	$ 41,033	$ 41,033				
Portland	$ 305,455	$ 305,455	$ 305,455	$ 305,455	$ 390,426	$ 393,492	$ 393,492	$ 384,294	$ 393,492	$ 390,426	$ 393,492	$ 390,426				$ 4,351,363
Tennessee	$ 137,938	$ 137,938	$ 137,938	$ 137,938	$ 132,065	$ 132,065	$ 132,065	$ 132,065	$ 132,065	$ 132,065	$ 132,065	$ 132,065				$ 1,608,270
Texas Eastern	$ 2,865	$ 2,879	$ 2,879	$ 2,879	$ 2,813	$ 2,821	$ 2,821	$ 2,787	$ 2,787	$ 2,787	$ 2,787	$ 2,787				$ 33,894
Total Pipeline Reservation	$ 898,435	$ 914,105	$ 903,690	$ 1,021,782	$ 1,159,373	$ 1,195,566	$ 1,274,999	$ 1,424,523	$ 1,471,985	$ 1,400,118	$ 1,395,671	$ 1,384,220				**$ 14,444,467**
Product Demand																
Excelon	$ -	$ -	$ -	$ -	$ 121,618	$ 121,618	$ 121,618	$ 121,618	$ 121,618	$ -	$ -	$ -				$ 608,090
Repsol	$ 335,475	$ 335,475	$ 335,475	$ 335,475	$ 327,778	$ 327,778	$ 327,778	$ 327,778	$ 327,778	$ 327,778	$ 327,778	$ 327,778				$ 3,964,127
Xpress	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,792	$ -				
Total Product Demand	$ 335,475	$ 335,475	$ 335,475	$ 335,475	$ 449,396	$ 449,396	$ 449,396	$ 449,396	$ 449,396	$ 327,778	$ 364,570	$ 327,778				**$ 4,609,009**
Storage Pipeline Transportation and Demand Reservation																
Emera	$ 99,021	$ 99,021	$ 99,021	$ 99,021	$ 96,749	$ 96,749	$ 96,749	$ 96,749	$ 96,749	$ 96,749	$ 96,749	$ 96,749				$ 1,170,080
Tennessee	$ 4,362	$ 4,362	$ 4,362	$ 4,362	$ 4,169	$ 4,169	$ 4,169	$ 4,169	$ 4,169	$ 4,169	$ 4,169	$ 4,169				$ 50,799
Total Storage & Demand Reservation	$ 103,383	$ 103,383	$ 103,383	$ 103,383	$ 100,918	$ 100,918	$ 100,918	$ 100,918	$ 100,918	$ 100,918	$ 100,918	$ 100,918				**$ 1,220,880**
Demand Cost Estimates	$ 1,189,356	$ 1,194,664	$ 1,194,681	$ 1,448,580	$ 1,458,596	$ 1,535,362	$ 1,685,240	$ 1,751,889	$ 1,736,554	$ 1,646,063	$ 1,639,529	$ 1,631,891				$ 18,112,405
Demand Cost Reversals	$ (1,183,761)	$ (1,189,356)	$ (1,194,664)	$ (1,194,681)	$ (1,448,580)	$ (1,458,596)	$ (1,535,362)	$ (1,685,240)	$ (1,751,889)	$ (1,736,554)	$ (1,646,063)	$ (1,639,529)				$ (17,664,275)
Subtotal	$ 5,595	$ 5,308	$ 17	$ 253,899	$ 10,016	$ 76,766	$ 149,878	$ 66,649	$ (15,335)	$ (90,492)	$ (6,534)	$ (7,638)				**$ 448,130**
Capacity Release[2]	$ (523,555)	$ (525,520)	$ (288,536)	$ (510,673)	$ (630,146)	$ (586,224)	$ (611,023)	$ (615,486)	$ (815,302)	$ (720,196)	$ (716,693)	$ (710,715)				$ (7,254,068)
Company Managed	$ (21,182)	$ -	$ (21,333)	$ -	$ (29,506)	$ -	$ (103,270)	$ (105,928)	$ -	$ (107,651)	$ -	$ (24,589)				
Other A&G Allowance	$ 18,818	$ 18,818	$ 18,818	$ 78,589	$ 78,589	$ 78,589	$ 78,589	$ 78,589	$ 78,589	$ 18,154	$ 18,154	$ 18,154				$ 582,449
Local Production and Storage Allowance	$ -	$ -	$ -	$ 79,351	$ 79,351	$ 79,351	$ 79,351	$ 79,351	$ 79,351	$ -	$ -	$ -				$ 476,106
Conversion & Re-entry Fees	$ (42)	$ (47)	$ (125)	$ (86)	$ (15)	$ (20)	$ (28)	$ (29)	$ (14)	$ 828	$ (1)	$ (1)				$ 420
Fuel Tax Recovery	$ -	$ -	$ -	$ -	$ -	$ -	$ 578	$ -	$ 1,958	$ 4,845	$ -	$ -				$ 7,381
Outage Replacement Costs	$ -	$ -	$ -	$ 114,821	$ -	$ -	$ -	$ -	$ -							
Total Indirect Demand Costs	$ (525,961)	$ (506,749)	$ (291,176)	$ (237,999)	$ (501,727)	$ (428,304)	$ (555,803)	$ (563,503)	$ (655,418)	$ (804,021)	$ (698,540)	$ (717,151)				**$ (6,486,351)**
Estimates - Cap Release & Comp Managed	$ (529,578)	$ (529,578)	$ (534,357)	$ (696,371)	$ (649,758)	$ (679,092)	$ (688,053)	$ (835,663)	$ (744,006)	$ (702,081)	$ (702,081)	$ (701,918)				$ (7,992,537)
Reversals - Cap Release & Comp Managed	$ 526,190	$ 529,578	$ 529,578	$ 534,357	$ 696,371	$ 649,758	$ 679,092	$ 688,053	$ 835,663	$ 744,006	$ 702,081	$ 702,081				$ 7,816,809
Subtotal	**$ (3,388)**	**$ -**	**$ (4,779)**	**$ (162,013)**	**$ 46,613**	**$ (29,334)**	**$ (8,961)**	**$ (147,610)**	**$ 91,657**	**$ 41,925**	**$ -**	**$ 164**				**$ (175,728)**
Annual Demand Costs	**$ 813,539**	**$ 851,523**	**$ 1,046,611**	**$ 1,314,528**	**$ 1,264,589**	**$ 1,365,008**	**$ 1,410,427**	**$ 1,330,373**	**$ 1,443,204**	**$ 976,227**	**$ 1,156,086**	**$ 1,088,291**	**$ 1,143,612**	**$ 1,143,612**	**$ 1,143,612**	**$ 17,491,243**
Total Gas Costs	$ 952,706	$ 1,122,305	$ 1,339,833	$ 2,199,518	$ 3,098,711	$ 3,453,314	$ 2,894,144	$ 2,832,065	$ 2,250,229	$ 1,380,129	$ 1,396,231	$ 1,434,047	$ 1,578,420	$ 1,589,679	**$ 2,061,893**	**$ 29,583,223**
	$ 813,539	$ 851,523	$ 1,046,611	$ 1,314,528	$ 1,264,589	$ 1,365,008	$ 1,410,427	$ 1,330,373	$ 1,441,245	$ 976,227	$ 1,156,086	$ 1,088,291				
	$ -	**$ (0)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	$ 1,958	$ 0	$ (0)	$ 0				

(1) Monthly estimates provided in Table 2 of Northern 's August 2021 Monthly Cost of Gas Report, submitted in DG 20-154 on August 19, 2021. Estimates updated for September 7, 2021 NYMEX prices
(2) Includes Asset Management Agreement Revenue

REDACTED

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - UNITS
August 2020 - October 2021

Indicates Confidential Data

													----------------------Estimated(1)	--------------------		
Commodity Volumes:	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
Citadel Energy	[redacted]															[redacted]
DTE Energy	[redacted]															[redacted]
Emera Energy Services Corp.	[redacted]															[redacted]
Repsol	[redacted]															[redacted]
Shell	[redacted]															[redacted]
Southwestern	[redacted]															[redacted]
Xpress Energy	[redacted]															[redacted]
Subtotal - Commodity Supply	[redacted]															[redacted]
Granite	[redacted]															[redacted]
Emera	[redacted]															[redacted]
Emera Energy Services	[redacted]															[redacted]
Maritimes	[redacted]															[redacted]
Tennessee	[redacted]															[redacted]
Subtotal - Commodity Transportation	[redacted]															[redacted]
Commodity Volume Estimates	[redacted]															[redacted]
Commodity Volume Reversals	[redacted]															[redacted]
Subtotal - Estimates	[redacted]															[redacted]
Subtotal - Supply	[redacted]															[redacted]
Withdrawal - Underground Storage	[redacted]															[redacted]
ATV Reconciliation Charges	[redacted]															[redacted]
Off System Sales	[redacted]															[redacted]
Net OBA Adjustment	[redacted]															[redacted]
Company Managed	[redacted]															[redacted]
LNG Withdrawal / Boiloff	[redacted]															[redacted]
Supplier Balancing	[redacted]															[redacted]
Inventory Finance Charge	[redacted]															[redacted]
Subtotal - Other Commodity	[redacted]															[redacted]
Sales for Resale Estimates	[redacted]															[redacted]
Sales for Resale Reversals	[redacted]															[redacted]
Subtotal - Estimates	[redacted]															[redacted]
Total Commodity Volumes	[redacted]												102,888	104,952	212,494	[redacted]

(1) Monthly estimates provided in Table 2 of Northern 's August 2021 Monthly Cost of Gas Report, submitted in DG 20-154 on August 19, 2021. Estimates updated for September 7, 2021 NYMEX prices

REDACTED

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
COST OF GAS ADJUSTMENT - FORM III, Schedule 4 - IN COST PER UNIT
August 2020 - October 2021

Indicates Confidential Data

													----Estimated[1]----			
Commodity Costs per Unit:	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
Citadel	[redacted]															[redacted]
DTE Energy																
Emera Energy Services Corp.													$ -	$ -	$ -	
Repsol																
Shell																
Southwestern																
Xpress Energy																
Subtotal - Commodity Supply																
Granite																
Emera																
Maritimes																
Tennessee																
Subtotal - Commodity Transportation													n/a	n/a	n/a	
Commodity Cost Estimates																
Commodity Cost Reversals																
Subtotal - Estimates													n/a	n/a	n/a	
Subtotal - Supply																
Withdrawal - Underground Storage																
ATV Reconciliation Charges																
Off System Sales																
Net OBA Adjustment																
Company Managed																
LNG Withdrawal / Boiloff																
Supplier Balancing																
Inventory Finance Charge																
Subtotal - Other Commodity													n/a	n/a	n/a	
Off System Sales Estimates																
Off System Sales Reversals																
Subtotal - Estimates																
Total Commodity Costs per unit													n/a	n/a	n/a	

(1) Monthly estimates provided in Table 2 of Northern 's August 2021 Monthly Cost of Gas Report, submitted in DG 20-154 on August 19, 2021. Estimates updated for September 7, 2021 NYMEX prices

Attachment NUI-CAK-10
FORM III
Schedule 5

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
2020-21 ANNUAL COG RECONCILIATION
SCHEDULE 5: PURCHASED AND MADE VOLUMES
August 2020 - July 2021

New Hampshire	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Total
Throughput IN													
BTU Factor	1.03	1.028	1.029	1.033	1.033	1.041	1.04	1.033	1.029	1.028	1.028	1.028	
GST Meter Throughput (MCF)	329,115	373,060	543,616	699,749	991,072	1,094,702	1,015,270	886,697	617,597	457,671	342,785	359,580	7,710,914
Salem Meter (MCF)	12,467	14,692	26,192	40,744	67,618	77,841	71,623	55,666	34,687	20,149	13,965	14,528	450,172
GST Meter Throughpurt (DTH)	338,988	383,506	559,381	722,841	1,023,777	1,139,585	1,055,881	915,958	635,507	470,486	352,383	369,648	7,967,941
Salem Meter (DTH)	12,841	15,103	26,952	42,089	69,849	81,032	74,488	57,503	35,693	20,713	14,356	14,935	465,554
LNG/Propane													-
Total Throughput	351,829	398,609	586,332	764,929	1,093,627	1,220,617	1,130,369	973,461	671,200	491,199	366,739	384,583	8,433,495
Throughput OUT													
Residential Gas													
Charged	31,451	40,551	56,652	129,223	233,549	305,880	342,819	325,375	164,754	108,962	51,370	37,613	1,828,199
Uncharged Current	19,467	18,890	30,360	106,076	160,391	208,113	168,985	100,904	76,526	61,569	25,108	18,971	995,360
Uncharged Prior	(19,236)	(19,467)	(18,890)	(30,360)	(106,076)	(160,391)	(208,113)	(168,985)	(100,904)	(76,526)	(61,569)	(25,108)	(995,625)
Total Residential Gas	**31,682**	**39,974**	**68,122**	**204,939**	**287,864**	**353,602**	**303,691**	**257,294**	**140,376**	**94,005**	**14,909**	**31,476**	1,827,934
Interruptible				-	-	-	-	-	-	-	-	-	-
<u>*Commercial/Industrial Gas*</u>													
Charged	46,120	63,063	75,428	160,876	270,849	335,203	384,200	357,677	180,780	121,546	65,434	76,744	2,137,920
Uncharged Current	28,546	29,377	40,422	117,409	176,223	221,298	192,828	120,773	87,490	68,679	31,981	38,707	1,153,733
Uncharged Prior	(26,280)	(28,546)	(29,377)	(40,422)	(117,409)	(176,223)	(221,298)	(192,828)	(120,773)	(87,490)	(68,679)	(31,981)	(1,141,306)
Total C/I Gas	**48,386**	**63,894**	**86,473**	**237,863**	**329,663**	**380,278**	**355,730**	**285,622**	**147,497**	**102,735**	**28,736**	**83,470**	2,150,347
Transportation													
Charged	253,143	283,307	320,339	359,833	424,328	475,023	471,219	481,163	375,026	344,405	279,262	285,167	4,352,215
Uncharged Current	100,616	88,390	115,685	170,836	200,965	230,672	193,612	146,957	142,266	132,821	88,819	93,246	1,704,885
Uncharged Prior	(84,128)	(100,616)	(88,390)	(115,685)	(170,836)	(200,965)	(230,672)	(193,612)	(146,957)	(142,266)	(132,821)	(88,819)	(1,695,767)
Total Transportation	**269,631**	**271,081**	**347,634**	**414,984**	**454,457**	**504,730**	**434,159**	**434,508**	**370,335**	**334,960**	**235,260**	**289,594**	**4,361,333**
Company Use	**89**	**118**	**61**	**98**	**171**	**263**	**328**	**327**	**162**	**99**	**78**	**99**	**1,894**
Total Throughput OUT	**349,788**	**375,067**	**502,290**	**857,884**	**1,072,155**	**1,238,873**	**1,093,908**	**977,751**	**658,370**	**531,799**	**278,983**	**404,639**	**8,341,508**
Total Throughput IN	**351,829**	**398,609**	**586,332**	**764,929**	**1,093,627**	**1,220,617**	**1,130,369**	**973,461**	**671,200**	**491,199**	**366,739**	**384,583**	**8,433,495**
Difference IN/OUT	2,041	23,542	84,043	(92,955)	21,472	(18,256)	36,461	(4,290)	12,831	(40,600)	87,756	(20,056)	91,987
%													1.09%

Attachment A

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
DEFERRED WORKING CAPITAL ALLOWANCE ON PURCHASED GAS COSTS
August 2020 - October 2021

ANNUAL BALANCE SEASON - Acct 173

	BEGINNING BALANCE	WORKING CAP ALLOWANCE (1)	WORKING CAP PERCENTAGE	WORKING CAP COLLECTIONS	WORKING CAP DEFERRED	ENDING BALANCE	AVE MONTHLY BALANCE	INTEREST RATE	INTEREST	ENDING BAL W/ INTEREST
	A	B	C	D	E = B + D	F = A + E	G = (A + F) / 2	H	I = G * (H / 12)	K = F + I + J
August 2020	$ (44,484)									
Adjustment	$ 197									
August 2020	$ (44,287)	850	0.0892%	48	898	(43,389)	(43,838)	3.25%	(119)	(43,508)
September	$ (43,508)	1,001	0.0892%	64	1,065	(42,442)	(42,975)	3.25%	(116)	(42,559)
October	$ (42,559)	1,195	0.0892%	120	1,315	(41,244)	(41,901)	3.25%	(113)	(41,358)
November	$ (41,358)	1,962	0.0892%	1,469	3,431	(37,927)	(39,642)	3.25%	(107)	(38,034)
December	$ (38,034)	2,764	0.0892%	2,330	5,095	(32,940)	(35,487)	3.25%	(96)	(33,036)
January 2021	$ (33,036)	3,080	0.0892%	2,854	5,935	(27,101)	(30,068)	3.25%	(81)	(27,182)
February	$ (27,182)	2,582	0.0892%	2,609	5,191	(21,992)	(24,587)	3.25%	(67)	(22,058)
March	$ (22,058)	2,526	0.0892%	2,228	4,754	(17,304)	(19,681)	3.25%	(53)	(17,357)
April	$ (17,357)	2,007	0.0892%	1,204	3,211	(14,146)	(15,752)	3.25%	(43)	(14,189)
May	$ (14,189)	*1,231*	0.0892%	*1,467*	2,698	(11,491)	(12,840)	3.25%	(35)	(11,526)
June	$ (11,526)	*1,245*	0.0892%	*411*	1,657	(9,869)	(10,697)	3.25%	(29)	(9,898)
July	$ (9,898)	*1,279*	0.0892%	*761*	2,040	(7,858)	(8,878)	3.25%	(24)	(7,882)
Estimated August	$ (7,882)	*725*	0.0892%	*(500)*	225	(7,656)	(7,769)	3.25%	(21)	(7,677)
Estimated September	$ (7,677)	*733*	0.0892%	*(500)*	233	(7,445)	(7,561)	3.25%	(20)	(7,465)
Estimated October	$ (7,465)	*1,030*	0.0892%	*(850)*	180	(7,285)	(7,375)	3.25%	(20)	(7,305)

(1) Working Capital Allowance calculated by taking monthly Total Gas Costs from Schedule 4, Page 2, and multiplying by (10.02/365)* prime interest rate.

Winter Season Sales Percentage		79.87%
Summer Season Sales Percentage		20.13%
Reconciliation Allocated to Winter Season	$	(5,834)
Reconciliation Allocated to Summer Season	$	(1,470)

Attachment B

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
BAD DEBT EXPENSE - CALCULATION OF COLLECTION ALLOWANCE
August 2020 - October 2021

ANNUAL BALANCE- Acct 173

	BEGINNING BALANCE	ACUTAL BAD DEBT	BAD DEBT COLLECTIONS	DEFERRED BALANCE	ENDING BALANCE	AVE MO BALANCE	INTEREST RATE	INTEREST	END BAL W/ INTEREST
	A	B	C	D = B + C	E = A + D	F = (A + E) / 2	G	H = (F *G) / 12	J = E + H + I
August 2020	($24,891)	6,359	(1,232)	5,127	(19,764)	(22,328)	3.25%	(60)	(19,825)
September	($19,825)	12,905	(1,677)	11,229	(8,596)	(14,210)	3.25%	(38)	(8,635)
October	($8,635)	3,830	(2,582)	1,248	(7,386)	(8,010)	3.25%	(22)	(7,408)
November	($7,408)	4,903	(17,172)	(12,269)	(19,677)	(13,543)	3.25%	(37)	(19,714)
December	($19,714)	10,407	(25,638)	(15,231)	(34,945)	(27,329)	3.25%	(74)	(35,019)
January 2021	($35,019)	12,015	(31,354)	(19,339)	(54,358)	(44,688)	3.25%	(121)	(54,479)
February	($54,479)	2,685	(28,673)	(25,988)	(80,467)	(67,473)	3.25%	(183)	(80,649)
March	($80,649)	5,854	(24,514)	(18,660)	(99,310)	(89,980)	3.25%	(244)	(99,554)
April	($99,554)	4,358	(13,290)	(8,932)	(108,486)	(104,020)	3.25%	(282)	(108,768)
May	($108,768)	734	(3,422)	(2,688)	(111,456)	(110,112)	3.25%	(298)	(111,754)
June	($111,754)	9,403	(995)	8,408	(103,346)	(107,550)	3.25%	(291)	(103,637)
July	($103,637)	9,523	(2,268)	7,255	(96,382)	(100,010)	3.25%	(271)	(96,653)
Estimated August	($96,653)	10,000	(850)	9,150	(87,503)	(92,078)	3.25%	(249)	(87,753)
Estimated September	($87,753)	10,000	(875)	9,125	(78,628)	(83,190)	3.25%	(225)	(78,853)
Estimated October	($78,853)	2,000	(500)	1,500	(77,353)	(78,103)	3.25%	(212)	(77,564)

Winter Season Sales Percentage		79.87%
Summer Season Sales Percentage		20.13%
Reconciliation Allocated to Winter Season	$	(61,950)
Reconciliation Allocated to Summer Season	$	(15,614)

Attachment C

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Costs
May 2020 - October 2021

		Beginning Balance		Firm Sales and Transportation (therms)	ERC Rate Recoveries /Passback		Current ERC Recoveries/ Passbacks	Ending Balance
May 2020	(act)	$ 130,988		4,861,662	$ 0.0057		$ 27,710	$ 103,277.64
June 2020	(act)	$ 103,278		3,038,865	$ 0.0057		$ 17,331	$ 85,947.07
July 2020	(act)	$ 85,947		2,540,626	$ 0.0057		$ 14,489	$ 71,457.96
August 2020	(act)	$ 71,458		2,401,297	$ 0.0057		$ 13,698	$ 57,759.86
September 2020	(act)	$ 57,760		2,933,578	$ 0.0057		$ 16,730	$ 41,029.68
October 2020	(act)	$ 41,030		3,479,470	$ 0.0057		$ 19,863	$ 21,166.39
November 2020	(act)	$ 439,696	(1)	5,519,681	$ 0.0059	(2)	$ 32,902	$ 406,794.08
December 2020	(act)	$ 406,794		8,367,336	$ 0.0061		$ 51,043	$ 355,750.77
January 2021	(act)	$ 355,751		10,114,055	$ 0.0061		$ 61,701	$ 294,050.20
February 2021	(act)	$ 294,050		11,010,433	$ 0.0061		$ 67,167	$ 226,883.46
March 2021	(act)	$ 226,883		10,551,678	$ 0.0061		$ 64,367	$ 162,516.12
April 2021	(act)	$ 162,516		6,201,510	$ 0.0061		$ 37,834	$ 124,682.50
May 2021	(act)	$ 124,683		4,655,705	$ 0.0061		$ 28,409	$ 96,273.40
June 2021	(act)	$ 96,273		2,985,287	$ 0.0061		$ 18,225	$ 78,048.39
July 2021	(act)	$ 78,048		2,992,333	$ 0.0061		$ 18,264	$ 59,784.48
August 2021	(est)	$ 59,784		2,728,710	$ 0.0061		$ 16,645	$ 43,139
September 2021	(est)	$ 43,139		2,821,820	$ 0.0061		$ 17,213	$ 25,926
October 2021	(est)	$ 25,926		3,685,223	$ 0.0061		$ 22,480	$ 3,446

(1) November Beginning Balance includes $421,540 amortization from all prior years at 1/7 of annual costs. (See Section 4.7 of Tariff.)

(2) November Current ERC Recoveries/Passbacks reflect an Average ERC Rate based on actual Firm Sales and Transportation (therms) at $0.0057 and actual Firm Sales and Transportation (therms) at $0.0060.

Attachment D

NORTHERN UTILITIES
NEW HAMPSHIRE DIVISION
RLIARA Reconciliation
May 2020 - October 2021

		Beginning Balance	Program Costs	Regulatory Assessments	RLIARA Recoveries	Ending Balance	Average Monthly Balance	Interest Rate	Interest	Ending Balance w/Interest
		A	B	C	D	E = A+B+C-D	F = (A+E)/2	G	H = F*(G/12)	I = E+H
May 2020	Actual	$ (86,723)	$ 24,284	$ 6,013	$ 17,501	$ (73,928)	$ (80,326)	4.75%	$ (318)	$ (74,246)
June 2020	Actual	$ (74,246)	$ 18,438	$ 6,013	$ 10,934	$ (60,729)	$ (67,487)	4.75%	$ (267)	$ (60,996)
July 2020	Actual	$ (60,996)	$ 12,176	$ 6,013	$ 9,142	$ (51,948)	$ (56,472)	3.25%	$ (153)	$ (52,101)
August 2020	Actual	$ (52,101)	$ 11,381	$ 6,013	$ 8,638	$ (43,345)	$ (47,723)	3.25%	$ (129)	$ (43,474)
September 2020	Actual	$ (43,474)	$ 11,506	$ (10,558)	$ 10,555	$ (53,081)	$ (48,278)	3.25%	$ (131)	$ (53,212)
October 2020	Actual	$ (53,212)	$ 12,912	$ 6,893	$ 12,568	$ (45,975)	$ (49,594)	3.25%	$ (134)	$ (46,110)
November 2020	Actual	$ (46,110)	$ 21,680	$ 6,893	$ 22,745	$ (40,282)	$ (43,196)	3.25%	$ (117)	$ (40,399)
December 2020	Actual	$ (40,399)	$ 39,553	$ 6,893	$ 36,817	$ (30,770)	$ (35,585)	3.25%	$ (96)	$ (30,867)
January 2021	Actual	$ (30,867)	$ 48,032	$ 6,893	$ 44,508	$ (20,449)	$ (25,658)	3.25%	$ (69)	$ (20,518)
February 2021	Actual	$ (20,518)	$ 57,968	$ 6,893	$ 48,446	$ (4,103)	$ (12,311)	3.25%	$ (33)	$ (4,136)
March 2021	Actual	$ (4,136)	$ 70,145	$ 6,893	$ 46,428	$ 26,474	$ 11,169	3.25%	$ 30	$ 26,505
April 2021	Actual	$ 26,505	$ 40,179	$ 6,893	$ 27,287	$ 46,289	$ 36,397	3.25%	$ 99	$ 46,388
May 2021	Actual	$ 46,388	$ 16,330	$ 6,893	$ 20,483	$ 49,127	$ 47,757	3.25%	$ 129	$ 49,257
June 2021	Actual	$ 49,257	$ 756	$ 6,893	$ 13,128	$ 43,777	$ 46,517	3.25%	$ 126	$ 43,903
July 2021	Actual	$ 43,903	$ -	$ 6,893	$ 13,163	$ 37,633	$ 40,768	3.25%	$ 110	$ 37,744
August 2021	Est.	$ 37,744	$ -	$ 5,292	$ 12,006	$ 31,029	$ 34,386	3.25%	$ 93	$ 31,122
September 2021	Est.	$ 31,122	$ -	$ 5,292	$ 12,416	$ 23,999	$ 27,561	3.25%	$ 75	$ 24,073
October 2021	Est.	$ 24,073	$ -	$ 5,292	$ 16,215	$ 13,150	$ 18,612	3.25%	$ 50	$ 13,201

Attachment E
Page 1 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS

	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	TOTAL
Forecast Bill Month Sales	104,573	107,393	132,485	294,521	541,934	702,409	817,468	680,722	452,687	265,253	148,939	102,281	4,350,666
Actual Sales	77,571	103,615	132,079	290,099	504,398	641,083	727,019	683,052	345,533	230,509	116,804	114,357	3,966,118
Difference	(27,002)	(3,779)	(406)	(4,422)	(37,536)	(61,326)	13,698	2,330	(107,154)	(34,745)	(32,135)	12,075	(384,548)
Normal Bill Month Actual Sales	77,571	103,615	132,079	332,383	546,059	701,880	777,437	599,273	410,072	230,509	116,804	114,357	4,142,038
Actual Sales	77,571	103,615	132,079	290,099	504,398	641,083	727,019	683,052	345,533	230,509	116,804	114,357	3,966,118
Weather Variance	-	-	-	42,284	41,662	60,797	50,418	(83,780)	64,539	-	-	-	175,920
Total Variance Excluding Weather (excl weather effect)	(27,002)	(3,779)	(406)	37,862	4,125	(529)	64,116	(81,449)	(42,615)	(34,745)	(32,135)	12,075	(208,628)
Variance-difference due to meter count													3,044
-difference in load pattern													(447,801)
Total Sales Variance													(444,757)

Attachment NUI-CAK-10
Attachment E
Page 2 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION
SALES VARIANCE ANALYSIS
August 2019 - July 2020

	NORMAL MMBtu			METERS		
	2020-21 Forecast	2020-21 Actual	Difference	2020-21 Forecast	2020-21 Actual	Difference
Res Heat	1,995,194	1,804,018	(191,176)	315,704	322,386	6,682
Res General	23,534	24,182	648	15,048	15,724	676
Total Res	2,018,728	1,828,199	(190,528)	330,752	338,110	7,358
G-40	960,465	862,510	(97,956)	54,544	55,858	1,314
G-50	170,442	134,879	(35,562)	8,901	9,071	170
G-41	721,741	692,124	(29,617)	5,089	4,883	(206)
G-51	239,930	229,440	(10,490)	1,897	1,747	(150)
G-42	106,561	141,129	34,568	125	126	1
G-52	193,009	77,838	(115,171)	30	27	(3)
Total C & I	2,392,148	2,137,919	(254,229)	70,586	71,712	1,126
Total Company	4,410,875	3,966,119	(444,757)	401,338	409,822	8,484

	NORMAL AVERAGE USE			Change in Sales Due to Change In:			
	2020-21 Forecast	2020-21 Actual	Difference	Meter Count	Load Pattern	Total Chg MMBtu	% Difference
Res Heat	6.32	5.60	(0.72)	42,229	(233,405)	(191,176)	-9.58%
Res General	1.56	1.54	(0.03)	1,057	(409)	648	2.75%
Total Res	7.88	7.13	(0.75)	43,286	(233,815)	(190,528)	-9.44%
G-40	17.61	15.44	(2.17)	23,138	(121,094)	(97,956)	-10.20%
G-50	19.15	14.87	(4.28)	3,255	(38,818)	(35,562)	-20.86%
G-41	141.82	141.74	(0.08)	(29,216)	(402)	(29,617)	-4.10%
G-51	126.48	131.33	4.85	(18,972)	8,481	(10,490)	-4.37%
G-42	852.48	1,120.07	267.59	852	33,716	34,568	32.44%
G-52	6,433.65	2,882.89	(3,550.76)	(19,301)	(95,870)	(115,171)	-59.67%
Total C & I	33.89	29.81	(4.08)	(40,242)	(213,986)	(254,229)	-10.63%
Total Company	10.99	9.68	(1.31)	3,044	(447,801)	(444,757)	-10.08%

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-CAK-11
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Northern Utilities Inc.
Calculation of Bad Debt Expense

1	**Actual Bad Debt Expense 12 Months Ended July 31, 2021**			
2				
3	Total	$	458,671	Company Analysis
4	Distribution	$	284,549	Company Analysis
5	Distribution (%)		62.04%	LN 4 / LN 3
6	Non-Distribution	$	174,123	Company Analysis
7	Non-Distribution(%)		37.96%	LN 6 / LN 3
8				
9	Winter Demand Cost %		90.43%	Attachment NUI-CAK-2
10	Summer Demand Cost %		9.57%	Attachment NUI-CAK-2
11				
12	**Forecast Bad Debt Expense 12 Months Ended December 31, 2022**			*
13				
14	Annual Total	$	400,000	Company Forecast
15	Annual Non-Distribution	$	151,850	LN 14 * LN 7
16	Winter Non-Distribution	**$**	**137,320**	LN 15 * LN 9
17	Summer Non-Distribution	**$**	**14,529**	LN 15 * LN 10

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

		Winter						Summer					
Sales Revenues		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)
Volumes	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
Residential Heat & Non Heat		2,235,193	3,205,961	3,752,145	3,220,112	2,745,230	1,615,855	791,744	517,185	437,049	443,237	491,840	992,084
Sales HLF Classes		368,357	503,160	586,466	509,647	444,531	280,756	418,861	285,038	250,296	254,950	275,778	512,036
Sales LLF Classes		2,109,633	3,011,324	3,541,686	3,044,843	2,604,500	1,559,929	697,006	455,024	386,854	392,235	440,500	865,314
Total		4,713,183	6,720,446	7,880,297	6,774,602	5,794,261	3,456,540	1,907,611	1,257,246	1,074,199	1,090,422	1,208,118	2,369,434
Rates													
Residential Heat & Non Heat CGA		$0.9392	$0.9392	$0.9392	$0.9392	$0.9392	$0.9392	$0.5176	$0.5176	$0.5176	$0.5176	$0.5176	$0.5176
Sales HLF Classes CGA		$0.8453	$0.8453	$0.8453	$0.8453	$0.8453	$0.8453	$0.4740	$0.4740	$0.4740	$0.4740	$0.4740	$0.4740
Sales LLF Classes CGA		$0.9551	$0.9551	$0.9551	$0.9551	$0.9551	$0.9551	$0.5445	$0.5445	$0.5445	$0.5445	$0.5445	$0.5445
Revenues													
Residential Heat & Non Heat		$ (2,099,293)	$ (3,011,039)	$ (3,524,015)	$ (3,024,329)	$ (2,578,320)	$ (1,517,611)	$ (409,807)	$ (267,695)	$ (226,216)	$ (229,419)	$ (254,576)	$ (513,503)
Sales HLF Classes		$ (311,373)	$ (425,321)	$ (495,740)	$ (430,805)	$ (375,762)	$ (237,323)	$ (198,540)	$ (135,108)	$ (118,640)	$ (120,846)	$ (130,719)	$ (242,705)
Sales LLF Classes		$ (2,014,910)	$ (2,876,116)	$ (3,382,664)	$ (2,908,129)	$ (2,487,558)	$ (1,489,888)	$ (379,520)	$ (247,760)	$ (210,642)	$ (213,572)	$ (239,852)	$ (471,164)
Total Sales		$ (4,425,576)	$ (6,312,476)	$ (7,402,419)	$ (6,363,263)	$ (5,441,640)	$ (3,244,823)	$ (987,867)	$ (650,563)	$ (555,499)	$ (563,838)	$ (625,147)	$ (1,227,371)

		Winter						Summer					
Gas Costs and Credits		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)
	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
Demand Costs (net of Capacity Assignment)													
Pipeline		$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451	$ 455,451
Storage		$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421	$ 644,421
On-system Peaking		$ 208,007	$ 208,007	$ 208,007	$ 208,007	$ 208,007	$ 97,714	$ 16,975	$ 16,975	$ 16,975	$ 16,975	$ 16,975	$ 16,975
Off-System Peaking		$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646	$ 312,646
Total Demand Costs		$ 1,620,524	$ 1,620,524	$ 1,620,524	$ 1,620,524	$ 1,620,524	$ 1,510,232	$ 1,429,493	$ 1,429,493	$ 1,429,493	$ 1,429,493	$ 1,429,493	$ 1,429,493
Asset Management and Capacity Release													
NUI AMA Revenue		$ (810,930)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)	$ (826,470)
NUI Capacity Release								$ -	$ -	$ -	$ -	$ -	$ -
NUI AMA Rev & Cap. Release Subtotal													
NH AMA Revenue		$ (333,866)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)
NH Capacity Release													
NH Total Asset Management and Capacity Release		$ (333,866)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)	$ (340,264)
Outage Replacement		$ 7,067	$ 7,067	$ 7,067	$ 7,067	$ 7,067	$ 7,067	$ 328	$ 328	$ 328	$ 328	$ 328	$ 328
Re-entry Rate & Conversion Rate Revenue		$ (1,000)	$ (1,000)	$ (1,000)	$ (1,000)	$ (1,000)		$ -	$ -	$ -	$ -	$ -	$ -
Net Demand Costs		$ 1,292,725	$ 1,286,327	$ 1,286,327	$ 1,286,327	$ 1,286,327	$ 1,177,035	$ 1,089,556	$ 1,089,556	$ 1,089,556	$ 1,089,556	$ 1,089,556	$ 1,089,556
NUI Commodity Costs													
NUI Total Pipeline Volumes		982,127	978,933	926,892	846,586	1,023,092	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859
Pipeline Costs Modeled in Sendout™		$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274
NYMEX Price Used for Forecast		$ 5.3050	$ 5.3980	$ 5.4650	$ 5.3700	$ 5.0130	$ 3.9390	$ 3.8100	$ 3.8390	$ 3.8710	$ 3.8790	$ 3.8630	$ 3.8900
NYMEX Price Used for Update		$ 5.3050	$ 5.3980	$ 5.4650	$ 5.3700	$ 5.0130	$ 3.9390	$ 3.8100	$ 3.8390	$ 3.8710	$ 3.8790	$ 3.8630	$ 3.8900
Increase/(Decrease) NYMEX Price		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Increase/(Decrease) in Pipeline Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Updated Pipeline Costs		$ 5,248,530	$ 5,735,184	$ 6,062,675	$ 5,455,995	$ 5,436,340	$ 4,220,796	$ 2,197,031	$ 1,475,856	$ 1,373,084	$ 1,382,979	$ 1,410,783	$ 2,512,274
New Hampshire Allocated Percentage		36.21%	36.93%	36.99%	36.38%	34.75%	31.67%	30.87%	29.65%	27.35%	27.40%	28.59%	33.29%
NH Updated Pipeline Costs		$ 1,900,723	$ 2,118,268	$ 2,242,311	$ 1,984,934	$ 1,889,389	$ 1,336,543	$ 678,216	$ 437,649	$ 375,599	$ 378,996	$ 403,363	$ 836,389
NH Peaking Volumes													
NH Peaking Costs Modeled in Sendout													
Change in NYMEX Price													
Change in Peaking Costs													
NH Updated Peaking Costs													
NH Commodity Costs													
Pipeline		$ 1,900,723	$ 2,118,268	$ 2,242,311	$ 1,984,934	$ 1,889,389	$ 1,336,543	$ 678,216	$ 437,649	$ 375,599	$ 378,996	$ 403,363	$ 836,389
Storage		$ 378,185	$ 836,645	$ 933,716	$ 983,140	$ 649,063	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Peaking		$ 3,450	$ 772,446	$ 1,684,032	$ 1,042,411	$ 447,024	$ 3,237	$ 3,258	$ 3,290	$ 3,136	$ 3,142	$ 3,847	$ 4,795
Total Commodity Costs		$ 2,282,359	$ 3,727,358	$ 4,860,059	$ 4,010,484	$ 2,985,476	$ 1,339,779	$ 681,474	$ 440,939	$ 378,735	$ 382,138	$ 407,210	$ 841,184
Inventory Finance Charge		$ 174	$ 268	$ 323	$ 275	$ 224	$ 114	$ -	$ -	$ -	$ -	$ -	$ -
Total Anticipated Direct Cost of Gas		$ 3,575,258	$ 5,013,954	$ 6,146,710	$ 5,297,087	$ 4,272,028	$ 2,516,929	$ 1,771,030	$ 1,530,495	$ 1,468,291	$ 1,471,694	$ 1,496,767	$ 1,930,741

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Anal

		Winter	Summer	Prior Period	Total
	Sales Revenues				
1	Volumes				
2	Residential Heat & Non Heat				20,447,634
3	Sales HLF Classes				4,689,876
4	Sales LLF Classes				19,108,849
5	Total	35,339,329	8,907,030		44,246,359
6	Rates				
7	Residential Heat & Non Heat CGA				
8	Sales HLF Classes CGA				
9	Sales LLF Classes CGA				
10	Revenues				
11	Residential Heat & Non Heat				$ (17,655,823)
12	Sales HLF Classes				$ (3,222,882)
13	Sales LLF Classes				$ (16,921,776)
14	Total Sales	$ (33,190,196)	$ (4,610,285)		$ (37,800,481)
15					
16					
17	**Gas Costs and Credits**				
18					Total
19	Demand Costs (net of Capacity Assignment)				
20	Pipeline	$ 2,732,703	$ 2,732,703		$ 5,465,407
21	Storage	$ 3,866,525	$ 3,866,525		$ 7,733,050
22	On-system Peaking	$ 1,137,749	$ 101,852		$ 1,239,601
23	Off-System Peaking	$ 1,875,877	$ 1,875,877		$ 3,751,755
24	Total Demand Costs	$ 9,612,854	$ 8,576,958		$ 18,189,812
25					
26	Asset Management and Capacity Release				
27	NUI AMA Revenue				$ (9,902,100)
28	NUI Capacity Release				$ -
29	NUI AMA Rev & Cap. Release Subtotal				$ -
30	NH AMA Revenue				$ (4,076,771)
31	NH Capacity Release				$ -
32	NH Total Asset Management and Capacity Release		$ -	$ -	$ (4,076,771)
33					
34	Outage Replacement	$ 42,402	$ 1,965		$ 44,367
35					
36	Re-entry Rate & Conversion Rate Revenue	$ (5,000)	$ -		$ (5,000)
37					
38	Net Demand Costs	$ 7,615,070	$ 6,537,339		$ 14,152,408
39					
40	NUI Commodity Costs				
41	NUI Total Pipeline Volumes				8,854,520
42	Pipeline Costs Modeled in Sendout™				$ 42,511,526
43	NYMEX Price Used for Forecast				
44	NYMEX Price Used for Update				
45	Increase/(Decrease) NYMEX Price				
46	Increase/(Decrease) in Pipeline Costs				
47	Updated Pipeline Costs				
48	New Hampshire Allocated Percentage				
49	NH Updated Pipeline Costs				$ 14,582,381
50					
51	NH Peaking Volumes				
52	NH Peaking Costs Modeled in Sendout				
53	Change in NYMEX Price				
54	Change in Peaking Costs				
55	NH Updated Peaking Costs				$ -
56					
57	NH Commodity Costs				
58	Pipeline				$ 14,582,381
59	Storage				$ 3,780,749
60	Peaking				$ 3,974,066
61	Total Commodity Costs	$ 19,205,516	$ 3,131,680		$ 22,337,197
62	Inventory Finance Charge	$ 1,378	$ -		$ 1,378
63					
64	**Total Anticipated Direct Cost of Gas**	$ 26,821,965	$ 9,669,019		$ 36,490,984

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-CAK-12
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Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Analysis, Balances and Interest Calculation

		Winter						Summer					
		(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)	(Forecast)
	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
Working Capital													
Total Anticipated Direct Cost of Gas		$ 3,575,258	$ 5,013,954	$ 6,146,710	$ 5,297,087	$ 4,272,028	$ 2,516,929	$ 1,771,030	$ 1,530,495	$ 1,468,291	$ 1,471,694	$ 1,496,767	$ 1,930,741
Working Capital Percentage		0.0892%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%
Working Capital Allowance		$ 3,189	$ 4,472	$ 5,483	$ 4,725	$ 3,811	$ 2,245	$ 1,580	$ 1,365	$ 1,310	$ 1,313	$ 1,335	$ 1,722
Beginning Period Working Capital Balance		$ (7,305)	$ (4,131)	$ 336	$ 5,828	$ 10,575	$ 14,419	$ 16,706	$ 18,334	$ 19,750	$ 21,115	$ 22,487	$ 23,885
End of Period Working Capital Allowance		$ (4,116)	$ 341	$ 5,819	$ 10,553	$ 14,385	$ 16,664	$ 18,286	$ 19,699	$ 21,060	$ 22,428	$ 23,822	$ 25,607
Interest		$ (15)	$ (5)	$ 8	$ 22	$ 34	$ 42	$ 47	$ 52	$ 55	$ 59	$ 63	$ 67
End of period with Interest	$ (7,305)	$ (4,131)	$ 336	$ 5,828	$ 10,575	$ 14,419	$ 16,706	$ 18,334	$ 19,750	$ 21,115	$ 22,487	$ 23,885	$ 25,674
Bad Debt													
Projected Bad Debt	$ -	$ 22,886.74	$ 22,886.74	$ 22,886.74	$ 22,886.74	$ 22,886.74	$ 22,886.74	$ 2,421.54	$ 2,421.54	$ 2,421.54	$ 2,421.54	$ 2,421.54	$ 2,421.54
Beginning Period Bad Debt Balance		$ (77,564)	$ (54,857)	$ (32,088)	$ (9,257)	$ 13,636	$ 36,591	$ 59,607	$ 62,194	$ 64,787	$ 67,387	$ 69,995	$ 72,609
End of Period Bad Debt Balance		*$ (54,678)*	*$ (31,970)*	*$ (9,201)*	*$ 13,630*	*$ 36,523*	*$ 59,477*	*$ 62,029*	*$ 64,615*	*$ 67,208*	*$ 69,809*	*$ 72,416*	*$ 75,030*
Interest		$ (179)	$ (118)	$ (56)	$ 6	$ 68	$ 130	$ 165	$ 172	$ 179	$ 186	$ 193	$ 200
End of Period Bad Debt Balance with Interest	$ (77,564)	$ (54,857)	$ (32,088)	$ (9,257)	$ 13,636	$ 36,591	$ 59,607	$ 62,194	$ 64,787	$ 67,387	$ 69,995	$ 72,609	$ 75,230
Local Production and Storage Capacity		$ 79,351	$ 79,351	$ 79,351	$ 79,351	$ 79,351	$ 79,351	$ -	$ -	$ -	$ -	$ -	$ -
		$ -	$ -	$ -									
Miscellaneous Overhead		$ 77,268	$ 77,268	$ 77,268	$ 77,268	$ 77,268	$ 77,268	$ 19,475	$ 19,475	$ 19,475	$ 19,475	$ 19,475	$ 19,475
Gas Cost Other than Bad Debt and Working Capital Over/Under Collection													
Beginning Balance Over/Under Collection	$ 237,004	$ 237,004	$ (456,992)	$ (1,601,680)	$ (2,706,597)	$ (3,624,716)	$ (4,648,898)	$ (5,233,538)	$ (4,443,986)	$ (3,555,397)	$ (2,631,496)	$ (1,710,036)	$ (822,367)
Net Costs - Revenues		$ (693,699)	$ (1,141,904)	$ (1,099,091)	$ (909,558)	$ (1,012,993)	$ (571,275)	$ 802,639	$ 899,407	$ 932,267	$ 927,331	$ 891,094	$ 722,844
Ending Balance before Interest		$ (456,695)	$ (1,598,896)	$ (2,700,771)	$ (3,616,154)	$ (4,637,710)	$ (5,220,174)	$ (4,430,899)	$ (3,544,579)	$ (2,623,130)	$ (1,704,165)	$ (818,942)	$ (99,523)
Average Balance		$ (109,845)	$ (1,027,944)	$ (2,151,225)	$ (3,161,376)	$ (4,131,213)	$ (4,934,536)	$ (4,832,219)	$ (3,994,283)	$ (3,089,263)	$ (2,167,831)	$ (1,264,489)	$ (460,945)
Interest Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Interest Expense		$ (297)	$ (2,784)	$ (5,826)	$ (8,562)	$ (11,189)	$ (13,364)	$ (13,087)	$ (10,818)	$ (8,367)	$ (5,871)	$ (3,425)	$ (1,248)
Ending Balance Incl Interest Expense	$ 237,004	$ (456,992)	$ (1,601,680)	$ (2,706,597)	$ (3,624,716)	$ (4,648,898)	$ (5,233,538)	$ (4,443,986)	$ (3,555,397)	$ (2,631,496)	$ (1,710,036)	$ (822,367)	$ (100,771)
Total Over/Under Collection Ending Balance	$ 152,135	$ (515,980)	$ (1,633,431)	$ (2,710,026)	$ (3,600,506)	$ (4,597,889)	**$ (5,157,224)**	$ (4,363,459)	$ (3,470,860)	$ (2,542,994)	$ (1,617,555)	$ (725,873)	$ 133
Total Indirect Cost of Gas	$ 152,135	$ 182,203	$ 181,071	$ 179,115	$ 175,697	$ 172,229	$ 168,558	$ 10,601	$ 12,667	$ 15,073	$ 17,583	$ 20,062	$ 22,637
Total Cost of Gas	$ 152,135	$ 3,757,461	$ 5,195,025	$ 6,325,824	$ 5,472,784	$ 4,444,257	$ 2,685,487	$ 1,781,631	$ 1,543,162	$ 1,483,365	$ 1,489,277	$ 1,516,829	$ 1,953,378
Total Interest	$ -	$ (492)	$ (2,907)	$ (5,874)	$ (8,534)	$ (11,087)	$ (13,192)	$ (12,875)	$ (10,595)	$ (8,133)	$ (5,626)	$ (3,169)	$ (981)

Northern Utilities
NEW HAMPSHIRE (Over) / Undercollection Anal

65					
66				Prior	
67		Winter	Summer	Period	Total
68	Working Capital				
69	Total Anticipated Direct Cost of Gas				$ 36,490,984
70	Working Capital Percentage				
71	Working Capital Allowance	$ 23,925	$ 8,625	$ (7,305)	$ 25,245
72	Beginning Period Working Capital Balance				
73	End of Period Working Capital Allowance				
74	Interest	$ 86	$ 343		$ 429
75	End of period with Interest				
76	Bad Debt				
77	Projected Bad Debt	$ 137,320	$ 14,529	$ (77,564)	$ 74,285
78	Beginning Period Bad Debt Balance				
79	End of Period Bad Debt Balance				
80	Interest	$ (149)	$ 1,094		$ 945
81	End of Period Bad Debt Balance with Interest				
82	Local Production and Storage Capacity				$ 476,106
83					$ -
84	Miscellaneous Overhead				$ 580,455
85					
86	Gas Cost Other than Bad Debt and Working Capital Over/U				
87	Beginning Balance Over/Under Collection				$ (31,198,700)
88	Net Costs - Revenues				$ (252,937)
89	Ending Balance before Interest				$ (31,451,637)
90	Average Balance				$ (31,325,168)
91	Interest Rate				
92	Interest Expense				$ (84,839)
93	Ending Balance Incl Interest Expense			$ 237,004	
94	**Total Over/Under Collection Ending Balance**				
95					
96	**Total Indirect Cost of Gas**	$ 1,058,872	$ 98,623	$ 152,135	$ 1,309,631
97					
98	**Total Cost of Gas**	$ 27,880,837	$ 9,767,642	$ 152,135	$ 37,800,614
99					
100	**Total Interest**	$ (42,086)	$ (41,380)		$ (83,465)

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2021 - April 31, 2022

	Column A	Column B	Column C
1	**ANTICIPATED DIRECT COST OF GAS**		
2	**Purchased Gas for Sales Service:**		
3	Demand Costs:	$ 4,553,044	
4	Supply Costs:	$ 11,472,168	
5			
6	**Storage & Peaking Gas for Sales Service:**		
7	Demand, Capacity:	$ 12,327,011	
8	Commodity Costs:	$ 7,733,349	
9			
10	**Inventory Finance Charge**	$ 1,378	
11			
12	**Capacity Release**	$ (4,076,771)	
13			
14	**Re-entry Rate & Conversion Rate Revenues**	$ (5,000)	
15			
16	**Total Anticipated Direct Cost of Gas**		$ 32,005,179
17			
18	**ANTICIPATED INDIRECT COST OF GAS**		
19	**Adjustments:**		
20	Prior Period Under/(Over) Collection	$ 189,294	
21	Interest	$ (42,086)	
22	Refunds	$ -	
23	Interruptible Margins	$ -	
24	Total Adjustments		$ 147,208
25			
26	**Working Capital:**		
27	Total Anticipated Direct Cost of Gas	$ 32,005,179	
28	Working Capital Allowance Percentage (10.02 [lag days]/365* prime rate)	0.0892%	
29	Working Capital Allowance	$ 28,555	
30			
31	Plus: Working Capital Reconciliation (Acct 173)	$ (5,834)	
32			
33	Total Working Capital Allowance		$ 22,721
34			
35	**Bad Debt:**		
36	Bad Debt Allowance	$ 137,320	
37	Plus: Bad Debt Reconciliation (Acct 173)	$ (61,950)	
38	Total Bad Debt Allowance		$ 75,370
39			
40	**Local Production and Storage Capacity**		$ 476,106
41			
42	**Miscellaneous Overhead-79.87% Allocated to Winter Season**		$ 463,606
43			
44	**Total Anticipated Indirect Cost of Gas**		$ 1,185,012
45			
46	**Total Cost of Gas**		$ 33,190,191

(*) Prime Rate is 3.25%

N.H.P.U.C No. 12 **Summary**
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2021 - April 31, 2022

	Column A	Column D
1	**ANTICIPATED DIRECT COST OF GAS**	
2	**Purchased Gas for Sales Service:**	
3	Demand Costs:	Attachment NUI-CAK-2, LN 71 + LN 75
4	Supply Costs:	Attachment NUI-CAK-6, LN 14
5		
6	**Storage & Peaking Gas for Sales Service:**	
7	Demand, Capacity:	Attachment NUI-CAK-2, LN 73 + LN 74
8	Commodity Costs:	Attachment NUI-CAK-6, LN 15 + LN 16
9		
10	**Inventory Finance Charge**	Attachment NUI-CAK-6, LN 17
11		
12	**Capacity Release**	-(Attachment NUI-CAK-2, LN 77)
13		
14	**Re-entry Rate & Conversion Rate Revenues**	Attachment NUI-CAK-2, LN 79
15		
16	**Total Anticipated Direct Cost of Gas**	Sum (LN 3 : LN 14)
17		
18	**ANTICIPATED INDIRECT COST OF GAS**	
19	**Adjustments:**	
20	Prior Period Under/(Over) Collection	Attachment NUI-CAK-10, Page 1
21	Interest	Attachment NUI-CAK-12, LN 94: Total
22	Refunds	
23	Interruptible Margins	-(Attachment NUI-CAK-2, LN 78)
24	Total Adjustments	Sum (LN 20 : LN 23)
25		
26	**Working Capital:**	
27	Total Anticipated Direct Cost of Gas	LN 16
28	Working Capital Allowance Percentage (10.02 [lag days]/365* prim	Tariff - NHPUC No. 12 , Section 6.1
29	Working Capital Allowance	LN 27 * LN 28
30		
31	Plus: Working Capital Reconciliation (Acct 173)	Attachment NUI-CAK-10, Attachment A
32		
33	Total Working Capital Allowance	Sum (LN 29 : LN 31)
34		
35	**Bad Debt:**	
36	Bad Debt Allowance	Attachment NUI-CAK-11, LN 16
37	Plus: Bad Debt Reconciliation (Acct 173)	Schedule 10-CAK, Attachment B
38	Total Bad Debt Allowance	LN 36 + LN 37
39		
40	**Local Production and Storage Capacity**	Attachment NUI-CAK-2, LN 84
41		
42	**Miscellaneous Overhead-79.87% Allocated to Winter Season**	Attachment NUI-CAK-2, LN 83
43		
44	**Total Anticipated Indirect Cost of Gas**	Sum (LN 24 : LN 42)
45		
46	**Total Cost of Gas**	LN 44 + LN 16

(*) Prime Rate is 3.25%

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-CAK-13
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CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: November 1, 2021 - April 31, 2022

Column A		**Column B**	**Column C**	
Total Anticipated Direct Cost of Gas		$ 32,005,179		
Projected Prorated Sales (11/01/21 - 04/30/22)		35,339,329		
Direct Cost of Gas Rate			$ 0.9057	per therm
Demand Cost of Gas Rate		$ 12,798,284	$ 0.3622	per therm
Commodity Cost of Gas Rate		$ 19,206,895	$ 0.5435	per therm
Total Direct Cost of Gas Rate		$ 32,005,179	$ 0.9057	per therm
Total Anticipated Indirect Cost of Gas		$ 1,185,012		
Projected Prorated Sales (11/01/21 - 04/30/22)		35,339,329		
Indirect Cost of Gas			$ 0.0335	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21			**$ 0.9392**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/21		**COGwr**	**$ 0.9392**	**per therm**
	Maximum (COG+25%)		**$ 1.1740**	
COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/21		**COGwl**	**$ 0.8453**	**per therm**
	Maximum (COG+25%)		**$ 1.0566**	
C&I HLF Demand Costs Allocated per SMBA	$ 668,845			
PLUS: Residential Demand Reallocation to C&I HLF	$ 15,887			
C&I HLF Total Adjusted Demand Costs	$ 684,732			
C&I HLF Projected Prorated Sales (11/01/21 - 04/30/22)	2,692,919			
Demand Cost of Gas Rate	**$ 0.2543**			
C&I HLF Commodity Costs Allocated per SMBA	$ 1,503,327			
PLUS: Residential Commodity Reallocation to C&I HLF	$ (2,088)			
C&I HLF Total Adjusted Commodity Costs	$ 1,501,239			
C&I HLF Projected Prorated Sales (11/01/21 - 05/30/22)	2,692,919			
Commodity Cost of Gas Rate	**$ 0.5575**			
Indirect Cost of Gas	**$ 0.0335**			
Total C&I HLF Cost of Gas Rate	**$ 0.8453**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/21		**COGwh**	**$ 0.9551**	**per therm**
	Maximum (COG+25%)		**$ 1.1939**	
C&I LLF Demand Costs Allocated per SMBA	$ 5,898,495			
PLUS: Residential Demand Reallocation to C&I LLF	$ 140,104			
C&I LLF Total Adjusted Demand Costs	$ 6,038,599			
C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	15,871,915			
Demand Cost of Gas Rate	**$ 0.3805**			
C&I LLF Commodity Costs Allocated per SMBA	$ 8,600,676			
PLUS: Residential Commodity Reallocation to C&I LLF	$ (11,944)			
C&I LLF Total Adjusted Commodity Costs	$ 8,588,732			
C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	15,871,915			
Commodity Cost of Gas Rate	**$ 0.5411**			
Indirect Cost of Gas	**$ 0.0335**			
Total C&I LLF Cost of Gas Rate	**$ 0.9551**			

48	CALCULATION OF FIRM SALES COST OF GAS RATE	
49	Period Covered: November 1, 2021 - April 31, 2022	
50		
51	**Column A**	**Column D**
52		
53	Total Anticipated Direct Cost of Gas	LN 16
54	Projected Prorated Sales (11/01/21 - 04/30/22)	Attachment NUI-CAK-3, LN 11
55	**Direct Cost of Gas Rate**	LN 53 / LN 54
56		
57	**Demand Cost of Gas Rate**	Column B : SUM (LN 3 , LN 7 , LN 12) : COLUMN C: LN 5
58	**Commodity Cost of Gas Rate**	Column B : SUM (LN 4 , LN 8) : COLUMN C: LN 58 / LN 5
59	**Total Direct Cost of Gas Rate**	SUM (LN 57 : LN 58)
60		
61	Total Anticipated Indirect Cost of Gas	Column B : LN 44
62	Projected Prorated Sales (11/01/21 - 04/30/22)	Column B : LN 54
63	**Indirect Cost of Gas**	LN 61 / LN 62
64		
65		
66	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21**	LN 59 + LN 63
67		
68	**RESIDENTIAL COST OF GAS RATE - 11/01/21**	LN 66
69		LN 68 * 1.25
70		
71		
72	**COM/IND LOW WINTER USE COST OF GAS RATE - 11/01/21**	LN 89
73		LN 72 * 1.25
74		
75	C&I HLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 170
76	PLUS: Residential Demand Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 16
77	C&I HLF Total Adjusted Demand Costs	Sum (LN 75 : LN 76)
78	C&I HLF Projected Prorated Sales (11/01/21 - 04/30/22)	Attachment NUI-CAK-3, LN 14
79	**Demand Cost of Gas Rate**	LN 77 / LN 78
80		
81	C&I HLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 83
82	PLUS: Residential Commodity Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 26
83	C&I HLF Total Adjusted Commodity Costs	Sum (LN 81 : LN 82)
84	C&I HLF Projected Prorated Sales (11/01/21 - 05/30/22)	LN 78
85	**Commodity Cost of Gas Rate**	LN 83 / LN 84
86		
87	**Indirect Cost of Gas**	LN 63
88		
89	**Total C&I HLF Cost of Gas Rate**	Sum (LN 79, LN 85, LN 87)
90		
91		
92	**COM/IND HIGH WINTER USE COST OF GAS RATE - 11/01/21**	LN 109
93		LN 92 * 1.25
94		
95	C&I LLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 171
96	PLUS: Residential Demand Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 17
97	C&I LLF Total Adjusted Demand Costs	Sum (LN 95 : LN 96)
98	C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	Attachment NUI-CAK-3, LN 15
99	**Demand Cost of Gas Rate**	LN 97 / LN 98
100		
101	C&I LLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 84
102	PLUS: Residential Commodity Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 27
103	C&I LLF Total Adjusted Commodity Costs	Sum (LN 101 : LN 102)
104	C&I LLF Projected Prorated Sales (11/01/21 - 04/30/22)	LN 98
105	**Commodity Cost of Gas Rate**	LN 103 / LN 104
106		
107	**Indirect Cost of Gas**	LN 63
108		
109	**Total C&I LLF Cost of Gas Rate**	Sum (LN 99, LN 105, LN 107)

N.H.P.U.C No.12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

Summary Schedule

New Hampshire Division
Period Covered: May 1, 2022 - October 31, 2022

	Column A	Column B	Column C
110	**ANTICIPATED DIRECT COST OF GAS**		
111	**Purchased Gas:**		
112	Demand Costs:	$ 956,729	
113	Supply Costs:	$ 3,110,213	
114			
115	**Storage & Peaking Gas:**		
116	Demand, Capacity:	$ 397,395	
117	Commodity Costs:	$ 21,467	
118			
119	**Inventory Finance Charge**	$ -	
120			
121	**Capacity Release**	$ -	
122			
123	**Re-entry Rate & Conversion Rate Revenues**	$ -	
124			
125	**Total Anticipated Direct Cost of Gas**		$ 4,485,805
126			
127	**ANTICIPATED INDIRECT COST OF GAS**		
128	**Adjustments:**		
129	Prior Period Under/(Over) Collection	$ 47,710	
130	Interest	$ (41,380)	
131	Refunds	$ -	
132	Interruptible Margins	$ -	
133	Total Adjustments		$ 6,330
134			
135	**Working Capital:**		
136	Total Anticipated Direct Cost of Gas	$ 4,485,805	
137	Working Capital Allowance Percentage (10.02 [lag days]/365* prime rate)	0.089%	
138	Working Capital Allowance	$ 4,002	
139	Plus: Working Capital Reconciliation (Acct. 173)	$ (1,470)	
140			
141	Total Working Capital Allowance		$ 2,532
142			
143	**Bad Debt:**		
144	Projected Bad Debt	$ 14,529	
145	Plus: Bad Debt Reconciliation (Acct 173)	$ (15,614)	
146	Total Bad Debt Expense		$ (1,085)
147			
148	**Local Production and Storage Capacity**		$ -
149			
150	**Miscellaneous Overhead-20.13% Allocated to Summer Season**		$ 116,849
151			
152	**Total Anticipated Indirect Cost of Gas**		$ 124,627
153			
154	**Total Cost of Gas**		$ 4,610,432
155			

(*) Prime Rate is 3.25%

N.H.P.U.C No.12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: May 1, 2022 - October 31, 2022

	Column A	Column D
110	**ANTICIPATED DIRECT COST OF GAS**	
111	**Purchased Gas:**	
112	Demand Costs:	Attachment NUI-CAK-2, LN 71 + LN 75
113	Supply Costs:	Attachment NUI-CAK-6, LN 14
114		
115	**Storage & Peaking Gas:**	
116	Demand, Capacity:	Attachment NUI-CAK-2, LN 73
117	Commodity Costs:	Attachment NUI-CAK-6, LN 15 + LN 16
118		
119	**Inventory Finance Charge**	- (Attachment NUI-CAK-6, LN 20)
120		
121	**Capacity Release**	- (Attachment NUI-CAK-2, LN 77)
122		
123	**Re-entry Rate & Conversion Rate Revenues**	
124		
125	**Total Anticipated Direct Cost of Gas**	Sum (LN 112 : LN 123)
126		
127	**ANTICIPATED INDIRECT COST OF GAS**	
128	**Adjustments:**	
129	Prior Period Under/(Over) Collection	Attachment NUI-CAK-10, Page 1
130	Interest	Attachment NUI-CAK-12, LN 94: Total
131	Refunds	Company Analysis
132	Interruptible Margins	- (Attachment NUI-CAK-2, LN 78)
133	Total Adjustments	Sum (LN 129 : LN 132)
134		
135	**Working Capital:**	
136	Total Anticipated Direct Cost of Gas	LN 125
137	Working Capital Allowance Percentage (10.02 [lag days]/365* prim	Tariff - NHPUC No. 12 , Section 6.1
138	Working Capital Allowance	LN 136 * LN 137
139	Plus: Working Capital Reconciliation (Acct. 173)	Attachment NUI-CAK-10, Attachment A
140		
141	Total Working Capital Allowance	Sum (LN 138 : LN 139)
142		
143	**Bad Debt:**	
144	Projected Bad Debt	Attachment NUI-CAK-11, LN 17
145	Plus: Bad Debt Reconciliation (Acct 173)	Schedule 10-CAK, Attachment B
146	Total Bad Debt Expense	Sum (LN 144 : LN 145)
147		
148	**Local Production and Storage Capacity**	Attachment NUI-CAK-2, LN 84
149		
150	**Miscellaneous Overhead-20.13% Allocated to Summer Season**	Attachment NUI-CAK-2, LN 83
151		
152	**Total Anticipated Indirect Cost of Gas**	Sum (LN 133 : LN 150)
153		
154	**Total Cost of Gas**	LN 152 + LN 125
155		

(*) Prime Rate is 3.25%

NORTHERN UTILITIES, INC.

CALCULATION OF FIRM SALES COST OF GAS RATE
Period Covered: May 1, 2022 - October 31, 2022

Column A		**Column B**	**Column C**	
Total Anticipated Direct Cost of Gas		$ 4,485,805		
Projected Prorated Sales (05/01/22 - 10/31/22)		8,907,030		
Direct Cost of Gas Rate			$ 0.5036	per therm
Demand Cost of Gas Rate		$ 1,354,125	$ 0.1520	per therm
Commodity Cost of Gas Rate		$ 3,131,680	$ 0.3516	per therm
Total Direct Cost of Gas Rate		$ 4,485,805	$ 0.5036	per therm
Total Anticipated Indirect Cost of Gas		$ 124,627		
Projected Prorated Sales (05/01/22 - 10/31/22)		8,907,030		
Indirect Cost of Gas			$ 0.0140	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/22			**$ 0.5176**	**per therm**
RESIDENTIAL COST OF GAS RATE - 05/01/22		**COGwr**	**$ 0.5176**	**per therm**
	Maximum (COG+25%)		**$ 0.6470**	
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/22		**COGwl**	**$ 0.4740**	**per therm**
	Maximum (COG+25%)		**$ 0.5925**	
C&I HLF Demand Costs Allocated per SMBA	$ 205,468			
PLUS: Residential Demand Reallocation to C&I HLF	$ 11,258			
C&I HLF Total Adjusted Demand Costs	$ 216,726			
C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	1,996,958			
Demand Cost of Gas Rate	**$ 0.1085**			
C&I HLF Commodity Costs Allocated per SMBA	$ 701,906			
PLUS: Residential Commodity Reallocation to C&I HLF	$ 64			
C&I HLF Total Adjusted Commodity Costs	$ 701,970			
C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	1,996,958			
Commodity Cost of Gas Rate	**$ 0.3515**			
Indirect Cost of Gas	**$ 0.0140**			
Total C&I HLF Cost of Gas Rate	**$ 0.4740**			
COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/22		**COGwh**	**$ 0.5445**	**per therm**
	Maximum (COG+25%)		**$ 0.6806**	
C&I LLF Demand Costs Allocated per SMBA	$ 549,002			
PLUS: Residential Demand Reallocation to C&I LLF	$ 30,080			
C&I LLF Total Adjusted Demand Costs	$ 579,082			
C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	3,236,934			
Demand Cost of Gas Rate	**$ 0.1789**			
C&I LLF Commodity Costs Allocated per SMBA	$ 1,138,131			
PLUS: Residential Commodity Reallocation to C&I LLF	$ 104			
C&I LLF Total Adjusted Commodity Costs	$ 1,138,235			
C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	3,236,934			
Commodity Cost of Gas Rate	**$ 0.3516**			
Indirect Cost of Gas	**$ 0.0140**			
Total C&I LLF Cost of Gas Rate	**$ 0.5445**			

NORTHERN UTILITIES, INC.

157	CALCULATION OF FIRM SALES COST OF GAS RATE	
158	Period Covered: May 1, 2022 - October 31, 2022	
160	**Column A**	**Column D**
162	Total Anticipated Direct Cost of Gas	LN 125
163	Projected Prorated Sales (05/01/22 - 10/31/22)	Attachment NUI-CAK-3, LN 11
164	**Direct Cost of Gas Rate**	LN 162 / LN 163
166	**Demand Cost of Gas Rate**	Column B : SUM (LN 112 , LN 116 , LN 121 , LN 123) : Co
167	**Commodity Cost of Gas Rate**	Column B : SUM (LN 113 , LN 117 , LN 119) : COLUMN C
168	**Total Direct Cost of Gas Rate**	SUM (LN 166 : LN 167)
170	Total Anticipated Indirect Cost of Gas	Column B : LN 152
171	Projected Prorated Sales (05/01/22 - 10/31/22)	Column B : LN 163
172	**Indirect Cost of Gas**	LN 170 / LN 171
175	**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/22**	LN 168 + LN 172
177	**RESIDENTIAL COST OF GAS RATE - 05/01/22**	LN 175
178		LN 177 * 1.25
181	**COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/22**	LN 198
182		LN 181 * 1.25
184	C&I HLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 170
185	PLUS: Residential Demand Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 16
186	C&I HLF Total Adjusted Demand Costs	Sum (LN 184 : LN 185)
187	C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	Attachment NUI-CAK-3, LN 14
188	**Demand Cost of Gas Rate**	LN 186 / LN 187
190	C&I HLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 83
191	PLUS: Residential Commodity Reallocation to C&I HLF	Attachment NUI-CAK-9, LN 26
192	C&I HLF Total Adjusted Commodity Costs	Sum (LN 190 : LN 191)
193	C&I HLF Projected Prorated Sales (05/01/22 - 10/31/22)	LN 187
194	**Commodity Cost of Gas Rate**	LN 192 / LN 193
196	**Indirect Cost of Gas**	LN 172
198	**Total C&I HLF Cost of Gas Rate**	Sum (LN 188, LN 194, LN 196)
201	**COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/22**	LN 218
202		LN 201 * 1.25
204	C&I LLF Demand Costs Allocated per SMBA	Attachment NUI-CAK-4, LN 171
205	PLUS: Residential Demand Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 17
206	C&I LLF Total Adjusted Demand Costs	Sum (LN 204 : LN 205)
207	C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	Attachment NUI-CAK-3, LN 15
208	**Demand Cost of Gas Rate**	LN 206 / LN 207
210	C&I LLF Commodity Costs Allocated per SMBA	Attachment NUI-CAK-8, LN 84
211	PLUS: Residential Commodity Reallocation to C&I LLF	Attachment NUI-CAK-9, LN 27
212	C&I LLF Total Adjusted Commodity Costs	Sum (LN 210 : LN 211)
213	C&I LLF Projected Prorated Sales (05/01/22 - 10/31/22)	LN 207
214	**Commodity Cost of Gas Rate**	LN 212 / LN 213
216	**Indirect Cost of Gas**	LN 172
218	**Total C&I LLF Cost of Gas Rate**	Sum (LN 208, LN 214, LN 216)

NORTHERN UTILITIES, INC.

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2021 - October 31, 2022

	Column A	Column B	Column C
219	**ANTICIPATED DIRECT COST OF GAS**		
220	**Purchased Gas for Sales Service:**		
221	Demand Costs:	$ 5,509,774	
222	Supply Costs:	$ 14,582,381	
223			
224	**Storage & Peaking Gas for Sales Service:**		
225	Demand, Capacity:	$ 12,724,406	
226	Commodity Costs:	$ 7,754,816	
227			
228	**Inventory Finance Charge**	$ 1,378	
229			
230	**Capacity Release**	$ (4,076,771)	
231			
232	**Re-entry Rate & Conversion Rate Revenues**	$ (5,000)	
233			
234	**Total Anticipated Direct Cost of Gas**		$ 36,490,984
235			
236	**ANTICIPATED INDIRECT COST OF GAS**		
237	**Adjustments:**		
238	Prior Period Under/(Over) Collection	$ 237,004	
239	Interest	$ (83,465)	
240	Refunds	$ -	
241	Interruptible Margins	$ -	
242	Total Adjustments		$ 153,539
243			
244	**Working Capital:**		
245	Total Anticipated Direct Cost of Gas	$ 36,490,984	
246	Working Capital Percentage	0.0892%	
247	Working Capital Allowance	$ 32,557	
248			
249	Plus: Working Capital Reconciliation (Acct 173)	$ (7,304)	
250			
251	Total Working Capital Allowance		$ 25,253
252			
253	**Bad Debt:**		
254	Bad Debt Allowance	$ 151,850	
255	Plus: Bad Debt Reconciliation (Acct 173)	$ (77,564)	
256	Total Bad Debt Allowance		$ 74,286
257			
258	**Local Production and Storage Capacity**		$ 476,106
259			
260	**Miscellaneous Overhead**		$ 580,455
261			
262	**Total Anticipated Indirect Cost of Gas**		$ 1,309,638
263			
264	**Total Cost of Gas**		$ 37,800,622

NORTHERN UTILITIES, INC.

N.H.P.U.C No. 12
NORTHERN UTILITIES, INC.

Anticipated Cost of Gas

New Hampshire Division
Period Covered: November 1, 2021 - October 31, 2022

	Column A	Column D
219	**ANTICIPATED DIRECT COST OF GAS**	
220	**Purchased Gas for Sales Service:**	
221	Demand Costs:	LN 3 + LN 112
222	Supply Costs:	LN 4 + LN 113
223		
224	**Storage & Peaking Gas for Sales Service:**	
225	Demand, Capacity:	LN 7 + LN 116
226	Commodity Costs:	LN 8 + LN 117
227		
228	**Inventory Finance Charge**	LN 10 + LN 119
229		
230	**Capacity Release**	LN 12 + LN 121
231		
232	**Re-entry Rate & Conversion Rate Revenues**	LN 14 + LN 123
233		
234	**Total Anticipated Direct Cost of Gas**	LN 16 + LN 125
235		
236	**ANTICIPATED INDIRECT COST OF GAS**	
237	**Adjustments:**	
238	Prior Period Under/(Over) Collection	LN 20 + LN 129
239	Interest	LN 21 + LN 130
240	Refunds	LN 22 + LN 131
241	Interruptible Margins	LN 23 + LN 132
242	Total Adjustments	LN 24 + LN 133
243		
244	**Working Capital:**	
245	Total Anticipated Direct Cost of Gas	LN 27 + LN 136
246	Working Capital Percentage	LN 28 + LN 137
247	Working Capital Allowance	LN 29 + LN 138
248		
249	Plus: Working Capital Reconciliation (Acct 173)	LN 31 + LN 139
250		
251	Total Working Capital Allowance	LN 33 + LN 141
252		
253	**Bad Debt:**	
254	Bad Debt Allowance	LN 36 + LN 144
255	Plus: Bad Debt Reconciliation (Acct 173)	LN 37 + LN 145
256	Total Bad Debt Allowance	LN 38 + LN 146
257		
258	**Local Production and Storage Capacity**	LN 40 + LN 148
259		
260	**Miscellaneous Overhead**	LN 42 + LN 150
261		
262	**Total Anticipated Indirect Cost of Gas**	LN 44 + LN 152
263		
264	**Total Cost of Gas**	LN 46 + LN 154

Northern Utilities New Hampshire Division
Cost of Gas Rate Comparison - Residential Rate Classes
(rates per therm)

Proposed Rates	2020-2021 Actual Cost of Gas Rates							
							Average	Variance
November 2021 - April 2022	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter 20-21	
$0.9392	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.2077
							Average	
May 2022 - October 2022	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer 2021	
$0.5176	$0.4970	$0.4970	$0.4970	$0.4970	$0.4970	$0.4970	$0.4970	$0.0206

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-CAK-15

Formula for Supplier Balancing Charge

Balancing Resources

Line	NU Storage Capacity Costs (Fixed)		NU Storage Space (Dth)		Reference
1	$ 122,375	TGP		259,337	Attachment NUI-FXW-4, Page 4
2	$ 2,840,000	Union		4,000,000	Attachment NUI-FXW-4, Page 4
3	$ 2,962,375	TOTAL		4,259,337	LN 1 + LN 2
4	Weighted Average Capacity Cost		$ 0.6955	per Dth	LN 3 Cost / LN3 Space
	NU Storage Commodity Costs (Variable)				
5	TGP FS-MA	Withdraw/Inject		$ 0.0174	Attachment NUI-FXW-9, PG 12, LN 10 * 2
6	Union	Withdraw/Inject		$ 0.0120	Attachment NUI-FXW-9, PG 13, LN 10 * 2
7	Weighted Average Commodity Cost		$ 0.0123	per Dth	LN 5, LN 6 (weighted)
8	Supplier Balancing Charge		$ 0.71	per Dth	LN 4 + LN 7

Re-entry Rate & Conversion Rate
Volumes and Revenues

Month	Re-entry Surcharage		Conversion Surcharge	
	Volumes	Revenues	Volumes	Revenues
May-20	0	$0	0	$0
Jun-20	1,161	$47	0	$0
Jul-20	1,069	$43	0	$0
Aug-20	1,025	$42	0	$0
Sep-20	1,169	$47	0	$0
Oct-20	3,077	$125	0	$0
Nov-20	4,860	$86	0	$0
Dec-20	12,779	$15	0	$0
Jan-21	16,710	$20	0	$0
Feb-21	23,305	$28	0	$0
Mar-21	24,188	$29	0	$0
Apr-21	11,950	$14	0	$0
May-21	0	$0		
Jun-21	529	$1	0	$0
Jul-21	866	$1	0	$0
Total	102,688	$499	0	$0

Northern Utilities, Inc.
Short-Term Debt Limit
($ in thousands)

NU Short-Term Debt Limit Calculation (11/1/2021 - 10/31/2022)			
Fuel Financing Purposes			
NU ME winter gas costs		51,535	
NU NH winter gas costs		33,189	
	Total	84,724	
30% of total winter gas costs		25,417	(a)
Non-Fuel Financing Purposes			
Estimated net utility plant @ 12/31/21		567,110	
15% of Net Utility Plant		85,066	(b)
Short-Term Debt Limit			
Short Term Debt Limit		**110,484**	(a) + (b)

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

	Total Division Metered Deliveries (Dth)										
	2021-2022	2021-2022 Compared to 2020-2021					2021-2022 Compared to 2019-2020				
	Forecast	2020-2021 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	742,238	706,201	36,038	5.1%	15,584	20,454	710,939	31,300	4.4%	37,416	-6,116
Dec	1,012,081	974,136	37,945	3.9%	22,020	15,925	967,728	44,354	4.6%	53,990	-9,637
Jan	1,300,722	1,195,414	105,308	8.8%	27,000	78,308	1,190,671	110,051	9.2%	63,943	46,108
Feb	1,335,467	1,256,408	79,058	6.3%	28,341	50,718	1,255,585	79,881	6.4%	67,147	12,734
Mar	1,107,637	1,052,431	55,206	5.2%	23,642	31,565	1,023,935	83,702	8.2%	55,370	28,332
Apr	877,111	812,809	64,303	7.9%	18,274	46,028	739,593	137,518	18.6%	41,521	95,997
May	631,324	583,125	48,199	8.3%	13,119	35,080	565,494	65,830	11.6%	26,082	39,747
Jun	446,553	426,376	20,177	4.7%	9,656	10,521	396,103	50,450	12.7%	18,152	32,298
Jul	401,291	384,587	16,704	4.3%	8,732	7,972	347,265	54,026	15.6%	15,680	38,346
Aug	401,013	385,149	15,864	4.1%	8,746	7,118	330,714	70,300	21.3%	14,936	55,364
Sep	408,450	392,793	15,657	4.0%	8,934	6,723	386,921	21,529	5.6%	17,533	3,997
Oct	505,819	486,861	18,958	3.9%	11,056	7,902	452,419	53,400	11.8%	20,457	32,943
Winter	6,375,256	5,997,398	377,858	6.3%	134,860	242,998	5,888,450	486,806	8.3%	319,768	167,038
Summer	2,794,451	2,658,891	135,560	5.1%	60,244	75,316	2,478,916	315,536	12.7%	112,703	202,833
Annual	9,169,707	8,656,289	513,418	5.9%	195,104	318,314	8,367,366	802,341	9.6%	417,316	385,025

Note 1 Company Forecast
Note 2 Pages 2 - 4; Sum of Column 2 of Billed Deliveries table. Actual Data through April is weather normalized.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Pages 2 - 4; Sum of Column 7 of Billed Deliveries Table. Actual Data provided is weather normalized.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	35,942	35,166	776	2.2%	34,145	1,797	5.3%
Dec	36,145	35,346	799	2.3%	34,235	1,910	5.6%
Jan	36,220	35,420	800	2.3%	34,374	1,846	5.4%
Feb	36,266	35,466	800	2.3%	34,425	1,841	5.3%
Mar	36,276	35,479	797	2.2%	34,415	1,861	5.4%
Apr	36,383	35,583	800	2.2%	34,449	1,934	5.6%
May	35,995	35,203	792	2.2%	34,408	1,587	4.6%
Jun	35,853	35,059	794	2.3%	34,282	1,571	4.6%
Jul	35,855	35,059	796	2.3%	34,306	1,549	4.5%
Aug	35,894	35,097	797	2.3%	34,343	1,551	4.5%
Sep	36,241	35,435	806	2.3%	34,670	1,571	4.5%
Oct	36,569	35,757	812	2.3%	34,987	1,582	4.5%
Winter	36,205	35,410	795	2.2%	34,341	1,865	5.4%
Summer	36,068	35,268	800	2.3%	34,499	1,569	4.5%
Annual	36,137	35,339	797	2.3%	34,420	1,717	5.0%

Note 1 Company Forecast
Note 2 Actual data through April. Forecast data beginning June. Page 2 - 4; Sum of Column 2 of Meter Counts table.
Note 3 Actual Data. Page 2 - 4; Sum of Column 5 of Meter Counts table.

	Total Division Use Per Meter						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	20.65	20.08	0.57	2.8%	20.82	-0.17	-0.8%
Dec	28.00	27.56	0.44	1.6%	28.27	-0.27	-0.9%
Jan	35.91	33.75	2.16	6.4%	34.64	1.27	3.7%
Feb	36.82	35.43	1.40	3.9%	36.47	0.35	1.0%
Mar	30.53	29.66	0.87	2.9%	29.75	0.78	2.6%
Apr	24.11	22.84	1.27	5.5%	21.47	2.64	12.3%
May	17.54	16.56	0.97	5.9%	16.43	1.10	6.7%
Jun	12.46	12.16	0.29	2.4%	11.55	0.90	7.8%
Jul	11.19	10.97	0.22	2.0%	10.12	1.07	10.6%
Aug	11.17	10.97	0.20	1.8%	9.63	1.54	16.0%
Sep	11.27	11.08	0.19	1.7%	11.16	0.11	1.0%
Oct	13.83	13.62	0.22	1.6%	12.93	0.90	7.0%
Winter	176.09	169.37	6.72	4.0%	171.47	4.61	2.7%
Summer	77.48	75.39	2.09	2.8%	71.85	5.63	7.8%
Annual	253.75	244.95	8.80	3.6%	243.10	10.24	4.2%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

	Residential Non-Heat Metered Deliveries (Dth)										
	2021-2022	2021-2022 Compared to 2020-2021					2021-2022 Compared to 2019-2020				
	Forecast	2020-2021 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	1,859	1,874	-16	-0.8%	-23	8	1,727	131	7.6%	29	102
Dec	2,658	2,616	42	1.6%	-33	75	2,569	89	3.4%	54	34
Jan	3,075	3,286	-211	-6.4%	-41	-170	3,033	42	1.4%	-80	122
Feb	3,131	3,456	-325	-9.4%	-43	-282	3,126	5	0.2%	-85	90
Mar	2,430	2,931	-501	-17.1%	-37	-465	2,626	-196	-7.5%	-59	-137
Apr	2,125	2,220	-94	-4.3%	-27	-67	2,221	-96	-4.3%	-15	-80
May	1,709	1,800	-91	-5.1%	-22	-69	1,866	-157	-8.4%	-45	-113
Jun	1,433	1,509	-76	-5.1%	-18	-58	1,474	-41	-2.8%	-36	-5
Jul	1,276	1,344	-68	-5.1%	-16	-52	1,261	15	1.2%	-31	46
Aug	1,213	1,278	-65	-5.1%	-15	-49	1,129	84	7.5%	-28	112
Sep	1,247	1,314	-66	-5.1%	-16	-51	1,402	-154	-11.0%	-34	-121
Oct	1,291	1,359	-69	-5.1%	-17	-52	1,285	5	0.4%	-31	37
Winter	15,277	16,382	-1,105	-6.7%	-205	-900	15,301	-24	-0.2%	-120	96
Summer	8,169	8,604	-435	-5.1%	-104	-331	8,417	-248	-2.9%	-204	-44
Annual	23,447	24,987	-1,540	-6.2%	-309	-1,231	23,718	-272	-1.1%	-385	113

Note 1 Company Forecast
Note 2 Actual, weather normalized data through April. Forecast data beginning June.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data through May. Forecast data beginning June.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1,265	1,281	-16	-1.2%	1,244	21	1.7%
Dec	1,260	1,276	-16	-1.3%	1,234	26	2.1%
Jan	1,259	1,275	-16	-1.3%	1,293	-34	-2.6%
Feb	1,256	1,272	-16	-1.3%	1,291	-35	-2.7%
Mar	1,263	1,279	-16	-1.3%	1,292	-29	-2.2%
Apr	1,296	1,312	-16	-1.2%	1,305	-9	-0.7%
May	1,304	1,320	-16	-1.2%	1,336	-32	-2.4%
Jun	1,317	1,333	-16	-1.2%	1,350	-33	-2.4%
Jul	1,316	1,332	-16	-1.2%	1,349	-33	-2.4%
Aug	1,318	1,334	-16	-1.2%	1,351	-33	-2.4%
Sep	1,306	1,322	-16	-1.2%	1,338	-32	-2.4%
Oct	1,284	1,300	-16	-1.2%	1,316	-32	-2.4%
Winter	1,267	1,283	-16	-1.2%	1,277	-10	-0.8%
Summer	1,308	1,324	-16	-1.2%	1,340	-33	-2.4%
Annual	1,287	1,303	-16	-1.2%	1,308	-21	-1.6%

Note 1 Company Forecast
Note 2 Actual data through April. Forecast data beginning June.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	1.47	1.46	0.01	0.4%	1.39	0.08	5.8%
Dec	2.11	2.05	0.06	2.9%	2.08	0.03	1.3%
Jan	2.44	2.58	-0.13	-5.2%	2.35	0.10	4.1%
Feb	2.49	2.72	-0.22	-8.3%	2.42	0.07	3.0%
Mar	1.92	2.29	-0.37	-16.1%	2.03	-0.11	-5.3%
Apr	1.64	1.69	-0.05	-3.1%	1.70	-0.06	-3.6%
May	1.31	1.36	-0.05	-3.9%	1.40	-0.09	-6.2%
Jun	1.09	1.13	-0.04	-3.9%	1.09	0.00	-0.4%
Jul	0.97	1.01	-0.04	-3.9%	0.93	0.04	3.8%
Aug	0.92	0.96	-0.04	-3.9%	0.84	0.08	10.2%
Sep	0.96	0.99	-0.04	-3.9%	1.05	-0.09	-8.8%
Oct	1.01	1.05	-0.04	-3.9%	0.98	0.03	2.9%
Winter	12.06	12.77	-0.71	-5.6%	11.99	0.11	0.9%
Summer	6.25	6.50	-0.25	-3.9%	6.28	-0.03	-0.5%
Annual	18.22	19.18	-0.96	-5.0%	18.13	0.07	0.4%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

	Residential Heat Metered Deliveries (Dth)										
	2021-2022	2021-2022 Compared to 2020-2021					2021-2022 Compared to 2019-2020				
	Forecast	2020-2021 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	152,046	148,118	3,928	2.7%	4,129	-201	144,623	7,423	5.1%	9,068	-1,644
Dec	259,212	249,123	10,089	4.0%	6,944	3,145	252,830	6,382	2.5%	16,744	-10,361
Jan	358,894	333,839	25,054	7.5%	9,297	15,757	325,777	33,116	10.2%	21,296	11,820
Feb	386,739	363,293	23,445	6.5%	10,108	13,338	359,118	27,621	7.7%	23,188	4,433
Mar	287,126	273,784	13,342	4.9%	7,585	5,757	269,023	18,103	6.7%	17,345	758
Apr	218,156	200,890	17,265	8.6%	5,571	11,694	200,431	17,725	8.8%	13,475	4,250
May	124,811	119,977	4,835	4.0%	3,323	1,512	132,059	-7,248	-5.5%	7,412	-14,659
Jun	61,437	59,013	2,424	4.1%	1,643	781	56,020	5,417	9.7%	3,160	2,256
Jul	39,664	38,089	1,575	4.1%	1,061	514	36,436	3,228	8.9%	2,057	1,172
Aug	35,409	34,000	1,409	4.1%	947	462	30,323	5,086	16.8%	1,713	3,374
Sep	38,017	36,505	1,512	4.1%	1,017	495	39,149	-1,132	-2.9%	2,211	-3,343
Oct	59,806	57,436	2,371	4.1%	1,602	768	55,366	4,440	8.0%	3,130	1,311
Winter	1,662,172	1,569,048	93,124	5.9%	43,634	49,491	1,551,802	110,370	7.1%	101,018	9,353
Summer	359,145	345,019	14,125	4.1%	9,593	4,532	349,353	9,792	2.8%	19,708	-9,916
Annual	2,021,317	1,914,067	107,250	5.6%	53,227	54,023	1,901,155	120,162	6.3%	115,469	4,693

Note 1 Company Forecast
Note 2 Actual, weather normalized data through April. Forecast data beginning June.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data through May. Forecast data beginning June.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	27,543	26,796	747	2.8%	25,918	1,625	6.3%
Dec	27,692	26,941	751	2.8%	25,972	1,720	6.6%
Jan	27,755	27,003	752	2.8%	26,052	1,703	6.5%
Feb	27,781	27,029	752	2.8%	26,096	1,685	6.5%
Mar	27,786	27,037	749	2.8%	26,103	1,683	6.4%
Apr	27,907	27,154	753	2.8%	26,149	1,758	6.7%
May	27,643	26,898	745	2.8%	26,174	1,469	5.6%
Jun	27,583	26,836	747	2.8%	26,110	1,473	5.6%
Jul	27,606	26,858	748	2.8%	26,131	1,475	5.6%
Aug	27,628	26,879	749	2.8%	26,151	1,477	5.6%
Sep	27,928	27,171	757	2.8%	26,435	1,493	5.6%
Oct	28,112	27,349	763	2.8%	26,608	1,504	5.7%
Winter	27,744	26,993	751	2.8%	26,048	1,696	6.5%
Summer	27,750	26,999	752	2.8%	26,268	1,482	5.6%
Annual	27,747	26,996	751	2.8%	26,158	1,589	6.1%

Note 1 Company Forecast
Note 2 Actual data through April. Forecast data beginning June.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	5.52	5.53	-0.01	-0.1%	5.58	-0.06	-1.1%
Dec	9.36	9.25	0.11	1.2%	9.73	-0.37	-3.8%
Jan	12.93	12.36	0.57	4.6%	12.50	0.43	3.4%
Feb	13.92	13.44	0.48	3.6%	13.76	0.16	1.2%
Mar	10.33	10.13	0.21	2.0%	10.31	0.03	0.3%
Apr	7.82	7.40	0.42	5.7%	7.66	0.15	2.0%
May	4.52	4.46	0.05	1.2%	5.05	-0.53	-10.5%
Jun	2.23	2.20	0.03	1.3%	2.15	0.08	3.8%
Jul	1.44	1.42	0.02	1.3%	1.39	0.04	3.0%
Aug	1.28	1.26	0.02	1.3%	1.16	0.12	10.5%
Sep	1.36	1.34	0.02	1.3%	1.48	-0.12	-8.1%
Oct	2.13	2.10	0.03	1.3%	2.08	0.05	2.2%
Winter	59.91	58.13	1.78	3.1%	59.57	0.33	0.6%
Summer	12.94	12.78	0.16	1.3%	13.30	-0.36	-2.7%
Annual	72.85	70.90	1.95	2.7%	72.68	-0.03	0.0%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Billed Distribution Service Volumes and Meter Counts

	Total Division C&I Metered Deliveries (Dth)										
	2021-2022	2021-2022 Compared to 2020-2021					2021-2022 Compared to 2019-2020				
	Forecast	2020-2021 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern	2019-2020 Normal	Change	Percent Change	Change Due to Meter Count	Change Due to Load Pattern
Column	1	2	3	4	5	6	7	8	9	10	11
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(3-5)	Note 4.	(1-5)	(6/5)	Note 5.	(8-10)
Nov	588,334	556,208	32,125	5.8%	3,531	28,595	564,588	23,745	4.2%	12,209	11,537
Dec	750,211	722,398	27,813	3.9%	6,485	21,328	712,329	37,883	5.3%	16,620	21,263
Jan	938,753	858,289	80,464	9.4%	7,691	72,773	861,860	76,893	8.9%	21,703	55,190
Feb	945,597	889,659	55,938	6.3%	7,947	47,991	893,342	52,256	5.8%	24,244	28,012
Mar	818,081	775,715	42,366	5.5%	6,931	35,435	752,286	65,794	8.7%	22,183	43,612
Apr	656,830	609,698	47,132	7.7%	5,397	41,735	536,941	119,889	22.3%	14,201	105,688
May	504,803	461,348	43,455	9.4%	4,161	39,294	431,569	73,235	17.0%	9,385	63,850
Jun	383,684	365,854	17,829	4.9%	3,345	14,484	338,609	45,075	13.3%	6,502	38,573
Jul	360,351	345,153	15,198	4.4%	3,216	11,982	309,569	50,782	16.4%	4,853	45,930
Aug	364,392	349,872	14,520	4.2%	3,253	11,267	299,262	65,129	21.8%	4,681	60,448
Sep	369,186	354,974	14,212	4.0%	3,324	10,888	346,370	22,816	6.6%	5,524	17,291
Oct	444,722	428,066	16,656	3.9%	3,914	12,742	395,767	48,955	12.4%	6,164	42,791
Winter	4,697,806	4,411,968	285,839	6.5%	37,982	247,857	4,321,347	376,459	8.7%	110,359	266,101
Summer	2,427,137	2,305,267	121,870	5.3%	21,213	100,657	2,121,146	305,992	14.4%	36,680	269,311
Annual	7,124,944	6,717,235	407,709	6.1%	59,195	348,514	6,442,493	682,451	10.6%	138,206	544,245

Note 1 Company Forecast
Note 2 Actual, weather normalized data through April. Forecast data beginning June.
Note 3 Column 3 of Meter Counts table times Column 2 of Use Per Meter table.
Note 4 Actual, weather normalized data through May. Forecast data beginning June.
Note 5 Column 6 of Meter Counts table times Column 5 of Use Per Meter table.

	Total Division Meter Counts						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	7,134	7,089	45	0.6%	6,983	151	2.2%
Dec	7,193	7,129	64	0.9%	7,029	164	2.3%
Jan	7,206	7,142	64	0.9%	7,029	177	2.5%
Feb	7,229	7,165	64	0.9%	7,038	191	2.7%
Mar	7,227	7,163	64	0.9%	7,020	207	2.9%
Apr	7,180	7,117	63	0.9%	6,995	185	2.6%
May	7,048	6,985	63	0.9%	6,898	150	2.2%
Jun	6,953	6,890	63	0.9%	6,822	131	1.9%
Jul	6,933	6,869	64	0.9%	6,826	107	1.6%
Aug	6,948	6,884	64	0.9%	6,841	107	1.6%
Sep	7,007	6,942	65	0.9%	6,897	110	1.6%
Oct	7,173	7,108	65	0.9%	7,063	110	1.6%
Winter	7,195	7,134	61	0.9%	7,016	179	2.6%
Summer	7,010	6,946	64	0.9%	6,891	119	1.7%
Annual	7,103	7,040	62	0.9%	6,953	149	2.1%

Note 1 Company Forecast
Note 2 Actual data through April. Forecast data beginning June.
Note 3 Actual Data.

	Total Division Use Per Meter						
	2021-2022	Compared to 2020-2021			Compared to 2019-2020		
	Forecast	Actual	Change	Percent Change	Actual	Change	Percent Change
Column	1	2	3	4	5	6	7
Reference	Note 1.	Note 2.	(1-2)	(3/2)	Note 3.	(1-5)	(6/5)
Nov	82.47	78.46	4.01	5.1%	80.85	1.62	2.0%
Dec	104.30	101.33	2.97	2.9%	101.34	2.96	2.9%
Jan	130.27	120.17	10.10	8.4%	122.61	7.66	6.2%
Feb	130.81	124.17	6.64	5.3%	126.93	3.87	3.1%
Mar	113.20	108.29	4.90	4.5%	107.16	6.03	5.6%
Apr	91.48	85.67	5.81	6.8%	76.76	14.72	19.2%
May	71.62	66.05	5.58	8.4%	62.56	9.06	14.5%
Jun	55.18	53.10	2.08	3.9%	49.63	5.55	11.2%
Jul	51.98	50.25	1.73	3.4%	45.35	6.62	14.6%
Aug	52.45	50.82	1.62	3.2%	43.75	8.70	19.9%
Sep	52.69	51.13	1.55	3.0%	50.22	2.47	4.9%
Oct	62.00	60.22	1.78	2.9%	56.03	5.97	10.6%
Winter	652.94	618.43	34.51	5.6%	615.96	36.86	6.0%
Summer	346.22	331.87	14.35	4.3%	307.81	38.37	12.5%
Annual	1,003.15	954.12	49.03	5.1%	926.52	75.23	8.1%

Note 1 Column 1 of Billed Deliveries table divided by Column 1 of Meter Counts table.
Note 2 Column 2 of Billed Deliveries table divided by Column 2 of Meter Counts table.
Note 3 Column 7 of Billed Deliveries table divided by Column 5 of Meter Counts table.

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Calendar Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-21	2,036	221,484	112,857	11,832	82,895	19,614	15,211	5,390	0	471,318
Dec-21	2,920	317,676	161,872	16,971	118,898	28,132	20,363	5,213	0	672,045
Jan-22	3,417	371,797	189,449	19,862	139,154	32,925	25,566	5,859	0	788,030
Feb-22	2,933	319,078	162,586	17,046	119,422	28,256	22,475	5,663	0	677,460
Mar-22	2,500	272,023	138,609	14,532	101,811	24,089	20,030	5,832	0	579,426
Apr-22	1,472	160,114	81,586	8,554	59,926	14,179	14,481	5,343	0	345,654
May-22	1,761	77,414	29,330	14,616	31,016	21,996	9,354	5,274	0	190,761
Jun-22	1,150	50,568	19,159	9,547	20,260	14,368	6,083	4,588	0	125,725
Jul-22	972	42,733	16,191	8,068	17,121	12,142	5,374	4,819	0	107,420
Aug-22	986	43,338	16,420	8,182	17,363	12,314	5,440	4,999	0	109,042
Sep-22	1,094	48,090	18,220	9,080	19,267	13,664	6,562	4,834	0	120,812
Oct-22	2,206	97,002	36,752	18,314	38,864	27,562	10,915	5,327	0	236,943
Winter	15,277	1,662,172	846,960	88,798	622,105	147,195	118,126	33,300	0	3,533,933
Summer	8,169	359,145	136,073	67,808	143,892	102,047	43,729	29,841	0	890,703
Total	23,447	2,021,317	983,033	156,605	765,997	249,241	161,855	63,141	0	4,424,636

Forecast Calendar Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-21	2,036	221,484	132,411	14,308	173,333	42,154	55,923	153,997	108,814	904,460
Dec-21	2,920	317,676	184,888	19,885	225,345	54,663	74,864	148,940	109,400	1,138,582
Jan-22	3,417	371,797	215,758	23,193	260,831	63,252	93,992	167,413	112,068	1,311,721
Feb-22	2,933	319,078	186,616	20,088	230,555	55,955	82,630	161,787	105,847	1,165,490
Mar-22	2,500	272,023	162,476	17,554	212,193	51,601	73,640	166,623	120,889	1,079,498
Apr-22	1,472	160,114	100,402	10,936	146,950	35,869	53,238	152,656	113,868	775,504
May-22	1,761	77,414	33,158	16,919	56,498	41,033	34,391	150,685	114,138	525,996
Jun-22	1,150	50,568	22,584	11,608	43,062	31,402	22,363	131,083	108,085	421,906
Jul-22	972	42,733	19,483	10,049	39,043	28,519	19,757	137,698	112,194	410,447
Aug-22	986	43,338	19,858	10,251	40,259	29,418	20,001	142,819	112,278	419,208
Sep-22	1,094	48,090	21,748	11,203	42,759	31,214	24,126	138,112	110,611	428,956
Oct-22	2,206	97,002	41,026	20,886	67,319	48,820	40,130	152,210	118,338	587,938
Winter	15,277	1,662,172	982,552	105,964	1,249,208	303,494	434,287	951,416	670,886	6,375,256
Summer	8,169	359,145	157,857	80,916	288,939	210,406	160,769	852,606	675,644	2,794,451
Total	23,447	2,021,317	1,140,409	186,880	1,538,147	513,900	595,055	1,804,022	1,346,530	9,169,707

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-21	100%	100%	85%	83%	48%	47%	27%	4%	0%	52%
Dec-21	100%	100%	88%	85%	53%	51%	27%	4%	0%	59%
Jan-22	100%	100%	88%	86%	53%	52%	27%	4%	0%	60%
Feb-22	100%	100%	87%	85%	52%	50%	27%	4%	0%	58%
Mar-22	100%	100%	85%	83%	48%	47%	27%	4%	0%	54%
Apr-22	100%	100%	81%	78%	41%	40%	27%	4%	0%	45%
May-22	100%	100%	88%	86%	55%	54%	27%	4%	0%	36%
Jun-22	100%	100%	85%	82%	47%	46%	27%	4%	0%	30%
Jul-22	100%	100%	83%	80%	44%	43%	27%	4%	0%	26%
Aug-22	100%	100%	83%	80%	43%	42%	27%	4%	0%	26%
Sep-22	100%	100%	84%	81%	45%	44%	27%	4%	0%	28%
Oct-22	100%	100%	90%	88%	58%	56%	27%	4%	0%	40%
Winter	100%	100%	86%	84%	50%	49%	27%	4%	0%	55%
Summer	100%	100%	86%	84%	50%	49%	27%	4%	0%	32%
Total	100%	100%	86%	84%	50%	49%	27%	4%	0%	48%

Northern Utilities, Inc.
New Hampshire Division
Sales Service Deliveries Forecast by Rate Class

Forecast Bill Month Sales Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-21	1,859	152,046	71,747	10,663	65,802	20,132	15,211	5,390	0	342,850
Dec-21	2,658	259,212	129,015	13,367	100,279	24,261	20,363	5,213	0	554,368
Jan-22	3,075	358,894	189,730	17,484	132,778	27,980	25,566	5,859	0	761,365
Feb-22	3,131	386,739	201,973	18,067	139,670	28,617	22,475	5,663	0	806,334
Mar-22	2,430	287,126	148,549	15,786	106,303	25,365	20,030	5,832	0	611,422
Apr-22	2,125	218,156	105,946	13,431	77,274	20,839	14,481	5,343	0	457,594
May-22	1,709	124,811	53,710	11,269	45,627	18,533	9,354	5,274	0	270,287
Jun-22	1,433	61,437	21,702	11,455	23,758	17,266	6,083	4,588	0	147,721
Jul-22	1,276	39,664	12,329	11,228	15,126	15,825	5,374	4,819	0	105,641
Aug-22	1,213	35,409	11,618	11,339	14,049	16,526	5,440	4,999	0	100,593
Sep-22	1,247	38,017	13,399	11,599	16,955	15,960	6,562	4,834	0	108,572
Oct-22	1,291	59,806	23,315	10,919	28,377	17,937	10,915	5,327	0	157,888
Winter	15,277	1,662,172	846,960	88,798	622,105	147,195	118,126	33,300	0	3,533,933
Summer	8,169	359,145	136,073	67,808	143,892	102,047	43,729	29,841	0	890,703
Total	23,447	2,021,317	983,033	156,605	765,997	249,241	161,855	63,141	0	4,424,636

Forecast Bill Month Distribution Service Deliveries (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-21	1,859	152,046	83,233	12,724	132,132	41,510	55,923	153,997	108,814	742,238
Dec-21	2,658	259,212	149,670	15,951	201,364	50,023	74,864	148,940	109,400	1,012,081
Jan-22	3,075	358,894	220,104	20,864	266,622	57,690	93,992	167,413	112,068	1,300,722
Feb-22	3,131	386,739	234,307	21,560	280,461	59,005	82,630	161,787	105,847	1,335,467
Mar-22	2,430	287,126	172,331	18,838	213,461	52,299	73,640	166,623	120,889	1,107,637
Apr-22	2,125	218,156	122,907	16,027	155,168	42,967	53,238	152,656	113,868	877,111
May-22	1,709	124,811	62,308	13,447	91,621	38,213	34,391	150,685	114,138	631,324
Jun-22	1,433	61,437	25,177	13,669	47,706	35,600	22,363	131,083	108,085	446,553
Jul-22	1,276	39,664	14,303	13,398	30,373	32,629	19,757	137,698	112,194	401,291
Aug-22	1,213	35,409	13,478	13,531	28,211	34,074	20,001	142,819	112,278	401,013
Sep-22	1,247	38,017	15,544	13,841	34,046	32,906	24,126	138,112	110,611	408,450
Oct-22	1,291	59,806	27,047	13,030	56,982	36,984	40,130	152,210	118,338	505,819
Winter	15,277	1,662,172	982,552	105,964	1,249,208	303,494	434,287	951,416	670,886	6,375,256
Summer	8,169	359,145	157,857	80,916	288,939	210,406	160,769	852,606	675,644	2,794,451
Total	23,447	2,021,317	1,140,409	186,880	1,538,147	513,900	595,055	1,804,022	1,346,530	9,169,707

Forecast Sales Service Percentage

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Total Division
Nov-21	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	46.2%
Dec-21	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	54.8%
Jan-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	58.5%
Feb-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	60.4%
Mar-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	55.2%
Apr-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	52.2%
May-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	42.8%
Jun-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	33.1%
Jul-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	26.3%
Aug-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	25.1%
Sep-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	26.6%
Oct-22	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	31.2%
Winter	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	55.4%
Summer	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	31.9%
Total	100.0%	100.0%	86.2%	83.8%	49.8%	48.5%	27.2%	3.5%	0.0%	48.3%

Northern Utilities, Inc.
New Hampshire Division
Forecast Total Billed Meters

Month	Res Non-Heat	Res Heat	G/T40	G/T50	G/T41	G/T51	G/T42	G/T52	Special Contracts	Total Division
Nov-21	1,220	26,228	5,059	815	727	278	34	33	3	34,397
Dec-21	1,210	26,264	5,097	819	732	278	34	32	3	34,469
Jan-22	1,268	26,349	5,097	818	733	278	34	32	3	34,612
Feb-22	1,266	26,391	5,104	820	732	278	35	32	3	34,661
Mar-22	1,267	26,399	5,085	822	731	278	35	32	3	34,652
Apr-22	1,280	26,442	5,055	829	729	278	35	32	3	34,683
May-22	1,261	26,321	4,989	835	668	281	30	33	3	34,421
Jun-22	1,265	26,219	4,880	830	667	281	30	33	3	34,208
Jul-22	1,261	26,054	4,834	828	666	282	30	33	3	33,991
Aug-22	1,261	26,062	4,817	826	664	282	30	33	3	33,978
Sep-22	1,242	26,232	4,822	826	678	290	30	33	3	34,156
Oct-22	1,213	26,489	4,938	822	728	281	33	33	3	34,540

Forecast Delivery Service Billed Meters

Month	Res Non-Heat	Res Heat	40	50	41	51	42	52	Special Contracts	Total Division
Nov-21	-	-	503	86	302	124	21	30	3	1,069
Dec-21	-	-	503	86	302	124	21	30	3	1,069
Jan-22	-	-	503	86	302	124	21	30	3	1,069
Feb-22	-	-	503	86	302	124	21	30	3	1,069
Mar-22	-	-	503	86	302	124	21	30	3	1,069
Apr-22	-	-	503	86	302	124	21	30	3	1,069
May-22	-	-	503	86	302	124	21	30	3	1,069
Jun-22	-	-	503	86	302	124	21	30	3	1,069
Jul-22	-	-	503	86	302	124	21	30	3	1,069
Aug-22	-	-	503	86	302	124	21	30	3	1,069
Sep-22	-	-	503	86	302	124	21	30	3	1,069
Oct-22	-	-	503	86	302	124	21	30	3	1,069

Forecast Sales Service Billed Meters

Month	Res Non-Heat	Res Heat	40	50	41	51	42	52	Special Contracts	Total Division
Nov-21	1,220	26,228	4,556	729	425	154	13	3	-	33,328
Dec-21	1,210	26,264	4,594	733	430	154	13	2	-	33,400
Jan-22	1,268	26,349	4,594	732	431	154	13	2	-	33,543
Feb-22	1,266	26,391	4,601	734	430	154	14	2	-	33,592
Mar-22	1,267	26,399	4,582	736	429	154	14	2	-	33,583
Apr-22	1,280	26,442	4,552	743	427	154	14	2	-	33,614
May-22	1,261	26,321	4,486	749	366	157	9	3	-	33,352
Jun-22	1,265	26,219	4,377	744	365	157	9	3	-	33,139
Jul-22	1,261	26,054	4,331	742	364	158	9	3	-	32,922
Aug-22	1,261	26,062	4,314	740	362	158	9	3	-	32,909
Sep-22	1,242	26,232	4,319	740	376	166	9	3	-	33,087
Oct-22	1,213	26,489	4,435	736	426	157	12	3	-	33,471

Northern Utilities, Inc.
New Hampshire Division
Estimation of Northern - New Hampshire City-Gate Sendout Requirement

Month	Sales Service Deliveries (Dth)	Company Gas Allowance (Percent)	Company Gas Allowance (LAUF and Company Use) (Dth)	Estimated Division Sales Service Sendout (Dth)	Estimated Company-Managed Sales	Total Estimated City-Gate Sendout Requirement
Nov-21	471,318	1.25%	5,966	477,284	23,850	501,134
Dec-21	672,045	1.25%	8,506	680,551	25,927	706,478
Jan-22	788,030	1.25%	9,975	798,005	30,414	828,419
Feb-22	677,460	1.25%	8,576	686,036	22,901	708,937
Mar-22	579,426	1.25%	7,335	586,761	24,645	611,406
Apr-22	345,654	1.25%	4,375	350,029	0	350,029
May-22	190,761	1.25%	2,415	193,176	0	193,176
Jun-22	125,725	1.25%	1,591	127,316	0	127,316
Jul-22	107,420	1.25%	1,360	108,780	0	108,780
Aug-22	109,042	1.25%	1,381	110,423	0	110,423
Sep-22	120,812	1.25%	1,529	122,341	0	122,341
Oct-22	236,943	1.25%	3,000	239,943	0	239,943
Winter	3,533,933	1.25%	44,733	3,578,666	127,737	3,706,403
Summer	890,703	1.25%	11,276	901,979	0	901,979
Annual	4,424,636	1.25%	56,009	4,480,645	127,737	4,608,382

Northern Utilities, Inc.
New Hampshire Division
Lost and Unaccounted For, Company Use and Therm Factor Data

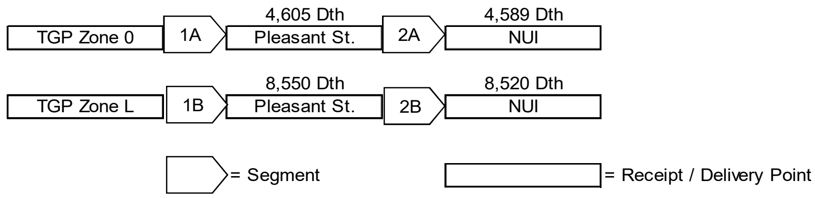
Month	GSGT - NH City-Gates (MCF)	Therm Factor	Total - NH City-Gate (Dth)	Total System Billed Sales (Dth)	Company Use (Dth)	Lost and Unaccounted For (Dth)	Company Gas Allowance (Dth)
May-17	505,254	1.0276	519,184	568,537	74	(49,427)	(49,353)
Jun-17	367,334	1.0280	377,630	385,479	56	(7,905)	(7,849)
Jul-17	339,837	1.0256	348,547	387,504	59	(39,016)	(38,957)
Aug-17	361,673	1.0280	371,789	366,064	62	5,663	5,725
Sep-17	357,543	1.0278	367,472	356,844	56	10,572	10,628
Oct-17	446,927	1.0284	459,625	427,725	32	31,868	31,900
Nov-17	794,934	1.0307	819,307	581,080	71	238,156	238,227
Dec-17	1,205,148	1.0339	1,245,942	1,003,583	209	242,150	242,359
Jan-18	1,274,596	1.0394	1,324,764	1,403,452	373	(79,061)	(78,688)
Feb-18	936,704	1.0340	968,580	1,110,067	270	(141,757)	(141,487)
Mar-18	999,035	1.0334	1,032,433	998,242	239	33,952	34,191
Apr-18	766,729	1.0318	791,111	889,669	211	(98,769)	(98,558)
May-18	443,025	1.0283	455,580	574,552	108	(119,080)	(118,972)
Jun-18	369,548	1.0292	380,339	409,352	40	(29,053)	(29,013)
Jul-18	351,086	1.0289	361,236	352,762	92	8,382	8,474
Aug-18	363,051	1.0284	373,373	369,837	131	3,406	3,537
Sep-18	378,195	1.0276	388,633	370,269	131	18,233	18,364
Oct-18	628,317	1.0303	647,361	485,553	100	161,708	161,808
Nov-18	923,290	1.0336	954,321	765,985	142	188,194	188,336
Dec-18	1,057,440	1.0382	1,097,877	1,067,650	207	30,020	30,227
Jan-19	1,259,492	1.0431	1,313,764	1,200,221	254	113,289	113,543
Feb-19	1,109,150	1.0375	1,150,732	1,229,927	257	(79,452)	(79,195)
Mar-19	1,008,861	1.0347	1,043,849	1,147,817	251	(104,219)	(103,968)
Apr-19	681,738	1.0309	702,824	843,446	173	(140,795)	(140,622)
May-19	545,305	1.0288	560,999	632,151	100	(71,252)	(71,152)
Jun-19	388,772	1.0290	400,027	430,401	58	(30,432)	(30,374)
Jul-19	365,810	1.0287	376,320	391,025	83	(14,788)	(14,705)
Aug-19	374,614	1.0280	385,103	380,773	140	4,190	4,330
Sep-19	394,298	1.0283	405,449	375,182	100	30,168	30,268
Oct-19	534,087	1.0295	549,837	485,413	89	64,335	64,424
Nov-19	930,426	1.0352	963,214	698,186	84	264,945	265,029
Dec-19	1,075,165	1.0460	1,124,591	1,016,439	240	107,912	108,152
Jan-20	1,077,141	1.0437	1,124,212	1,130,011	294	(6,093)	(5,799)
Feb-20	1,041,031	1.0434	1,086,254	1,133,789	289	(47,824)	(47,535)
Mar-20	839,434	1.0376	871,030	1,005,451	257	(134,678)	(134,421)
Apr-20	651,269	1.0343	673,594	707,067	180	(33,653)	(33,473)
May-20	441,527	1.0303	454,923	565,494	141	(110,712)	(110,571)
Jun-20	344,089	1.0300	354,401	396,103	60	(41,762)	(41,702)
Jul-20	332,377	1.0285	341,836	347,265	64	(5,493)	(5,429)
Aug-20	341,582	1.0299	351,806	330,714	89	21,003	21,092
Sep-20	387,752	1.0284	398,768	386,921	118	11,729	11,847
Oct-20	569,808	1.0286	586,110	452,419	61	133,631	133,691
Nov-20	740,493	1.0331	765,011	649,932	98	114,981	115,079
Dec-20	1,058,690	1.0409	1,101,990	928,725	171	173,094	173,265
Jan-21	1,172,543	1.0407	1,220,219	1,116,107	263	103,849	104,112
Feb-21	1,086,893	1.0402	1,130,630	1,198,238	328	(67,936)	(67,608)
Mar-21	942,363	1.0334	973,866	1,164,215	327	(190,676)	(190,349)
Apr-21	652,284	1.0292	671,331	720,559	162	(49,390)	(49,228)
Total	33,216,660	1.0347	34,367,794	33,938,194	7,395	422,205	429,600
48-Month Average					0.02%	1.23%	1.25%

Table 3. Northern Capacity Summary (Dth/Day)

Pipeline Capacity Paths	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
PXP Dawn Hub	9,965
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	40,586
Storage Capacity Paths	
Tennessee Firm Storage	2,644
Dawn Hub Storage	39,863
Total Storage Capacity	42,507
Peaking Capacity Paths	
LNG - On-System	6,500
PNGTS Delivered Baseload (Dec-Feb)	2,491
Peaking Contract 1	39,860
Peaking Contract 2	9,965
Additional Granite Capacity	935
Total Peaking Capacity	59,751
Total Design Day Capacity	142,844

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Zone 0 100 Leg, Zone L 500 and 800 Leg Pools

Capacity Path Diagram



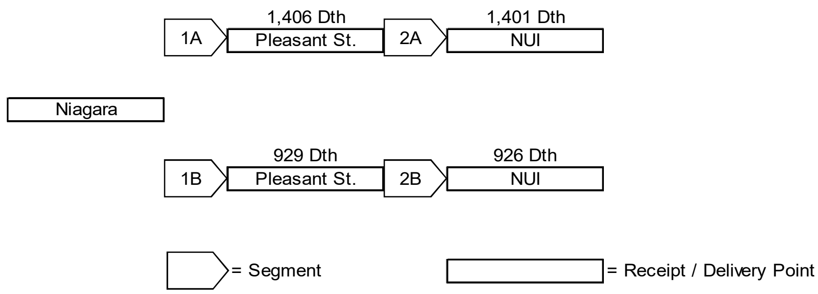
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A[1]	Transportation	Tennessee	5083	FT-A	10/31/2023	4,605	Dth	Year-Round	Zone 0, 100 Leg	Pleasant St.	Granite
2A	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	4,589	Dth	Year-Round	Granite	Northern City Gates	
1B[1]	Transportation	Tennessee	5083	FT-A	10/31/2023	8,550	Dth	Year-Round	Zone L, 500 & 800 Legs	Pleasant St.	Granite
2B	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	8,520	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						13,109	Dth				

Note 1: Tennessee Contract No. 5083 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Production could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Niagara (Interconnection of TransCanada and Tennessee Pipelines)

Capacity Path Diagram

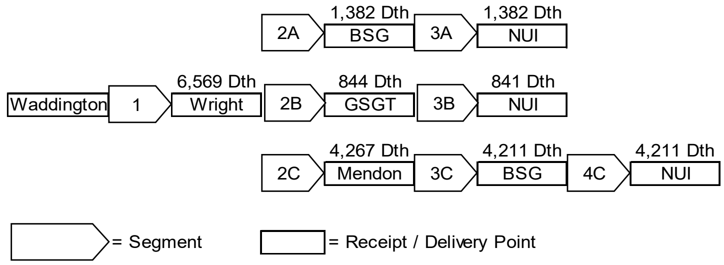


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1A	Transportation	Tennessee	5292	FT-A	3/31/2025	1,406	Dth	Year-Round	Niagara	Pleasant St.	Granite
2A	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	1,401	Dth	Year-Round	Granite	Northern City Gates	
1B	Transportation	Tennessee	39735	FT-A	3/31/2025	929	Dth	Year-Round	Niagara	Pleasant St.	Granite
2B	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	926	Dth	Year-Round	Granite	Northern City Gates	
Total Path Deliverable						2,327	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Iroquois Receipts

Capacity Path Diagram

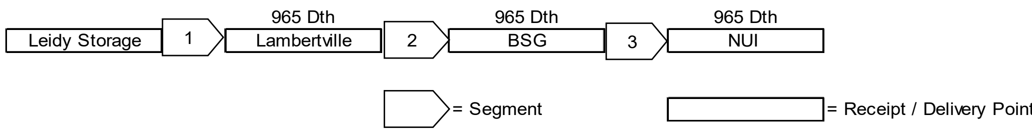


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Iroquois	R181003	RTS-1	10/31/2024	6,569	Dth	Year-Round	Waddington	Wright	Tennessee
2A	Transportation	Tennessee	95196	FT-A	10/31/2022	1,382	Dth	Year-Round	Wright	Bay State City Gate	
3A	Exchange	Bay State Gas	NA	NA	Renewal Clause	1,382	Dth	Year-Round	Bay State City Gate	Northern City Gates	
2B	Transportation	Tennessee	95196	FT-A	10/31/2022	844	Dth	Year-Round	Wright	Pleasant St.	Granite
3B	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	841	Dth	Year-Round	Granite	Northern City Gates	
2C	Transportation	Tennessee	41099	FT-A	10/31/2022	4,267	Dth	Year-Round	Wright	Mendon	Algonquin
3C	Transportation	Algonquin	93200F	AFT-1	10/31/2022	4,211	Dth	Year-Round	Mendon	Bay State City Gate	
4C	Exchange	Bay State Gas	NA	NA	Renewal Clause	4,211	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						6,434	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Algonquin Receipt Points

Capacity Path Diagram

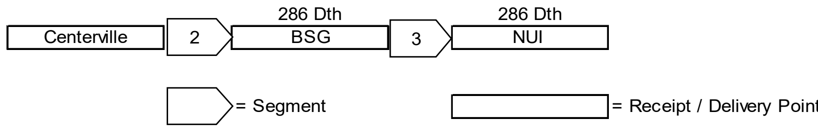


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Texas Eastern	800384	FT-1	10/31/2022	965	Dth	Year-Round	Leidy Storage	Lambertville, NJ	Algonquin
2	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2022	965	Dth	Year-Round	Lambertville, NJ	Bay State City Gate	
3	Exchange	Bay State Gas	NA	NA	Renewal Clause	965	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						965	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Algonquin Receipt Points

Capacity Path Diagram

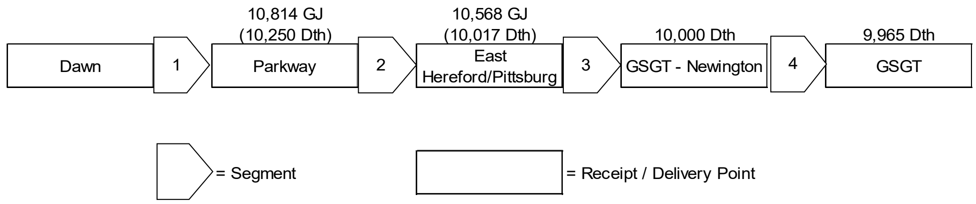


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	93201A1C	AFT-1 (F-2/F-3)	10/31/2022	286	Dth	Year-Round	Centerville, NJ	Bay State City Gate	
2	Exchange	Bay State Gas	NA	NA	Renewal Clause	286	Dth	Year-Round	Bay State City Gate	Northern City Gates	
Total Path Deliverable						286	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: PXP Dawn Hub

Capacity Path Diagram

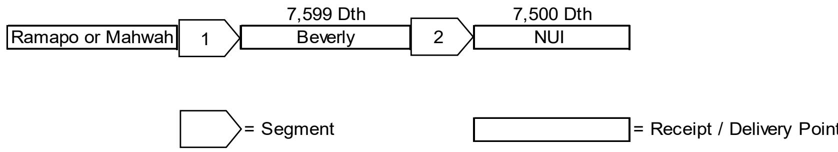


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Union	M12296	M12	10/31/2040	10,814	GJ	Year-Round	Dawn	Parkway	TransCanada
2	Transportation	TransCanada	63265	FT	10/31/2040	10,568	GJ	Year-Round	Parkway	East Hereford	PNGTS
3	Transportation	PNGTS	23339	FT	10/31/2040	10,000	Dth	Year-Round	Pittsburg, NH	Newington, NH	Granite
4	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	9,965	Dth	Year-Round	Newington, NH	Northern City Gates	
Total Path Deliverable						9,965	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Atlantic Bridge Ramapo

Capacity Path Diagram

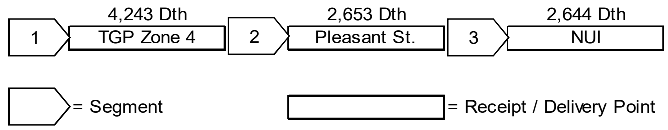


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Transportation	Algonquin	510939	FT	2/11/2036	7,599	Dth	Year-Round	Ramapo or Mawhah	Beverly, MA	Maritimes
2	Transportation	Maritimes	210363	FT	2/11/2036	7,500	Dth	Year-Round	Beverly, MA	Northern City Gates	
Total Path Deliverable						7,500	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Tennessee Firm Storage - Market Area

Capacity Path Diagram



Capacity Path Detail

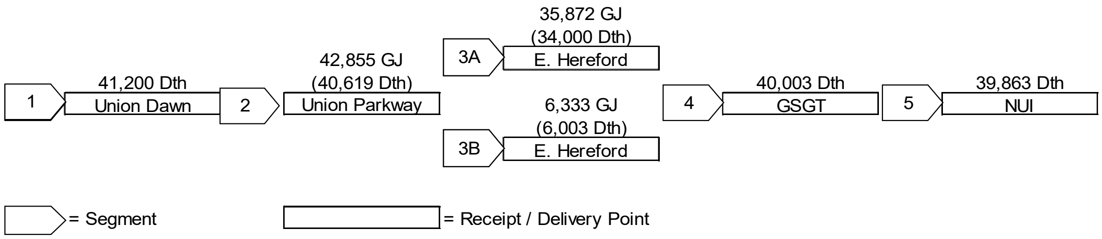
Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Storage	Tennessee	5195	FS-MA	3/31/2025	4,243	Dth	Year-Round	NA	TGP Zone 4	Tennessee
2[2]	Transportation	Tennessee	5265	FT-A	3/31/2025	2,653	Dth	Year-Round	TGP Zone 4	Pleasant St.	Granite
3	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	2,644	Dth	Year-Round	Pleasant St.	Northern City Gates	
Total Path Deliverable						2,644	Dth				

Note 1: Tennessee Contract No. 5195 has a maximum storage quantity of 259,337 Dth.

Note 2: Tennessee Contract No. 5265 also allows for firm delivery rights to Bay State Gas city gates. As such, Tennessee Firm Storage could also be delivered to Northern City Gates via the Bay State Exchange.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Union Dawn Storage

Capacity Path Diagram

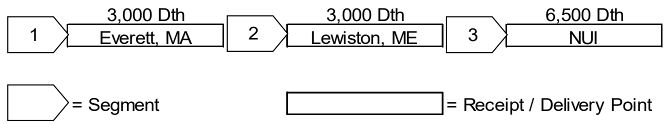


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1	Storage	Union	LST086	Firm Storage (MDWD)	3/31/2023	43,468	GJ	Year-Round	NA	Dawn	Union
1	Storage	Union	LST086	Firm Storage (MSB)	3/31/2023	4,220,224	GJ	Year-Round	NA	Dawn	
1	Storage	Union	LST086	Firm Storage (MDID)	3/31/2023	31,652	GJ	Year-Round	NA	Dawn	
2	Transportation	Union	M12256	M12	10/31/2033	42,962	GJ	Year-Round	Dawn	Parkway	TransCanada
3A	Transportation	TransCanada	57901	FT	3/31/2033	35,872	GJ	Year-Round	Parkway	East Hereford	PNGTS
3B	Transportation	TransCanada	57055	FT	10/31/2032	6,333	GJ	Year-Round	Parkway	East Hereford	PNGTS
4	Transportation	PNGTS	208543	FT	11/30/2032	40,003	Dth	Year-Round	Pittsburg, NH	Newington, NH	Granite
5	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	39,863	Dth	Year-Round	Newington, NH	Northern City Gates	
Total Path Deliverable						39,863	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Lewiston LNG Plant

Capacity Path Diagram



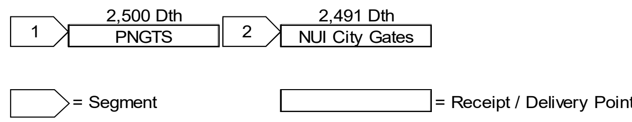
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	LNG Contract	Confidential	NA	NA	10/31/2022	3,000	Dth	Year-Round	NA		NA
2	LNG Trucking Contract	Confidential			10/31/2022	3,000	Dth	Year-Round		Lewiston, ME	NA
3	Lewiston LNG Plant	N/A	NA	NA	N/A	6,500	Dth	Year-Round	Lewiston, ME	Northern Distribution System	
Total Path Deliverable						6,500	Dth				

Note 1: The LNG Contract allows Northern to nominate up to 3,000 Dth per day (3 trucks) with an annual maximum take equal to 75,000 Dth.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: PNGTS Delivered Supply (Dec-Feb)

Capacity Path Diagram

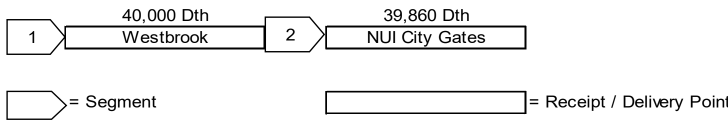


Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	2/28/2022	2,500	Dth	Winter Only (Dec - Feb)	NA	PNGTS	Granite or Northern City Gates
2	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	2,491	Dth	Year-Round	PNGTS	Northern City Gates	
Total Path Deliverable						2,491	Dth				

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Contract 1

Capacity Path Diagram



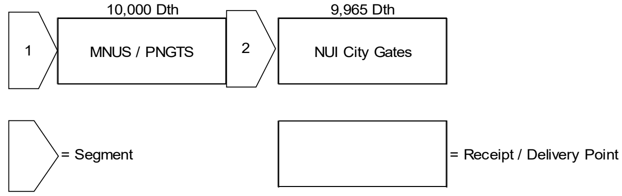
Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2024	40,000	Dth	Winter Only (Nov - Mar)	NA	Westbrook or Lewiston	Granite or Northern City Gates
2	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	39,860	Dth	Year-Round	Westbrook or Lewiston	Northern City Gates	
Total Path Deliverable						39,860	Dth				

Note 1: Peaking Contract 1 allows Northern to nominate up to 40,000 Dth per Day and up to 600,000 Dth from November through March with takes above 30,000 Dth per Day capped at 50,000 Dth. Contract volumes may also be delivered to NUI - Lewiston in which case no Granite capacity is utilized.

Northern Utilities, Inc.
Capacity Path Diagram and Detail
Source of Supply: Peaking Contract 2

Capacity Path Diagram



Capacity Path Detail

Segment	Product	Vendor	Contract ID	Rate Schedule	Contract Termination Date	Northern MDQ	Dth / GJ	Availability	Receipt Point	Delivery Point	Interconnecting Pipeline
1[1]	Peaking Supply	Confidential	NA	NA	3/31/2022	10,000	Dth	Winter Only (Nov - Mar)	NA	MNUS / PNGTS	Granite or Northern City Gates
2	Transportation	Granite	19-100-FT-NN	FT-NN	10/31/2022	9,965	Dth	Year-Round	MNUS / PNGTS	Northern City Gates	
Total Path Deliverable						9,965	Dth				

Note 1: Peaking Contract 2 allows Northern to nominate up to 10,000 Dth per Day and up to 300,000 Dth from November through March. Contract volumes may also be delivered to NUI - Lewiston in which case no Granite capacity is utilized.

Northern Utilities, Inc.
Estimated Gas Supply Demand Costs
November 1, 2021 through October 31, 2022

Line	Description	Estimate	Reference
1.	Pipeline Demand Costs	$ 17,953,274	Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 22,032,867	Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 2,959,638	Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 2,216,171	Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 11,397,667	Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (9,902,100)	Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 46,657,517	Sum Lines 1 through 6.

Northern Utilities, Inc.
Pipeline Contract Demand Cost Estimates
November 1, 2021 through October 31, 2022

Capacity Path	Segment	Pipeline	Contract ID	Rate	Negotiated Rate	Maximum Daily Quantity (Dth)	Monthly Demand Rate ($/MDQ)	Months Per Year	Reference (Att NUI-FXW-9, Page 2)	Monthly Demand	Annual Demand
Tennessee Zone 0/L Pools	1A	Tennessee	5083	FT-A	No	4,605	$ 19.9192	12	Line 8	$ 91,728	$ 1,100,735
Tennessee Zone 0/L Pools	2A	Granite	19-100-FT-NN	FT-NN	No	4,589	$ 5.9096	12	Line 3	$ 27,119	$ 325,430
Tennessee Zone 0/L Pools	1B	Tennessee	5083	FT-A	No	8,550	$ 17.6842	12	Line 9	$ 151,200	$ 1,814,399
Tennessee Zone 0/L Pools	2B	Granite	19-100-FT-NN	FT-NN	No	8,520	$ 5.9096	12	Line 3	$ 50,350	$ 604,198
Tennessee Niagara	1A	Tennessee	5292	FT-A	No	1,406	$ 6.1560	12	Line 11	$ 8,655	$ 103,864
Tennessee Niagara	2A	Granite	19-100-FT-NN	FT-NN	No	1,401	$ 5.9096	12	Line 3	$ 8,279	$ 99,352
Tennessee Niagara	1B	Tennessee	39735	FT-A	No	929	$ 6.1560	12	Line 11	$ 5,719	$ 68,627
Tennessee Niagara	2B	Granite	19-100-FT-NN	FT-NN	No	926	$ 6.1560	12	Line 3	$ 5,700	$ 68,405
Iroquois Receipts	1	Iroquois	181003	RTS-1	No	5,715	$ 5.2357	12	Line 4	$ 29,922	$ 359,064
Iroquois Receipts	1	Iroquois	181003	RTS-1	No	854	$ 5.2357	12	Line 4	$ 4,471	$ 53,655
Iroquois Receipts	2A	Tennessee	95196	FT-A	No	1,382	$ 6.1560	12	Line 11	$ 8,508	$ 102,091
Iroquois Receipts	2B	Tennessee	95196	FT-A	No	844	$ 6.1560	12	Line 11	$ 5,196	$ 62,348
Iroquois Receipts	3B	Granite	19-100-FT-NN	FT-NN	No	841	$ 5.9096	12	Line 3	$ 4,970	$ 59,640
Iroquois Receipts	2C	Tennessee	41099	FT-A	No	4,267	$ 6.1560	12	Line 11	$ 26,268	$ 315,212
Iroquois Receipts	3C	Algonquin	93002F	AFT-1	No	4,211	$ 8.5927	12	Line 1	$ 36,184	$ 434,206
Leidy Hub	1	Texas Eastern	800384	FT-1	No	965	$ 7.0660	12	Line 12	$ 6,819	$ 81,824
Leidy Hub	2	Algonquin	93201A1C	AFT-1	No	965	$ 8.5927	12	Line 1	$ 8,292	$ 99,503
Transco Zone 6, non-NY	1	Algonquin	93201A1C	AFT-1	No	286	$ 8.5927	12	Line 1	$ 2,458	$ 29,490
PXP Dawn Hub	1	Union	M12296	M12	No	10,250	$ 3.0942	12	Line 14	$ 31,716	$ 380,587
PXP Dawn Hub	2	TransCanada	63265	FT	No	10,017	$ 17.7546	12	Line 13	$ 177,848	$ 2,134,174
PXP Dawn Hub	3	PNGTS	233320	FT (PXP)	Yes	10,000	$ 22.8125	12	Line 7	$ 228,125	$ 2,737,500
PXP Dawn Hub	4	Granite	19-100-FT-NN	FT-NN	No	9,965	$ 5.9096	12	Line 3	$ 58,889	$ 706,670
Atlantic Bridge	1	Algonquin	510939	AFT	Yes	7,599	$ 54.9173	12	Line 2	$ 417,317	$ 5,007,799
Atlantic Bridge	2	Maritimes	210363	MN365	Yes	7,500	$ 13.3833	12	Line 5	$ 100,375	$ 1,204,500
Tennessee Firm Storage	2	Tennessee	5265	FT-A	No	2,653	$ 7.0053	12	Line 10	$ 18,585	$ 223,021
Tennessee Firm Storage	3	Granite	19-100-FT-NN	FT-NN	No	2,644	$ 5.9096	12	Line 3	$ 15,625	$ 187,500
Union Dawn Storage	2	Union	M12256	M12	No	40,720	$ 3.0942	12	Line 14	$ 125,996	$ 1,511,950
Union Dawn Storage	3A	TransCanada	57901	FT	No	34,000	$ 17.7546	12	Line 13	$ 603,656	$ 7,243,877
Union Dawn Storage	3B	TransCanada	57055	FT	No	6,003	$ 17.7546	12	Line 13	$ 106,581	$ 1,278,970
Union Dawn Storage	4	PNGTS	208543	FT (C2C)	Yes	40,003	$ 18.2500	12	Line 6	$ 730,055	$ 8,760,657
Union Dawn Storage	5	Granite	19-100-FT-NN	FT-NN	No	39,863	$ 5.9096	12	Line 3	$ 235,574	$ 2,826,893
Peaking Capacity (Nov-Oct)	N/A	Granite	19-100-FT-NN	FT-NN	No	9,251	$ 5.9096	12	Line 3	$ 54,670	$ 656,037
Peaking Capacity (Nov-Apr)	N/A	Granite	19-100-FT-NN	FT-NN	No	44,000	$ 5.9096	6	Line 3	$ 260,022	$ 1,560,134
Total Annual Demand Costs											$ 42,202,312

Northern Utilities, Inc.
PIpeline Contract Demand Cost Allocations
November 1, 2021 through October 31, 2022

Capacity Path	Segment	Pipeline	Contract ID	MDQ	Pipeline MDQ	Storage MDQ	Peaking MDQ	Annual Demand	Annual Pipeline Allocated Cost	Annual Storage Allocated Cost	Annual Peaking Allocated Cost
Tennessee Zone 0/L Pools	1A	Tennessee	5083	4,605	4,605	-	-	$ 1,100,735	$ 1,100,735	$ -	$ -
Tennessee Zone 0/L Pools	2A	Granite	19-100-FT-NN	4,589	4,589	-	-	$ 325,430	$ 325,430	$ -	$ -
Tennessee Zone 0/L Pools	1B	Tennessee	5083	8,550	8,550	-	-	$ 1,814,399	$ 1,814,399	$ -	$ -
Tennessee Zone 0/L Pools	2B	Granite	19-100-FT-NN	8,520	8,520	-	-	$ 604,198	$ 604,198	$ -	$ -
Tennessee Niagara	1A	Tennessee	5292	1,406	1,406	-	-	$ 103,864	$ 103,864	$ -	$ -
Tennessee Niagara	2A	Granite	19-100-FT-NN	1,401	1,401	-	-	$ 99,352	$ 99,352	$ -	$ -
Tennessee Niagara	1B	Tennessee	39735	929	929	-	-	$ 68,627	$ 68,627	$ -	$ -
Tennessee Niagara	2B	Granite	19-100-FT-NN	926	926	-	-	$ 68,405	$ 68,405	$ -	$ -
Iroquois Receipts	1	Iroquois	181003	5,715	5,715	-	-	$ 359,064	$ 359,064	$ -	$ -
Iroquois Receipts	1	Iroquois	181003	854	854	-	-	$ 53,655	$ 53,655	$ -	$ -
Iroquois Receipts	2A	Tennessee	95196	1,382	1,382	-	-	$ 102,091	$ 102,091	$ -	$ -
Iroquois Receipts	2B	Tennessee	95196	844	844	-	-	$ 62,348	$ 62,348	$ -	$ -
Iroquois Receipts	3B	Granite	19-100-FT-NN	841	841	-	-	$ 59,640	$ 59,640	$ -	$ -
Iroquois Receipts	2C	Tennessee	41099	4,267	4,267	-	-	$ 315,212	$ 315,212	$ -	$ -
Iroquois Receipts	3C	Algonquin	93002F	4,211	4,211	-	-	$ 434,206	$ 434,206	$ -	$ -
Leidy Hub	1	Texas Eastern	800384	965	965	-	-	$ 81,824	$ 81,824	$ -	$ -
Leidy Hub	2	Algonquin	93201A1C	965	965	-	-	$ 99,503	$ 99,503	$ -	$ -
Transco Zone 6, non-NY	1	Algonquin	93201A1C	286	286	-	-	$ 29,490	$ 29,490	$ -	$ -
PXP Dawn Hub	1	Union	M12296	10,250	10,250	-	-	$ 380,587	$ 380,587	$ -	$ -
PXP Dawn Hub	2	TransCanada	63265	10,017	10,017	-	-	$ 2,134,174	$ 2,134,174	$ -	$ -
PXP Dawn Hub	3	PNGTS	233320	10,000	10,000	-	-	$ 2,737,500	$ 2,737,500	$ -	$ -
PXP Dawn Hub	4	Granite	19-100-FT-NN	9,965	9,965	-	-	$ 706,670	$ 706,670	$ -	$ -
Atlantic Bridge	1	Algonquin	510939	7,599	7,599	-	-	$ 5,007,799	$ 5,007,799	$ -	$ -
Atlantic Bridge	2	Maritimes	210363	7,500	7,500	-	-	$ 1,204,500	$ 1,204,500	$ -	$ -
Tennessee Firm Storage	2	Tennessee	5265	2,653	-	2,653	-	$ 223,021	$ -	$ 223,021	$ -
Tennessee Firm Storage	3	Granite	19-100-FT-NN	2,644	-	2,644	-	$ 187,500	$ -	$ 187,500	$ -
Union Dawn Storage	2	Union	M12256	40,720	-	40,720	-	$ 1,511,950	$ -	$ 1,511,950	$ -
Union Dawn Storage	3A	TransCanada	57901	34,000	-	34,000	-	$ 7,243,877	$ -	$ 7,243,877	$ -
Union Dawn Storage	3B	TransCanada	57055	6,003	-	6,003	-	$ 1,278,970	$ -	$ 1,278,970	$ -
Union Dawn Storage	4	PNGTS	208543	40,003	-	40,003	-	$ 8,760,657	$ -	$ 8,760,657	$ -
Union Dawn Storage	5	Granite	19-100-FT-NN	39,863	-	39,863	-	$ 2,826,893	$ -	$ 2,826,893	$ -
Peaking Capacity (Nov-Oct)	N/A	Granite	19-100-FT-NN	9,251	-	-	26,216	$ 656,037	$ -	$ -	$ 656,037
Peaking Capacity (Nov-Apr)	N/A	Granite	19-100-FT-NN	44,000	-	-	30,000	$ 1,560,134	$ -	$ -	$ 1,560,134
Total Annual Demand Costs								$ 42,202,312	$ 17,953,274	$ 22,032,867	$ 2,216,171

Northern Utilities, Inc.
Storage Contract Demand Cost Estimates
November 1, 2021 through October 31, 2022

Vendor	Contract ID	Rate	Negotiated	MSQ (Dth)	MDWQ	Space Rate	Demand Rate	Months Per Year	Reference (Att NUI-FXW-10, Page 2)	Annual Space Charge	Annual Demand Charge	Annual Fixed Charges
Tennessee	5195	FS-MA	No	259,337	4,243	$ 0.0175	$ 1.2801	12	Line 1	$ 54,461	$ 65,178	$ 119,638
Union	LST086	Storage	Yes	4,000,000	41,200	$ 0.0592		12	Line 2	$ 2,840,000		$ 2,840,000

Total Annual Fixed Charges $ 2,959,638

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.

Peaking Contract Demand Cost Estimates

November 1, 2021 through October 31, 2022

Denotes Confidential Information

Resource	Supplier	Contract Quantity	Maximum Daily Quantity	Months per Year	Annual Fixed Charges
LNG Contract	[redacted]	75,000	5,000	5	[redacted]
Peaking Contract 1		600,000	40,000	5	
Total Peaking Supply Contract Demand Costs					$ 11,397,667

Northern Utilities, Inc.
Asset Management and Capacity Release Revenue Projections
November 1, 2021 through October 31, 2022

Denotes Confidential Information

Capacity Path	Projected Revenue
Tennessee Zone 0/L Pools	[redacted]
Tennessee Niagara	
Iroquois Receipts	
Leidy Hub & Transco Zone 6, non-NY	
Atlantic Bridge	
Union Dawn Storage & PXP Dawn Hub	
Total Asset Management	$ (9,902,100)

Northern Utilities, Inc. New Hampshire Division Retail Marketer Capacity Assignment Revenue Projections November 2021 through October 2022		
Item	Revenue	Reference
Pipeline Contract Capacity Assignment	$ (4,477,852)	Page 2
Storage Contract Capacity Assignment	$ (291,946)	Page 3
On-System Peaking Service Demand	$ (276,318)	Page 4
Asset Management Revenue Assigned to Retail Suppliers	$ 33,381	Page 5
Total Division Capacity Assignment Demand Revenue	$ (5,012,735)	Sum of Items Above

Northern Utilities, Inc.
New Hampshire Division Pipeline Capacity Assignment Estimates
November 2021 through October 2022

Capacity Path	Segment	Pipeline	Contract ID	Pipeline Allocated Cost	Storage Allocated Cost	Peaking Allocated Cost	Capacity Assigned? (Y/N)	Assigned Pipeline MDQ	Assigned Storage MDQ	Assigned Peaking MDQ	Assigned Pipeline Credits	Assigned Storage Credits	Assigned Peaking Credits	NH Annual Cap Assign Credit
Tennessee Zone 0/L Pools	1A	Tennessee	5083	$ 1,100,735	$ -	$ -	Y	(535)	-	-	$ (127,881)	$ -	$ -	$ (127,881)
Tennessee Zone 0/L Pools	2A	Granite	19-100-FT-NN	$ 325,430	$ -	$ -	Y	(533)	-	-	$ (37,798)	$ -	$ -	$ (37,798)
Tennessee Zone 0/L Pools	1B	Tennessee	5083	$ 1,814,399	$ -	$ -	Y	(993)	-	-	$ (210,725)	$ -	$ -	$ (210,725)
Tennessee Zone 0/L Pools	2B	Granite	19-100-FT-NN	$ 604,198	$ -	$ -	Y	(990)	-	-	$ (70,206)	$ -	$ -	$ (70,206)
Tennessee Niagara	1A	Tennessee	5292	$ 103,864	$ -	$ -	Y	(163)	-	-	$ (12,041)	$ -	$ -	$ (12,041)
Tennessee Niagara	2A	Granite	19-100-FT-NN	$ 99,352	$ -	$ -	Y	(163)	-	-	$ (11,559)	$ -	$ -	$ (11,559)
Tennessee Niagara	1B	Tennessee	39735	$ 68,627	$ -	$ -	Y	(108)	-	-	$ (7,978)	$ -	$ -	$ (7,978)
Tennessee Niagara	2B	Granite	19-100-FT-NN	$ 68,405	$ -	$ -	Y	(108)	-	-	$ (7,978)	$ -	$ -	$ (7,978)
Iroquois Receipts	1	Iroquois	181003	$ 359,064	$ -	$ -	Y	(664)	-	-	$ (41,718)	$ -	$ -	$ (41,718)
Iroquois Receipts	1	Iroquois	181003	$ 53,655	$ -	$ -	Y	(99)	-	-	$ (6,220)	$ -	$ -	$ (6,220)
Iroquois Receipts	2A	Tennessee	95196	$ 102,091	$ -	$ -	Y	(161)	-	-	$ (11,893)	$ -	$ -	$ (11,893)
Iroquois Receipts	2B	Tennessee	95196	$ 62,348	$ -	$ -	Y	(98)	-	-	$ (7,239)	$ -	$ -	$ (7,239)
Iroquois Receipts	3B	Granite	19-100-FT-NN	$ 59,640	$ -	$ -	Y	(98)	-	-	$ (6,950)	$ -	$ -	$ (6,950)
Iroquois Receipts	2C	Tennessee	41099	$ 315,212	$ -	$ -	Y	(496)	-	-	$ (36,641)	$ -	$ -	$ (36,641)
Iroquois Receipts	3C	Algonquin	93002F	$ 434,206	$ -	$ -	Y	(489)	-	-	$ (50,422)	$ -	$ -	$ (50,422)
Leidy Hub	1	Texas Eastern	800384	$ 81,824	$ -	$ -	Y	(112)	-	-	$ (9,497)	$ -	$ -	$ (9,497)
Leidy Hub	2	Algonquin	93201A1C	$ 99,503	$ -	$ -	Y	(112)	-	-	$ (11,549)	$ -	$ -	$ (11,549)
Transco Zone 6, non-NY	1	Algonquin	93201A1C	$ 29,490	$ -	$ -	Y	(33)	-	-	$ (3,403)	$ -	$ -	$ (3,403)
PXP Dawn Hub	1	Union	M12296	$ 380,587	$ -	$ -	Y	(1,191)	-	-	$ (44,222)	$ -	$ -	$ (44,222)
PXP Dawn Hub	2	TransCanada	63265	$ 2,134,174	$ -	$ -	Y	(1,164)	-	-	$ (247,996)	$ -	$ -	$ (247,996)
PXP Dawn Hub	3	PNGTS	233320	$ 2,737,500	$ -	$ -	Y	(1,162)	-	-	$ (318,098)	$ -	$ -	$ (318,098)
PXP Dawn Hub	4	Granite	19-100-FT-NN	$ 706,670	$ -	$ -	Y	(1,158)	-	-	$ (82,120)	$ -	$ -	$ (82,120)
Atlantic Bridge	1	Algonquin	510939	$ 5,007,799	$ -	$ -	Y	(883)	-	-	$ (581,904)	$ -	$ -	$ (581,904)
Atlantic Bridge	2	Maritimes	210363	$ 1,204,500	$ -	$ -	Y	(871)	-	-	$ (139,883)	$ -	$ -	$ (139,883)
Tennessee Firm Storage	2	Tennessee	5265	$ -	$ 223,021	$ -	Y	-	(262)	-	$ -	$ (22,025)	$ -	$ (22,025)
Tennessee Firm Storage	3	Granite	19-100-FT-NN	$ -	$ 187,500	$ -	Y	-	(261)	-	$ -	$ (18,509)	$ -	$ (18,509)
Union Dawn Storage	2	Union	M12256	$ -	$ 1,511,950	$ -	Y	-	(4,017)	-	$ -	$ (149,153)	$ -	$ (149,153)
Union Dawn Storage	3A	TransCanada	57901	$ -	$ 7,243,877	$ -	Y	-	(3,354)	-	$ -	$ (714,587)	$ -	$ (714,587)
Union Dawn Storage	3B	TransCanada	57055	$ -	$ 1,278,970	$ -	Y	-	(592)	-	$ -	$ (126,129)	$ -	$ (126,129)
Union Dawn Storage	4	PNGTS	208543	$ -	$ 8,760,657	$ -	Y	-	(3,946)	-	$ -	$ (864,174)	$ -	$ (864,174)
Union Dawn Storage	5	Granite	19-100-FT-NN	$ -	$ 2,826,893	$ -	Y	-	(3,932)	-	$ -	$ (278,839)	$ -	$ (278,839)
Peaking Capacity (Nov-Oct)	N/A	Granite	19-100-FT-NN	$ -	$ -	$ 656,037	Y	-	-	(2,585)	$ -	$ -	$ (64,688)	$ (64,688)
Peaking Capacity (Nov-Apr)	N/A	Granite	19-100-FT-NN	$ -	$ -	$ 1,560,134	Y	-	-	(2,958)	$ -	$ -	$ (153,829)	$ (153,829)
Total Capacity Assignment Credits											$ (2,085,920)	$ (2,173,415)	$ (218,517)	$ (4,477,852)

Northern Utilities, Inc.
New Hampshire Division Storage Contract Capacity Assignment Estimates
November 2021 through October 2022

Vendor	Contract ID	Annual Fixed Charges	Capacity Assigned (Y/N)	Company Managed (Y/N)	Storage Assigned ME	Assigned MSQ	Assigned MDWQ	Annual Cap Assign Credit
Tennessee	5195	$ 119,638	Y	N	9.86%	(25,582)	(419)	$ (11,801)
Union	LST068	$ 2,840,000	Y	N	9.86%	(394,570)	(4,064)	$ (280,145)

Total Division Storage Capacity Assignment $ (291,946)

MSQ = Maximum Space Quantity
MDWQ = Maximum Daily Withdrawal Quantity

Northern Utilities, Inc.
New Hampshire Division
On-System Peaking Demand Capacity Assignment Revenues
November 2021 through October 2022

Month	On-System Peaking Demand TCQ	Rate	Demand Revenue
Nov-21	641	$ 71.85	$ (46,053)
Dec-21	641	$ 71.85	$ (46,053)
Jan-22	641	$ 71.85	$ (46,053)
Feb-22	641	$ 71.85	$ (46,053)
Mar-22	641	$ 71.85	$ (46,053)
Apr-22	641	$ 71.85	$ (46,053)

Total Division Peaking Demand Revenue $ (276,318)

REDACTED

Northern Utilities, Inc. - New Hampshire Division
Asset Management and Capacity Release Revenue Assigned to Retail Suppliers
November 2021 through October 2022

Indicates Confidential Information

Resources	Projected Value	Company-Managed Resources	Resource Type	Percentage Capacity Assigned	Annual Value to Retail Marketers
Tennessee Zone 0/L Pools	[redacted]	No	Pipeline	11.62%	[redacted]
Tennessee Niagara		No	Pipeline	11.62%	
Iroquois Receipts		Yes	Pipeline	11.62%	
Leidy Hub & Transco Zone 6, non-NY		Yes	Pipeline	11.62%	
0		No	Pipeline	11.62%	
Atlantic Bridge		No	Pipeline	11.62%	
Union Dawn Storage & PXP Dawn Hub		No	Storage	9.86%	
Total Asset Management	$ (9,902,100)				$ 33,381

REDACTED

Northern Utilities, Inc.
New Hampshire Division Peaking Capacity Assignment Demand Rate
November 2021 through October 2022

Indicates Confidential Information

Line	Description	Northern	NH Division
2	Capacity Allocation Factor		40.99%
3	Peaking Plants	6,500	2,664
4	Total	6,500	2,664
5	LNG Demand Costs	[redacted]	[redacted]
6	Peaking Plants Fixed Costs		$ 420,658
7	Total On-System Peaking Fixed Costs		$ 1,148,640
8	NH Division Peaking Service Demand Rate		$ 71.85

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Northern Utilities
New Hampshire Division
Retail Supplier Capacity Assignment Estimates
November 2021 through October 2022

	Pipeline MDQ	Storage MDQ	Peaking MDQ	Total MDQ
HLF Allocation	60.95%	16.23%	22.82%	100.00%
LLF Allocation	22.28%	32.31%	45.41%	100.00%
HLF TCQ	2,230	594	835	3,658
LLF TCQ	2,476	3,591	5,047	11,114
Retail Supplier Total	4,715	4,193	5,892	14,800
Northern MDQ	40,586	42,507	59,751	142,844
Cap Assign/ Total MDQ	11.62%	9.86%	9.86%	10.36%
On System Peaking			6,500	
On System Peaking Allocation			10.88%	

Northern Utilities - New Hampshire Division
Capacity Assignment Calculations 2021-2022
<u>Derivation of Class Assignments and Weightings</u>

Basic assumptions:

1 The MBA method allocates capacity costs based on design day demands in two pieces:
  - a The base use portion of the class design day demand based on base use
  - b The remaining portion of design day demand based on remaining design day demand

2 Base demand is composed solely of pipeline supplies

3 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

		Design Day Demand, Dt	Adjusted Design Day Demand, Dt	Percent of Total	Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE A-Resi Non-Htg	222	213	0.3%	32	181
2	RATE B-Resi Htg	24,141	23,132	36.8%	1,406	21,726
3	RATE G-40	11,858	11,362	18.1%	533	10,830
4	RATE G-50	905	867	1.4%	265	602
5	RATE G-41	9,240	8,854	14.1%	563	8,291
6	RATE G-51	1,441	1,380	2.2%	399	981
7	RATE G-42	1,952	1,871	3.0%	177	1,694
8	RATE G-52	365	350	0.6%	160	189
9	Special Contract	1,619	1,551	2.5%	1,537	14
10	RATE T-40	1,725	1,653	2.6%	109	1,544
11	RATE T-50	134	128	0.2%	-	128
12	RATE T-41	8,134	7,794	12.4%	677	7,117
13	RATE T-51	1,154	1,106	1.8%	512	594
14	RATE T-42	1,740	1,667	2.7%	114	1,553
15	RATE T-52	911	873	1.4%	444	429
16	Total	65,540	62,801	100.0%	6,928	55,874
17						-
18	Residential Total	24,363	23,345	37.2%	1,438	21,907
19	LLF Total	34,649	33,201	52.9%	2,172	31,029
20	HLF Total	6,529	6,256	10.0%	3,318	2,938
21	Total	65,540	62,801	100.0%	6,928	55,874
22						
23						

		Resdential MDQ, Dt	Total C&I MDQ, Dt	LLF C&I MDQ, Dt	HLF C&I MDQ, Dt	Total MDQ, Dt
24						
25	Residential Allocation					
26	Pipeline - Base	1,438	5,490	2,172	3,318	6,928
27	Pipeline - Remaining	5,195	5,721	5,226	495	10,916
28	Storage	6,947	11,741	10,726	1,016	18,688
29	Peaking	9,765	16,505	15,077	1,428	26,270
30	Total	23,345	39,457	33,201	6,256	62,801
31	Check - Should be 0	-	-	-	-	-
32						

		LLF C&I	HLF C&I
33	Caapcity Allocations %s		
34			
35	Pipeline	**22.28%**	**60.95%**
36	Storage	**32.31%**	**16.23%**
37	Peaking	**45.41%**	**22.82%**
38	Total	**100.00%**	**100.00%**

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-FXW-7
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Northern Utilities

New Hampshire Division Capacity Assignment Calculations

	HLF	LLF	Total TCQ	Capacity Assignment	Pipeline MDQ	Storage MDQ	Peaking MDQ	Total MDQ
Retail Supplier Total	3,658	11,114	14,772	14,800	4,715	4,193	5,892	14,800
Northern -Total MDQ					17,844	18,688	26,270	62,801
NH Cap Assign/ Total MDQ		CHECK S/B 0 ->	0		26.42%	22.44%	22.43%	23.57%

HLF Capacity Allocator	60.95%	16.23%	22.82%	100.00%
LLF Capacity Allocator	22.28%	32.31%	45.41%	100.00%

	Percentage Design Day	43.97%		Capacity Assignment Plan
Pipeline Capacity Paths	Northern MDQ	NH Division MDQ	Pipeline Assigned %	Capacity Assigned
Tennessee Long-Haul	13,109	5,763	26.43%	1,523
Tennessee Niagara	2,327	1,023	26.39%	270
Iroquois Receipts	6,434	2,829	26.44%	748
Leidy Supply (Texas Eastern, Algonquin)	965	424	26.42%	112
Transco Zone 6, non-NY Supply (Algonquin)	286	126	26.19%	33
PXP Dawn Hub	9,965	4,381	26.43%	1,158
Atlantic Bridge Ramapo	7,500	3,297	26.42%	871
Total Pipeline Capacity	**40,586**	**17,843**	**26.42%**	**4,715**
Storage Capacity Paths	Northern MDQ	NH Division MDQ	Storage Assigned %	Capacity Assigned
Tennessee Firm Storage	2,644	1,162	22.44%	261
Dawn Hub Storage	39,863	17,526	22.44%	3,932
Total Storage Capacity	**42,507**	**18,688**	**22.44%**	**4,193**
Peaking Capacity Paths	Northern MDQ	NH Division MDQ	Peaking Assigned %	Capacity Assigned
LNG - On-System	6,500	2,858	22.43%	641
Granite - Not assigned as Storage or Pipeline Capacity	53,251	23,412	22.43%	5,251
Total Peaking Capacity	**59,751**	**26,270**	**22.43%**	**5,892**
Total Capacity	**142,844**	**62,801**	**23.57%**	**14,800**

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-FXW-7
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Northern Utilities, Inc.
New Hampshire Division
Design Day Forecast by Rate Class

2021-2022 Forecast Annual Sales (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	23,447	2,021,317	983,033	156,605	765,997	249,241	161,855	63,141	0	2,044,763	1,910,885	468,988	4,424,636
Capacity Assigned Delivery Service			155,432	28,877	732,925	249,618	156,780	197,110	554,272		1,045,137	1,029,877	2,075,014
Capacity Exempt Delivery Service			1,945	1,398	39,225	15,040	276,420	1,543,771	792,258		317,590	2,352,468	2,670,058
Total System	23,447	2,021,317	1,140,409	186,880	1,538,147	513,900	595,055	1,804,022	1,346,530	2,044,763	3,273,611	3,851,332	9,169,707

2020-2021 Forecast Annual Sendout (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division	Prior Year WN Act Total Division	Percent Change
Sales Service	23,743	2,046,904	995,476	158,588	775,693	252,396	163,904	63,940		2,070,647	1,935,074	474,924	4,480,645	4,167,075	7.5%
Capacity Assigned Delivery Service			157,399	29,242	742,202	252,778	158,765	199,605	561,288		1,058,366	1,042,913	2,101,279	1,969,209	6.7%
Capacity Exempt Delivery Service			1,969	1,416	39,721	15,231	279,919	1,563,312	802,287		321,610	2,382,245	2,703,855	2,434,507	11.1%
Total System	23,743	2,046,904	1,154,845	189,246	1,557,617	520,405	602,588	1,826,858	1,363,575	2,070,647	3,315,049	3,900,083	9,285,779	8,570,791	8.3%

2020-2021 Forecast Load Factor (%)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division	Prior Year Actual Total Division	Percent Change
Sales Service	29.3%	23.2%	23.0%	48.0%	23.0%	48.0%	23.0%	48.0%		23.3%	23.0%	48.0%	24.5%	23.6%	3.6%
Capacity Assigned Delivery Service			25.0%	60.0%	25.0%	60.0%	25.0%	60.0%	95.0%		25.0%	74.8%	37.3%	37.4%	-0.2%
Capacity Exempt Delivery Service			40.0%	70.0%	40.0%	70.0%	40.0%	70.0%	85.0%		40.0%	74.4%	67.5%	63.5%	6.3%
Total System	29.3%	23.2%	23.3%	49.7%	24.2%	53.7%	29.4%	67.7%	88.8%	23.3%	24.6%	69.8%	33.3%	32.1%	3.7%

2020-2021 Design Day Sendout (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division	Prior Year Design Day Actual Total Division	Percent Change
Sales Service	222	24,141	11,858	905	9,240	1,441	1,952	365		24,363	23,050	2,711	50,124	48,308	3.8%
Capacity Assigned Delivery Service			1,725	134	8,134	1,154	1,740	911	1,619		11,599	3,818	15,416	14,413	7.0%
Capacity Exempt Delivery Service			13	6	272	60	1,917	6,119	2,586		2,203	8,770	10,973	10,504	4.5%
Total System	222	24,141	13,596	1,044	17,646	2,654	5,610	7,395	4,205	24,363	36,852	15,298	76,513	73,224	4.5%

2020-2021 Baseload Sendout (Dth)
(Average Daily July and August Sendout)

	Res Non-Heat	Res Heat	G40	63689.86	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	32	1,406	533	265	563	399	177	160		1,438	1,273	825	3,536
Capacity Assigned Delivery Service			109	0	677	512	114	444	1,537		899	2,493	3,392
Capacity Exempt Delivery Service			1	0	55	35	359	3,978	2,129		415	6,142	6,557
Total System	32	1,406	643	265	1,295	946	649	4,582	3,666	1,438	2,587	9,460	13,485

2020-2021 Planning Load Design Day Sendout (Dth)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	222	24,141	11,858	905	9,240	1,441	1,952	365		24,363	23,050	2,711	50,124
Capacity Assigned Delivery Service			1,725	134	8,134	1,154	1,740	911	1,619		11,599	3,818	15,416
Capacity Exempt Delivery Service			0	0	0	0	0	0	0		0	0	0
Total System	222	24,141	13,583	1,039	17,374	2,595	3,692	1,276	1,619	24,363	34,649	6,529	65,540

2020-2021 Planning Load Baseload Sendout (Dth)
(Average Daily July and August Sendout)

	Res Non-Heat	Res Heat	G40	G50	G41	G51	G42	G52	Special Contracts	Res	LLF	HLF	Total Division
Sales Service	32	1,406	533	265	563	399	177	160		1,438	1,273	825	3,536
Capacity Assigned Delivery Service			109	0	677	512	114	444	1,537		899	2,493	3,392
Capacity Exempt Delivery Service			0	0	0	0	0	0	0		0	0	0
Total System	32	1,406	641	265	1,240	911	290	604	1,537	1,438	2,172	3,318	6,928

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Northern Utilities, Inc.
Commodity Cost by Supply Source ($)
November 2021 through October 2022

Description	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Winter	Summer	Year
Pipeline Supplies															
TGP Zone 4 300 Leg Supply	[redacted]														
Tennessee FS-MA Storage Path	[redacted]														
Dawn Supply	[redacted]														
Union Dawn Storage Path	[redacted]														
Leidy Hub	[redacted]														
Texas Eastern Zone M-3	[redacted]														
Transco Zone 6, non-NY	[redacted]														
Algonquin Receipts Pipeline Path	[redacted]														
Tennessee Niagara Pipeline Path	[redacted]														
PXP Dawn Pipeline Path	[redacted]														
Tennessee Zone 0	[redacted]														
Tennessee Zone L	[redacted]														
Tennessee Long-Haul Pipeline Path	[redacted]														
Iroquois Receipts Pipeline Path	[redacted]														
Atlantic Bridge Ramapo Pipeline Path	[redacted]														
Total Pipeline	[redacted]														
NH CM Pipeline (Leidy/M-3)	[redacted]														
ME CM Pipeline (Leidy/M-3)	[redacted]														
NH CM Pipeline (Transco)	[redacted]														
ME CM Pipeline (Transco)	[redacted]														
NH CM Pipeline (Iroq Rec)	[redacted]														
ME CM Pipeline (Iroq Rec)	[redacted]														
Net Pipeline	**$ 5,248,530**	**$ 5,735,184**	**$ 6,062,675**	**$ 5,455,995**	**$ 5,436,340**	**$ 4,220,796**	**$ 2,197,031**	**$ 1,475,856**	**$ 1,373,084**	**$ 1,382,979**	**$ 1,410,783**	**$ 2,512,274**	**$ 32,159,520**	**$ 10,352,007**	**$ 42,511,526**
Underground Storage															
Tennessee Storage	$ -	$ 186,678	$ 186,678	$ 167,685	$ 40,601	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 581,642	$ -	$ 581,642
Tennessee FS-MA Storage Path	$ -	$ 186,678	$ 186,678	$ 167,685	$ 40,601	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 581,642	$ -	$ 581,642
Union Dawn Storage	$ 1,044,295	$ 2,078,528	$ 2,337,868	$ 2,534,675	$ 1,826,950	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,822,316	$ -	$ 9,822,316
Union Dawn Storage Path	$ 1,044,295	$ 2,078,528	$ 2,337,868	$ 2,534,675	$ 1,826,950	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,822,316	$ -	$ 9,822,316
Net Storage	**$ 1,044,295**	**$ 2,265,206**	**$ 2,524,545**	**$ 2,702,360**	**$ 1,867,551**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 10,403,958**	**$ -**	**$ 10,403,958**
Peaking Supplies															
PNGTS Delivered (Dec - Feb)	[redacted]														
Baseload Delivered Supplies	[redacted]														
Lewiston LNG	[redacted]														
Peaking Contract 1	[redacted]														
Peaking Contract 2	[redacted]														
Off-System Peaking / Incremental Supply	[redacted]														
Total Peaking	[redacted]														
NH Peaking Service - (On System)	[redacted]														
ME Peaking Service - (On-System)	[redacted]														
Net Peaking	**$ 9,526**	**$ 2,091,388**	**$ 4,553,220**	**$ 2,865,280**	**$ 1,286,222**	**$ 10,221**	**$ 10,555**	**$ 11,094**	**$ 11,464**	**$ 11,464**	**$ 13,455**	**$ 14,402**	**$ 10,815,857**	**$ 72,433**	**$ 10,888,290**
Total NUI Commodity	$ 6,546,727	$ 10,387,112	$ 13,523,178	$ 11,317,910	$ 8,838,734	$ 4,231,017	$ 2,207,586	$ 1,486,950	$ 1,384,547	$ 1,394,443	$ 1,424,238	$ 2,526,676	$ 54,844,677	$ 10,424,440	$ 65,269,117
Company Managed Sales	$ (244,376)	$ (295,334)	$ (382,738)	$ (294,275)	$ (248,621)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,465,343)	$ -	
Net Commodity Costs	**$ 6,302,351**	**$ 10,091,778**	**$ 13,140,440**	**$ 11,023,635**	**$ 8,590,113**	**$ 4,231,017**	**$ 2,207,586**	**$ 1,486,950**	**$ 1,384,547**	**$ 1,394,443**	**$ 1,424,238**	**$ 2,526,676**	**$ 53,379,334**	**$ 10,424,440**	**$ 63,803,774**

Northern Utilities, Inc.
Commodity Volumes by Supply Source (Dth)
November 2021 through October 2022

Description	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Winter	Summer	Year
Pipeline Supplies															
TGP Zone 4 300 Leg Supply	64,244	0	0	330	51,947	64,244	66,386	64,244	66,386	66,386	64,244	66,386	180,766	394,032	574,798
Tennessee FS-MA Storage Path	64,244	0	0	330	51,947	64,244	66,386	64,244	66,386	66,386	64,244	66,386	180,766	394,032	574,798
Dawn Supply	0	0	0	7,166	27,942	746,591	320,425	133,836	92,313	97,584	132,390	415,365	781,700	1,191,914	1,973,613
Union Dawn Storage Path	0	0	0	7,166	27,942	746,591	320,425	133,836	92,313	97,584	132,390	415,365	781,700	1,191,914	1,973,613
Leidy Hub	28,681	29,625	29,625	26,758	29,625	0	0	0	0	0	0	0	144,313	0	144,313
Texas Eastern Zone M-3	269	290	290	262	290	0	0	0	0	0	0	0	1,402	0	1,402
Transco Zone 6, non-NY	8,580	8,866	8,866	8,008	8,866	0	0	0	0	0	0	0	43,186	0	43,186
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	35,028	38,781	0	0	0	0	0	0	0	188,901	0	188,901
Tennessee Niagara Pipeline Path	54,349	56,161	56,161	50,726	56,161	54,349	56,161	54,349	56,161	56,161	54,349	56,161	327,906	333,341	661,247
PXP Dawn Pipeline Path	227,792	240,125	240,125	216,887	240,125	52,641	0	0	0	0	0	0	1,217,695	0	1,217,695
Tennessee Zone 0	103,572	110,715	58,675	65,081	110,715	10,470	0	0	0	0	0	0	459,229	0	459,229
Tennessee Zone L	177,608	205,552	205,552	175,472	169,822	189	0	0	0	0	0	0	934,196	0	934,196
Tennessee Long-Haul Pipeline Path	281,181	316,267	264,227	240,554	280,537	10,660	0	0	0	0	0	0	1,393,425	0	1,393,425
Iroquois Receipts Pipeline Path	187,431	193,679	193,679	174,936	193,679	0	0	0	0	0	0	0	943,403	0	943,403
Atlantic Bridge Ramapo Pipeline Path	175,110	180,947	180,947	163,436	180,947	175,110	180,947	175,110	180,947	180,947	175,110	180,947	1,056,497	1,074,008	2,130,505
Total Pipeline	1,027,637	1,025,960	973,919	889,062	1,070,119	1,103,596	623,919	427,539	395,807	401,078	426,093	718,859	6,090,292	2,993,295	9,083,587
NH CM Pipeline (Leidy/M-3)	-3,360	-3,472	-3,472	-3,136	-3,472	0	0	0	0	0	0	0	-16,912	0	-16,912
ME CM Pipeline (Leidy/M-3)	-3,060	-3,162	-3,162	-2,856	-3,162	0	0	0	0	0	0	0	-15,402	0	-15,402
NH CM Pipeline (Transco)	-990	-1,023	-1,023	-924	-1,023	0	0	0	0	0	0	0	-4,983	0	-4,983
ME CM Pipeline (Transco)	-900	-930	-930	-840	-930	0	0	0	0	0	0	0	-4,530	0	-4,530
NH CM Pipeline (Iroq Rec)	-19,500	-20,150	-20,150	-18,200	-20,150	0	0	0	0	0	0	0	-98,150	0	-98,150
ME CM Pipeline (Iroq Rec)	-17,700	-18,290	-18,290	-16,520	-18,290	0	0	0	0	0	0	0	-89,090	0	-89,090
Net Pipeline	**982,127**	**978,933**	**926,892**	**846,586**	**1,023,092**	**1,103,596**	**623,919**	**427,539**	**395,807**	**401,078**	**426,093**	**718,859**	**5,861,225**	**2,993,295**	**8,854,520**
Underground Storage															
Tennessee Storage	0	66,386	66,386	59,632	14,438	0	0	0	0	0	0	0	206,842	0	206,842
Tennessee FS-MA Storage Path	0	66,386	66,386	59,632	14,438	0	0	0	0	0	0	0	206,842	0	206,842
Union Dawn Storage	334,018	664,818	747,767	810,716	584,350	0	0	0	0	0	0	0	3,141,670	0	3,141,670
Union Dawn Storage Path	334,018	664,818	747,767	810,716	584,350	0	0	0	0	0	0	0	3,141,670	0	3,141,670
Net Storage	**334,018**	**731,204**	**814,153**	**870,348**	**598,789**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,348,512**	**0**	**3,348,512**
Peaking Supplies															
PNGTS Delivered (Dec - Feb)	0	77,229	77,229	69,755	0	0	0	0	0	0	0	0	224,213	0	224,213
Baseload Delivered Supplies	0	77,229	77,229	69,755	0	0	0	0	0	0	0	0	224,213	0	224,213
													0	0	0
Lewiston LNG	1,794	1,854	1,854	1,674	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	10,824	11,040	21,864
Peaking Contract 1	0	13,649	243,664	11,017	261	0	0	0	0	0	0	0	268,591	0	268,591
Peaking Contract 2	0	42,181	104,918	87,560	64,291	0	0	0	0	0	0	0	298,950	0	298,950
Off-System Peaking / Incremental Supply	0	55,830	348,582	98,577	64,552	0	0	0	0	0	0	0	567,541	0	567,541
Total Peaking	1,794	134,913	427,664	170,007	66,406	1,794	1,860	1,800	1,860	1,860	1,800	1,860	802,578	11,040	813,618
NH Peaking Service - (On System)	0	-1,282	-5,769	-641	0	0	0	0	0	0	0	0	-7,692	0	-7,692
ME Peaking Service - (On-System)	0	-1,184	-5,328	-592	0	0	0	0	0	0	0	0	-7,104	0	-7,104
Net Peaking	**1,794**	**132,447**	**416,567**	**168,774**	**66,406**	**1,794**	**1,860**	**1,800**	**1,860**	**1,860**	**1,800**	**1,860**	**787,782**	**11,040**	**798,822**
Total NUI Commodity	1,363,449	1,892,076	2,215,737	1,929,417	1,735,313	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	10,241,382	3,004,335	13,245,717
Company Managed Sales	-45,510	-49,493	-58,124	-43,709	-47,027	0	0	0	0	0	0	0	-243,863	0	-243,863
Net Commodity Costs	**1,317,939**	**1,842,583**	**2,157,613**	**1,885,708**	**1,688,286**	**1,105,390**	**625,779**	**429,339**	**397,667**	**402,938**	**427,893**	**720,719**	**9,997,519**	**3,004,335**	**13,001,854**

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Northern Utilities, Inc.
Average Delivered Commodity Cost by Supply Source ($/Dth)
November 2021 through October 2022

Description	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Winter	Summer	Year
Pipeline Supplies															
TGP Zone 4 300 Leg Supply	[redacted]														
Tennessee FS-MA Storage Path															
Dawn Supply															
Union Dawn Storage Path															
Leidy Hub															
Texas Eastern Zone M-3															
Transco Zone 6, non-NY															
Algonquin Receipts Pipeline Path															
Tennessee Niagara Pipeline Path															
PXP Dawn Pipeline Path															
Tennessee Zone 0															
Tennessee Zone L															
Tennessee Long-Haul Pipeline Path															
Iroquois Receipts Pipeline Path															
Atlantic Bridge Ramapo Pipeline Path															
Total Pipeline															
NH CM Pipeline (Leidy/M-3)															
ME CM Pipeline (Leidy/M-3)															
NH CM Pipeline (Transco)															
ME CM Pipeline (Transco)															
NH CM Pipeline (Iroq Rec)															
ME CM Pipeline (Iroq Rec)															
Net Pipeline	**$ 5.344**	**$ 5.859**	**$ 6.541**	**$ 6.445**	**$ 5.314**	**$ 3.825**	**$ 3.521**	**$ 3.452**	**$ 3.469**	**$ 3.448**	**$ 3.311**	**$ 3.495**	**$ 5.487**	**$ 3.458**	**$ 4.801**
Underground Storage															
Tennessee Storage		$ 2.812	$ 2.812	$ 2.812	$ 2.812								$ 2.812		$ 2.812
Tennessee FS-MA Storage Path		$ 2.812	$ 2.812	$ 2.812	$ 2.812								$ 2.812		$ 2.812
Union Dawn Storage	$ 3.126	$ 3.126	$ 3.126	$ 3.126	$ 3.126								$ 3.126		$ 3.126
Union Dawn Storage Path	$ 3.126	$ 3.126	$ 3.126	$ 3.126	$ 3.126								$ 3.126		$ 3.126
Net Storage	**$ 3.126**	**$ 3.098**	**$ 3.101**	**$ 3.105**	**$ 3.119**								**$ 3.107**		**$ 3.107**
Peaking Supplies															
PNGTS Delivered (Dec - Feb)	[redacted]														
Baseload Delivered Supplies															
Lewiston LNG															
Peaking Contract 1															
Peaking Contract 2															
Off-System Peaking / Incremental Su															
Total Peaking															
NH Peaking Service - (On System)															
ME Peaking Service - (On-System)															
Net Peaking	**$ 5.310**	**$ 15.790**	**$ 10.930**	**$ 16.977**	**$ 19.369**	**$ 5.697**	**$ 5.675**	**$ 6.163**	**$ 6.163**	**$ 6.163**	**$ 7.475**	**$ 7.743**	**$ 13.730**	**$ 6.561**	**$ 13.630**
Total NUI Commodity	$ 4.802	$ 5.490	$ 6.103	$ 5.866	$ 5.093	$ 3.828	$ 3.528	$ 3.463	$ 3.482	$ 3.461	$ 3.328	$ 3.506	$ 5.355	$ 3.470	$ 4.928
Company Managed Sales	$ 5.370	$ 5.967	$ 6.585	$ 6.733	$ 5.287								$ 6.009		$ -
Net Commodity Costs	**$ 4.782**	**$ 5.477**	**$ 6.090**	**$ 5.846**	**$ 5.088**	**$ 3.828**	**$ 3.528**	**$ 3.463**	**$ 3.482**	**$ 3.461**	**$ 3.328**	**$ 3.506**	**$ 5.339**	**$ 3.470**	**$ 4.907**

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Source of Supply: TGP Zone 4 300 Leg Supply (Tennessee FS-MA Storage Path)

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Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	65,266	-	-	335	52,774	65,266	67,442	65,266	67,442	67,442	65,266	67,442	183,641	400,300
2	City Gate Delivered Volume	Line 35	64,244	-	-	330	51,947	64,244	66,386	64,244	66,386	66,386	64,244	66,386	180,766	394,032
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 28 and 37	$ 6,414	$ -	$ -	$ 33	$ 5,187	$ 6,414	$ 6,628	$ 6,414	$ 6,628	$ 6,628	$ 6,414	$ 6,628	$ 18,049	$ 39,342
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Tennessee Zone 4 Supply Costs															
9	Purchased Volumes	Sendout Optimization	65,266	-	-	335	52,774	65,266	67,442	65,266	67,442	67,442	65,266	67,442	183,641	400,300
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 4.736	$ 3.859
11	NYMEX Cost	Line 9 times Line 10	$ 346,237	$ -	$ -	$ 1,798	$ 264,554	$ 257,084	$ 256,953	$ 250,557	$ 261,067	$ 261,607	$ 252,124	$ 262,349	$ 869,674	$ 1,544,656
12	NYMEX Basis Price	Att FXW-10, Line 8 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Tennessee Gas Pipeline (Contract 5265)															
19	Receipt Point: Tennessee Zone 4 Station 313 Pool															
20	Delivery Point: Pleasant St. (Interconnection with Granite)															
21	Total Contract Recevied Volume	Sendout Optimization	65,266	67,442	67,442	60,915	67,442	65,266	67,442	65,266	67,442	67,442	65,266	67,442	393,773	
22	Received Volume	Line 14	65,266	-	-	335	52,774	65,266	67,442	65,266	67,442	67,442	65,266	67,442	183,641	
23	Percentage Allocated	Line 22 divided by Line 21	100.00%	0.00%	0.00%	0.55%	78.25%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	46.64%	100.00%
24	Received Volume	Line 9	65,266	-	-	335	52,774	65,266	67,442	65,266	67,442	67,442	65,266	67,442	183,641	400,300
25	Fuel Loss Rate	Att FXW-10, Line 37 of Page 2	1.22%			1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
26	Delivered Volume	Line 24 times (1 - Line 25)	64,470	-	-	331	52,130	64,470	66,619	64,470	66,619	66,619	64,470	66,619	181,401	395,416
27	Variable Transportation Rate	Att FXW-10, Line 24 of Page 2	$ 0.0983			$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983
28	Variable Transportation Costs	Line 26 times Line 27	$ 6,337	$ -	$ -	$ 33	$ 5,124	$ 6,337	$ 6,549	$ 6,337	$ 6,549	$ 6,549	$ 6,337	$ 6,549	$ 17,832	$ 38,869
29																
30	Granite State Gas Transmission (Contract 19-100-FT-NN)															
31	Receipt Point: Pleasant St.															
32	Delivery Point: Northern City Gates															
33	Received Volume	Line 26	64,470	-	-	331	52,130	64,470	66,619	64,470	66,619	66,619	64,470	66,619	181,401	395,416
34	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	64,244	-	-	330	51,947	64,244	66,386	64,244	66,386	66,386	64,244	66,386	180,766	394,032
36	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
37	Variable Transportation Costs	Line 35 times Line 36	$ 77	$ -	$ -	$ 0	$ 62	$ 77	$ 80	$ 77	$ 80	$ 80	$ 77	$ 80	$ 217	$ 473

REDACTED

Source of Supply: Dawn Supply (Union Dawn Storage Path)

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	-	-	-	7,349	28,653	765,591	328,580	137,241	94,663	100,068	135,759	425,936	801,592	1,222,246
2	City Gate Delivered Volume	Line 57	-	-	-	7,166	27,942	746,591	320,425	133,836	92,313	97,584	132,390	415,365	781,700	1,191,914
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 28, 50 and 59	$ -	$ -	$ -	$ 198	$ 772	$ 20,628	$ 8,853	$ 3,698	$ 2,551	$ 2,696	$ 3,658	$ 11,476	$ 21,598	$ 32,932
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Portland Supply Costs															
9	Purchased Volumes	Sendout Optimization	-	-	-	7,349	28,653	765,591	328,580	137,241	94,663	100,068	135,759	425,936	801,592	1,222,246
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 3.991	$ 3.857
11	NYMEX Cost	Line 9 times Line 10	$ -	$ -	$ -	$ 39,462	$ 143,637	$ 3,015,662	$ 1,251,888	$ 526,870	$ 366,439	$ 388,163	$ 524,435	$ 1,656,890	$ 3,198,761	$ 4,714,685
12	NYMEX Basis Price	Att FXW-10, Line 10 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Union Pipeline (Contract M12256)															
19	Receipt Point: Union Dawn															
20	Delivery Point: Parkway															
21	Total Contract Recevied Volume	Sendout Optimization	342,518	681,736	766,797	838,696	627,874	765,591	328,580	137,241	94,663	100,068	135,759	425,936	4,023,212	1,222,246
22	Received Volume	Line 9	-	-	-	7,349	28,653	765,591	328,580	137,241	94,663	100,068	135,759	425,936	801,592	1,222,246
23	Percentage Allocated	Line 22 divided by Line 21	0.00%	0.00%	0.00%	0.88%	4.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	19.92%	100.00%
24	Received Volume	Line 9	-	-	-	7,349	28,653	765,591	328,580	137,241	94,663	100,068	135,759	425,936	801,592	1,222,246
25	Fuel Loss Rate	Att FXW-10, Line 41 of Page 2				0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
26	Delivered Volume	Line 24 times (1 - Line 25)	-	-	-	7,289	28,421	759,389	325,918	136,130	93,896	99,257	134,659	422,486	795,099	1,212,346
27	Variable Transportation Rate	Att FXW-10, Line 26 of Page 2				$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248
28	Variable Transportation Costs	Line 26 times Line 27	$ -	$ -	$ -	$ 181	$ 705	$ 18,833	$ 8,083	$ 3,376	$ 2,329	$ 2,462	$ 3,340	$ 10,478	$ 19,718	$ 30,066
29																
30	TransCanada Pipeline (Contracts 57055 & 57091)															
31	Receipt Point: Parkway															
32	Delivery Point: East Hereford															
33	Total Contract Recevied Volume	Sendout Optimization	339,744	676,214	760,586	831,903	622,788	759,389	325,918	136,130	93,896	99,257	134,659	422,486	3,990,624	1,212,346
34	Received Volume	Line 26	-	-	-	7,289	28,421	759,389	325,918	136,130	93,896	99,257	134,659	422,486	795,099	1,212,346
35	Percentage Allocated	Line 34 divided by Line 33	0.00%	0.00%	0.00%	0.88%	4.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	19.92%	100.00%
36	Received Volume	Line 26	-	-	-	7,289	28,421	759,389	325,918	136,130	93,896	99,257	134,659	422,486	795,099	1,212,346
37	Fuel Loss Rate	Att FXW-10, Line 40 of Page 2				1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%
38	Delivered Volume	Line 36 times (1 - Line 37)	-	-	-	7,191	28,040	749,214	321,551	134,306	92,638	97,927	132,855	416,824	784,445	1,196,100
39																
40	PNGTS Pipeline (Contract 208543)															
41	Receipt Point: Pittsburg (interconnect with East Hereford)															
42	Delivery Point: Westbrook, Newington, Eliot															
43	Total Contract Recevied Volume	Sendout Optimization	335,191	667,153	750,394	820,755	614,443	749,214	321,551	134,306	92,638	97,927	132,855	416,824	3,937,150	1,196,100
44	Received Volume	Line 38	-	-	-	7,191	28,040	749,214	321,551	134,306	92,638	97,927	132,855	416,824	784,445	1,196,100
45	Percentage Allocated	Line 44 divided by Line 43	0.00%	0.00%	0.00%	0.88%	4.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	19.92%	100.00%
46	Received Volume	Line 38	-	-	-	7,191	28,040	749,214	321,551	134,306	92,638	97,927	132,855	416,824	784,445	1,196,100
47	Fuel Loss Rate	Att FXW-10, Line 33 of Page 2				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
48	Delivered Volume	Line 46 times (1 - Line 47)	-	-	-	7,191	28,040	749,214	321,551	134,306	92,638	97,927	132,855	416,824	784,445	1,196,100
49	Variable Transportation Rate	Att FXW-10, Line 20 of Page 2				$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
50	Variable Transportation Costs	Line 48 times Line 49	$ -	$ -	$ -	$ 9	$ 34	$ 899	$ 386	$ 161	$ 111	$ 118	$ 159	$ 500	$ 941	$ 1,435
51																
52	Granite State Gas Transmission (Contract 19-100-FT-NN)															
53	Receipt Point: Westbrook, Newington, Eliot															
54	Delivery Point: Northern City Gates															
55	Received Volume	Line 48	-	-	-	7,191	28,040	749,214	321,551	134,306	92,638	97,927	132,855	416,824	784,445	1,196,100
56	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
57	City Gate Delivered Volume	Line 55 times (1 - Line 56)	-	-	-	7,166	27,942	746,591	320,425	133,836	92,313	97,584	132,390	415,365	781,700	1,191,914
58	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
59	Variable Transportation Costs	Line 57 times Line 58	$ -	$ -	$ -	$ 9	$ 34	$ 896	$ 385	$ 161	$ 111	$ 117	$ 159	$ 498	$ 938	$ 1,430

REDACTED

Source of Supply: Leidy Hub

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	29,373	30,374	30,432	27,487	30,432	-	-	-	-	-	-	-	148,099	-
2	City Gate Delivered Volume	Sum Lines 35	28,681	29,625	29,625	26,758	29,625	-	-	-	-	-	-	-	144,313	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 37	$ 2,675	$ 1,916	$ 1,916	$ 1,731	$ 1,916	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,153	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Texas Eastern Zone M-3 Purchases															
9	Purchased Volumes	Sendout Optimization	29,373	30,374	30,432	27,487	30,432	-	-	-	-	-	-	-	148,099	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.309	-
11	NYMEX Cost	Line 9 times Line 10	$ 155,824	$ 163,957	$ 166,313	$ 147,607	$ 152,557	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 786,257	$ -
12	NYMEX Basis Price	Att FXW-10, Line 7 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Texas Eastern Pipeline (Contract 800384)															
19	Receipt Point: Leidy Hub															
20	Delivery Point: Lambertville, NJ															
21	Received Volume	Line 15	29,373	30,374	30,432	27,487	30,432	-	-	-	-	-	-	-	148,099	-
22	Fuel Loss Rate	Att FXW-10, Line 39 of Page 2	1.44%	1.51%	1.70%	1.70%	1.70%								1.20%	1.20%
23	Delivered Volume	Line 21 times (1 - Line 22)	28,950	29,915	29,915	27,020	29,915	-	-	-	-	-	-	-	145,715	-
24	Variable Transportation Rate	Att FXW-10, Line 27 of Page 2	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587								$ 0.0587	
25	Variable Transportation Costs	Line 23 times Line 24	$ 1,699	$ 1,756	$ 1,756	$ 1,586	$ 1,756	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,553	$ -
26																
27	Algonquin Pipeline (Contract 93201A1C)															
28	Receipt Point: Lamberville, NJ															
29	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
30	Total Contract Recevied Volume	Sendout Optimization	29,222	30,208	30,208	27,285	30,208	-	-	-	-	-	-	-	147,130	-
31	Received Volume	Line 14	28,950	29,915	29,915	27,020	29,915	-	-	-	-	-	-	-	145,715	-
32	Percentage Allocated	Line 31 divided by Line 30	99.07%	99.03%	99.03%	99.03%	99.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	99.04%	0.00%
33	Received Volume	Line 15	28,950	29,915	29,915	27,020	29,915	-	-	-	-	-	-	-	145,715	-
34	Fuel Loss Rate	Att FXW-10, Line 28 of Page 2	0.93%	0.97%	0.97%	0.97%	0.97%								1.20%	1.20%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	28,681	29,625	29,625	26,758	29,625	-	-	-	-	-	-	-	144,313	-
36	Variable Transportation Rate	Att FXW-10, Line 15 of Page 2	$ 0.0340	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054								$ 0.0111	
37	Variable Transportation Costs	Line 35 times Line 36	$ 975	$ 160	$ 160	$ 144	$ 160	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,600	$ -

REDACTED

Source of Supply: Texas Eastern Zone M-3

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	272	293	293	265	293	-	-	-	-	-	-	-	1,415	-
2	City Gate Delivered Volume	Sum Lines 26	269	290	290	262	290	-	-	-	-	-	-	-	1,402	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 28	$ 9	$ 2	$ 2	$ 1	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Texas Eastern Zone M-3 Purchases															
9	Purchased Volumes	Sendout Optimization	272	293	293	265	293	-	-	-	-	-	-	-	1,415	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.309	
11	NYMEX Cost	Line 9 times Line 10	$ 1,442	$ 1,582	$ 1,601	$ 1,421	$ 1,469	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,515	$ -
12	NYMEX Basis Price	Att FXW-10, Line 6 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Algonquin Pipeline (Contract 93201A1C)															
19	Receipt Point: Lamberville, NJ															
20	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
21	Total Contract Recevied Volume	Sendout Optimization	29,222	30,208	30,208	27,285	30,208	-	-	-	-	-	-	-	147,130	-
22	Received Volume	Line 14	272	293	293	265	293	-	-	-	-	-	-	-	1,415	-
23	Percentage Allocated	Line 22 divided by Line 21	0.93%	0.97%	0.97%	0.97%	0.97%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.96%	0.00%
24	Received Volume	Line 15	272	293	293	265	293	-	-	-	-	-	-	-	1,415	-
25	Fuel Loss Rate	Att FXW-10, Line 28 of Page 2	0.93%	0.97%	0.97%	0.97%	0.97%								1.20%	1.20%
26	City Gate Delivered Volume	Line 24 times (1 - Line 25)	269	290	290	262	290	-	-	-	-	-	-	-	1,402	-
27	Variable Transportation Rate	Att FXW-10, Line 15 of Page 2	$ 0.0340	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054								$ 0.0109	
28	Variable Transportation Costs	Line 26 times Line 27	$ 9	$ 2	$ 2	$ 1	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15	$ -

REDACTED

Source of Supply: Transco Zone 6, non-NY

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	8,661	8,953	8,953	8,086	8,953	-	-	-	-	-	-	-	43,606	-
2	City Gate Delivered Volume	Sum Lines 23	8,580	8,866	8,866	8,008	8,866	-	-	-	-	-	-	-	43,186	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 25	$ 292	$ 48	$ 48	$ 43	$ 48	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 479	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Tranco Zone 6, non-NY Purchases															
9	Purchased Volumes	Sendout Optimization	8,661	8,953	8,953	8,086	8,953	-	-	-	-	-	-	-	43,606	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.309	
11	NYMEX Cost	Line 9 times Line 10	$ 45,944	$ 48,327	$ 48,927	$ 43,424	$ 44,881	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 231,504	$ -
12	NYMEX Basis Price	Att FXW-10, Line 5 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Algonquin Pipeline (Contract 93201A1C)															
19	Receipt Point: Centerville, NJ															
20	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
21	Received Volume	Line 15	8,661	8,953	8,953	8,086	8,953	-	-	-	-	-	-	-	43,606	-
22	Fuel Loss Rate	Att FXW-10, Line 28 of Page 2	0.93%	0.97%	0.97%	0.97%	0.97%								1.20%	1.20%
23	City Gate Delivered Volume	Line 21 times (1 - Line 22)	8,580	8,866	8,866	8,008	8,866	-	-	-	-	-	-	-	43,186	-
24	Variable Transportation Rate	Att FXW-10, Line 15 of Page 2	$ 0.0340	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054								$ 0.0111	
25	Variable Transportation Costs	Line 23 times Line 24	$ 292	$ 48	$ 48	$ 43	$ 48	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 479	$ -

REDACTED

Source of Supply: Tennessee Niagara Pipeline Path

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	55,013	56,847	56,847	51,346	56,847	55,013	56,847	55,013	56,847	56,847	55,013	56,847	331,912	337,414
2	City Gate Delivered Volume	Line 41	54,349	56,161	56,161	50,726	56,161	54,349	56,161	54,349	56,161	56,161	54,349	56,161	327,906	333,341
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 25, 34 and 43	$ 4,134	$ 4,272	$ 4,272	$ 3,858	$ 4,272	$ 4,134	$ 4,272	$ 4,134	$ 4,272	$ 4,272	$ 4,134	$ 4,272	$ 24,941	$ 25,355
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Niagara Supply Costs															
9	Purchased Volumes	Sendout Optimization	55,013	56,847	56,847	51,346	56,847	55,013	56,847	55,013	56,847	56,847	55,013	56,847	331,912	337,414
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.082	$ 3.859
11	NYMEX Cost	Line 9 times Line 10	$ 291,845	$ 306,859	$ 310,668	$ 275,726	$ 284,973	$ 216,697	$ 216,587	$ 211,195	$ 220,054	$ 220,509	$ 212,516	$ 221,134	$ 1,686,768	$ 1,301,995
12	NYMEX Basis Price	Att FXW-10, Line 3 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Tennessee Gas Pipeline (Contract 5292)															
19	Receipt Point: Niagara															
20	Delivery Point: Pleasant St. (Interconnection with Granite)															
21	Received Volume	Line 9	33,135	34,239	34,239	30,926	34,239	33,135	34,239	33,135	34,239	34,239	33,135	34,239	199,914	203,228
22	Fuel Loss Rate	Att FXW-10, Line 38 of Page 2	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
23	Delivered Volume	Line 21 times (1 - Line 22)	32,850	33,945	33,945	30,660	33,945	32,850	33,945	32,850	33,945	33,945	32,850	33,945	198,195	201,480
24	Variable Transportation Rate	Att FXW-10, Line 25 of Page 2	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746
25	Variable Transportation Costs	Line 23 times Line 24	$ 2,451	$ 2,532	$ 2,532	$ 2,287	$ 2,532	$ 2,451	$ 2,532	$ 2,451	$ 2,532	$ 2,532	$ 2,451	$ 2,532	$ 14,785	$ 15,030
26																
27	Tennessee Gas Pipeline (Contract 39735)															
28	Receipt Point: Niagara															
29	Delivery Point: Pleasant St. (Interconnection with Granite)															
30	Received Volume	Line 9	21,878	22,607	22,607	20,420	22,607	21,878	22,607	21,878	22,607	22,607	21,878	22,607	131,998	134,186
31	Fuel Loss Rate	Att FXW-10, Line 38 of Page 2	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
32	Delivered Volume	Line 30 times (1 - Line 31)	21,690	22,413	22,413	20,244	22,413	21,690	22,413	21,690	22,413	22,413	21,690	22,413	130,863	133,032
33	Variable Transportation Rate	Att FXW-10, Line 25 of Page 2	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746
34	Variable Transportation Costs	Line 32 times Line 33	$ 1,618	$ 1,672	$ 1,672	$ 1,510	$ 1,672	$ 1,618	$ 1,672	$ 1,618	$ 1,672	$ 1,672	$ 1,618	$ 1,672	$ 9,762	$ 9,924
35																
36	Granite State Gas Transmission (Contract 19-100-FT-NN)															
37	Receipt Point: Pleasant St.															
38	Delivery Point: Northern City Gates															
39	Received Volume	Line 32	54,540	56,358	56,358	50,904	56,358	54,540	56,358	54,540	56,358	56,358	54,540	56,358	329,058	334,512
40	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
41	City Gate Delivered Volume	Line 39 times (1 - Line 40)	54,349	56,161	56,161	50,726	56,161	54,349	56,161	54,349	56,161	56,161	54,349	56,161	327,906	333,341
42	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
43	Variable Transportation Costs	Line 41 times Line 42	$ 65	$ 67	$ 67	$ 61	$ 67	$ 65	$ 67	$ 65	$ 67	$ 67	$ 65	$ 67	$ 393	$ 400

REDACTED

Source of Supply: PXP Dawn Pipeline Path

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	234,244	246,927	246,927	223,031	246,927	54,132	-	-	-	-	-	-	1,252,189	-
2	City Gate Delivered Volume	Line 57	227,792	240,125	240,125	216,887	240,125	52,641	-	-	-	-	-	-	1,217,695	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 28, 50 and 59	$ 8,390	$ 8,844	$ 8,844	$ 7,988	$ 8,844	$ 1,939	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,850	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Portland Supply Costs															
9	Purchased Volumes	Sendout Optimization	234,244	246,927	246,927	223,031	246,927	54,132	-	-	-	-	-	-	1,252,189	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.250	
11	NYMEX Cost	Line 9 times Line 10	$ 1,242,667	$ 1,332,913	$ 1,349,457	$ 1,197,676	$ 1,237,846	$ 213,228	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,573,786	$ -
12	NYMEX Basis Price	Att FXW-10, Line 14 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Union Pipeline (Contract M12296)															
19	Receipt Point: Union Dawn															
20	Delivery Point: Parkway															
21	Total Contract Recevied Volume	Sendout Optimization	234,244	246,927	246,927	223,031	246,927	54,132	-	-	-	-	-	-	1,252,189	-
22	Received Volume	Line 9	234,244	246,927	246,927	223,031	246,927	54,132	-	-	-	-	-	-	1,252,189	-
23	Percentage Allocated	Line 22 divided by Line 21	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%
24	Received Volume	Line 9	234,244	246,927	246,927	223,031	246,927	54,132	-	-	-	-	-	-	1,252,189	-
25	Fuel Loss Rate	Att FXW-10, Line 41 of Page 2	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%							0.81%	
26	Delivered Volume	Line 24 times (1 - Line 25)	232,347	244,927	244,927	221,224	244,927	53,694	-	-	-	-	-	-	1,242,047	-
27	Variable Transportation Rate	Att FXW-10, Line 26 of Page 2	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248							$ 0.0248	
28	Variable Transportation Costs	Line 26 times Line 27	$ 5,762	$ 6,074	$ 6,074	$ 5,486	$ 6,074	$ 1,332	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,803	$ -
29																
30	TransCanada Pipeline (Contract 63265)															
31	Receipt Point: Parkway															
32	Delivery Point: E. Hereford (Interconnects with PNGTS at Pittsburg)															
33	Total Contract Recevied Volume	Sendout Optimization	232,347	244,927	244,927	221,224	244,927	53,694	-	-	-	-	-	-	1,242,047	-
34	Received Volume	Line 26	232,347	244,927	244,927	221,224	244,927	53,694	-	-	-	-	-	-	1,242,047	-
35	Percentage Allocated	Line 34 divided by Line 33	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
36	Received Volume	Line 26	232,347	244,927	244,927	221,224	244,927	53,694	-	-	-	-	-	-	1,242,047	-
37	Fuel Loss Rate	Att FXW-10, Line 40 of Page 2	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%							1.34%	
38	Delivered Volume	Line 36 times (1 - Line 37)	229,234	241,645	241,645	218,260	241,645	52,975	-	-	-	-	-	-	1,225,403	-
39																
40	PNGTS Pipeline (Contract 23339)															
41	Receipt Point: Pittsburg															
42	Delivery Point: Westbrook, Newington, Eliot															
43	Total Contract Recevied Volume	Sendout Optimization	229,234	241,645	241,645	218,260	241,645	52,975	-	-	-	-	-	-	1,225,403	-
44	Received Volume	Line 38	229,234	241,645	241,645	218,260	241,645	52,975	-	-	-	-	-	-	1,225,403	-
45	Percentage Allocated	Line 44 divided by Line 43	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
46	Received Volume	Line 38	229,234	241,645	241,645	218,260	241,645	52,975	-	-	-	-	-	-	1,225,403	-
47	Fuel Loss Rate	Att FXW-10, Line 34 of Page 2	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%							0.28%	
48	Delivered Volume	Line 46 times (1 - Line 47)	228,592	240,968	240,968	217,649	240,968	52,826	-	-	-	-	-	-	1,221,972	-
49	Variable Transportation Rate	Att FXW-10, Line 21 of Page 2	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103							$ 0.0103	
50	Variable Transportation Costs	Line 48 times Line 49	$ 2,354	$ 2,482	$ 2,482	$ 2,242	$ 2,482	$ 544	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,586	$ -
51																
52	Granite State Gas Transmission (Contract 19-100-FT-NN)															
53	Receipt Point: Westbrook, Newington, Eliot															
54	Delivery Point: Northern City Gates															
55	Received Volume	Line 48	228,592	240,968	240,968	217,649	240,968	52,826	-	-	-	-	-	-	1,221,972	-
56	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
57	City Gate Delivered Volume	Line 55 times (1 - Line 56)	227,792	240,125	240,125	216,887	240,125	52,641	-	-	-	-	-	-	1,217,695	-
58	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
59	Variable Transportation Costs	Line 57 times Line 58	$ 273	$ 288	$ 288	$ 260	$ 288	$ 63	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,461	$ -

REDACTED

Source of Supply: Tennessee Zone 0

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 21	109,016	116,535	61,759	68,502	116,535	11,021	-	-	-	-	-	-	483,367	-
2	City Gate Delivered Volume	Line 32	103,572	110,715	58,675	65,081	110,715	10,470	-	-	-	-	-	-	459,229	-
3	Total Purchase Cost	Line 2 times Line 3	[redacted]													
4	Variable Transportation Costs	Sum Lines 25 and 34	$ 30,068	$ 32,142	$ 17,034	$ 18,894	$ 32,142	$ 3,040	$ -	$ -	$ -	$ -	$ -	$ -	$ 133,320	$ -
5	Total City Gate Delivered Costs	Sum Lines 4 and 5	[redacted]													
6	Average Delivered Price	Line 6 divided by Line 2														
7																
8	Tennessee Zone 0 Supply Costs															
9	Purchased Volumes	Sendout Optimization	109,016	116,535	61,759	68,502	116,535	11,021	-	-	-	-	-	-	483,367	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.256	-
11	NYMEX Cost	Line 9 times Line 10	$ 578,331	$ 629,053	$ 337,512	$ 367,857	$ 584,187	$ 43,411	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,540,351	$ -
12	NYMEX Basis Price	Att FXW-10, Line 1 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Tennessee Gas Pipeline (Contract 5083)															
19	Receipt Point: Tennessee Zone 0															
20	Delivery Point: Pleasant St. (Interconnection with Granite)															
21	Received Volume	Line 9	109,016	116,535	61,759	68,502	116,535	11,021	-	-	-	-	-	-	483,367	-
22	Fuel Loss Rate	Att FXW-10, Line 35 of Page 2	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%							4.66%	
23	Delivered Volume	Line 21 times (1 - Line 22)	103,936	111,104	58,881	65,310	111,104	10,507	-	-	-	-	-	-	460,842	-
24	Variable Transportation Rate	Att FXW-10, Line 22 of Page 2	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881							$ 0.2881	
25	Variable Transportation Costs	Line 23 times Line 24	$ 29,944	$ 32,009	$ 16,964	$ 18,816	$ 32,009	$ 3,027	$ -	$ -	$ -	$ -	$ -	$ -	$ 132,769	$ -
26																
27	Granite State Gas Transmission (Contract 19-100-FT-NN)															
28	Receipt Point: Pleasant St.															
29	Delivery Point: Northern City Gates															
30	Received Volume	Line 23	103,936	111,104	58,881	65,310	111,104	10,507	-	-	-	-	-	-	460,842	-
31	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
32	City Gate Delivered Volume	Line 30 times (1 - Line 31)	103,572	110,715	58,675	65,081	110,715	10,470	-	-	-	-	-	-	459,229	-
33	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
34	Variable Transportation Costs	Line 32 times Line 33	$ 124	$ 133	$ 70	$ 78	$ 133	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ 551	$ -

REDACTED

Source of Supply: Tennessee Zone L

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 21	185,775	215,003	215,003	183,540	177,630	198	-	-	-	-	-	-	977,149	-
2	City Gate Delivered Volume	Line 32	177,608	205,552	205,552	175,472	169,822	189	-	-	-	-	-	-	934,196	-
3	Total Purchase Cost	Line 2 times Line 3	[redacted]													
4	Variable Transportation Costs	Sum Lines 25 and 34	$ 45,003	$ 52,083	$ 52,083	$ 44,462	$ 43,030	$ 48	$ -	$ -	$ -	$ -	$ -	$ -	$ 236,709	$ -
5	Total City Gate Delivered Costs	Sum Lines 4 and 5	[redacted]													
6	Average Delivered Price	Line 6 divided by Line 2														
7																
8	Tennessee Zone L Supply Costs															
9	Purchased Volumes	Sendout Optimization	185,775	215,003	215,003	183,540	177,630	198	-	-	-	-	-	-	977,149	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.320	-
11	NYMEX Cost	Line 9 times Line 10	$ 985,535	$ 1,160,587	$ 1,174,992	$ 985,611	$ 890,458	$ 780	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,197,964	$ -
12	NYMEX Basis Price	Att FXW-10, Line 2 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Tennessee Gas Pipeline (Contract 5083)															
19	Receipt Point: Tennessee Zone L															
20	Delivery Point: Pleasant St. (Interconnection with Granite)															
21	Received Volume	Line 9	185,775	215,003	215,003	183,540	177,630	198	-	-	-	-	-	-	977,149	-
22	Fuel Loss Rate	Att FXW-10, Line 36 of Page 2	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%							4.06%	
23	Delivered Volume	Line 21 times (1 - Line 22)	178,232	206,274	206,274	176,089	170,418	190	-	-	-	-	-	-	937,477	-
24	Variable Transportation Rate	Att FXW-10, Line 23 of Page 2	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513							$ 0.2513	
25	Variable Transportation Costs	Line 23 times Line 24	$ 44,790	$ 51,837	$ 51,837	$ 44,251	$ 42,826	$ 48	$ -	$ -	$ -	$ -	$ -	$ -	$ 235,588	$ -
26																
27	Granite State Gas Transmission (Contract 19-100-FT-NN)															
28	Receipt Point: Pleasant St.															
29	Delivery Point: Northern City Gates															
30	Received Volume	Line 23	178,232	206,274	206,274	176,089	170,418	190	-	-	-	-	-	-	937,477	-
31	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
32	City Gate Delivered Volume	Line 30 times (1 - Line 31)	177,608	205,552	205,552	175,472	169,822	189	-	-	-	-	-	-	934,196	-
33	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
34	Variable Transportation Costs	Line 32 times Line 33	$ 213	$ 247	$ 247	$ 211	$ 204	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,121	$ -

REDACTED

Source of Supply: Iroquois Receipts Pipeline Path

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	190,570	196,977	196,977	177,914	196,977	-	-	-	-	-	-	-	959,414	-
2	City Gate Delivered Volume	Line 35	187,431	193,679	193,679	174,936	193,679	-	-	-	-	-	-	-	943,403	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 28, 37, 46, 55, 64 and 73	$ 19,270	$ 16,183	$ 16,183	$ 14,617	$ 16,183	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 82,437	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Irqoquois Receipts Supply Costs															
9	Purchased Volumes	Sendout Optimization	190,570	196,977	196,977	177,914	196,977	-	-	-	-	-	-	-	959,414	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.309	
11	NYMEX Cost	Line 9 times Line 10	$ 1,010,976	$ 1,063,279	$ 1,076,477	$ 955,400	$ 987,443	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,093,575	$ -
12	NYMEX Basis Price	Att FXW-10, Line 4 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Iroquois Pipeline (Contract R181001)															
19	Receipt Point: Waddington															
20	Delivery Point: Wright (Interconnection with Tennessee)															
21	Total Contract Recevied Volume	Sendout Optimization	190,570	196,977	196,977	177,914	196,977	-	-	-	-	-	-	-	959,414	-
22	Received Volume	Line 9	190,570	196,977	196,977	177,914	196,977	-	-	-	-	-	-	-	959,414	-
23	Percentage Allocated	Line 22 divided by Line 21	100.00%	100.00%	100.00%	100.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100%	
24	Received Volume	Line 14	190,570	196,977	196,977	177,914	196,977	-	-	-	-	-	-	-	959,414	-
25	Fuel Loss Rate	Att FXW-10, Line 31 of Page 2	0.13%	0.13%	0.13%	0.13%	0.13%								0.13%	
26	Delivered Volume	Line 24 times (1 - Line 25)	190,323	196,720	196,720	177,683	196,720	-	-	-	-	-	-	-	958,167	-
27	Variable Transportation Rate	Att FXW-10, Line 18 of Page 2	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046								$ -	
28	Variable Transportation Costs	Line 26 times Line 27	$ 875	$ 905	$ 905	$ 817	$ 905	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29																
30	Tennessee Gas Pipeline (Contract 95196)															
31	Receipt Point: Wright															
32	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
33	Received Volume	Line 26	41,820	43,214	43,214	39,032	43,214	-	-	-	-	-	-	-	210,492	-
34	Fuel Loss Rate	Att FXW-10, Line 38 of Page 2	0.86%	0.86%	0.86%	0.86%	0.86%								0.86%	
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	41,460	42,842	42,842	38,696	42,842	-	-	-	-	-	-	-	208,682	-
36	Variable Transportation Rate	Att FXW-10, Line 25 of Page 2	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746								$ 0.0746	
37	Variable Transportation Costs	Line 35 times Line 36	$ 3,093	$ 3,196	$ 3,196	$ 2,887	$ 3,196	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,568	$ -
38																
39	Tennessee Gas Pipeline (Contract 95196)															
40	Receipt Point: Wright															
41	Delivery Point: Pleasant St. (Interconnection with Granite)															
42	Received Volume	Line 35	19,881	20,544	20,544	18,556	20,544	-	-	-	-	-	-	-	100,068	-
43	Fuel Loss Rate	Att FXW-10, Line 38 of Page 2	0.86%	0.86%	0.86%	0.86%	0.86%								0.86%	
44	Delivered Volume	Line 42 times (1 - Line 43)	19,710	20,367	20,367	18,396	20,367	-	-	-	-	-	-	-	99,207	-
45	Variable Transportation Rate	Att FXW-10, Line 25 of Page 2	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746								$ 0.0746	
46	Variable Transportation Costs	Line 44 times Line 45	$ 1,470	$ 1,519	$ 1,519	$ 1,372	$ 1,519	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,401	$ -
47																
48	Granite State Gas Transmission (Contract 19-100-FT-NN)															
49	Receipt Point: Pleasant St.															
50	Delivery Point: Northern City Gates															
51	Received Volume	Line 44	19,710	20,367	20,367	18,396	20,367	-	-	-	-	-	-	-	99,207	-
52	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
53	City Gate Delivered Volume	Line 51 times (1 - Line 52)	19,641	20,296	20,296	18,332	20,296	-	-	-	-	-	-	-	98,860	-
54	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
55	Variable Transportation Costs	Line 53 times Line 54	$ 24	$ 24	$ 24	$ 22	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 119	$ -
56																
57	Tennessee Gas Pipeline (Contract 41099)															
58	Receipt Point: Wright															
59	Delivery Point: Mendon (Interconnection with Algonquin)															
60	Received Volume	Line 26	128,622	132,963	132,963	120,096	132,963	-	-	-	-	-	-	-	647,607	-
61	Fuel Loss Rate	Att FXW-10, Line 38 of Page 2	0.86%	0.86%	0.86%	0.86%	0.86%								0.86%	
62	Delivered Volume	Line 60 times (1 - Line 61)	127,516	131,820	131,820	119,063	131,820	-	-	-	-	-	-	-	642,038	-
63	Variable Transportation Rate	Att FXW-10, Line 25 of Page 2	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746								$ 0.0746	
64	Variable Transportation Costs	Line 62 times Line 63	$ 9,513	$ 9,834	$ 9,834	$ 8,882	$ 9,834	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,896	$ -
65																
66	Algonquin Gas Transmission (Contract 93200F)															
67	Receipt Point: Mendon															
68	Delivery Point: Bay State City Gate (Delivered to Northern via Exchange Agreement)															
69	Received Volume	Line 62	127,516	131,820	131,820	119,063	131,820	-	-	-	-	-	-	-	642,038	-
70	Fuel Loss Rate	Att FXW-10, Line 28 of Page 2	0.93%	0.97%	0.97%	0.97%	0.97%								0.96%	
71	City Gate Delivered Volume	Line 69 times (1 - Line 70)	126,330	130,541	130,541	117,908	130,541	-	-	-	-	-	-	-	635,861	-
72	Variable Transportation Rate	Att FXW-10, Line 15 of Page 2	$ 0.0340	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054								$ 0.0111	
73	Variable Transportation Costs	Line 71 times Line 72	$ 4,295	$ 705	$ 705	$ 637	$ 705	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,047	$ -

REDACTED

Source of Supply: Atlantic Bridge Ramapo Pipeline Path

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	183,178	192,545	192,545	173,911	192,545	183,714	189,838	183,714	189,838	189,838	183,714	189,838	1,118,438	1,126,782
2	City Gate Delivered Volume	Sum Lines 35	175,110	180,947	180,947	163,436	180,947	175,110	180,947	175,110	180,947	180,947	175,110	180,947	1,056,497	1,074,008
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Sum Lines 37	$ (10,174)	$ (10,514)	$ (10,514)	$ (9,496)	$ (10,514)	$ (10,205)	$ (10,545)	$ (10,205)	$ (10,545)	$ (10,545)	$ (10,205)	$ (10,545)	$ (61,416)	$ (62,590)
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Ramapo Supply Purchases															
9	Purchased Volumes	Sendout Optimization	183,178	192,545	192,545	173,911	192,545	183,714	189,838	183,714	189,838	189,838	183,714	189,838	1,118,438	1,126,782
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.084	$ 3.859
11	NYMEX Cost	Line 9 times Line 10	$ 971,760	$ 1,039,357	$ 1,052,257	$ 933,904	$ 965,227	$ 723,651	$ 723,284	$ 705,280	$ 734,864	$ 736,383	$ 709,689	$ 738,471	$ 5,686,156	$ 4,347,971
12	NYMEX Basis Price	Att FXW-10, Line 13 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Transportation Fuel Losses and Variable Charges															
18	Algonquin Pipeline (Contract 510939)															
19	Receipt Point: Ramapo, NJ															
20	Delivery Point: Beverly															
21	Received Volume	Line 15	183,178	192,545	192,545	173,911	192,545	183,714	189,838	183,714	189,838	189,838	183,714	189,838	1,118,438	1,126,782
22	Fuel Loss Rate	Att FXW-10, Line 29 of Page 2	3.75%	5.38%	5.38%	5.38%	5.38%								1.20%	1.20%
23	Delivered Volume	Line 21 times (1 - Line 22)	176,309	182,186	182,186	164,555	182,186	176,825	182,719	176,825	182,719	182,719	176,825	182,719	1,064,247	1,084,528
24	Variable Transportation Rate	Att FXW-10, Line 16 of Page 2	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)								$ (0.0589)	
25	Variable Transportation Costs	Line 23 times Line 24	$ (10,385)	$ (10,731)	$ (10,731)	$ (9,692)	$ (10,731)	$ (10,415)	$ (10,762)	$ (10,415)	$ (10,762)	$ (10,762)	$ (10,415)	$ (10,762)	$ (62,684)	$ (63,879)
26																
27	Maritimes Pipeline (Contract 210363)															
28	Receipt Point: Beverly															
29	Delivery Point: Lewiston City-Gate															
30	Total Contract Recevied Volume	Sendout Optimization	176,309	182,186	182,186	164,555	182,186	176,825	182,719	176,825	182,719	182,719	176,825	182,719	1,064,247	1,084,528
31	Received Volume	Line 14	176,309	182,186	182,186	164,555	182,186	176,825	182,719	176,825	182,719	182,719	176,825	182,719	1,064,247	1,084,528
32	Percentage Allocated	Line 31 divided by Line 30	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
33	Received Volume	Line 15	176,309	182,186	182,186	164,555	182,186	176,825	182,719	176,825	182,719	182,719	176,825	182,719	1,064,247	1,084,528
34	Fuel Loss Rate	Att FXW-10, Line 32 of Page 2	0.68%	0.68%	0.68%	0.68%	0.68%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%	1.20%	1.20%
35	City Gate Delivered Volume	Line 33 times (1 - Line 34)	175,110	180,947	180,947	163,436	180,947	175,110	180,947	175,110	180,947	180,947	175,110	180,947	1,056,497	1,074,008
36	Variable Transportation Rate	Att FXW-10, Line 19 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
37	Variable Transportation Costs	Line 35 times Line 36	$ 210	$ 217	$ 217	$ 196	$ 217	$ 210	$ 217	$ 210	$ 217	$ 217	$ 210	$ 217	$ 1,268	$ 1,289

Source of Supply: Tennessee Storage

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
2	Gross Withdrawn Volume	Line 10	-	67,442	67,442	60,580	14,668	-	-	-	-	-	-	-	210,132	-
3	City Gate Delivered Volume	Line 38	-	66,386	66,386	59,632	14,438	-	-	-	-	-	-	-	206,842	-
4	Total Withdrawal Costs	Line 18	$ -	$ 180,049	$ 180,049	$ 161,731	$ 39,160	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 560,989	$ -
5	Variable Transportation Costs	Sum Lines 31 and 40	$ -	$ 6,628	$ 6,628	$ 5,954	$ 1,442	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,652	$ -
6	Total City Gate Delivered Costs	Line 3 plus Line 4	$ -	$ 186,678	$ 186,678	$ 167,685	$ 40,601	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 581,642	$ -
7	Average Delivered Price	Line 5 divided by Line 2		$ 2.812	$ 2.812	$ 2.812	$ 2.812								$ 2.812	
8																
9	<u>Tennessee Storage Withdrawals</u>															
10	Gross Withdrawn Volume	Sendout Optimization	-	67,442	67,442	60,580	14,668	-	-	-	-	-	-	-	210,132	-
11	Withdrawal Rate	FXW-10, Line 1 of Page 3		$ 0.0087	$ 0.0087	$ 0.0087	$ 0.0087								$ 0.0087	
12	Withdrawal Charges	Line 9 times Line 10	$ -	$ 587	$ 587	$ 527	$ 128	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,828	$ -
13	Inventory Rate	CAK-7		$ 2.6610	$ 2.6610	$ 2.6610	$ 2.6610								$ 2.6610	
14	Withdrawn Inventory Value	Line 9 times Line 12	$ -	$ 179,463	$ 179,463	$ 161,204	$ 39,032	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 559,161	$ -
15	Withdrawal Fuel Rate	FXW-10, Line 2 of Page 3		0.00%	0.00%	0.00%	0.00%								0.00%	
16	Withdrawal Fuel Losses	FXW-10, Line 1 of Page 3 times Line 9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Net Withdrawn Volume	Line 9 minus Line 14	-	67,442	67,442	60,580	14,668	-	-	-	-	-	-	-	210,132	-
18	Total Withdrawal Costs	Line 11 plus Line 13	$ -	$ 180,049	$ 180,049	$ 161,731	$ 39,160	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 560,989	$ -
19																
20	<u>Transportation Fuel Losses and Variable Charges</u>															
21	Tennessee Gas Pipeline (Contract 5265)															
22	Receipt Point: Tennessee FS-MA Withdrawal Meter															
23	Delivery Point: Pleasant St. (Interconnection with Granite)															
24	Total Contract Recevied Volume	Sendout Optimization	65,266	67,442	67,442	60,915	67,442	65,266	67,442	65,266	67,442	67,442	65,266	67,442	393,773	400,300
25	Received Volume	Line 17	-	67,442	67,442	60,580	14,668	-	-	-	-	-	-	-	210,132	-
26	Percentage Allocated	Line 25 divided by Line 24	0.00%	100.00%	100.00%	99.45%	21.75%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	53.36%	0.00%
27	Received Volume	Line 25	-	67,442	67,442	60,580	14,668	-	-	-	-	-	-	-	210,132	-
28	Fuel Loss Rate	Att FXW-10, Line 37 of Page 2		1.22%	1.22%	1.22%	1.22%								1.22%	
29	Delivered Volume	Line 27 times (1 - Line 28)	-	66,619	66,619	59,841	14,489	-	-	-	-	-	-	-	207,568	-
30	Variable Transportation Rate	Att FXW-10, Line 24 of Page 2		$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983								$ 0.0983	
31	Variable Transportation Costs	Line 29 times Line 30	$ -	$ 6,549	$ 6,549	$ 5,882	$ 1,424	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,404	$ -
32																
33	Granite State Gas Transmission (Contract 19-100-FT-NN)															
34	Receipt Point: Pleasant St.															
35	Delivery Point: Northern City Gates															
36	Received Volume	Line 29	-	66,619	66,619	59,841	14,489	-	-	-	-	-	-	-	207,568	-
37	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
38	City Gate Delivered Volume	Line 36 times (1 - Line 37)	-	66,386	66,386	59,632	14,438	-	-	-	-	-	-	-	206,842	-
39	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
40	Variable Transportation Costs	Line 38 times Line 39	$ -	$ 80	$ 80	$ 72	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 248	$ -

Source of Supply: Union Dawn Storage

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Gross Withdrawn Volume	Line 9	344,586	685,851	771,425	836,366	602,838	-	-	-	-	-	-	-	3,241,066	-
2	City Gate Delivered Volume	Line 59	334,018	664,818	747,767	810,716	584,350	-	-	-	-	-	-	-	3,141,670	-
3	Total Withdrawal Costs	Line 17	$ 1,035,067	$ 2,060,160	$ 2,317,207	$ 2,512,276	$ 1,810,804	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,735,514	$ -
4	Variable Transportation Costs	Sum Lines 30, 52 and 61	$ 9,229	$ 18,368	$ 20,660	$ 22,400	$ 16,145	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 86,802	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	$ 1,044,295	$ 2,078,528	$ 2,337,868	$ 2,534,675	$ 1,826,950	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,822,316	$ -
6	Average Delivered Price	Line 5 divided by Line 2	$ 3.126	$ 3.126	$ 3.126	$ 3.126	$ 3.126								$ 3.126	
7																
8	Union Dawn Storage Withdrawals															
9	Gross Withdrawn Volume	Sendout Optimization	344,586	685,851	771,425	836,366	602,838	-	-	-	-	-	-	-	3,241,066	-
10	Withdrawal Rate	FXW-10, Line 2 of Page 3	$ 0.006	$ 0.006	$ 0.006	$ 0.006	$ 0.006								$ 0.006	
11	Withdrawal Charges	Line 9 times Line 10	$ 1,999	$ 3,978	$ 4,474	$ 4,851	$ 3,496	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,798	$ -
12	Inventory Rate	CAK-7	$ 2.998	$ 2.998	$ 2.998	$ 2.998	$ 2.998								$ 2.998	
13	Withdrawn Inventory Value	Line 9 times Line 12	$ 1,033,068	$ 2,056,182	$ 2,312,733	$ 2,507,425	$ 1,807,308	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,716,716	$ -
14	Withdrawal Fuel Rate	FXW-10, Line 2 of Page 3	0.60%	0.60%	0.60%	0.60%	0.60%								0.60%	
15	Withdrawal Fuel Losses	Line 14 times Line 9	2,068	4,115	4,629	5,018	3,617	-	-	-	-	-	-	-	19,446	-
16	Net Withdrawn Volume	Line 9 minus Line 14	342,518	681,736	766,797	831,348	599,221	-	-	-	-	-	-	-	3,221,620	-
17	Total Withdrawal Costs	Line 11 plus Line 13	$ 1,035,067	$ 2,060,160	$ 2,317,207	$ 2,512,276	$ 1,810,804	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,735,514	$ -
18																
19	Transportation Fuel Losses and Variable Charges															
20	Union Pipeline (Contract M12256)															
21	Receipt Point: Union Dawn															
22	Delivery Point: Parkway															
23	Total Contract Recevied Volume	Sendout Optimization	342,518	681,736	766,797	838,696	627,874	765,591	328,580	137,241	94,663	100,068	135,759	425,936	4,023,212	1,222,246
24	Received Volume	Line 16	342,518	681,736	766,797	831,348	599,221	-	-	-	-	-	-	-	3,221,620	-
25	Percentage Allocated	Line 24 divided by Line 23	100.00%	100.00%	100.00%	99.12%	95.44%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	80.08%	0.00%
26	Received Volume	Line 24	342,518	681,736	766,797	831,348	599,221	-	-	-	-	-	-	-	3,221,620	-
27	Fuel Loss Rate	Att FXW-10, Line 41 of Page 2	0.81%	0.81%	0.81%	0.81%	0.81%								0.81%	
28	Delivered Volume	Line 26 times (1 - Line 27)	339,744	676,214	760,586	824,614	594,367	-	-	-	-	-	-	-	3,195,524	-
29	Variable Transportation Rate	Att FXW-10, Line 26 of Page 2	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248	$ 0.0248								$ 0.0248	
30	Variable Transportation Costs	Line 28 times Line 29	$ 8,426	$ 16,770	$ 18,863	$ 20,450	$ 14,740	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 79,249	$ -
31																
32	TransCanada Pipeline (Contracts 57055 & 57091)															
33	Receipt Point: Parkway															
34	Delivery Point: East Hereford															
35	Total Contract Recevied Volume	Sendout Optimization	339,744	676,214	760,586	831,903	622,788	759,389	325,918	136,130	93,896	99,257	134,659	422,486	3,990,624	1,212,346
36	Received Volume	Line 28	339,744	676,214	760,586	824,614	594,367	-	-	-	-	-	-	-	3,195,524	-
37	Percentage Allocated	Line 36 divided by Line 35	100.00%	100.00%	100.00%	99.12%	95.44%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	80.08%	0.00%
38	Received Volume	Line 36	339,744	676,214	760,586	824,614	594,367	-	-	-	-	-	-	-	3,195,524	-
39	Fuel Loss Rate	Att FXW-10, Line 40 of Page 2	1.34%	1.34%	1.34%	1.34%	1.34%									
40	Delivered Volume	Line 38 times (1 - Line 39)	335,191	667,153	750,394	813,564	586,403	-	-	-	-	-	-	-	3,152,704	-
41																
42	PNGTS Pipeline (Contract 208543)															
43	Receipt Point: Pittsburg (interconnect with East Hereford)															
44	Delivery Point: Westbrook, Newington, Eliot															
45	Total Contract Recevied Volume	Sendout Optimization	335,191	667,153	750,394	820,755	614,443	749,214	321,551	134,306	92,638	97,927	132,855	416,824	3,937,150	1,196,100
46	Received Volume	Line 40	335,191	667,153	750,394	813,564	586,403	-	-	-	-	-	-	-	3,152,704	-
47	Percentage Allocated	Line 46 divided by Line 45	100.00%	100.00%	100.00%	99.12%	95.44%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	80.08%	0.00%
48	Received Volume	Sendout Optimization	335,191	667,153	750,394	813,564	586,403	-	-	-	-	-	-	-	3,152,704	-
49	Fuel Loss Rate	Att FXW-10, Line 33 of Page 2	0.00%	0.00%	0.00%	0.00%	0.00%								0.00%	
50	Delivered Volume	Line 48 times (1 - Line 49)	335,191	667,153	750,394	813,564	586,403	-	-	-	-	-	-	-	3,152,704	-
51	Variable Transportation Rate	Att FXW-10, Line 20 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012								$ 0.0012	
52	Variable Transportation Costs	Line 50 times Line 51	$ 402	$ 801	$ 900	$ 976	$ 704	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,783	$ -
53																
54	Granite State Gas Transmission (Contract 19-100-FT-NN)															
55	Receipt Point: Westbrook, Newington, Eliot															
56	Delivery Point: Northern City Gates															
57	Received Volume	Line 50	335,191	667,153	750,394	813,564	586,403	-	-	-	-	-	-	-	3,152,704	-
58	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
59	City Gate Delivered Volume	Line 57 times (1 - Line 58)	334,018	664,818	747,767	810,716	584,350	-	-	-	-	-	-	-	3,141,670	-
60	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
61	Variable Transportation Costs	Line 59 times Line 60	$ 401	$ 798	$ 897	$ 973	$ 701	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,770	$ -

REDACTED

Source of Supply: PNGTS Delivered Baseload (Dec - Feb

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	-	77,500	77,500	70,000	-	-	-	-	-	-	-	-	225,000	-
2	City Gate Delivered Volume	Line 23	-	77,229	77,229	69,755	-	-	-	-	-	-	-	-	224,213	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Line 25	$ -	$ 93	$ 93	$ 84	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 269	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2	[redacted]													
7																
8	Portland Supply Costs															
9	Purchased Volumes	Sendout Optimization	-	77,500	77,500	70,000	-	-	-	-	-	-	-	-	225,000	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.412	-
11	NYMEX Cost	Line 9 times Line 10	$ -	$ 418,345	$ 423,538	$ 375,900	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,217,783	$ -
12	NYMEX Basis Price	Att FXW-10, Line 16 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12	[redacted]													
14	Total Purchase Price	Line 10 plus Line 12	[redacted]													
15	Total Purchase Cost	Line 11 plus Line 13	[redacted]													
16																
17	Transportation Fuel Losses and Variable Charges															
18	Granite State Gas Transmission (Contract 19-100-FT-NN)															
19	Receipt Point: Granite (Westbrook, Newington, Eliot)															
20	Delivery Point: Northern City Gates															
21	Received Volume	Line 9	-	77,500	77,500	70,000	-	-	-	-	-	-	-	-	225,000	-
22	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
23	City Gate Delivered Volume	Line 21 times (1 - Line 22)	-	77,229	77,229	69,755	-	-	-	-	-	-	-	-	224,213	-
24	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
25	Variable Transportation Costs	Line 23 times Line 24	$ -	$ 93	$ 93	$ 84	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 269	$ -

REDACTED

Source of Supply: Northern LNG Inventory
On-System Storage

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Gross Withdrawn Volume	Line 9	1,794	1,854	1,854	1,674	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	10,824	11,040
2	City Gate Delivered Volume	Line 15	1,794	1,854	1,854	1,674	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	10,824	11,040
3	Total Withdrawal Costs	Line 16	[redacted]													
4	Variable Transportation Costs	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total City Gate Delivered Costs	Line 3 plus Line 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Northern LNG Withdrawn Inventory															
9	Gross Withdrawn Volume	Sendout Optimization	1,794	1,854	1,854	1,674	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	10,824	11,040
10	Withdrawal Rate	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Withdrawal Charges	Line 9 times Line 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Inventory Rate	CAK-7	[redacted]													
13	Withdrawn Inventory Value	Line 9 times Line 12														
14	Withdrawal Fuel Losses	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Net Withdrawn Volume	Line 9 minus Line 14	1,794	1,854	1,854	1,674	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	10,824	11,040
16	Total Withdrawal Costs	Line 11 plus Line 13	[redacted]													

REDACTED

Source of Supply: Peaking Contract 1

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	-	13,649	243,843	11,017	261	-	-	-	-	-	-	-	268,770	-
2	City Gate Delivered Volume	Line 24	-	13,649	243,664	11,017	261	-	-	-	-	-	-	-	268,591	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	Line 26	$ -	$ -	$ 61	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	<u>Peaking Contract 1 Costs</u>															
9	Purchased Volumes	Sendout Optimization	-	13,649	243,843	11,017	261	-	-	-	-	-	-	-	268,770	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.457	-
11	NYMEX Cost	Line 9 times Line 10	$ -	$ 73,680	$ 1,332,601	$ 59,164	$ 1,307	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,466,752	$ -
12	NYMEX Basis Price	Att FXW-10, Line 17 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	<u>Transportation Fuel Losses and Variable Charges</u>															
18	Granite State Gas Transmission (Contract 19-100-FT-NN)															
19	Receipt Point: Westbrook															
20	Delivery Point: Northern City Gates															
21	City Gate Delivered Volume	Lewiston City-Gate - Non-GSGT	-	13,649	192,693	11,017	261	-	-	-	-	-	-	-	-	-
22	Received Volume	Line 9	-	-	51,150	-	-	-	-	-	-	-	-	-	51,150	-
23	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
24	City Gate Delivered Volume	Line 22 times (1 - Line 23)	-	-	50,971	-	-	-	-	-	-	-	-	-	50,971	-
25	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	
26	Variable Transportation Costs	Line 24 times Line 25	$ -	$ -	$ 61	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61	$ -

REDACTED

Source of Supply: Peaking Contract 2

Denotes Confidential Information

Line	City Gate Delivered Costs	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	2021-2022 Winter	2022 Summer
1	Purchased Volumes	Line 9	-	42,329	105,286	87,868	64,517	-	-	-	-	-	-	-	300,000	-
2	City Gate Delivered Volume	Line 1	-	42,181	104,918	87,560	64,291	-	-	-	-	-	-	-	298,950	-
3	Total Purchase Cost	Line 15	[redacted]													
4	Variable Transportation Costs	N/A	$ -	$ 51	$ 126	$ 105	$ 77	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 359	$ -
5	Total City Gate Delivered Costs	Sum Lines 3 and 4	[redacted]													
6	Average Delivered Price	Line 5 divided by Line 2														
7																
8	Maritimes Supply Costs															
9	Purchased Volumes	Sendout Optimization	-	42,329	105,286	87,868	64,517	-	-	-	-	-	-	-	300,000	-
10	Monthly NYMEX Price	Att FXW-10, Line 20 of Page 1	$ 5.305	$ 5.398	$ 5.465	$ 5.370	$ 5.013	$ 3.939	$ 3.810	$ 3.839	$ 3.871	$ 3.879	$ 3.863	$ 3.890	$ 5.331	-
11	NYMEX Cost	Line 9 times Line 10	$ -	$ 228,491	$ 575,391	$ 471,849	$ 323,424	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,599,155	$ -
12	NYMEX Basis Price	Att FXW-10, Line 18 of Page 1	[redacted]													
13	NYMEX Basis Costs	Line 9 times Line 12														
14	Total Purchase Price	Line 10 plus Line 12														
15	Total Purchase Cost	Line 11 plus Line 13														
16																
17	Granite State Gas Transmission (Contract 19-100-FT-NN)															
18	Receipt Point: Westbrook, Newington, Eliot															
19	Delivery Point: Northern City Gates															
20	Received Volume	Line 12	-	42,329	105,286	87,868	64,517	-	-	-	-	-	-	-	-	-
21	Fuel Loss Rate	Att FXW-10, Line 30 of Page 2	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%		
22	City Gate Delivered Volume	Line 20 times (1 - Line 21)	-	42,181	104,918	87,560	64,291	-	-	-	-	-	-	-	-	-
23	Variable Transportation Rate	Att FXW-10, Line 17 of Page 2	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012		
24	Variable Transportation Costs	Line 22 times Line 23	$ -	$ 51	$ 126	$ 105	$ 77	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

Northern Utilities, Inc.
Natural Gas Commodity Price Forecast
Based upon NYMEX Settlement for September 1, 2021

Denotes Confidential Information

Estimated Adders to NYMEX Last Day Settlement

Line	Supply Source	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
1	Tennesee Zone 0	[redacted]											
2	Tennesee Zone L												
3	Tennesee Niagara												
4	Iroquois Receipts												
5	Transco Zone 6, non-NY												
6	Texas Eastern Zone M-3												
7	Leidy Hub												
8	Tennesee Zone 4 Station 313 Pool												
9	Tennesee Zone 4 Storage Injection												
10	Union Dawn Storage - Dawn Supply												
11	Union Dawn Storage Injection												
12	LNG Contract												
13	Atlantic Bridge - Ramapo												
14	PXP - Dawn Supply												
15	Incremental Supply												
16	PNGTS Delivered Baseload (Dec - Feb)												
17	Peaking Contract 1												
18	Peaking Contract 2												
19	WXP - Dawn Supply												
20	NYMEX	$ 4.663	$ 4.749	$ 4.798	$ 4.683	$ 4.321	$ 3.553	$ 3.442	$ 3.467	$ 3.499	$ 3.506	$ 3.492	$ 3.521

Northern Utilities, Inc.
Transportation Contract Rates
November 2021 through October 2022

Fixed Demand Rates ($ per Dth/Month)

Line	Pipeline	Rate Schedule	Receipt	Delivery	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
1	Algonquin	AFT-1	N/A	N/A	AGT-1	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927	$ 8.5927
2	Algonquin	AFT-1 (AB)	N/A	N/A	AGT-4	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170	$ 54.9170
3	Granite	FT-NN	N/A	N/A	GSGT-1	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096	$ 5.9096
4	Iroquois	RTS-1	Zone 1	Zone 1	IGTS-1	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357	$ 5.2357
5	Maritimes	MN365	N/A	N/A	MNUS-1	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833	$ 13.3833
6	PNGTS	FT (C2C)	N/A	N/A	PNGTS-1	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500	$ 18.2500
7	PNGTS	FT (PXP)	N/A	N/A	PNGTS-3	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125	$ 22.8125
8	Tennessee	FT-A	Zone 0	Zone 6	TGP-1 (PCB & PS/GHG), TGP-5 (2021 Rates)	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192	$ 19.9192
9	Tennessee	FT-A	Zone L	Zone 6	TGP-1 (PCB & PS/GHG), TGP-5 (2021 Rates)	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842	$ 17.6842
10	Tennessee	FT-A	Zone 4	Zone 6	TGP-1 (PCB & PS/GHG), TGP-5 (2021 Rates)	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053	$ 7.0053
11	Tennessee	FT-A	Zone 5	Zone 6	TGP-1 (PCB & PS/GHG), TGP-5 (2021 Rates)	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560	$ 6.1560
12	Texas Eastern	FT-1/FTS	M3	M3	TETCO-1	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660	$ 7.0660
13	TransCanada	FT	Parkway	E. Hereford	CAD-1	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546	$ 17.7546
14	Union	M12	Dawn	Parkway	CAD-1	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942	$ 3.0942

Variable Transportation Commodity Rates ($/Dth)

Line	Pipeline	Rate Schedule	Receipt	Delivery	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
15	Algonquin	AFT-1	N/A	N/A	AGT-1 (Max Commodity, Surcharge), FERC-1 (ACA)	$ 0.0340	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054
16	Algonquin	AFT-1 (AB)	N/A	N/A	AGT-1 (Surcharge), FERC-1 (ACA), See Note 1.	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)	$ (0.0589)
17	Granite	FT-NN	N/A	N/A	GSGT-1 (Commodity), FERC-1 (ACA)	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
18	Iroquois	RTS-1	Zone 1	Zone 1	IGTS-1 (Commodity), FERC-1 (ACA)	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0046
19	Maritimes	MN365	N/A	N/A	MNUS-1 (Commodity), FERC-1 (ACA)	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
20	PNGTS	FT (C2C)	N/A	N/A	FERC-1 (ACA)	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012
21	PNGTS	FT (PXP)	N/A	N/A	PNGTS-7 (PXP Commodity), FERC-1 (ACA)	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103
22	Tennessee	FT-A	Zone 0	Zone 6	TGP-2 (PS/GHG), TGP-3 (EPCR), TGP-5, FERC-1	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881	$ 0.2881
23	Tennessee	FT-A	Zone L	Zone 6	TGP-2 (PS/GHG), TGP-3 (EPCR), TGP-5, FERC-1	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513	$ 0.2513
24	Tennessee	FT-A	Zone 4	Zone 6	TGP-2 (PS/GHG), TGP-3 (EPCR), TGP-5, FERC-1	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983	$ 0.0983
25	Tennessee	FT-A	Zone 5	Zone 6	TGP-2 (PS/GHG), TGP-3 (EPCR), TGP-5, FERC-1	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746	$ 0.0746
26	Union	M12	Dawn	Parkway	CAD-1	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253	$ 0.0253
27	Texas Eastern	FT-1/FTS	M3	M3	TGP-2 (PS/GHG), TGP-3 (EPCR), TGP-5, FERC-1	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587	$ 0.0587

Transportation Fuel Rates (Percentage)

Line	Pipeline	Rate Schedule	Receipt	Delivery	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
28	Algonquin	AFT-1	N/A	N/A	AGT-2	0.93%	0.97%	0.97%	0.97%	0.97%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%	0.93%
29	Algonquin	AFT-1 (AB)	N/A	N/A	AGT-2	3.75%	5.38%	5.38%	5.38%	5.38%	3.75%	3.75%	3.75%	3.75%	3.75%	3.75%	3.75%
30	Granite	FT-NN	N/A	N/A	GSGT-1	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%
31	Iroquois	RTS-1	Zone 1	Zone 1	IGTS-3	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%
32	Maritimes	MN365	N/A	N/A	MNUS-3	0.68%	0.68%	0.68%	0.68%	0.68%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%
33	PNGTS	FT (C2C)	N/A	N/A	PNGTS-5 (Measurement Variance)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	PNGTS	FT (PXP)	N/A	N/A	PNGTS-5 (Measurement Variance), PNGTS-6 (PXP Fuel)	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%
35	Tennessee	FT-A	Zone 0	Zone 6	TGP-3	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%
36	Tennessee	FT-A	Zone L	Zone 6	TGP-3	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
37	Tennessee	FT-A	Zone 4	Zone 6	TGP-3	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
38	Tennessee	FT-A	Zone 5	Zone 6	TGP-3	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
39	Texas Eastern	FT-1/FTS	M3	M3	TETLP-3&4	1.44%	1.51%	1.70%	1.70%	1.70%	1.44%	1.44%	1.44%	1.44%	1.44%	1.44%	1.44%
40	TransCanada	FT	Parkway	E. Hereford	CAD-7	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%	1.34%
41	Union	M12	Dawn	Parkway	CAD-8	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%

DG 21-131
Hearing Exhibit 1

Northern Utilities, Inc. Underground Storage Contract Rates November 2021 through October 2022										
Line	Storage	Rate Schedule	Notes	Reference	Space Rate	Demand Rate	Withdrawal Rate	Withdrawal Fuel Loss	Injection Rate	Injection Fuel Loss
1	Tennessee	FS-MA		TGP-5 (2021 TGP Settlement Rates), TGP-4 (Inj Fuel)	$ 0.0175	$ 1.2801	$ 0.0087	0.00%	$ 0.0087	1.62%
2	Union	Storage	1	CAD-9	$ 0.0592	$ -	$ 0.0059	0.60%	$ 0.0059	0.60%

Note 1 The demand charge for Union Storage shall be $236,666.67 per month divided by Maximum Storage Balance of 4,000,000 Dth.
The Withdrawal Rate and Injection Rate are equal to contractual variable rate converted from $CAD/GJ to $USD/Dth. Calculations are on CAD-1.

ALGONQUIN GAS TRANSMISSION, LLC

SUMMARY OF RATES

Effective Rates 12/01/2020

RATE SCHEDULE AFT-1

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res	System Balancing Surcharge (Credit) Rate Non Beverly	System Balancing Surcharge (Credit) Rate Beverly
(F-1/WS-1)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(F-2/F-3)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(F-4)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(STB/SS-3)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(FTP)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(PSS-T)	$ 8.5626	$0.0000	$0.0000	$0.2815	$0.0000	$0.2815	$0.0286	$0.0200
(AFT-2)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(AFT-3)	$ 8.7363	$0.0000	$0.0000	$0.2872	$0.0000	$0.2872	$0.0286	$0.0200
(AFT-5)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(ITP)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(X-35)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(X-39)	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
Tiverton	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
Incremental								
Hubline	**$ 9.4048**	**$0.0042**	**$0.0042**	**$0.3134**	**$0.0042**	**$0.3092**	**$0.0286**	**$0.0200***
Secondary Surcharge 1/		**$0.0267**	**$0.0000**				**$0.0286**	**$0.0200**
Ramapo	**$ 8.7496**	**$0.0126**	**$0.0126**	**$0.3003**	**$0.0126**	**$0.2877**	**$0.0487**	**$0.0341**
AIM	**$33.3680**	**$0.0155**	**$0.0155**	**$1.1125**	**$0.0155**	**$1.0970**	**$0.0536**	**$0.0375**
Atlantic Br.	**$55.6932**	**$0.0115**	**$0.0115**	**$1.8425**	**$0.0115**	**$1.8310**	**-$0.0601**	**-$0.0420**

***For Deliveries off of Hubline Facilities**

RATE SCHEDULE AFT-1S

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res	System Balancing Surcharge (Credit) Rate Non Beverly	System Balancing Surcharge (Credit) Rate Beverly
(F-1/WS-1)	$ 3.4371	$0.2867	$0.0042	$0.2867	$0.0042	$0.1130	$0.0286	$0.0200
(F-2/F-3)	$ 3.4371	$0.2867	$0.0042	$0.2867	$0.0042	$0.1130	$0.0286	$0.0200
(F-4)	$ 3.4371	$0.2867	$0.0042	$0.2867	$0.0042	$0.1130	$0.0286	$0.0200
(STB/SS-3)	$ 3.4371	$0.2867	$0.0042	$0.2867	$0.0042	$0.1130	$0.0286	$0.0200
(Hubline) 2/		$0.0267	$0.0000				$0.0286	$0.0200*

*For Deliveries off of Hubline Facilities

OTHER FIRM RATE SCHEDULES

	Reservation	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	Capacity Release Vol Res	System Balancing Surcharge (Credit) Rate Non Beverly	System Balancing Surcharge (Credit) Rate Beverly
AFT-E	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
(Hubline) 2/		$0.0267	$0.0000				$0.0286	$0.0200*
AFT-ES	$ 3.4371	$0.2867	$0.0042	$0.2867	$0.0042	$0.1130	$0.0286	$0.0200
(Hubline) 2/		$0.0267	$0.0000				$0.0286	$0.0200*
T-1	$ 1.6687	$0.0042		$0.0591			$0.0286	$0.0200
AFT-4	$ 8.5927	$0.0042	$0.0042	$0.2867	$0.0042	$0.2825	$0.0286	$0.0200
AFT-CL:								
Canal	$ 0.5111	$0.0000	$0.0000	$0.0168	$0.0000	$0.0168		
Middletown	$ 0.7872	$0.0000	$0.0000	$0.0259	$0.0000	$0.0259		
Cleary	$ 0.3758	$0.0000	$0.0000	$0.0124	$0.0000	$0.0124		
Lake Road	$ 0.2224	$0.0000	$0.0000	$0.0073	$0.0000	$0.0073		
Manchester	$ 1.6789	$0.0000	$0.0000	$0.0552	$0.0000	$0.0552		
Bellingham	$ 0.3715	$0.0000	$0.0000	$0.0122	$0.0000	$0.0122		
Phelps Dodge	$ 0.0000	$0.0166	$0.0000	$0.0166	$0.0000	$0.0000		
Cape Cod	$ 3.3204	$0.0000	$0.0000	$0.1092	$0.0000	$0.1092		
Northeast Gateway	$ 2.4859	$0.0000	$0.0000	$0.0817	$0.0000	$0.0817		
J-2 Facility	$ 2.3731	$0.0000	$0.0000	$0.0780	$0.0000	$0.0780		
Kleen Energy	$ 0.8035	$0.0000	$0.0000	$0.0264	$0.0000	$0.0264		
Salem	$ 7.3635	$0.0000	$0.0000	$0.2421	$0.0000	$0.2421		
West Roxbury	$15.5204	$0.0000	$0.0000	$0.5103	$0.0000	$0.5103		
X-33	$ 2.7241	$0.0000		$0.0896			$0.0286	$0.0200

*For Deliveries off of Hubline Facilities

INTERRUPTIBLE SERVICE

	Commodity Max	Commodity Min	Authorized Overrun Max	Authorized Overrun Min	System Balancing Surcharge (Credit) Rate Non Beverly	System Balancing Surcharge (Credit) Rate Beverly
AIT-1	$0.2867	$0.0042	$0.2867	$0.0042	$0.0286	$0.0200
(Hubline 2/)	$0.0267	$0.0000			$0.0286	$0.0200*
AIT-2						
Manchester	$0.0552	$0.0000	$0.0552	$0.0000		
Canal	$0.0168	$0.0000	$0.0168	$0.0000		
Cape Cod	$0.1092	$0.0000	$0.1092	$0.0000		
Northeast Gateway	$0.0817	$0.0000	$0.0817	$0.0000		
J-2 Facility	$0.0780	$0.0000	$0.0780	$0.0000		
Kleen Energy	$0.0264	$0.0000	$0.0264	$0.0000		
Salem	$0.2421	$0.0000	$0.2421	$0.0000		
West Roxbury	$0.5103	$0.0000	$0.5103	$0.0000		
PAL	$0.2867	$0.0000	$0.0000	$0.0000	$0.0286	$0.0200

TITLE TRANSFER TRACKING SERVICE

	Max	Min
TTT	$5.3900	$0.0000

Rates are per MMBTU. Rate excludes the Annual Charge Adjustment (ACA) Surcharge. The ACA Commodity Surcharge to applicable customers, pursuant to Section 34 of the General Terms and Conditions.

FUEL REIMBURSEMENT PERCENTAGES

Period	Duration	FRP
System Services 1/		
Winter	Dec 1 - Mar 31	0.97%
Spring, Summer and Fall	Apr 1 - Nov 30	0.93%
Incremental Ramapo Service 1/		
Winter	Dec 1 - Mar 31	1.82%
Spring, Summer and Fall	Apr 1 - Nov 30	1.40%
Incremental AIM Service 1/		
Winter	Dec 1 - Mar 31	3.46%
Spring, Summer and Fall	Apr 1 - Nov 30	2.74%
Incremental Atlantic Bridge Service 1/		
Winter	Dec 1 - Mar 31	5.38%
Spring, Summer and Fall	Apr 1 - Nov 30	3.75%

1/ For all receipt points other than Beverly, Meter No. 00215

Period	Duration	FRP
System Services - Beverly Receipts/Non-Hubline Deliveries		
Winter	Dec 1 - Mar 31	0.64%
Spring, Summer and Fall	Apr 1 - Nov 30	0.69%
Incremental Ramapo Service - Beverly Receipts/Non-Hubline Deliveries		
Winter	Dec 1 - Mar 31	1.18%
Spring, Summer and Fall	Apr 1 - Nov 30	0.00%
Incremental AIM Service - Beverly Receipts/Non-Hubline Deliveries		
Winter	Dec 1 - Mar 31	0.10%
Spring, Summer and Fall	Apr 1 - Nov 30	0.00%
Incremental Atlantic Bridge Service - Beverly Receipts/Non-Hubline Deliveries		
Winter	Dec 1 - Mar 31	4.31%
Spring, Summer and Fall	Apr 1 - Nov 30	0.00%

2/ Hubline Surcharge applicable to all customers utilizing secondary receipt points between and including Beverly and Weymouth and/or utilizing secondary delivery points between Beverly and Weymouth,including Beverly and excluding Weymouth,and in addition to other applicable charges.

The Summary of Rates serves as a handy reference and does not replace Algonquin's Tariff. The rates are subject to commission approval.

STATEMENT OF NEGOTIATED RATES 1/2/3/4/5/9/

Customer Name: Northern Utilities, Inc. d/b/a Unitil

Service Agreement: 510939

Term of Negotiated Rate: The term of this negotiated rate commences on the Service Commencement Date (as defined in the Precedent Agreement between Pipeline and Customer) of Contract No. 510939 and continues for the Primary Term (as such term is defined in the Precedent Agreement and Contract No. 510939. In the event Customer exercises its one-time option to extend the Primary Term of Contract No. 510939 for up to 100% of the MDTQ, then (a) Pipeline and Customer will amend the Negotiated Rate to reflect the extension of the term of the Negotiated Rate for an additional (i) five (5) years at a new negotiated reservation rate equal to $45.124 per Dth per month or (ii) ten (10) years at a new negotiated reservation rate equal to $43.375 per Dth per month for the elected volume, or (b) if Customer elects to extend the Primary Term of Contract No. 510939 at the then-effective maximum recourse reservation rate, then the term of the Negotiated Rate will expire at the end of the Primary Term. 10/11/

Rate Schedule: AFT-1 [Atlantic Bridge Project]

MDTQ: 7,599 Dth/d

Reservation Rate: Customer shall pay a negotiated reservation rate of $54.917 per Dth, per month of Customer's MDTQ under Contract No. 510939 during the Primary Term thereof. 3/6/8/

Commodity Charge and Other Charges: 7/

Primary Receipt Point: 4/

Mahwah (Meter No. 00201) – 7,599 Dth/d
Ramapo (Meter No. 00214) – 7,599 Dth/d

Primary Delivery Point: 4/

Beverly (Meter No. 01215) – 7,599 Dth/d

Recourse Rate(s): The Recourse Rate(s) applicable to this service is the applicable maximum rate(s) stated on Pipeline's Statement of Rates for Rate Schedule AFT-1 [Atlantic Bridge Project] at the applicable time.

FOOTNOTES:

1/ This negotiated rate transaction does not deviate in any material respect from the form of service agreement set forth in Pipeline's FERC Gas Tariff.

replaced with the adjusted Reservation Rate and adjusted term extension rates, which are the applicable rates updated to reflect the cost sharing rate adjustment set forth in footnote 3.

7/ Customer shall pay: (i) a commodity charge which shall be zero for the quantity of gas, in Dekatherms, delivered during the applicable Day under Pipeline's Rate Schedule AFT-1 for the Project; (ii) the applicable Fuel Reimbursement Quantity ("FRQ") under Pipeline's Rate Schedule AFT-1 for the Project; (iii) the applicable Annual Charge Adjustment and all other charges and surcharges applicable to Rate Schedule AFT-1 for the Project; and (iv) any future surcharge or additional usage charge pursuant to any FERC-approved cost recovery mechanism of general applicability implemented in a generic proceeding or in a Pipeline specific proceeding, which mechanism recovers cost components not reflected in Pipeline's initial recourse rate(s) applicable to service under Pipeline's Rate Schedule AFT-1 for the Project.

8/ **Most Favored Nations (MFN)**

(a) MFN Related to Service on the Project and Future Expansions–In the event Pipeline enters into a long-term firm transportation service agreement under Rate Schedule AFT-1, or any similar, firm non-lateral only transportation rate schedule for service on Pipeline's mainline, (i) prior to the in-service date of the Project for service on the Project or (ii) for a period within ten years following the in-service date of the Project for incremental expansion service under any future project, with any customer who is similarly situated to Customer, and such customer's reservation rate is less than Customer's Reservation Rate, Pipeline will promptly offer Customer the same reservation rate as such other customer, or an agreed rate as set forth in subpart (b)(iii), provided that, in the case of subpart (a)(ii) for incremental expansion service under any future project, all the requirements of subpart (b) are met. If Customer is willing to accept such reservation rate, Customer must do so under the same or substantially similar terms and conditions of service of the Algonquin Tariff or other Commission-approved provisions and the same or substantially similar rate related provisions applicable to such other customer, and as further described in subparts (c) and (d) below. For purposes of this footnote 8, Customer will be considered "similarly situated" to another Project customer or Qualifying Incremental Project Customer (as such latter term is defined in subpart (b)(ii) below) if Customer meets the criteria in subparts (a) and/or (b), as applicable, and in either case, if Customer is receiving firm transportation service under a service agreement (and rate agreement, if applicable) under the same or substantially similar terms and conditions of service of the Algonquin Tariff or other Commission-approved provisions and the same or substantially similar rate/rate related provisions as such Project customer or Qualifying Incremental Project Customer ("Similarly Situated Customer").

(b) Interrelationship to Future Expansions

(i) Determination of Indicative Rate - Except as otherwise provided herein, in the event Pipeline enters into a long-term firm transportation service agreement (i.e., one year or longer) under Rate Schedule AFT-1, or any similar firm non-lateral only transportation rate schedule for service using Pipeline's mainline, for service on an incremental expansion project of comparable scope with any Similarly Situated Customer all of whose Primary Receipt Point(s) are located at or upstream of the Mahwah Interconnect and all of whose Primary Delivery Point(s) are located at or downstream of the HubLine Interconnection (i.e., the point on Algonquin's I-9 line between Fore River 803 and Potter 081 near the town of Weymouth that Algonquin identifies as interconnection of its

Canadian Tolls

Line	Item	Units	TCPL and Enbridge Tolls	Reference
1	Union Parkway Belt to East Hereford on TCPL			
2	Demand Toll	$CAD / GJ	$ 19.27504	CAD-3
3	Delivery Pressure Demand Toll	$CAD / GJ	$ 0.60833	CAD-2
4	Abandonment Surcharge	$CAD / GJ	$ 1.14671	CAD-4
5	Total Demand Toll	$CAD / GJ	$ 21.03008	Sum of Above
6	$USD to $CAD	Ratio	1.2497	CAD-6
7	Total Demand Toll	$US / GJ	$ 16.8281	Line 5 divided by Line 6
8	GJ per Dth	Ratio	1.055056	
9	Total Demand Toll	$US / Dth	$ 17.7546	Line 7 divided by Line 8
10				
11	Dawn to Parkway on Enbridge Gas, Inc. Pipeline			
12	Total Demand Toll	$CAD / GJ	$ 3.6650	CAD-5
13	$USD to $CAD	Ratio	1.2497	CAD-6
14	Total Demand Toll	$US / GJ	$ 2.9327	Line 12 divided by Line 13
15	GJ per Dth	Ratio	1.055056	
16	Total Demand Toll	$US / Dth	$ 3.0942	Line 14 divided by Line 15
17				
18	Dawn to Parkway on Enbridge Gas, Inc. Pipeline			
19	Facility Carbon Charge	$CAD / GJ	$ 0.0300	CAD-5
20	$USD to $CAD	Ratio	1.2497	CAD-6
21	Total Demand Toll	$US / GJ	$ 0.0240	Line 12 divided by Line 13
22	GJ per Dth	Ratio	1.055056	
23	Facility Carbon Charge	$US / Dth	$ 0.0253	Line 14 divided by Line 15
24				
18	Enbridge Gas, Inc. Storage Injection/Withdrawal Charges			
19	Variable Storage Charges	$CAD / GJ	$ 0.0070	CAD-9
20	$USD to $CAD	Ratio	1.2497	CAD-6
21	Variable Storage Charges	$US / GJ	$ 0.0056	Line 12 divided by Line 13
22	GJ per Dth	Ratio	1.055056	
23	Variable Storage Charges	$US / Dth	$ 0.0059	Line 14 divided by Line 15

North Bay Junction Long Term Fixed Price (NBJ LTFP) Service

Line No.	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
1	NBJ LTFP	28.28750	0.9300
2	NBJ LTFP Differential Surcharge	0.00000	0.0000

Note: The toll for NBJ LTFP is inclusive of the applicable Abandonment Surcharge for FT service from Empress to North Bay Junction. The NBJ LTFP Differential Surcharge is zero provided the Abandonment Surcharge for FT service from Empress to North Bay Junction is equal or less than $6.69167/GJ/Month.

Enhanced Market Balancing Service

Line No	Particulars	Monthly Toll (2021) ($/GJ/MO)	Daily Equivalent (2021) ($/GJ)	Monthly Toll (2022-2026) ($/GJ/MO)	Daily Equivalent (2022-2026) ($/GJ)
	(a)	(b)	(c)	(d)	(e)
3	Union Parkway Belt to Union EDA	9.92374	0.3262	9.92374	0.3262

Delivery Pressure

Line No	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
4	Average Delivery Pressure Toll	0.60833	0.0200

Note: Delivery Pressure toll applies to the following locations: Emerson 1 , Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford. The Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions, and STFT.

Union Dawn Receipt Point Surcharge

Line No	Particulars	Monthly Toll (2021) ($/GJ/MO)	Daily Equivalent (2021) ($/GJ)	Monthly Toll (2022-2026) ($/GJ/MO)	Daily Equivalent (2022-2026) ($/GJ)
	(a)	(b)	(c)	(d)	(e)
5	Union Dawn Receipt Point Surcharge	0.13135	0.0043	0.13135	0.0043

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll ($/GJ/MO)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
6	SNB Toll	2.97597	0.0978

Note: This SNB Toll is a representative toll for the Eastern Region.

Energy Deficient Gas Allowance (EDGA) Service

Line No	Particulars	Capacity Charge (2021) ($/GJ/D)	Capacity Charge (2022-2026) ($/GJ/D)
	(a)	(b)	(b)
7	Western Section	0.9982	0.9388
8	Eastern Section	0.3302	0.3302

Note: The EDGA Service capacity charge for the Western Section is the effective Empress to North Bay Junction FT Toll and the capacity charge for the Eastern Section is the effective Parkway to North Bay Junction FT Toll. The EDGA Service fuel charge for the Western Section includes the effective Empress to North Bay Junction monthly fuel ratio and the fuel charge for the Eastern Section includes the effective Parkway to North Bay Junction monthly fuel ratio.

Line No.	Receipt Point	Delivery Point	FT Toll (2021) ($/GJ/Month)	Daily Equivalent FT for IT / STFT (2021) ($/GJ)	FT Toll (2022-2026) ($/GJ/Month)	Daily Equivalent FT for IT / STFT (2022-2026) ($/GJ)
1	Union NDA	Enbridge CDA	-	0.4489	-	0.4482
2	Union NDA	Enbridge Parkway CDA	-	0.4544	-	0.4537
3	Union NDA	Enbridge EDA	-	0.4776	-	0.4769
4	Union NDA	KPUC EDA	-	0.5755	-	0.5748
5	Union NDA	Energir EDA	-	0.6356	-	0.6348
6	Union NDA	Enbridge SWDA	-	0.6022	-	0.6014
7	Union NDA	Union SWDA	-	0.6036	-	0.6029
8	Union NDA	Chippawa	-	0.5424	-	0.5417
9	Union NDA	Cornwall	-	0.5231	-	0.5224
10	Union NDA	East Hereford	-	0.7551	-	0.7544
11	Union NDA	Emerson 1	-	0.6495	-	0.6135
12	Union NDA	Emerson 2	-	0.6495	-	0.6135
13	Union NDA	Iroquois	-	0.5015	-	0.5008
14	Union NDA	Kirkwall	-	0.4793	-	0.4785
15	Union NDA	Napierville	-	0.6232	-	0.6225
16	Union NDA	Niagara Falls	-	0.5408	-	0.5401
17	Union NDA	North Bay Junction	-	0.1249	-	0.1241
18	Union NDA	Philipsburg	-	0.6346	-	0.6339
19	Union NDA	Spruce	-	0.5990	-	0.5665
20	Union NDA	St. Clair	-	0.6177	-	0.6170
21	Union NDA	Welwyn	-	0.7378	-	0.6959
22	Union NDA	Dawn Export	-	0.6022	-	0.6014
23	Union Parkway Belt	Empress	38.33717	1.2604	36.52433	1.2008
24	Union Parkway Belt	TransGas SSDA	34.49250	1.1340	32.93821	1.0829
25	Union Parkway Belt	Centram SSDA	31.72763	1.0431	30.35888	0.9981
26	Union Parkway Belt	Centram MDA	29.00533	0.9536	27.81908	0.9146
27	Union Parkway Belt	Centrat MDA	29.57717	0.9724	28.49738	0.9369
28	Union Parkway Belt	Union WDA	24.64054	0.8101	23.89229	0.7855
29	Union Parkway Belt	Nipigon WDA	22.51746	0.7403	21.91217	0.7204
30	Union Parkway Belt	Union NDA	13.82133	0.4544	13.80004	0.4537
31	Union Parkway Belt	Calstock NDA	18.94350	0.6228	18.57850	0.6108
32	Union Parkway Belt	Tunis NDA	16.12996	0.5303	15.95354	0.5245
33	Union Parkway Belt	Energir NDA	13.74529	0.4519	13.73008	0.4514
34	Union Parkway Belt	Union SSMDA	16.67746	0.5483	16.31854	0.5365
35	Union Parkway Belt	Union NCDA	6.64604	0.2185	6.64604	0.2185
36	Union Parkway Belt	Union CDA	4.16100	0.1368	4.16100	0.1368
37	Union Parkway Belt	Union ECDA	3.47358	0.1142	3.47358	0.1142
38	Union Parkway Belt	Union EDA	9.02158	0.2966	9.02158	0.2966
39	Union Parkway Belt	Union Parkway Belt	2.92000	0.0960	2.92000	0.0960
40	Union Parkway Belt	Enbridge CDA	4.55946	0.1499	4.55946	0.1499
41	Union Parkway Belt	Enbridge Parkway CDA	2.92000	0.0960	2.92000	0.0960
42	Union Parkway Belt	Enbridge EDA	12.02067	0.3952	12.02067	0.3952
43	Union Parkway Belt	KPUC EDA	8.94250	0.2940	8.94250	0.2940
44	Union Parkway Belt	Energir EDA	15.63721	0.5141	15.63721	0.5141
45	Union Parkway Belt	Enbridge SWDA	7.41558	0.2438	7.41558	0.2438
46	Union Parkway Belt	Union SWDA	7.45817	0.2452	7.45817	0.2452
47	Union Parkway Belt	Chippawa	5.59667	0.1840	5.59667	0.1840
48	Union Parkway Belt	Cornwall	12.21838	0.4017	12.21838	0.4017
49	Union Parkway Belt	East Hereford	19.27504	0.6337	19.27504	0.6337
50	Union Parkway Belt	Emerson 1	27.28071	0.8969	26.21004	0.8617
51	Union Parkway Belt	Emerson 2	27.28071	0.8969	26.21004	0.8617
52	Union Parkway Belt	Iroquois	11.37888	0.3741	11.37888	0.3741
53	Union Parkway Belt	Kirkwall	3.67738	0.1209	3.67738	0.1209
54	Union Parkway Belt	Napierville	15.26004	0.5017	15.26004	0.5017
55	Union Parkway Belt	Niagara Falls	5.55104	0.1825	5.55104	0.1825
56	Union Parkway Belt	North Bay Junction	10.04358	0.3302	10.04358	0.3302
57	Union Parkway Belt	Philipsburg	15.60679	0.5131	15.60679	0.5131
58	Union Parkway Belt	Spruce	29.57717	0.9724	28.49738	0.9369
59	Union Parkway Belt	St. Clair	7.88704	0.2593	7.88704	0.2593
60	Union Parkway Belt	Welwyn	31.72763	1.0431	30.35888	0.9981
61	Union Parkway Belt	Dawn Export	7.41558	0.2438	7.41558	0.2438
62	Union SSMDA	Empress	-	0.8516	-	0.8020
63	Union SSMDA	TransGas SSDA	-	0.7252	-	0.6841
64	Union SSMDA	Centram SSDA	-	0.6344	-	0.5994
65	Union SSMDA	Centram MDA	-	0.5448	-	0.5158
66	Union SSMDA	Centrat MDA	-	0.5385	-	0.5100
67	Union SSMDA	Union WDA	-	0.7145	-	0.6741
68	Union SSMDA	Nipigon WDA	-	1.0474	-	1.0178
69	Union SSMDA	Union NDA	-	0.8256	-	0.8110
70	Union SSMDA	Calstock NDA	-	0.9938	-	0.9678
71	Union SSMDA	Tunis NDA	-	0.9013	-	0.8815
72	Union SSMDA	Energir NDA	-	0.8229	-	0.8084
73	Union SSMDA	Union SSMDA	-	0.0960	-	0.0960
74	Union SSMDA	Union NCDA	-	0.6708	-	0.6590
75	Union SSMDA	Union CDA	-	0.5412	-	0.5295
76	Union SSMDA	Union ECDA	-	0.5659	-	0.5541
77	Union SSMDA	Union EDA	-	0.7488	-	0.7371
78	Union SSMDA	Union Parkway Belt	-	0.5483	-	0.5365
79	Union SSMDA	Enbridge CDA	-	0.5955	-	0.5837
80	Union SSMDA	Enbridge Parkway CDA	-	0.5483	-	0.5365
81	Union SSMDA	Enbridge EDA	-	0.8475	-	0.8357

TransCanada PipeLines Limited

Line No.	Receipt Point	Delivery Point	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
1	Union Parkway Belt	Union NDA	0.67829	0.0223
2	Union Parkway Belt	Calstock NDA	1.32313	0.0435
3	Union Parkway Belt	Tunis NDA	0.97029	0.0319
4	Union Parkway Belt	Energir NDA	0.66917	0.0220
5	Union Parkway Belt	Union SSMDA	1.16192	0.0382
6	Union Parkway Belt	Union NCDA	0.27983	0.0092
7	Union Parkway Belt	Union CDA	0.10950	0.0036
8	Union Parkway Belt	Union ECDA	0.06388	0.0021
9	Union Parkway Belt	Union EDA	0.44408	0.0146
10	Union Parkway Belt	Union Parkway Belt	0.02433	0.0008
11	Union Parkway Belt	Enbridge CDA	0.13688	0.0045
12	Union Parkway Belt	Enbridge Parkway CDA	0.02433	0.0008
13	Union Parkway Belt	Enbridge EDA	0.65092	0.0214
14	Union Parkway Belt	KPUC EDA	0.43800	0.0144
15	Union Parkway Belt	Energir EDA	0.89729	0.0295
16	Union Parkway Belt	Enbridge SWDA	0.33458	0.0110
17	Union Parkway Belt	Union SWDA	0.33763	0.0111
18	Union Parkway Belt	Chippawa	0.20683	0.0068
19	Union Parkway Belt	Cornwall	0.66308	0.0218
20	Union Parkway Belt	East Hereford	1.14671	0.0377
21	Union Parkway Belt	Emerson 1	2.49721	0.0821
22	Union Parkway Belt	Emerson 2	2.49721	0.0821
23	Union Parkway Belt	Iroquois	0.60529	0.0199
24	Union Parkway Belt	Kirkwall	0.07604	0.0025
25	Union Parkway Belt	Napierville	0.87296	0.0287
26	Union Parkway Belt	Niagara Falls	0.20379	0.0067
27	Union Parkway Belt	North Bay Junction	0.51404	0.0169
28	Union Parkway Belt	Philipsburg	0.89729	0.0295
29	Union Parkway Belt	Spruce	2.66450	0.0876
30	Union Parkway Belt	St. Clair	0.36500	0.0120
31	Union Parkway Belt	Welwyn	3.05688	0.1005
32	Union Parkway Belt	Dawn Export	0.33458	0.0110
33	Union SSMDA	Empress	-	0.0979
34	Union SSMDA	TransGas SSDA	-	0.0819
35	Union SSMDA	Centram SSDA	-	0.0705
36	Union SSMDA	Centram MDA	-	0.0592
37	Union SSMDA	Centrat MDA	-	0.0584
38	Union SSMDA	Union WDA	-	0.0806
39	Union SSMDA	Nipigon WDA	-	0.0877
40	Union SSMDA	Union NDA	-	0.0597
41	Union SSMDA	Calstock NDA	-	0.0809
42	Union SSMDA	Tunis NDA	-	0.0693
43	Union SSMDA	Energir NDA	-	0.0594
44	Union SSMDA	Union SSMDA	-	0.0008
45	Union SSMDA	Union NCDA	-	0.0466
46	Union SSMDA	Union CDA	-	0.0377
47	Union SSMDA	Union ECDA	-	0.0394
48	Union SSMDA	Union EDA	-	0.0520
49	Union SSMDA	Union Parkway Belt	-	0.0382
50	Union SSMDA	Enbridge CDA	-	0.0414
51	Union SSMDA	Enbridge Parkway CDA	-	0.0382
52	Union SSMDA	Enbridge EDA	-	0.0587
53	Union SSMDA	KPUC EDA	-	0.0518
54	Union SSMDA	Energir EDA	-	0.0669
55	Union SSMDA	Enbridge SWDA	-	0.0280
56	Union SSMDA	Union SWDA	-	0.0279
57	Union SSMDA	Chippawa	-	0.0416
58	Union SSMDA	Cornwall	-	0.0592
59	Union SSMDA	East Hereford	-	0.0751
60	Union SSMDA	Emerson 1	-	0.0521
61	Union SSMDA	Emerson 2	-	0.0521
62	Union SSMDA	Iroquois	-	0.0573
63	Union SSMDA	Kirkwall	-	0.0365
64	Union SSMDA	Napierville	-	0.0661
65	Union SSMDA	Niagara Falls	-	0.0415
66	Union SSMDA	North Bay Junction	-	0.0543
67	Union SSMDA	Philipsburg	-	0.0668

Effective
2021-07-01
Rate M12
Page 1 of 4

ENBRIDGE GAS INC.
UNION SOUTH
TRANSPORTATION RATES

(A) Applicability

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

Applicable Points
Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).
Dawn as a delivery point: Dawn (Facilities).

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Parkway facilities.

(C) Rates

The identified rates represent maximum prices for service. These rates may change periodically.
Multi-year prices may also be negotiated, which may be higher than the identified rates.

	Monthly Demand Charges (applied to daily contract demand)	Fuel and Commodity Charges			
		Union Supplied Fuel	Shipper Supplied Fuel		
	Rate/GJ	Fuel and Commodity Charge Rate/GJ	Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1), (5)					
Dawn to Parkway	$3.665	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$3.110				
Kirkwall to Parkway	$0.555				
M12-X Firm Transportation					
Between Dawn, Kirkwall and Parkway	$4.530	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)					
Dawn to Parkway – Maximum	$8.796	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$8.796				
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)	n/a	n/a	0.165%		
Carbon Charge (applied to all quantities transported)					
Facility Carbon Charge		$0.003			$0.003

BANK OF CANADA
BANQUE DU CANADA

Daily Exchange Rates Lookup

All Bank of Canada exchange rates are indicative rates only, obtained from averages of aggregated price quotes from financial institutions. For details, please read our full **Terms and Conditions**.

US dollar (USD)

Date	USD → CAD	CAD → USD
2021-08-05	1.2497	0.8002

TransCanada Fuel Ratios

Service Type	Receipt Location	Delivery Location	From Gas Day	To Gas Day	Combined Ratio
FH	Union Parkway Belt	East Hereford	11/1/2019	11/30/2019	1.48
FH	Union Parkway Belt	East Hereford	12/1/2019	12/31/2019	1.73
FH	Union Parkway Belt	East Hereford	1/1/2020	1/31/2020	1.56
FH	Union Parkway Belt	East Hereford	2/1/2020	2/29/2020	1.54
FH	Union Parkway Belt	East Hereford	3/1/2020	3/31/2020	1.25
FH	Union Parkway Belt	East Hereford	4/1/2020	4/30/2020	1.25
FH	Union Parkway Belt	East Hereford	5/1/2020	5/31/2020	1.21
FH	Union Parkway Belt	East Hereford	6/1/2020	6/30/2020	1.66
FH	Union Parkway Belt	East Hereford	7/1/2020	7/31/2020	1.46
FH	Union Parkway Belt	East Hereford	8/1/2020	8/31/2020	1.14
FH	Union Parkway Belt	East Hereford	9/1/2020	9/30/2020	1.17
FH	Union Parkway Belt	East Hereford	10/1/2020	10/31/2020	1.15
Annual	Union Parkway Belt	East Hereford	11/1/2019	10/31/2020	1.38

SCHEDULE "C"

ENBRIDGE GAS INC.
Union South
M12 Monthly Transportation Fuel Ratios and Fuel Rates
Firm or Interruptible Transportation Commodity
Effective October 1, 2020

	VT1 Easterly Dawn to Parkway (TCPL), Parkway (EGT) With Dawn Compression		VT1 Easterly Dawn to Kirkwall, Lisgar, Parkway (Consumers) With Dawn Compression		M12-X Westerly Kirkwall to Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.899	0.028	0.559	0.018	0.162	0.005
May	0.640	0.020	0.382	0.011	0.162	0.005
June	0.535	0.018	0.282	0.009	0.162	0.005
July	0.519	0.017	0.269	0.008	0.162	0.005
August	0.414	0.012	0.163	0.005	0.162	0.005
September	0.410	0.012	0.163	0.005	0.162	0.005
October	0.768	0.024	0.472	0.016	0.162	0.005
November	0.915	0.029	0.639	0.020	0.162	0.005
December	1.036	0.033	0.760	0.024	0.162	0.005
January	1.193	0.037	0.902	0.028	0.162	0.005
February	1.133	0.035	0.850	0.028	0.162	0.005
March	1.057	0.034	0.760	0.024	0.162	0.005

	M12-X Easterly Kirkwall to Parkway (TCPL), Parkway (EGT)		M12-X Easterly Kirkwall to Lisgar, Parkway (Consumers)		M12-X Westerly Parkway to Kirkwall, Dawn	
Month	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)	Fuel Ratio (%)	Fuel Rate ($/GJ)
April	0.501	0.017	0.162	0.005	0.307	0.010
May	0.420	0.012	0.162	0.005	0.307	0.010
June	0.415	0.012	0.162	0.005	0.307	0.010
July	0.413	0.012	0.162	0.005	0.307	0.010
August	0.413	0.012	0.162	0.005	0.307	0.010
September	0.409	0.012	0.162	0.005	0.307	0.010
October	0.457	0.014	0.162	0.005	0.307	0.010
November	0.437	0.013	0.162	0.005	0.162	0.005
December	0.437	0.013	0.162	0.005	0.162	0.005
January	0.452	0.013	0.162	0.005	0.162	0.005
February	0.444	0.013	0.162	0.005	0.162	0.005
March	0.459	0.014	0.162	0.005	0.162	0.005

SCHEDULE 2
Page 1 of 1
Contract No. LST086

PRICING PROVISIONS

Shipper agrees to pay Union the following for the Storage Services:

(a) **Monthly Demand Charge:** For the period of April, 2018 to March, 2023 inclusive, a monthly demand charge of $236,666.67 US if the Maximum Storage Balance is 4,220,224 GJ (4,000,000 MMBtu); or a monthly demand charge of $201,666.67 US if Shipper elects a lower Maximum Storage Balance of 3,587,190 GJ (3,400,000 MMBtu).

(b) **Demand Charge Escalation:** *Intentionally blank*

(c) **Variable Storage Charges:**

(i) Firm: For each GJ of gas withdrawn from or injected into the Storage Account on a firm basis, a charge equal to $0.007 CDN/GJ;

(ii) Interruptible: For each GJ of gas withdrawn from or injected into the Storage Account on an interruptible basis, a charge equal to the price set out under the heading 'If Shipper supplies fuel Commodity Charge Price/GJ' in the 'Storage Services' section under '(C) Pricing' in the MPSS (currently $0.041CDN/GJ);

(iii) Authorized Overrun: For each GJ of gas withdrawn from or injected into the Storage Account on an authorized overrun basis, a charge equal to the price set out under the heading 'If Shipper supplies fuel Commodity Charge Price/GJ' in the 'Authorized Overrun' section under '(C) Pricing' in the MPSS (currently $0.041CDN/GJ);

(iv) Dehydration Charge: Not Applicable.

(d) **Fuel:**

(i) Firm and Interruptible: For each GJ of gas withdrawn from or injected into the Storage Account on a firm or interruptible basis, an amount of fuel in kind equal to the fuel ratio set out under the heading of 'If Shipper supplies fuel' in the 'Storage Services' section under '(C) Pricing' in the MPSS (currently 0.600%).

(ii) Authorized Overrun: For each GJ of gas withdrawn from or injected into the Storage Account on an authorized overrun basis, an amount of fuel in kind equal to the fuel ratio set out under the heading of 'If Shipper supplies fuel' in the 'Authorized Overrun' section under '(C) Pricing' in the MPSS (currently 1.03%).

(e) **Late Season Balance Charge and Early Season Balance Charge:** *Intentionally blank*

(f) **Shortfall Charge:** *Intentionally blank*

(g) **Other Charges:** Any and all other charges as may be set out in this Contract, and any charges relating to Unauthorized Overrun, Drafted Storage Balance and Overrun of Maximum Storage Balance as set out in the MPSS.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2021 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 16, 2021

The annual charges unit charge (ACA) to be applied to in fiscal year 2022 for recovery of FY 2021 Current year and 2020 True-Up is **$0.0012** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2021.

The following calculations were used to determine the FY 2021 unit charge:

2021 CURRENT:

Estimated Program Cost $73,470,000 divided by 61,333,716,267 Dth = 0.0011978730

2020 TRUE-UP:

Debit/Credit Cost ($1,115,938) divided by 60,594,054,316 Dth = (0.0000184166)

TOTAL UNIT CHARGE = 0.0011794564

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

PUBLIC

4.2 Rate Schedule FT-NN
Firm Transportation Service
Currently Effective Rates

	$/Dth	
	Base Tariff Rate	ACA Adj.
Reservation Charge:		
Maximum	$5.9096	N/A
Minimum	$0.0000	N/A
Commodity Charge:		
Maximum	$0.0000	a/
Minimum	$0.0000	a/
Authorized Overrun Commodity Charge:		
Maximum	$0.1943	a/
Minimum	$0.0000	a/
Fuel and Losses Percentage	0.35%	N/A
Volumetric Reservation Charge		
Maximum	$0.1943	a/
Minimum	$0.0000	a/

a/ The ACA Adj. Surcharge is revised annually and posted on the FERC website at the web address http://www.ferc.gov on the Annual Charges page of the Natural Gas Section. The ACA Adj. Surcharge is incorporated by reference in the Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Section 6.17 of the General Terms and Conditions.

---------- NON-EASTCHESTER RATES (All in $ Per Dth) 1/ ----------

	Minimum	RP16-301 Rates 2/ Maximum			RP19-445 Rates Maximum	
		Effective 9/1/2016	Effective 9/1/2017	Effective 9/1/2018	Effective 3/1/2019	Effective 4/1/2020
RTS DEMAND (Monthly):						
Zone 1	$0.0000	$ 6.1928	$ 5.9982	$ 5.5997	$5.4177	$5.2357
Zone 2	$0.0000	$ 5.3381	$ 5.1678	$ 4.7998	$4.6438	$4.4878
Inter-Zone	$0.0000	$10.4755	$ 9.8672	$ 8.8026	$8.5165	$8.2304
RTS COMMODITY (Daily):						
Zone 1	$0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$0.0034	$0.0034
Zone 2	$0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$0.0022	$0.0022
Inter-Zone	$0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$0.0056	$0.0056
ITS COMMODITY (Daily):						
Zone 1	$0.0034	$ 0.2070	$ 0.2006	$ 0.1875	$0.1815	$0.1755
Zone 2	$0.0022	$ 0.1777	$ 0.1721	$ 0.1600	$0.1549	$0.1497
Inter-Zone	$0.0056	$ 0.3500	$ 0.3300	$ 0.2950	$0.2856	$0.2762
VOLUMETRIC CAPACITY RELEASE (Daily) 3/:						
Zone 1	$0.0000	$ 0.2036	$ 0.1972	$ 0.1841	$0.1781	$0.1721
Zone 2	$0.0000	$ 0.1755	$ 0.1699	$ 0.1578	$0.1527	$0.1475
Inter-Zone	$0.0000	$ 0.3444	$ 0.3244	$ 0.2894	$0.2800	$0.2706

**SEE SHEET NOS. 4A, 4B, AND 4C FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

1/ Transporter's Settlement dated February 28, 2019, in Docket Nos. RP19-445-000, et al., approved by Commission Order issued May 2, 2019, established two additional rate step-downs effective 3/1/2019 and 4/1/2020 referred to as "RP19-445 Rates", but otherwise did not modify Transporter's Settlement dated August 18, 2016, in Docket No. RP16-301-000, which remains effective, including the moratorium on initiation of changes to Transporter's Settlement Rates prior to September 1, 2020. All Maximum and Minimum Rates listed on Sheet Nos. 4, 4B, 4C, and 5A are subject to the moratorium.
2/ The RP16-301 Rates that became effective 9/1/2018 shall be applicable to any Contesting Party to the Settlement dated February 28, 2019, pursuant to Section 5.2 and 5.3 of that Settlement, and shall become Transporter's effective base tariff rates in the event and as of the date that the Settlement dated February 28, 2019 terminates early pursuant to Sections 6.2 and 6.3. See footnote 1.
3/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

Historic Iroquois Zone 1 Fuel Rates	
Jul-20	0.00%
Aug-20	0.00%
Sep-20	0.00%
Oct-20	0.00%
Nov-20	0.10%
Dec-20	0.20%
Jan-21	0.20%
Feb-21	0.30%
Mar-21	0.40%
Apr-21	0.30%
May-21	0.10%
Jun-21	0.00%
Annual	0.13%

STATEMENT OF NEGOTIATED RATES 1/2/4/6/

Customer Name: Northern Utilities, Inc. d/b/a Unitil

Service Agreement: 210371

Rate Schedule: MN365

Reservation Rate: Customer shall pay a negotiated reservation rate of $13.3833 per Dth, per month (equivalent to $0.44 per Dth, per Day) of Customer's MDTQ under Contract No. 210371 during the Term of Negotiated Rate.

Usage Rate and Other Charges: 3/

Term of Negotiated Rate: The term of this negotiated rate commences on January 1, 2021 and extends through December 31, 2035. 5/

Quantity ("MDTQ"): 7,500 Dth/d

Primary Receipt Point:

Beverly – Essex Co., MA (Meter No. 30035) - 7,500 Dth/d

Primary Delivery Points:

Northern Utilities – Cotton Rd – Androscoggin Co, ME (Meter No. 30028)– 7,500 Dth/d

Recourse Rate(s): The Recourse Rate(s) applicable to this service is the applicable maximum rate(s) stated on Pipeline's Statement of Rates for Rate Schedule MN365 at the applicable time.

FOOTNOTES:

1/ This negotiated rate transaction does not deviate in any material respect from the form of service agreement set forth in Pipeline's FERC Gas Tariff.

2/ This Negotiated Rate shall apply only to transportation service under Contract No. 210371, up to Customer's specified MDTQ, using the Primary Receipt Point and Primary Delivery Point designated herein, and any secondary receipt and delivery points available under Rate Schedule MN365.

3/ Customer shall pay: (i) a commodity charge which shall be zero for the quantity of gas, in Dekatherms, delivered during the applicable Day under Pipeline's Rate Schedule MN365; (ii) the applicable Fuel Reimbursement Quantity ("FRQ") under Pipeline's Rate Schedule MN365; (iii) the applicable Annual Charge Adjustment and all other charges and surcharges applicable to Rate Schedule MN365; and (iv) any future surcharge or additional usage charge pursuant to any FERC-approved cost recovery mechanism of general applicability implemented in a generic proceeding or in a Pipeline specific proceeding, which mechanism recovers cost components not reflected in Pipeline's recourse rate(s) applicable to service under Pipeline's Rate Schedule MN365.

4/ Pipeline and Customer agree that Contract No. 210371 is a ROFR Agreement.

5/ If the term of Contract No. 210371 renews for one or more twelve (12) month evergreen period(s) at the negotiated reservation rate, then the term of this Negotiated Rate Agreement shall be extended for such evergreen period(s).

6/ Customer will be eligible to receive reservation charge adjustments under this Negotiated Rate Agreement in accordance with Pipeline's FERC Gas Tariff.

FUEL RETAINAGE PERCENTAGES

FUEL RETAINAGE PERCENTAGE: PURSUANT TO SECTION 20 OF THE GT&C

Winter Period (November 1 - March 31)	0.68%
Non-Winter Period (April 1 - October 31)	0.97%

SCHEDULE 1

Receipt Point(s):	01-0100 Pittsburg, NH
Delivery Point(s):	05-0850 Newington Granite State
Maximum Daily Quantity:	40003 Dth/day
Maximum Contract Demand:	219176437 Dth
Effective Service Period:	April 1, 2018 through November 30, 2032

Rate Provision(s) (check if applicable rate):

__ ___ Discounted Rate

__x ___ Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

$0.6000/Dth/day

Additional Terms: Shipper shall have the right to deliver, on a secondary basis, to the following meters, at the Negotiated Rate of $0.60/Dth/day. Delivery to all other secondary delivery points on this Negotiated Rate contract shall be priced at the Maximum Recourse Rate.

Meter #	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
02-0650	Gorham	Maine Natural Gas
05-0725	Eliot	Granite State
05-0750	Eliot CNG	XPress Natural Gas
02-0775	Newington	Essential Power
02-0900	Newington	Eversource
05-0850	Newington	Granite State
05-1000	Haverhill	Tennessee Gas Pipeline
05-1025	Haverhill	National Grid
05-1050	Methuen	M&NE
05-1150	Dracut	Tennessee Gas Pipeline

Revision No. 1

SCHEDULE 1

Primary Receipt Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
1/	1/	10100	Pittsburg (East Hereford)	0 (Phase I Quantity) plus 0 (Phase II Quantity) plus 10,000 (Phase III Quantity)

Primary Delivery Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
1/	1/	50850	Newington Granite State	0 (Phase I Quantity) plus 0 (Phase II Quantity) plus 10,000 (Phase III Quantity)

Maximum Contract Demand	0 Dth (Phase I Quantity)
plus	0 Dth (Phase II Quantity)
plus	10,000 Dth (Phase III Quantity)
Total Maximum Contract Demand	10,000 Dth (Phase I, II and III Quantities)

Effective Service Period 1/ to 1/

Rate Provision(s) (check if applicable rate):

_______ Discounted Rate
____X__ Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

For volumes received at the primary receipt point and delivered to the primary delivery point, the reservation charge shall be $0.7500/Dth/day (the "Negotiated Daily Demand Rate").

For volumes received at the primary receipt point and delivered to any of the following secondary delivery points, the reservation charge shall be the Negotiated Daily Demand Rate: Westbrook M&NE, Westbrook Granite State, Eliot Granite State, Dracut and Haverhill Tennessee Gas. Deliveries to any other secondary delivery point(s) will be at the Recourse Reservation Rate.

Shipper shall have secondary receipt point access for delivery to any delivery point at the Recourse Reservation Rate.

In addition to the applicable reservation rate stated above, Shipper shall pay or furnish, as applicable, all maximum applicable demand and commodity surcharges, unit charges, Measurement Variance Quantities, and other fuel requirements and charges, as specified in the Tariff, in addition to any charges associated with mandated compliance with new or revised regulations or legislation (i.e. environmental, modernization and safety), which may change from time to time, and any other amounts contemplated under Article IV of this Contract.

1/ Pursuant to Article VII – TERM above.

PNGTS Construction Cost Sharing:

Shipper's Negotiated Daily Demand Rate for PNGTS reflected above shall be adjusted as follows:

To the extent Actual PNGTS Construction Costs (defined below) exceed Estimated PNGTS Construction Costs (defined below), Shipper's Negotiated Daily Demand Rate shall be multiplied by the Capital Cost Overrun Factor ("CCO Factor"). The CCO Factor shall be equal to 1 + [(CCO/EPCC) X 50%]. In no event shall the CCO Factor exceed 1.0667.

To the extent Actual PNGTS Construction Costs, as defined below, are less than Estimated PNGTS Construction Costs as defined below, Shipper's Negotiated Daily Demand Rate shall be multiplied by the Capital Cost Underrun Factor ("CCU Factor"). The CCU Factor shall be equal to 1 - [(CCU/EPCC) X 50%]. In no event shall the CCU Factor be less than 0.9333.

Any such adjustment to Shipper's Negotiated Daily Demand Rate for PNGTS shall be subject to a rate adjustment cap of +/- US$0.05 per Dth (overruns/ underruns). Such adjustment shall be effective on the actual in-service date for Phase III based on the final costs estimated by PNGTS at such time, and subsequently adjusted, if necessary, as soon as administratively feasible based on the Phase III final cost report filed with the FERC, to keep the applicable Parties financially whole as if the actual costs were known as of the actual in-service date of Phase III. Any subsequent adjustment shall not be later than the first anniversary date of the actual in-service date of Phase III and shall remain in effect for the balance of the Initial Term.

"Actual PNGTS Construction Costs" or "APCC" shall mean the amount filed by PNGTS with the FERC following completion of construction of the facilities associated with PXP Phase III (such construction shall be referred to herein as "PNGTS Construction"). PNGTS shall maintain books and records reasonably necessary for Shipper to verify the APCC.

"Capital Cost Overrun" or "CCO" shall be an amount in U.S. dollars equal to the difference between the Actual PNGTS Construction Costs and the Estimated PNGTS Construction Costs, if Actual PNGTS Construction Costs exceed Estimated Project Costs.

"Capital Cost Underrun" or "CCU" shall be an amount in U.S. dollars equal to the difference between the Actual PNGTS Construction Costs and the Estimated PNGTS Construction Costs, if Actual PNGTS Construction Costs are less than Estimated PNGTS Construction Costs.

"Estimated PNGTS Construction Costs" or "EPCC" shall mean all costs and expenses that are projected to be incurred by PNGTS to complete the PNGTS Construction in the manner contemplated by this Agreement as filed with the FERC in its Section 7 of the Natural Gas Act certificate application for Phase III.

Shipper shall have one-time audit right to be exercised no later than thirteen (13) months after the actual in-service date for Phase III, at Shipper's sole cost and expense, to review PNGTS's books and records as reasonably necessary to verify costs associated with Phase III of the PNGTS Construction for purposes of this provision.

Historic PNGTS Zone 1 Measurement Variance Rates

Jul-20	-0.60%
Aug-20	-0.60%
Sep-20	-0.80%
Oct-20	-0.80%
Nov-20	-0.60%
Dec-20	-0.60%
Jan-21	-0.60%
Feb-21	-0.20%
Mar-21	-0.30%
Apr-21	-1.00%
May-21	-1.00%
Jun-21	-1.00%
Annual	-0.68%
Projected (Greater of Annual Average or 0%)	0.00%

PNGTS
Docket No. CP18-____-000
Exhibit Z-2
Page 1 of 3

Portland Natural Gas Transmission System
Portland XPress Project (PXP) Phase III
Project Fuel Study

M&N Operating Company, LLC, the operator of the Joint Facilities between Westbrook and Dracut, estimated the daily fuel consumption for PXP. The result of the study is shown on Line 3 below. The proposed initial Fuel Rate was calculated by dividing the total estimated daily fuel consumption by the estimated daily volume to be transported on the Joint Facilities.

Once in service, the Fuel Rate will be adjusted monthly pursuant to proposed Section 6.2.26 of the General Terms & Conditions of PNGTS's FERC Gas Tariff, Third Revised Volume No. 1, so that the Fuel Rate is based upon actual fuel usage and transportation activity. Currently, the PNGTS system has no compression facilities and therefore shippers only pay a charge related to Lost And Unaccounted For Gas.

Line No.	Description		
1	Installed Horsepower	6,300	hp
2	PXP Volume Transported on both Northern Facilities and Joint Facilities	119,378	Dth/d
3	Estimated Fuel	296.2	Dth/d
4	Assumed Load Factor	90%	
5	Initial Compressor Fuel Rate	0.28%	

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/
FT	Recourse Reservation Rate		
	-- Maximum	$25.9843	---------
	-- Minimum	$00.0000	---------
	Seasonal Recourse Reservation Rate		
	-- Maximum	$49.3701	---------
	-- Minimum	$00.0000	---------
	Recourse Usage Rate		
	-- Maximum	$00.0000	2/
	-- Minimum	$00.0000	2/
	-- PXP Project	$00.0091	
FT-FLEX	Recourse Reservation Rate		
	--Maximum	$17.4406	---------
	--Minimum	$00.0000	---------
	Recourse Usage Rate		
	--Maximum	$00.2809	2/
	--Minimum	$00.0000	2/

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE FACTOR-LAUF:

Minimum	down to -1.00%
Maximum	up to +1.00%

MEASUREMENT VARIANCE FACTOR-FUEL 3/

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

2/ The currently effective ACA unit charge as published on the Commission's website (www.ferc.gov) is incorporated herein by reference.

CURRENTLY EFFECTIVE SERVICE RATES APPLICABLE TO OPEN ACCESS, PART 284, RATE SCHEDULES IN FERC GAS TARIFF, EIGHTH REVISED VOLUME NO. 1

FT-1
RESERVATION
CHARGES

Pursuant to Sections 3.2(A), 3.3(A), and 3.5 of Rate Schedule FT-1:

	FT-1 RESERVATION CHARGE* $/dth		FT-1 RESERVATION CHARGE ADJUSTMENT $/dth	
ACCESS AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
STX-AAB	7.1630	0.0000	0.2355	0.0000
WLA-AAB	3.8410	0.0000	0.1262	0.0000
ELA-AAB	2.6420	0.0000	0.0869	0.0000
ETX-AAB	2.7240	0.0000	0.0896	0.0000
STX-STX	5.0300	0.0000	0.1654	0.0000
STX-WLA	6.2290	0.0000	0.2048	0.0000
STX-ELA	7.1960	0.0000	0.2366	0.0000
STX-ETX	7.1960	0.0000	0.2366	0.0000
WLA-WLA	2.9080	0.0000	0.0957	0.0000
WLA-ELA	3.8740	0.0000	0.1274	0.0000
WLA-ETX	3.8700	0.0000	0.1272	0.0000
ELA-ELA	2.6750	0.0000	0.0880	0.0000
ETX-ETX	2.7570	0.0000	0.0906	0.0000
ETX-ELA	2.6750	0.0000	0.0880	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2390	0.0000	0.1065	0.0000
M1-M2	6.9240	0.0000	0.2276	0.0000
M1-M3	12.2810	0.0000	0.4038	0.0000
M2-M2	5.3940	0.0000	0.1773	0.0000
M2-M3	10.7490	0.0000	0.3534	0.0000
M3-M3	7.0660	0.0000	0.2323	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

CURRENTLY EFFECTIVE SERVICE RATES APPLICABLE TO OPEN ACCESS, PART 284, RATE SCHEDULES IN FERC GAS TARIFF, EIGHTH REVISED VOLUME NO. 1

FT-1
USAGE
CHARGES

ZONE RATE
$/dth

Pursuant to Sections 3.2(A) and 3.3(A) of Rate Schedule FT-1:

	STX	WLA	ELA	ETX	M1	M2	M3
USAGE-1 - MAXIMUM							
from STX	0.0239	0.0264	0.0339	0.0339	0.0575	0.0865	0.1377
from WLA	0.0264	0.0156	0.0253	0.0253	0.0489	0.0779	0.1291
from ELA	0.0339	0.0253	0.0235	0.0235	0.0471	0.0761	0.1273
from ETX	0.0339	0.0253	0.0235	0.0235	0.0471	0.0761	0.1273
from M1	0.0575	0.0489	0.0471	0.0471	0.0236	0.0526	0.1038
from M2	0.0865	0.0779	0.0761	0.0761	0.0526	0.0407	0.0836
from M3	0.1377	0.1291	0.1273	0.1273	0.1038	0.0836	0.0575
USAGE-1 - MINIMUM							
from STX	0.0221	0.0246	0.0321	0.0321	0.0539	0.0828	0.1340
from WLA	0.0246	0.0138	0.0235	0.0235	0.0453	0.0742	0.1254
from ELA	0.0321	0.0235	0.0217	0.0217	0.0435	0.0724	0.1236
from ETX	0.0321	0.0235	0.0217	0.0217	0.0435	0.0724	0.1236
from M1	0.0539	0.0453	0.0435	0.0435	0.0218	0.0507	0.1019
from M2	0.0828	0.0742	0.0724	0.0724	0.0507	0.0388	0.0818
from M3	0.1340	0.1254	0.1236	0.1236	0.1019	0.0818	0.0557
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0094						
from WLA		0.0045					
from ELA			0.0092				
from ETX				0.0092			
from M1				0.0346	0.0111		
from M2				0.0571	0.0336	0.0244	
from M3						0.0578	0.0353
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0076						
from WLA		0.0027					
from ELA			0.0074				
from ETX				0.0074			
from M1				0.0310	0.0093		
from M2				0.0534	0.0317	0.0225	
from M3						0.0560	0.0335
USAGE-2	0.1885	0.1885	0.1885	0.1885	0.3186	0.4687	0.6961

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Winter Period: December 1 through December 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.93	1.04	1.64	1.64	2.49	3.59	4.34
Base	from WLA	0.53	0.53	1.13	1.13	1.98	3.08	3.83
Applicable	from ELA	0.91	0.91	0.91	0.91	1.76	2.86	3.61
Shrinkage	from ETX	0.93	0.91	0.91	0.91	1.76	2.86	3.61
Percentage	from M1	2.49	1.98	1.76	1.76	0.85	1.95	2.70
|	from M2	3.59	3.08	2.86	2.86	1.95	1.42	2.17
|	from M3	4.34	3.83	3.61	3.61	2.70	2.17	1.07
|	from STX	-0.04	-0.10	-0.42	-0.42	-0.31	-0.88	-0.87
Applicable	from WLA	0.41	0.20	-0.10	-0.10	0.01	-0.56	-0.55
Shrinkage	from ELA	0.31	0.12	0.16	0.16	0.27	-0.30	-0.29
Adjustment	from ETX	0.29	0.12	0.16	0.16	0.27	-0.30	-0.29
Percentage	from M1	-0.31	0.01	0.27	0.27	0.11	-0.46	-0.45
|	from M2	-0.88	-0.56	-0.30	-0.30	-0.46	-0.15	-0.13
|	from M3	-0.87	-0.55	-0.29	-0.29	-0.45	-0.13	0.44
|	from STX	0.89	0.94	1.22	1.22	2.18	2.71	3.47
Applicable	from WLA	0.94	0.73	1.03	1.03	1.99	2.52	3.28
Shrinkage	from ELA	1.22	1.03	1.07	1.07	2.03	2.56	3.32
Percentage	from ETX	1.22	1.03	1.07	1.07	2.03	2.56	3.32
|	from M1	2.18	1.99	2.03	2.03	0.96	1.49	2.25
|	from M2	2.71	2.52	2.56	2.56	1.49	1.27	2.04
|	from M3	3.47	3.28	3.32	3.32	2.25	2.04	1.51

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				1.07			
Percentage	from M1				1.07	0.00		
|	from M2				1.07	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				1.07			
|	from M1				1.07	0.00		
|	from M2				1.07	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.70 %	-1.03 %	1.67 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.22 %	0.54 %
Monthly Injections	1.76 %	-1.22 %	0.54 %
Monthly Inventory Level	0.08 %	-0.04 %	0.04 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Winter Period: January 1 through March 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	1.09	1.25	2.12	2.12	3.08	4.70	5.81
Base	from WLA	0.50	0.50	1.38	1.38	2.34	3.96	5.07
Applicable	from ELA	1.05	1.05	1.05	1.05	2.01	3.63	4.74
Shrinkage	from ETX	1.09	1.05	1.05	1.05	2.01	3.63	4.74
Percentage	from M1	3.08	2.34	2.01	2.01	0.96	2.58	3.69
|	from M2	4.70	3.96	3.63	3.63	2.58	1.80	2.90
|	from M3	5.81	5.07	4.74	4.74	3.69	2.90	1.28
|	from STX	-0.25	-0.34	-0.86	-0.86	-0.88	-1.76	-1.82
Applicable	from WLA	0.41	0.13	-0.37	-0.37	-0.39	-1.27	-1.33
Shrinkage	from ELA	0.21	-0.04	0.06	0.06	0.04	-0.84	-0.90
Adjustment	from ETX	0.17	-0.04	0.06	0.06	0.04	-0.84	-0.90
Percentage	from M1	-0.88	-0.39	0.04	0.04	-0.02	-0.90	-0.96
|	from M2	-1.76	-1.27	-0.84	-0.84	-0.90	-0.43	-0.47
|	from M3	-1.82	-1.33	-0.90	-0.90	-0.96	-0.47	0.42
|	from STX	0.84	0.91	1.26	1.26	2.20	2.94	3.99
Applicable	from WLA	0.91	0.63	1.01	1.01	1.95	2.69	3.74
Shrinkage	from ELA	1.26	1.01	1.11	1.11	2.05	2.79	3.84
Percentage	from ETX	1.26	1.01	1.11	1.11	2.05	2.79	3.84
|	from M1	2.20	1.95	2.05	2.05	0.94	1.68	2.73
|	from M2	2.94	2.69	2.79	2.79	1.68	1.37	2.43
|	from M3	3.99	3.74	3.84	3.84	2.73	2.43	1.70

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				1.11			
Percentage	from M1				1.11	0.00		
|	from M2				1.11	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				1.11			
|	from M1				1.11	0.00		
|	from M2				1.11	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.86 %	-1.01 %	1.85 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.09 %	0.67 %
Monthly Injections	1.76 %	-1.09 %	0.67 %
Monthly Inventory Level	0.08 %	-0.06 %	0.02 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Spring, Summer and Fall Periods: April 1 through November 30

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.93	1.04	1.64	1.64	2.49	3.59	4.34
Base	from WLA	0.53	0.53	1.13	1.13	1.98	3.08	3.83
Applicable	from ELA	0.91	0.91	0.91	0.91	1.76	2.86	3.61
Shrinkage	from ETX	0.93	0.91	0.91	0.91	1.76	2.86	3.61
Percentage	from M1	2.49	1.98	1.76	1.76	0.85	1.95	2.70
|	from M2	3.59	3.08	2.86	2.86	1.95	1.42	2.17
|	from M3	4.34	3.83	3.61	3.61	2.70	2.17	1.07
|	from STX	-0.09	-0.15	-0.50	-0.50	-0.41	-1.02	-1.08
Applicable	from WLA	0.36	0.21	-0.12	-0.12	-0.03	-0.64	-0.70
Shrinkage	from ELA	0.23	0.10	0.15	0.15	0.24	-0.37	-0.43
Adjustment	from ETX	0.21	0.10	0.15	0.15	0.24	-0.37	-0.43
Percentage	from M1	-0.41	-0.03	0.24	0.24	0.09	-0.52	-0.58
|	from M2	-1.02	-0.64	-0.37	-0.37	-0.52	-0.19	-0.25
|	from M3	-1.08	-0.70	-0.43	-0.43	-0.58	-0.25	0.37
|	from STX	0.84	0.89	1.14	1.14	2.08	2.57	3.26
Applicable	from WLA	0.89	0.74	1.01	1.01	1.95	2.44	3.13
Shrinkage	from ELA	1.14	1.01	1.06	1.06	2.00	2.49	3.18
Percentage	from ETX	1.14	1.01	1.06	1.06	2.00	2.49	3.18
|	from M1	2.08	1.95	2.00	2.00	0.94	1.43	2.12
|	from M2	2.57	2.44	2.49	2.49	1.43	1.23	1.92
|	from M3	3.26	3.13	3.18	3.18	2.12	1.92	1.44

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				1.06			
Percentage	from M1				1.06	0.00		
|	from M2				1.06	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				1.06			
|	from M1				1.06	0.00		
|	from M2				1.06	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.70 %	-0.93 %	1.77 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.09 %	0.67 %
Monthly Injections	1.76 %	-1.09 %	0.67 %
Monthly Inventory Level	0.08 %	-0.06 %	0.02 %

Footnote: Due to the bidirectional flow patterns of Pipeline’s Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Seventeenth Revised Sheet No. 14
Superseding
Sixteenth Revised Sheet No. 14

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$4.8571		$10.1498	$13.6529	$13.8945	$15.2673	$16.2055	$20.3323
L		$4.3119						
1	$7.3119		$7.0090	$9.3276	$13.2135	$13.0132	$14.6759	$18.0462
2	$13.6530		$9.2716	$4.8222	$4.5078	$5.7679	$7.9331	$10.2407
3	$13.8945		$7.3440	$4.8611	$3.5070	$5.3870	$9.7428	$11.2581
4	$17.6413		$16.2638	$6.1979	$9.4190	$4.6105	$4.9861	$7.1232
5	$21.0347		$14.7807	$6.5015	$7.8669	$5.1218	$4.8044	$6.2544
6	$24.3333		$16.9768	$11.6840	$12.8717	$9.0920	$4.7831	$4.1405

Daily Base Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1597		$0.3337	$0.4489	$0.4568	$0.5019	$0.5328	$0.6685
L		$0.1418						
1	$0.2404		$0.2304	$0.3067	$0.4344	$0.4278	$0.4825	$0.5933
2	$0.4489		$0.3048	$0.1585	$0.1482	$0.1896	$0.2608	$0.3367
3	$0.4568		$0.2414	$0.1598	$0.1153	$0.1771	$0.3203	$0.3701
4	$0.5800		$0.5347	$0.2038	$0.3097	$0.1516	$0.1639	$0.2342
5	$0.6916		$0.4859	$0.2137	$0.2586	$0.1684	$0.1580	$0.2056
6	$0.8000		$0.5581	$0.3841	$0.4232	$0.2989	$0.1573	$0.1361

Maximum Reservation Rates 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$4.8984		$10.1911	$13.6942	$13.9358	$15.3086	$16.2468	$20.3736
L		$4.3532						
1	$7.3532		$7.0503	$9.3689	$13.2548	$13.0545	$14.7172	$18.0875
2	$13.6943		$9.3129	$4.8635	$4.5491	$5.8092	$7.9744	$10.2820
3	$13.9358		$7.3853	$4.9024	$3.5483	$5.4283	$9.7841	$11.2994
4	$17.6826		$16.3051	$6.2392	$9.4603	$4.6518	$5.0274	$7.1645
5	$21.0760		$14.8220	$6.5428	$7.9082	$5.1631	$4.8457	$6.2957
6	$24.3746		$17.0181	$11.7253	$12.9130	$9.1333	$4.8244	$4.1818

Notes:

1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0413.

Issued: September 30, 2020
Effective: November 1, 2020

Docket No. RP20-1253-000
Accepted: October 29, 2020

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base
Commodity Rates

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2339	$0.2232	$0.2656
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.1989	$0.2028	$0.2315
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0644	$0.1032	$0.1144
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0860	$0.1190	$0.1300
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0398	$0.0563	$0.0912
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0560	$0.0555	$0.0689
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0862	$0.0467	$0.0284

Minimum
Commodity Rates 1/, 2/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020

Maximum
Commodity Rates 1/, 2/, 3/

DELIVERY ZONE

RECEIPT ZONE	0	L	1	2	3	4	5	6
0	$0.0048		$0.0131	$0.0193	$0.0235	$0.2355	$0.2248	$0.2672
L		$0.0028						
1	$0.0058		$0.0097	$0.0163	$0.0195	$0.2005	$0.2044	$0.2331
2	$0.0183		$0.0103	$0.0028	$0.0044	$0.0660	$0.1048	$0.1160
3	$0.0223		$0.0185	$0.0042	$0.0018	$0.0876	$0.1206	$0.1316
4	$0.0266		$0.0221	$0.0103	$0.0121	$0.0414	$0.0579	$0.0928
5	$0.0300		$0.0272	$0.0116	$0.0134	$0.0576	$0.0571	$0.0705
6	$0.0362		$0.0316	$0.0159	$0.0179	$0.0878	$0.0483	$0.0300

Notes:

1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0016.

FUEL AND EPCR

F&LR 1/, 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.43%		1.54%	2.34%	2.97%	3.59%	4.08%	4.66%
L		0.16%						
1	0.56%		1.09%	1.96%	2.43%	2.92%	3.55%	4.06%
2	2.40%		1.17%	0.15%	0.38%	0.79%	1.44%	1.96%
3	2.97%		2.37%	0.38%	0.03%	1.14%	1.67%	2.26%
4	3.46%		2.71%	1.16%	1.40%	0.40%	0.66%	1.22%
5	4.08%		3.55%	1.42%	1.67%	0.66%	0.65%	0.86%
6	4.88%		4.06%	1.96%	2.26%	1.14%	0.50%	0.20%

Broad Run Expansion Project – Market Component (Z3-Z1): 5/ 7.62%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0021		$0.0081	$0.0125	$0.0155	$0.0188	$0.0214	$0.0256
L		$0.0007						
1	$0.0028		$0.0057	$0.0104	$0.0127	$0.0157	$0.0193	$0.0221
2	$0.0125		$0.0061	$0.0007	$0.0018	$0.0041	$0.0074	$0.0102
3	$0.0155		$0.0127	$0.0018	$0.0000	$0.0060	$0.0088	$0.0118
4	$0.0188		$0.0145	$0.0060	$0.0074	$0.0019	$0.0034	$0.0063
5	$0.0214		$0.0193	$0.0074	$0.0088	$0.0033	$0.0033	$0.0044
6	$0.0256		$0.0221	$0.0102	$0.0118	$0.0059	$0.0025	$0.0009

Broad Run Expansion Project – Market Component (Z3-Z1): 5/ $0.0272

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.00%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.00%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
5/ The incremental F&LR and EPCR set forth above are applicable to a Shipper(s) utilizing capacity on the Broad Run Expansion Project – Market Component facilities, from any receipt point(s) to any delivery point(s) located on the project's transportation path. Any service provided to a Shipper(s) outside the project's transportation path shall be subject to the greater of the incremental F&LR and EPCR for the project or the applicable F&LR and EPCR for the applicable receipt(s) and delivery point(s) as shown in the rate matrices above. Included in the above F&LR is the Losses component of the F&LR equal to 0.00%.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Twentieth Revised Sheet No. 61
Superseding
Nineteenth Revised Sheet No. 61

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$1.7824	$1.7824 1/		
Space Rate	$0.0181	$0.0181 1/		
Injection Rate	$0.0073	$0.0073	1.62%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.2139	$0.2139 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.3094	$1.3094 1/		
Space Rate	$0.0179	$0.0179 1/		
Injection Rate	$0.0087	$0.0087	1.62%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1572	$0.1572 1/		

Notes:

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.03%.

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Tennessee Gas Pipeline Company, L.L.C.
Settlement Rates effective November 1, 2021 - Base Reservation and Commodity
12.5 % Rate Reduction from the Appendix A-0 Rates

Line No.

General System Transportation Services

Rate Schedule FT-A, FT-G, NET, NET-284

Line No.	Reservation	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
1	Zone 0	$4.7485		$9.9230	$13.3478	$13.5840	$14.9261	$15.8434	$19.8779
2	Zone L		$4.2156						
3	Zone 1	$7.1485		$6.8524	$9.1192	$12.9182	$12.7224	$14.3480	$17.6429
4	Zone 2	$13.3479		$9.0644	$4.7144	$4.4071	$5.6390	$7.7558	$10.0118
5	Zone 3	$13.5840		$7.1799	$4.7525	$3.4286	$5.2666	$9.5251	$11.0065
6	Zone 4	$17.2471		$15.9003	$6.0594	$9.2085	$4.5075	$4.8747	$6.9640
7	Zone 5	$20.5647		$14.4505	$6.3563	$7.6911	$5.0074	$4.6970	$6.1147
8	Zone 6	$23.7895		$16.5974	$11.4230	$12.5841	$8.8889	$4.6763	$4.0480

Line No.	Commodity	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
9	Zone 0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2286	$0.2182	$0.2597
10	Zone L		$0.0012						
11	Zone 1	$0.0042		$0.0081	$0.0147	$0.0179	$0.1944	$0.1983	$0.2264
12	Zone 2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0629	$0.1009	$0.1118
13	Zone 3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0841	$0.1164	$0.1271
14	Zone 4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0389	$0.0550	$0.0892
15	Zone 5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0548	$0.0543	$0.0674
16	Zone 6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0843	$0.0457	$0.0277

Line No.	Min. Commodity				Delivery Zone				
		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
17	Zone 0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
18	Zone L		$0.0012						
19	Zone 1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
20	Zone 2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
21	Zone 3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
22	Zone 4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
23	Zone 5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
24	Zone 6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020

Rate Schedule FT-GS

Line No.		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
25	Zone 0	$0.2629		$0.5533	$0.7461	$0.7625	$1.0466	$1.0863	$1.3489
26	Zone L		$0.2320						
27	Zone 1	$0.3952		$0.3822	$0.5119	$0.7228	$0.8915	$0.9845	$1.1931
28	Zone 2	$0.7453		$0.5039	$0.2594	$0.2439	$0.3719	$0.5260	$0.6604
29	Zone 3	$0.7615		$0.4075	$0.2626	$0.1880	$0.3728	$0.6383	$0.7301
30	Zone 4	$0.9658		$0.8883	$0.3393	$0.5133	$0.2859	$0.3221	$0.4708
31	Zone 5	$1.1505		$0.8131	$0.3567	$0.4313	$0.3292	$0.3118	$0.4024
32	Zone 6	$1.3324		$0.9343	$0.6378	$0.7031	$0.5714	$0.3018	$0.2496

Rate Schedule IT, PTR and FT Overrun

Line No.		Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
33	Zone 0	$0.1588		$0.3358	$0.4535	$0.4648	$0.7193	$0.7390	$0.9132
34	Zone L		$0.1397						
35	Zone 1	$0.2385		$0.2320	$0.3120	$0.4396	$0.6127	$0.6700	$0.8063
36	Zone 2	$0.4527		$0.3052	$0.1560	$0.1472	$0.2483	$0.3560	$0.4410
37	Zone 3	$0.4638		$0.2502	$0.1585	$0.1129	$0.2573	$0.4296	$0.4889
38	Zone 4	$0.5877		$0.5398	$0.2064	$0.3115	$0.1871	$0.2153	$0.3182
39	Zone 5	$0.6997		$0.4964	$0.2172	$0.2627	$0.2195	$0.2087	$0.2685
40	Zone 6	$0.8109		$0.5706	$0.3875	$0.4273	$0.3765	$0.1993	$0.1608

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Tennessee Gas Pipeline Company, L.L.C.
Settlement Rates effective November 1, 2021 - Base Reservation and Commodity
12.5 % Rate Reduction from the Appendix A-0 Rates

Rate Schedule FT-BH

Line No.	Reservation	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
1	Zone 0	$2.3742							
2	Zone L		$2.1078						
3	Zone 1	$3.5742		$3.4262					
4	Zone 2	$6.6740		$4.5322	$2.3572				
5	Zone 3	$6.7920		$3.5900	$2.3763	$1.7143			
6	Zone 4	$8.6236		$7.9502	$3.0297	$4.6043	$2.2537		
7	Zone 5	$10.2823		$7.2252	$3.1781	$3.8455	$2.5036	$2.3485	
8	Zone 6	$11.8947		$8.2987	$5.7116	$6.2920	$4.4445	$2.3382	$2.0241

Line No.	Commodity	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
9	Zone 0	$0.0417							
10	Zone L		$0.0357						
11	Zone 1	$0.0623		$0.0631					
12	Zone 2	$0.1236		$0.0817	$0.0397				
13	Zone 3	$0.1289		$0.0731	$0.0412	$0.0284			
14	Zone 4	$0.1626		$0.1477	$0.0571	$0.0844	$0.0760		
15	Zone 5	$0.1927		$0.1401	$0.0606	$0.0730	$0.0959	$0.0929	
16	Zone 6	$0.2244		$0.1614	$0.1057	$0.1171	$0.1573	$0.0840	$0.0610

Rate Schedule FT-A EDS/ERS (Extended Delivery/Receipt)

Line No.	Reservation	Zone 0	Zone L	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6
17	Zone 0			$0.3263	$0.4388	$0.4466	$0.4907	$0.5209	$0.6535
18	Zone L								
19	Zone 1	$0.2350			$0.2999	$0.4247	$0.4183	$0.4717	$0.5800
20	Zone 2	$0.4388		$0.2980		$0.1449	$0.1854	$0.2551	$0.3292
21	Zone 3	$0.4466		$0.2361	$0.1563		$0.1732	$0.3133	$0.3618
22	Zone 4	$0.5670		$0.5228	$0.1992	$0.3028		$0.1603	$0.2289
23	Zone 5	$0.6760		$0.4751	$0.2089	$0.2529	$0.1647		$0.2011
24	Zone 6	$0.7822		$0.5457	$0.3756	$0.4137	$0.2922	$0.1537	

Rate Schedule PAL

Line No.		Commodity	Overrun
25	PAL (Daily)	$0.3400	$0.3400
26	PAL (Term)	$0.3400	$0.3400

Incremental Transportation Services

Line No.			Reservation	Commodity	Overrun	Min. Comm.
27	Stagecoach - CP00-65	FT-A	$3.1960	$0.0000	$0.1051	$0.0000
28	ConneXion NY/NJ - CP05-355	FT-A	$8.9823	$0.0000	$0.2953	$0.0000
29	Concord - CP08-65	FT-A	$10.5931	$0.0000	$0.3483	$0.0000
30	Tewksbury - CP04-60	FT-IL	$5.3511	$0.0000	$0.1760	$0.0000
31	300 Line Market - CP09-444	FT-A	$22.3939	$0.0000	$0.7362	$0.0000
32	NSD - CP11-30	FT-A	$5.4214	$0.0000	$0.1782	$0.0000
33	Northampton - CP11-36	FT-A	$24.1587	$0.0000	$0.7942	$0.0000
34	NEUP - CP11-161	FT-A	$7.7389	$0.0000	$0.2545	$0.0000
35	Niagara Expansion - CP14-88	FT-A	$8.7163	$0.0000	$0.2866	$0.0000
36	Connecticut Expansion - CP14-529	FT-A	$16.9478	$0.0674	$0.6246	$0.0066
37	Broad Run Expansion Project - CP15-77	FT-A	$26.1755	$0.0336	$0.8900	$0.0336
38	Susquehanna West Project - CP15-148	FT-A	$14.9795	$0.0389	$0.5314	$0.0028
39	Triad Expansion Project - CP 15-520	FT-A	$6.5881	$0.0389	$0.2555	$0.0028
40	Orion Project - CP 16-4	FT-A	$14.4557	$0.0389	$0.5142	$0.0028

Storage Services

Line No.		Deliverability	Space	Inj/With	Overrun
41	FS - PA [1]	$1.7426	$0.0177	$0.0073	$0.2091
42	FS - MA	$1.2801	$0.0175	$0.0087	$0.1537
43	IS - PA		$0.0873	$0.0073	
44	IS - MA		$0.0704	$0.0087	

Notes:
[1] The Rate Schedule FS-PA Rates set forth herein do not include the impact of the Bear Creek Proceeding, if any.

Winter Period Re-Entry Surcharge Calculation
(Applicable to Capacity Assigned Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	Weighted Average	Reference
1	Winter Demand Cost of Gas Rate	$0.2543	$0.3805	$0.3379	Summary
2	Winter Commodity Cost of Gas Rate	$0.5575	$0.5411	$0.5466	Summary
3	Winter Indirect Cost of Gas	$0.0335	$0.0335	$0.0335	Summary, Removing any Prior Period Over-Collection or Supplier Refunds
4	Winter Cost of Gas Rate (Exclusive of Credits)	$0.8453	$0.9551	$0.9180	Sum Lines 1 through 3
5	Winter Cost of Gas Rate for Incumbent Sales Customers	$0.8453	$0.9551	$0.9180	Summary
6	**Winter Re-Entry Surcharge**	$0.0000	$0.0000	**$0.0000**	**Positive Difference between Line 4 and Line 5**
7	Projected Sales (therms)	13,608,737	26,660,466	40,269,203	FXW-2 - Distribution Service Delilveries, excluding Special Contracts

Summer Period Re-Entry Surcharge & Conversion Surcharge Calculation
(Applicable to Capacity Assigned & Capacity Exempt Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	Weighted Average	Reference
8	Summer Demand Cost of Gas Rate	$0.1085	$0.1789	$0.1551	Summary
9	Summer Commodity Cost of Gas Rate	$0.3515	$0.3516	$0.3516	Summary
10	Summer Indirect Cost of Gas	$0.0140	$0.0140	$0.0140	Summary, Removing any Prior Period Over-Collection or Supplier Refunds
11	Summer Cost of Gas Rate (Exclusive of Credits)	$0.4740	$0.5445	$0.5207	Sum Lines 8 through 10
12	Summer Cost of Gas Rate for Incumbent Sales Customers	$0.4741	$0.5446	$0.5208	Summary
13	**Summer Re-Entry Surcharge**	$0.0000	$0.0000	**$0.0000**	**Positive Difference between Line 11 and Line 12**
14	Projected Sales (therms)	11,439,284	6,075,647	17,514,931	FXW-2 - Distribution Service Delilveries, excluding Special Contracts

Winter Period Conversion Surcharge Calculation
(Applicable to Capacity Exempt Customers Returning to Sales Service)

Line	Item	HLF (50, 51, 52)	LLF (40, 41, 42)	Reference
1	LLF Winter Demand Cost of Gas Rate	$0.3805	$0.3805	Page 3 of Summary
2	LLF Winter Commodity Cost of Gas Rate	$0.5411	$0.5411	Page 3 of Summary
3	LLF Winter Indirect Cost of Gas	$0.0335	$0.0335	Page 3 of Summary, Removing any Prior Period Over-Collection or Supplier Refunds
4	Floor Price (LLF Winter Cost of Gas Rate, Exclusive of Credits)	$0.9551	$0.9551	Sum Lines 1 through 3.
5	Total Incremental Cost	$1.4368	$1.4368	See Line 15 of Incremental Commodity Price Worksheet
6	Total Conversion Rate	$1.4368	$1.4368	Maximum of Line 4 and Line 5
7	Winter Gas Adjustment Factor for Incumbent Sales Customers	$0.8453	$0.9551	Summary
8	**Conversion Surcharge**	**$0.5915**	**$0.4817**	**Positive Difference between Line 6 and Line 7**

Incremental Commodity Price Worksheet

Line	Month	NYMEX	Projected PNGTS Delivered Basis	Projected FOM Index	Projected Non-Capacity Assigned Delivery Service Loads	Comments
1	Nov-21	$ 5.305	$ 3.352	$ 8.657	227,140	
2	Dec-21	$ 5.398	$ 9.742	$ 15.140	231,339	
3	Jan-22	$ 5.465	$ 14.867	$ 20.332	256,763	
4	Feb-22	$ 5.370	$ 14.057	$ 19.427	242,833	
5	Mar-22	$ 5.013	$ 5.159	$ 10.172	255,609	
6	Apr-22	$ 3.939	$ 1.532	$ 5.471	232,427	
7	Winter Period Weigthed Average Baseload Price ($/Dth)			$ 13.331	1,446,111	Average, Weighted by Loads, Lines 1 through 6
8	Load Shape Price Factor			1.046		See Load Shape Price Factor Worksheet
9	Winter Period Incremental Load Shape Price ($/Dth)			$ 13.944		Line 7 times Line 8
10	Granite Fuel			0.35%		Granite Tariff
11	Granite Variable Transport ($/Dth)			$ 0.1954		Granite Tariff (IT Daily Rate plus ACA)
12	Northern City-Gate Price ($/Dth)			$ 14.188		Line 9 times (1 plus Line 10) plus Line 11
13	New Hampshire Division City-Gate Sendout to Sales Ratio			1.0127		See FXW-2
14	Northern Retail Meter Price ($/Dth)			$ 14.368		Line 12 times Line 13
15	Northern Retail Meter Price ($/therm)			$ 1.4368		Line 14 divided by 10

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2020-2021 Cost Analysis	
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Nov-20	11/1/2020	5,214	5,687	10,901	5,214	-	5,214	$ 3.540	$ 18,458
Nov-20	11/2/2020	7,917	7,680	15,597	7,917	-	7,917	$ 3.540	$ 28,026
Nov-20	11/3/2020	8,861	7,600	16,461	8,861	-	8,861	$ 3.870	$ 34,292
Nov-20	11/4/2020	8,610	6,394	15,004	8,610	-	8,610	$ 2.150	$ 18,512
Nov-20	11/5/2020	7,067	3,727	10,794	7,067	-	7,067	$ 0.840	$ 5,936
Nov-20	11/6/2020	6,242	3,333	9,575	6,242	-	6,242	$ 0.775	$ 4,838
Nov-20	11/7/2020	5,621	3,529	9,150	5,621	-	5,621	$ 0.375	$ 2,108
Nov-20	11/8/2020	4,856	4,706	9,562	4,856	-	4,856	$ 0.375	$ 1,821
Nov-20	11/9/2020	7,024	5,256	12,280	7,024	-	7,024	$ 0.375	$ 2,634
Nov-20	11/10/2020	6,973	3,416	10,389	6,973	-	6,973	$ 0.605	$ 4,219
Nov-20	11/11/2020	6,542	3,277	9,819	6,542	-	6,542	$ 1.045	$ 6,836
Nov-20	11/12/2020	7,298	5,781	13,079	7,298	-	7,298	$ 1.580	$ 11,531
Nov-20	11/13/2020	7,241	6,614	13,855	7,241	-	7,241	$ 2.155	$ 15,604
Nov-20	11/14/2020	6,910	6,675	13,585	6,910	-	6,910	$ 2.280	$ 15,755
Nov-20	11/15/2020	5,002	5,543	10,545	5,002	-	5,002	$ 2.280	$ 11,405
Nov-20	11/16/2020	8,084	6,553	14,637	8,084	-	8,084	$ 2.280	$ 18,432
Nov-20	11/17/2020	8,481	7,686	16,167	8,481	-	8,481	$ 4.210	$ 35,705
Nov-20	11/18/2020	8,787	9,407	18,194	8,787	-	8,787	$ 4.360	$ 38,311
Nov-20	11/19/2020	7,805	6,860	14,665	7,805	-	7,805	$ 2.225	$ 17,366
Nov-20	11/20/2020	6,803	4,945	11,748	6,803	-	6,803	$ 1.550	$ 10,545
Nov-20	11/21/2020	6,874	5,906	12,780	6,874	-	6,874	$ 1.985	$ 13,645
Nov-20	11/22/2020	6,401	5,695	12,096	6,401	-	6,401	$ 1.985	$ 12,706
Nov-20	11/23/2020	7,890	7,243	15,133	7,890	-	7,890	$ 1.985	$ 15,662
Nov-20	11/24/2020	8,841	8,329	17,170	8,841	-	8,841	$ 3.260	$ 28,822
Nov-20	11/25/2020	6,628	7,063	13,691	6,628	-	6,628	$ 1.945	$ 12,891
Nov-20	11/26/2020	3,997	6,466	10,463	3,997	-	3,997	$ 1.380	$ 5,516
Nov-20	11/27/2020	3,744	5,664	9,408	3,744	-	3,744	$ 1.380	$ 5,167

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2020-2021 Cost Analysis	
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Nov-20	11/28/2020	4,035	6,272	10,307	4,035	-	4,035	$ 1.380	$ 5,568
Nov-20	11/29/2020	5,149	6,821	11,970	5,149	-	5,149	$ 1.380	$ 7,106
Nov-20	11/30/2020	6,843	4,951	11,794	6,843	-	6,843	$ 1.380	$ 9,443
Dec-20	12/1/2020	7,332	6,331	13,663	7,332	-	7,332	$ 2.370	$ 17,377
Dec-20	12/2/2020	8,043	7,477	15,520	8,043	-	8,043	$ 2.780	$ 22,360
Dec-20	12/3/2020	7,734	6,707	14,441	7,734	-	7,734	$ 2.405	$ 18,600
Dec-20	12/4/2020	6,547	5,920	12,467	6,547	-	6,547	$ 2.155	$ 14,109
Dec-20	12/5/2020	7,116	7,800	14,916	7,116	-	7,116	$ 3.055	$ 21,739
Dec-20	12/6/2020	5,951	8,437	14,388	5,951	-	5,951	$ 3.055	$ 18,180
Dec-20	12/7/2020	8,066	8,911	16,977	8,066	-	8,066	$ 3.055	$ 24,642
Dec-20	12/8/2020	8,480	9,370	17,850	8,480	-	8,480	$ 2.985	$ 25,313
Dec-20	12/9/2020	8,370	8,109	16,479	8,370	-	8,370	$ 2.645	$ 22,139
Dec-20	12/10/2020	8,039	8,137	16,176	8,039	-	8,039	$ 2.695	$ 21,665
Dec-20	12/11/2020	7,233	7,275	14,508	7,233	-	7,233	$ 2.225	$ 16,093
Dec-20	12/12/2020	6,580	6,332	12,912	6,580	-	6,580	$ 2.705	$ 17,799
Dec-20	12/13/2020	5,067	6,691	11,758	5,067	-	5,067	$ 2.705	$ 13,706
Dec-20	12/14/2020	8,057	8,229	16,286	8,057	-	8,057	$ 2.705	$ 21,794
Dec-20	12/15/2020	9,613	10,146	19,759	9,613	-	9,613	$ 5.825	$ 55,996
Dec-20	12/16/2020	9,237	9,185	18,422	9,237	-	9,237	$ 7.530	$ 69,555
Dec-20	12/17/2020	8,644	8,794	17,438	8,644	-	8,644	$ 9.445	$ 81,643
Dec-20	12/18/2020	8,393	8,763	17,156	8,393	-	8,393	$ 11.920	$ 100,045
Dec-20	12/19/2020	7,408	7,746	15,154	7,408	-	7,408	$ 7.200	$ 53,338
Dec-20	12/20/2020	7,735	7,676	15,411	7,735	-	7,735	$ 7.200	$ 55,692
Dec-20	12/21/2020	7,338	7,396	14,734	7,338	-	7,338	$ 7.200	$ 52,834
Dec-20	12/22/2020	7,272	6,990	14,262	7,272	-	7,272	$ 4.105	$ 29,852
Dec-20	12/23/2020	6,822	7,119	13,941	6,822	-	6,822	$ 3.320	$ 22,649
Dec-20	12/24/2020	3,918	4,510	8,428	3,918	-	3,918	$ 2.495	$ 9,775

Load Shape Price Factor Worksheet

Month	Date	Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2020-2021 Cost Analysis	
		Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Dec-20	12/25/2020	4,013	5,032	9,045	4,013	-	4,013	$ 4.475	$ 17,958
Dec-20	12/26/2020	5,798	7,330	13,128	5,798	-	5,798	$ 4.475	$ 25,946
Dec-20	12/27/2020	7,065	6,960	14,025	7,065	-	7,065	$ 4.475	$ 31,616
Dec-20	12/28/2020	7,385	6,500	13,885	7,385	-	7,385	$ 4.475	$ 33,048
Dec-20	12/29/2020	8,499	9,339	17,838	8,499	-	8,499	$ 3.835	$ 32,594
Dec-20	12/30/2020	6,752	7,317	14,069	6,752	-	6,752	$ 3.265	$ 22,045
Dec-20	12/31/2020	4,898	7,525	12,423	4,898	-	4,898	$ 2.580	$ 12,637
Jan-21	1/1/2021	4,433	7,143	11,576	4,433	-	4,433	$ 2.410	$ 10,684
Jan-21	1/2/2021	6,493	7,628	14,121	6,493	-	6,493	$ 2.410	$ 15,648
Jan-21	1/3/2021	6,968	7,850	14,818	6,968	-	6,968	$ 2.410	$ 16,793
Jan-21	1/4/2021	7,451	8,205	15,656	7,451	-	7,451	$ 2.410	$ 17,957
Jan-21	1/5/2021	7,833	8,386	16,219	7,833	-	7,833	$ 3.295	$ 25,810
Jan-21	1/6/2021	7,790	8,017	15,807	7,790	-	7,790	$ 3.260	$ 25,395
Jan-21	1/7/2021	7,892	8,367	16,259	7,892	-	7,892	$ 2.990	$ 23,597
Jan-21	1/8/2021	7,662	8,339	16,001	7,662	-	7,662	$ 3.320	$ 25,438
Jan-21	1/9/2021	6,854	7,555	14,409	6,854	-	6,854	$ 3.860	$ 26,456
Jan-21	1/10/2021	5,920	8,156	14,076	5,920	-	5,920	$ 3.860	$ 22,851
Jan-21	1/11/2021	8,023	8,429	16,452	8,023	-	8,023	$ 3.860	$ 30,969
Jan-21	1/12/2021	7,803	7,910	15,713	7,803	-	7,803	$ 4.000	$ 31,212
Jan-21	1/13/2021	7,521	7,689	15,210	7,521	-	7,521	$ 4.385	$ 32,980
Jan-21	1/14/2021	7,688	7,663	15,351	7,688	-	7,688	$ 4.470	$ 34,365
Jan-21	1/15/2021	7,307	6,839	14,146	7,307	-	7,307	$ 3.020	$ 22,067
Jan-21	1/16/2021	6,162	6,627	12,789	6,162	-	6,162	$ 5.205	$ 32,073
Jan-21	1/17/2021	4,892	6,958	11,850	4,892	-	4,892	$ 5.205	$ 25,463
Jan-21	1/18/2021	7,655	8,534	16,189	7,655	-	7,655	$ 5.205	$ 39,844
Jan-21	1/19/2021	8,011	8,381	16,392	8,011	-	8,011	$ 5.205	$ 41,697
Jan-21	1/20/2021	8,359	9,349	17,708	8,359	-	8,359	$ 4.295	$ 35,902

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2020-2021 Cost Analysis	
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Jan-21	1/21/2021	8,075	8,874	16,949	8,075	-	8,075	$ 3.040	$ 24,548
Jan-21	1/22/2021	7,722	7,959	15,681	7,722	-	7,722	$ 3.660	$ 28,263
Jan-21	1/23/2021	7,985	10,489	18,474	7,985	-	7,985	$ 5.475	$ 43,718
Jan-21	1/24/2021	6,426	9,990	16,416	6,426	-	6,426	$ 5.475	$ 35,182
Jan-21	1/25/2021	8,865	9,599	18,464	8,865	-	8,865	$ 5.475	$ 48,536
Jan-21	1/26/2021	8,866	8,719	17,585	8,866	-	8,866	$ 4.975	$ 44,108
Jan-21	1/27/2021	8,151	8,214	16,365	8,151	-	8,151	$ 4.770	$ 38,880
Jan-21	1/28/2021	8,920	10,600	19,520	8,920	-	8,920	$ 9.890	$ 88,219
Jan-21	1/29/2021	9,125	11,601	20,726	9,125	-	9,125	$ 11.595	$ 105,804
Jan-21	1/30/2021	8,971	11,186	20,157	8,971	-	8,971	$ 11.595	$ 104,019
Jan-21	1/31/2021	7,100	10,356	17,456	7,100	-	7,100	$ 11.595	$ 82,325
Feb-21	2/1/2021	7,127	9,370	16,497	7,127	-	7,127	$ 5.440	$ 38,771
Feb-21	2/2/2021	7,175	8,657	15,832	7,175	-	7,175	$ 8.110	$ 58,189
Feb-21	2/3/2021	7,982	8,300	16,282	7,982	-	7,982	$ 11.810	$ 94,267
Feb-21	2/4/2021	8,149	8,909	17,058	8,149	-	8,149	$ 10.835	$ 88,294
Feb-21	2/5/2021	7,370	8,112	15,482	7,370	-	7,370	$ 7.420	$ 54,685
Feb-21	2/6/2021	7,437	8,283	15,720	7,437	-	7,437	$ 11.465	$ 85,265
Feb-21	2/7/2021	6,237	9,304	15,541	6,237	-	6,237	$ 11.465	$ 71,507
Feb-21	2/8/2021	8,807	10,463	19,270	8,807	-	8,807	$ 11.465	$ 100,972
Feb-21	2/9/2021	8,050	10,366	18,416	8,050	-	8,050	$ 11.365	$ 91,488
Feb-21	2/10/2021	8,615	10,055	18,670	8,615	-	8,615	$ 10.465	$ 90,156
Feb-21	2/11/2021	8,576	10,944	19,520	8,576	-	8,576	$ 11.100	$ 95,194
Feb-21	2/12/2021	7,683	10,167	17,850	7,683	-	7,683	$ 12.310	$ 94,578
Feb-21	2/13/2021	7,218	8,929	16,147	7,218	-	7,218	$ 10.405	$ 75,103
Feb-21	2/14/2021	5,802	8,571	14,373	5,802	-	5,802	$ 10.405	$ 60,370
Feb-21	2/15/2021	7,746	8,615	16,361	7,746	-	7,746	$ 10.405	$ 80,597
Feb-21	2/16/2021	8,502	8,976	17,478	8,502	-	8,502	$ 10.405	$ 88,463

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2020-2021 Cost Analysis	
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Feb-21	2/17/2021	8,801	9,842	18,643	8,801	-	8,801	$ 10.955	$ 96,415
Feb-21	2/18/2021	8,591	9,328	17,919	8,591	-	8,591	$ 10.600	$ 91,065
Feb-21	2/19/2021	8,137	8,933	17,070	8,137	-	8,137	$ 8.590	$ 69,897
Feb-21	2/20/2021	7,695	9,051	16,746	7,695	-	7,695	$ 6.725	$ 51,749
Feb-21	2/21/2021	7,311	8,994	16,305	7,311	-	7,311	$ 6.725	$ 49,166
Feb-21	2/22/2021	7,646	8,259	15,905	7,646	-	7,646	$ 6.725	$ 51,419
Feb-21	2/23/2021	7,878	7,452	15,330	7,878	-	7,878	$ 4.460	$ 35,136
Feb-21	2/24/2021	6,880	6,751	13,631	6,880	-	6,880	$ 3.180	$ 21,878
Feb-21	2/25/2021	7,527	8,443	15,970	7,527	-	7,527	$ 3.440	$ 25,893
Feb-21	2/26/2021	7,524	7,810	15,334	7,524	-	7,524	$ 2.655	$ 19,976
Feb-21	2/27/2021	7,288	6,952	14,240	7,288	-	7,288	$ 2.655	$ 19,350
Feb-21	2/28/2021	6,104	6,711	12,815	6,104	-	6,104	$ 2.655	$ 16,206
Mar-21	3/1/2021	8,079	9,677	17,756	8,079	-	8,079	$ 3.385	$ 27,347
Mar-21	3/2/2021	8,796	10,247	19,043	8,796	-	8,796	$ 6.470	$ 56,910
Mar-21	3/3/2021	7,816	7,786	15,602	7,816	-	7,816	$ 4.125	$ 32,241
Mar-21	3/4/2021	8,360	9,744	18,104	8,360	-	8,360	$ 8.235	$ 68,845
Mar-21	3/5/2021	8,375	9,774	18,149	8,375	-	8,375	$ 7.100	$ 59,463
Mar-21	3/6/2021	7,996	8,849	16,845	7,996	-	7,996	$ 5.355	$ 42,819
Mar-21	3/7/2021	6,194	8,556	14,750	6,194	-	6,194	$ 5.355	$ 33,169
Mar-21	3/8/2021	8,003	8,062	16,065	8,003	-	8,003	$ 5.355	$ 42,856
Mar-21	3/9/2021	7,960	7,104	15,064	7,960	-	7,960	$ 2.845	$ 22,646
Mar-21	3/10/2021	7,491	6,984	14,475	7,491	-	7,491	$ 2.740	$ 20,525
Mar-21	3/11/2021	6,480	4,286	10,766	6,480	-	6,480	$ 2.370	$ 15,358
Mar-21	3/12/2021	6,533	5,868	12,401	6,533	-	6,533	$ 2.310	$ 15,091
Mar-21	3/13/2021	6,799	6,843	13,642	6,799	-	6,799	$ 4.115	$ 27,978
Mar-21	3/14/2021	7,184	9,346	16,530	7,184	-	7,184	$ 4.115	$ 29,562
Mar-21	3/15/2021	9,579	10,470	20,049	9,579	-	9,579	$ 4.115	$ 39,418

Load Shape Price Factor Worksheet

		Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2020-2021 Cost Analysis	
Month	Date	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Mar-21	3/16/2021	8,684	8,172	16,856	8,684	-	8,684	$ 4.515	$ 39,208
Mar-21	3/17/2021	7,487	6,764	14,251	7,487	-	7,487	$ 2.675	$ 20,028
Mar-21	3/18/2021	7,432	7,003	14,435	7,432	-	7,432	$ 2.760	$ 20,512
Mar-21	3/19/2021	7,727	7,428	15,155	7,727	-	7,727	$ 3.450	$ 26,658
Mar-21	3/20/2021	7,107	5,773	12,880	7,107	-	7,107	$ 2.205	$ 15,671
Mar-21	3/21/2021	6,247	5,921	12,168	6,247	-	6,247	$ 2.205	$ 13,775
Mar-21	3/22/2021	7,056	6,419	13,475	7,056	-	7,056	$ 2.205	$ 15,558
Mar-21	3/23/2021	7,138	5,720	12,858	7,138	-	7,138	$ 2.090	$ 14,918
Mar-21	3/24/2021	6,554	5,333	11,887	6,554	-	6,554	$ 2.140	$ 14,026
Mar-21	3/25/2021	6,493	4,764	11,257	6,493	-	6,493	$ 1.930	$ 12,531
Mar-21	3/26/2021	6,198	3,976	10,174	6,198	-	6,198	$ 1.835	$ 11,373
Mar-21	3/27/2021	6,841	5,323	12,164	6,841	-	6,841	$ 1.835	$ 12,553
Mar-21	3/28/2021	5,780	5,948	11,728	5,780	-	5,780	$ 1.835	$ 10,606
Mar-21	3/29/2021	8,314	6,789	15,103	8,314	-	8,314	$ 1.835	$ 15,256
Mar-21	3/30/2021	7,551	5,889	13,440	7,551	-	7,551	$ 1.940	$ 14,649
Mar-21	3/31/2021	6,621	4,326	10,947	6,621	-	6,621	$ 1.915	$ 12,679
Apr-21	4/1/2021	7,906	7,027	14,933	7,906	-	7,906	$ 2.535	$ 20,042
Apr-21	4/2/2021	7,608	7,070	14,678	7,608	-	7,608	$ 2.255	$ 17,156
Apr-21	4/3/2021	6,982	6,066	13,048	6,982	-	6,982	$ 2.255	$ 15,744
Apr-21	4/4/2021	6,600	4,836	11,436	6,600	-	6,600	$ 2.255	$ 14,883
Apr-21	4/5/2021	7,170	6,015	13,185	7,170	-	7,170	$ 2.255	$ 16,168
Apr-21	4/6/2021	7,074	5,130	12,204	7,074	-	7,074	$ 1.930	$ 13,653
Apr-21	4/7/2021	6,780	4,551	11,331	6,780	-	6,780	$ 2.000	$ 13,560
Apr-21	4/8/2021	6,921	5,239	12,160	6,921	-	6,921	$ 1.920	$ 13,288
Apr-21	4/9/2021	6,754	4,501	11,255	6,754	-	6,754	$ 1.795	$ 12,123
Apr-21	4/10/2021	5,806	3,678	9,484	5,806	-	5,806	$ 1.775	$ 10,306
Apr-21	4/11/2021	7,038	5,408	12,446	7,038	-	7,038	$ 1.775	$ 12,492

Load Shape Price Factor Worksheet

Month	Date	Historic Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment			2020-2021 Cost Analysis	
		Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total	AGT City-Gate Price	AGT City-Gate Cost
Apr-21	4/12/2021	7,731	5,835	13,566	7,731	-	7,731	$ 1.775	$ 13,723
Apr-21	4/13/2021	7,458	4,824	12,282	7,458	-	7,458	$ 1.940	$ 14,469
Apr-21	4/14/2021	7,358	5,139	12,497	7,358	-	7,358	$ 2.065	$ 15,194
Apr-21	4/15/2021	7,168	5,815	12,983	7,168	-	7,168	$ 2.355	$ 16,881
Apr-21	4/16/2021	7,696	6,650	14,346	7,696	-	7,696	$ 3.170	$ 24,396
Apr-21	4/17/2021	6,818	5,338	12,156	6,818	-	6,818	$ 2.865	$ 19,534
Apr-21	4/18/2021	6,832	5,282	12,114	6,832	-	6,832	$ 2.865	$ 19,574
Apr-21	4/19/2021	7,530	4,850	12,380	7,530	-	7,530	$ 2.865	$ 21,573
Apr-21	4/20/2021	7,775	4,321	12,096	7,775	-	7,775	$ 2.445	$ 19,010
Apr-21	4/21/2021	7,506	6,009	13,515	7,506	-	7,506	$ 2.605	$ 19,553
Apr-21	4/22/2021	8,365	6,834	15,199	8,365	-	8,365	$ 3.135	$ 26,224
Apr-21	4/23/2021	6,142	4,519	10,661	6,142	-	6,142	$ 2.465	$ 15,140
Apr-21	4/24/2021	3,760	3,191	6,951	3,760	-	3,760	$ 2.160	$ 8,122
Apr-21	4/25/2021	5,260	5,107	10,367	5,260	-	5,260	$ 2.160	$ 11,362
Apr-21	4/26/2021	8,383	6,029	14,412	8,383	-	8,383	$ 2.160	$ 18,107
Apr-21	4/27/2021	7,309	4,561	11,870	7,309	-	7,309	$ 2.600	$ 19,003
Apr-21	4/28/2021	6,835	5,023	11,858	6,835	-	6,835	$ 2.525	$ 17,258
Apr-21	4/29/2021	6,866	5,165	12,031	6,866	-	6,866	$ 2.465	$ 16,925
Apr-21	4/30/2021	6,859	4,898	11,757	6,859	-	6,859	$ 2.400	$ 16,462
Winter Period		1,311,091	1,303,347	2,614,438	1,311,091	-	1,311,091	$ 4.343	$ 5,694,604

Weighted Average Daily Price	$ 4.343
Straight Average Daily Price	$ 4.154
Load Shape Price Factor	1.046

Month	Projected Delivery Service Loads			Delivery Service Loads Not Subject to Capacity Assignment		
	Capacity Exempt	Capacity Assigned	Total	Capacity Exempt	Capacity Assigned	Total
Nov-21	227,140	211,485	438,625	227,140	-	227,140
Dec-21	231,339	241,104	472,443	231,339	-	231,339
Jan-22	256,763	273,557	530,320	256,763	-	256,763
Feb-22	242,833	251,374	494,207	242,833	-	242,833
Mar-22	255,609	250,793	506,402	255,609	-	255,609
Apr-22	232,427	202,864	435,291	232,427	-	232,427
Winter	1,446,111	1,431,177	2,877,288	1,446,111	-	1,446,111

REDACTED

Estimated Delivered City-Gate Commodity Costs and Volumes
November 2021 through April 2022

Denotes Confidential Information

Rank	Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
1	Tennessee Storage	[redacted]	206,842	[redacted]
2	Union Dawn Storage	[redacted]	3,141,670	[redacted]
3	Dawn Supply	[redacted]	781,700	[redacted]
4	TGP Zone 4 300 Leg Supply	[redacted]	180,766	[redacted]
5	Leidy Hub	[redacted]	144,313	[redacted]
6	Tennessee Niagara Pipeline Path	[redacted]	327,906	[redacted]
7	PXP Dawn Pipeline Path	[redacted]	1,217,695	[redacted]
8	Lewiston LNG	[redacted]	10,824	[redacted]
9	Peaking Contract 1	[redacted]	268,591	[redacted]
10	Tennessee Zone L	[redacted]	934,196	[redacted]
11	Tennessee Zone 0	[redacted]	459,229	[redacted]
12	Iroquois Receipts Pipeline Path	[redacted]	943,403	[redacted]
13	Atlantic Bridge Ramapo Pipeline Path	[redacted]	1,056,497	[redacted]
14	Transco Zone 6, non-NY	[redacted]	43,186	[redacted]
15	Texas Eastern Zone M-3	[redacted]	1,402	[redacted]
16	PNGTS Delivered (Dec - Feb)	[redacted]	224,213	[redacted]
17	Peaking Contract 2	[redacted]	298,950	[redacted]
	Total Delivered Commodity Cost	$54,844,677	10,241,382	$5.355

REDACTED

Rank	Estimated Delivered City-Gate Commodity Costs and Volumes May 2022 through October 2022 Denotes Confidential Information			
Rank	Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
1	TGP Zone 4 300 Leg Supply	[redacted]	394,032	[redacted]
2	Atlantic Bridge Ramapo Pipeline Path	[redacted]	1,074,008	[redacted]
3	Tennessee Niagara Pipeline Path	[redacted]	333,341	[redacted]
4	Dawn Supply	[redacted]	1,191,914	[redacted]
5	Lewiston LNG	[redacted]	11,040	[redacted]
	Total Delivered Commodity Cost	$10,424,440	3,004,335	$3.470

Northern Utilities, Inc.
Normal Year Sendout Volumes (Dth)
Sales Service and Company Managed Sales Sendout
November 2021 through October 2022

Description	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Winter
Pipeline Supplies													
Tennessee Long-Haul Pipeline Path	281,181	316,267	264,227	240,554	280,537	10,660	0	0	0	0	0	0	1,393,425
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	35,028	38,781	0	0	0	0	0	0	0	188,901
Iroquois Receipts Pipeline Path	187,431	193,679	193,679	174,936	193,679	0	0	0	0	0	0	0	943,403
Tennessee Niagara Pipeline Path	54,349	56,161	56,161	50,726	56,161	54,349	56,161	54,349	56,161	56,161	54,349	56,161	327,906
Atlantic Bridge Ramapo Pipeline Path	175,110	180,947	180,947	163,436	180,947	175,110	180,947	175,110	180,947	180,947	175,110	180,947	1,056,497
PXP Dawn Pipeline Path	227,792	240,125	240,125	216,887	240,125	52,641	0	0	0	0	0	0	1,217,695
WXP Dawn Pipeline Path	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Pipeline	963,393	1,025,960	973,919	881,566	990,229	292,760	237,108	229,459	237,108	237,108	229,459	237,108	5,127,827
Underground Storage													
Tennessee Storage	0	66,386	66,386	59,632	14,438	0	0	0	0	0	0	0	206,842
TGP Zone 4 300 Leg Supply	64,244	0	0	330	51,947	64,244	66,386	64,244	66,386	66,386	64,244	66,386	180,766
Tennessee FS-MA Storage Path	64,244	66,386	66,386	59,961	66,386	64,244	66,386	64,244	66,386	66,386	64,244	66,386	387,608
Union Dawn Storage	334,018	664,818	747,767	810,716	584,350	0	0	0	0	0	0	0	3,141,670
Dawn Supply	0	0	0	7,166	27,942	746,591	320,425	133,836	92,313	97,584	132,390	415,365	781,700
Union Dawn Storage Path	334,018	664,818	747,767	817,882	612,292	746,591	320,425	133,836	92,313	97,584	132,390	415,365	3,923,369
Subtotal Storage	398,262	731,204	814,153	877,844	678,678	810,836	386,811	198,080	158,699	163,970	196,634	481,751	4,310,977
Peaking Supplies													
Lewiston LNG	1,794	1,854	1,854	1,674	1,854	1,794	1,860	1,800	1,860	1,860	1,800	1,860	10,824
PNGTS Delivered (Dec - Feb)	0	77,229	77,229	69,755	0	0	0	0	0	0	0	0	224,213
Peaking Contract 1	0	13,649	243,664	11,017	261	0	0	0	0	0	0	0	268,591
Peaking Contract 2	0	42,181	104,918	87,560	64,291	0	0	0	0	0	0	0	298,950
Incremental Delivered Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Peaking	1,794	134,913	427,664	170,007	66,406	1,794	1,860	1,800	1,860	1,860	1,800	1,860	802,578
Total Delivered (Dth)	1,363,449	1,892,076	2,215,737	1,929,417	1,735,313	1,105,390	625,779	429,339	397,667	402,938	427,893	720,719	10,241,382

Northern Utilities, Inc.
Design Year Sendout Volumes (Dth)
Planning Load
November 2021 through October 2022

Description	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Winter
Pipeline Supplies													
Tennessee Long-Haul Pipeline Path	355,539	406,378	406,378	367,051	406,378	0	0	0	0	0	0	0	1,941,723
Algonquin Receipts Pipeline Path	37,530	38,781	38,781	35,028	38,781	37,530	38,781	37,530	38,781	38,781	37,530	38,781	226,431
Iroquois Receipts Pipeline Path	193,021	199,455	199,455	180,153	199,455	0	0	0	0	0	0	0	971,541
Tennessee Niagara Pipeline Path	69,805	72,132	72,132	65,151	72,132	69,805	69,384	60,774	53,825	72,132	69,805	72,132	421,156
Atlantic Bridge Ramapo Pipeline Path	225,000	232,500	232,500	210,000	232,500	225,000	232,500	225,000	232,500	232,500	225,000	232,500	1,357,500
PXP Dawn Pipeline Path	291,718	308,574	308,574	278,712	308,574	11,515	0	0	0	0	0	0	1,507,666
WXP Dawn Pipeline Path	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Pipeline	1,172,613	1,257,819	1,257,819	1,136,095	1,257,819	343,850	340,665	323,304	325,106	343,413	332,335	343,413	6,426,016
Underground Storage													
Tennessee Storage	0	81,955	81,955	73,607	17,760	0	0	0	0	0	0	0	255,276
TGP Zone 4 300 Leg Supply	79,311	0	0	417	64,196	79,311	81,955	79,311	81,955	81,955	79,311	81,955	223,236
Tennessee FS-MA Storage Path	79,311	81,955	81,955	74,024	81,955	79,311	81,955	79,311	81,955	81,955	79,311	81,955	478,512
Union Dawn Storage	384,599	867,675	1,034,348	960,599	630,109	0	0	0	0	0	0	0	3,877,329
Dawn Supply	0	0	0	71,125	162,753	793,077	270,139	24,877	0	2,737	102,054	463,431	1,026,955
Union Dawn Storage Path	384,599	867,675	1,034,348	1,031,724	792,862	793,077	270,139	24,877	0	2,737	102,054	463,431	4,904,284
Subtotal Storage	463,910	949,630	1,116,303	1,105,748	874,817	872,388	352,094	104,188	81,955	84,692	181,365	545,386	5,382,797
Peaking Supplies													
Lewiston LNG	1,794	1,854	35,371	9,634	13,513	1,794	1,860	1,800	1,860	1,860	1,800	1,860	63,960
PNGTS Delivered (Dec - Feb)	0	77,229	77,229	69,755	0	0	0	0	0	0	0	0	224,213
Peaking Contract 1	0	33,640	208,002	88,429	38,427	0	0	0	0	0	0	0	368,498
Peaking Contract 2	0	50,431	153,400	95,120	0	0	0	0	0	0	0	0	298,950
Incremental Delivered Supplies	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Peaking	1,794	163,153	474,002	262,937	51,940	1,794	1,860	1,800	1,860	1,860	1,800	1,860	955,620
Total Delivered (Dth)	1,638,317	2,370,603	2,848,124	2,504,780	2,184,576	1,218,032	694,618	429,292	408,921	429,965	515,500	890,659	12,764,433

Northern Utilities, Inc.
Normal Year Capacity Utilization (Dth)
Sales Service and Company Managed Sales Sendout
November 2021 through October 2022

Description	Winter Projected Volume (Dth)	Winter Maximum Volume (Dth)	Winter Capacity Utilization	Summer Projected Volume (Dth)	Summer Maximum Volume (Dth)	Summer Capacity Utilization	Annual Projected Volume (Dth)	Annual Maximum Volume (Dth)	Annual Capacity Utilization
Pipeline Supplies									
Tennessee Long-Haul Pipeline Path	1,393,425	1,846,592	75%	0	1,877,199	0%	1,393,425	3,723,791	37%
Algonquin Receipts Pipeline Path	188,901	226,431	83%	0	230,184	0%	188,901	456,615	41%
Iroquois Receipts Pipeline Path	943,403	1,123,542	84%	0	1,142,371	0%	943,403	2,265,913	42%
Tennessee Niagara Pipeline Path	327,906	327,906	100%	333,341	333,341	100%	661,247	661,248	100%
Atlantic Bridge Ramapo Pipeline Path	1,056,497	1,056,497	100%	1,074,008	1,074,008	100%	2,130,505	2,130,505	100%
PXP Dawn Pipeline Path	1,217,695	1,403,612	87%	0	1,426,876	0%	1,217,695	2,830,489	43%
Subtotal Pipeline	5,127,827	5,984,580	86%	1,407,349	6,083,979	23%	6,535,176	12,068,560	54%
Underground Storage									
Tennessee Storage	206,842			0			206,842		
TGP Zone 4 300 Leg Supply	180,766			394,032			574,798		
Tennessee FS-MA Storage Path	387,608	387,608	100%	394,032	394,032	100%	781,640	781,640	100%
Union Dawn Storage	3,141,670			0			3,141,670		
Dawn Supply	781,700			1,191,914			1,973,613		
Union Dawn Storage Path	3,923,369	5,846,219	67%	1,191,914	5,943,118	20%	5,115,283	11,789,337	43%
Subtotal Storage	4,310,977	6,233,827	69%	1,585,946	6,337,150	25%	5,896,923	12,570,976	47%
Peaking Supplies									
Lewiston LNG	10,824	113,960	9%	11,040	11,040	100%	21,864	125,000	17%
PNGTS Delivered (Dec - Feb)	224,213	224,213	100%	0	0		224,213	224,213	
Peaking Contract 1	268,591	597,900	45%	0	0		268,591	597,900	
Peaking Contract 2	298,950	298,950	100%	0	0		298,950	298,950	
Subtotal Peaking	802,578	1,235,023	65%	11,040	11,040	100%	813,618	1,246,063	65%
Portfolio Utilization	10,241,382	13,453,429	76%	3,004,335	12,432,169	24%	13,245,717	25,885,598	51%
Incremental Delivered Supplies	0	N/A		0	N/A		0	N/A	
Total Delivered	10,241,382	N/A		3,004,335	N/A		13,245,717	N/A	

Northern Utilities, Inc.
Design Year Capacity Utilization
Planning Load
November 2021 through October 2022

Description	Winter Projected Volume (Dth)	Winter Maximum Volume (Dth)	Winter Capacity Utilization	Summer Projected Volume (Dth)	Summer Maximum Volume (Dth)	Summer Capacity Utilization	Annual Projected Volume (Dth)	Annual Maximum Volume (Dth)	Annual Capacity Utilization
Pipeline Supplies									
Tennessee Long-Haul Pipeline Path	1,941,723	2,372,721	82%	0	2,412,048	0%	1,941,723	4,784,770	41%
Algonquin Receipts Pipeline Path	226,431	226,431	100%	230,184	230,184	100%	456,615	456,615	100%
Iroquois Receipts Pipeline Path	971,541	1,157,270	84%	0	1,176,659	0%	971,541	2,333,929	42%
Tennessee Niagara Pipeline Path	421,156	421,156	100%	398,051	428,136	93%	819,207	849,292	96%
Atlantic Bridge Ramapo Pipeline Path	1,357,500	1,357,500	100%	1,380,000	1,380,000	100%	2,737,500	2,737,500	100%
PXP Dawn Pipeline Path	1,507,666	1,803,665	84%	0	1,833,560	0%	1,507,666	3,637,225	41%
Subtotal Pipeline	6,426,016	7,338,743	88%	2,008,235	7,460,587	27%	8,434,251	14,799,330	57%
Underground Storage									
Tennessee Storage	255,276			0			255,276		
TGP Zone 4 300 Leg Supply	223,236			486,443			709,679		
Tennessee FS-MA Storage Path	478,512	478,512	100%	486,443	486,443	100%	964,956	964,956	100%
Union Dawn Storage	3,877,329			0			3,877,329		
Dawn Supply	1,026,955			863,237			1,890,192		
Union Dawn Storage Path	4,904,284	7,215,201	68%	863,237	7,334,790	12%	5,767,521	14,549,991	40%
Subtotal Storage	5,382,797	7,693,713	70%	1,349,681	7,821,233	17%	6,732,477	15,514,946	43%
Peaking Supplies									
Lewiston LNG	63,960	63,960	100%	11,040	11,040	100%	75,000	75,000	100%
PNGTS Delivered (Dec - Feb)	224,213	224,213	100%	0	0		224,213	224,213	
Peaking Contract 1	368,498	597,900	62%	0	0		368,498	597,900	
Peaking Contract 2	298,950	298,950	100%	0	0		298,950	298,950	
Subtotal Peaking	955,620	1,185,023	81%	11,040	11,040	100%	966,660	1,196,063	81%
Portfolio Utilization	12,764,433	16,217,479	79%	3,368,955	15,292,860	22%	16,133,388	31,510,339	51%
Incremental Delivered Supplies	0	N/A		0	N/A		0	N/A	
Total Delivered	12,764,433	N/A		3,368,955	N/A		16,133,388	N/A	

Northern Utilities Inc.
Forecast of Upcoming Winter Period Design Day Report
2021 / 2022 Winter Period
(Therms)

Demand	
NH Firm Sales	501,240
NH Non-Capacity Exempt Transportation	154,160
NH Capacity Exempt Transportation	109,730
NH Interruptible Sales	0
NH Interruptible Transportation	0
NH Design Day Demand	765,130
ME Firm Sales	693,200
ME Non-Capacity Exempt Transportation	142,180
ME Capacity Exempt Transportation	121,070
ME Interruptible Sales	0
ME Interruptible Transportation	0
ME Design Day Demand	956,450
Total Firm Sales	1,194,440
Total Non-Capacity Exempt Transportation	296,340
Total Capacity Exempt Transportation	230,800
Total Interruptible Sales	0
Total Interruptible Transportation	0
Total Design Day Demand	1,721,580
Supplies	
Capacity Exempt Transportation	230,800
Additional Supplies Required for Non-Capacity Exempt Transporta	113,360
Pipeline	405,860
Storage	425,070
On-System LNG	65,000
Off-System Peaking Contracts & Delivered Baseload	523,163
Additional Granite Capacity	9,350
Total	1,772,603

Effective Degree Day	
New Hampshire	80.2
Maine	78.6
Probability	1 in 30

Report Prepared By	Francis X. Wells
Title	Manager, Energy Planning
Signature	Fran X Wells

Northern Utilities Inc.
New Hampshire 7 Day Cold Snap Analysis
Winter 2019-2020

Coldest 7 Consecutive Days
Based on historic Portsmouth weather data

Date	EDD
February 11, 1979	68
February 12, 1979	60
February 13, 1979	73
February 14, 1979	73
February 15, 1979	64
February 16, 1979	69
February 17, 1979	72
Total	479

Maximum Projected Design Week Demand (Dth)

Daily Baseload	3,793
Weekly Baseload	26,554
Heating Increment*	715
Effective Degree Days	479
Total Heat Load	342,423
Projected Cold Snap Demand	368,977

New Hampshire Allocation **40.99%**
Based on the latest demand cost allocator in the Winter COG filing.

Maximum Supply Capability (Dth)

Amount to be Supplied by Natural Gas Pipelines	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
PXP Dawn Hub	9,965
Atlantic Bridge Ramapo	7,500
Tennessee Firm Storage	2,644
Union Dawn Storage	39,863
Peaking Contract 1	39,860
Peaking Contract 2	9,965
PNGTS Dec - Feb	2,491
Total Daily Pipeline	135,409
Pipeline for 7 days	947,863
New Hampshire Allocation	388,529

Available LNG Storage

Facility	Gallons	Dth
Lewiston LNG	145,134	12,140
Total	145,134	12,140
New Hampshire Allocation - 7 Days		4,976

LNG Delivery Contract

Northern Utilities plans to secure a contract for LNG Delivery for up to three loads of LNG per day.

The storage credit for LNG is calculated as follows:

Number of Days	7
Number of Loads	3
Delivery Reliability	70%
Assumed Number of LNG Deliveries	15
Dth Per Load	900
Total Storage Credit	13,230
NH Storage Credit - 7 Days	5,423

Summary	
Maximum projected design week demand	368,977
Amount to be furnished by natural gas pipeline	388,529
Remaining Balance	-19,552
Storage available	4,976
Credit from LNG delivery supply contract	5,423
Total available storage and LNG deliveries	10,399
Net Surplus/(Deficiency)	**29,951**

Report Prepared By	Francis X. Wells
Title	Manager, Energy Planning
Signature	Fran X Wells

Northern Utilities, Inc.
New Hampshire Division
Migration to Transportation Only Service by Rate Class
November 2021 through October 2022

C&I Rate Class	Annual Sales Service Deliveries (Dth)	Percentage of Sales Service Total by Rate Class	Sales Service Percentage by Rate Class
G40	983,033	41%	86%
G50	156,605	7%	84%
G41	765,997	32%	50%
G51	249,241	10%	49%
G42	161,855	7%	27%
G52	63,141	3%	4%
Special Contracts	-	0%	0%
Total C&I	2,379,872	100%	33%

C&I Rate Class	Annual Transport-Only Deliveries (Dth)	Percentage of Transport Only Total by Rate Class	Transportation Service Percentage by Rate Class
G40	157,376	3%	14%
G50	30,275	1%	16%
G41	772,150	16%	50%
G51	264,658	6%	52%
G42	433,200	9%	73%
G52	1,740,881	37%	97%
Special Contracts	1,346,530	28%	100%
Total C&I	4,745,071	100%	67%

C&I Rate Class	Annual Total Deliveries (Dth)	Percentage of Total by Rate Class
G40	1,140,409	16%
G50	186,880	3%
G41	1,538,147	22%
G51	513,900	7%
G42	595,055	8%
G52	1,804,022	25%
Special Contracts	1,346,530	19%
Total C&I	7,124,944	100%

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
Gas Assistance Program and Regulatory Assessment (GAPRA)

1	Peak Period	**Customer Charge**	**First Block**	**Last Block**	**Cost of Gas**	**Total**
2	R-10 Base Rates	$22.20	$0.6920	$0.6920	$0.9392	
3	R-10 Rate Discounted 45%	$12.21	$0.3806	$0.3806	$0.5166	
4	Program Subsidy	$9.99	$0.3114	$0.3114	$0.4226	
5	Average Winter Therms		271	293	564	
6						
7	Peak Period Subsidy	$59.94	$84.30	$91.33	$238.37	$473.94
8						
9						
10	Number of Estimated 2021/2022 Participants (1)					694
11						
12	Annual Subsidy times Number of Participants (Ln 7 * Ln 10)					$328,913
13	Prior Year Ending Balance 10/31/2021 - GAPRA Page 2					$26,008
14	Estimated Annual Administrative Costs					$0
15	Estimated Non-Distribution Regulatory Assessment (Based on NHPUC invoice dated August 19, 2020)					$116,230
16	Total Program Costs					$471,152
17						
18	Estimated weather normalized firm therms billed for					
19	the twelve months ended 10/31/22 sales and transportation					78,231,768
20	(Attachment NUI-FXW-2, Page 2 of 4, "Total Division"					
21	minus "Special Contracts").					
22	**Total Gas Assistance Program and Regulatory Assessment Charge**					**$0.0060**

(1) Based on actual prior winter period particiption.

Northern Utilities, Inc.
New Hampshire Division
Attachment NUI-SED-1 - GAPRA
Page 1 of 3

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
NOVEMBER 2020 THROUGH OCTOBER 2021
GAS ASSISTANCE PROGRAM AND REGIULATORY ASSESSMENT (GAPRA) RECONCILIATION

				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
1	**FOR THE MONTH OF:**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
2	**DAYS IN MONTH**	30	31	31	28	31	30	31	30	31	31	30	31	365
3														**Average**
4	GAPRA Participant Count	638	651	660	676	761	780	745	607	673	662	650	649	679
5														**Total**
6	Beginning Balance	($46,110)	($40,399)	($30,867)	($20,518)	($4,136)	$26,505	$46,388	$49,257	$43,903	$37,320	$35,097	$32,459	($46,110)
7														
8	Add: Actual Costs	$21,680	$39,553	$48,032	$57,968	$70,145	$40,179	$16,330	$756	$0	$0	$0	$0	$294,644
9														
10	Add: Regulatory Assessments	$6,893	$6,893	$6,893	$6,893	$6,893	$6,893	$6,893	$6,893	$5,292	$9,686	$9,686	$9,686	$89,494
11														
12	Less: Collected Revenue	$22,745	$36,817	$44,508	$48,446	$46,428	$27,287	$20,483	$13,128	$11,985	$12,006	$12,416	$16,215	($312,465)
13														
14	Add: Administrative and Start Up Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15														
16	Ending Balance Pre-Interest	($40,282)	($30,770)	($20,449)	($4,103)	$26,474	$46,289	$49,127	$43,777	$37,210	$34,999	$32,367	$25,929	
17														
18	Month's Average Balance	($43,196)	($35,585)	($25,658)	($12,311)	$11,169	$36,397	$47,757	$46,517	$40,557	$36,160	$33,732	$29,194	
19														
20	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
21														
22	Interest Applied	($117)	($96)	($69)	($33)	$30	$99	$129	$126	$110	$98	$91	$79	
23														
24	Ending Balance	($40,399)	($30,867)	($20,518)	($4,136)	$26,505	$46,388	$49,257	$43,903	$37,320	$35,097	$32,459	**$26,008**	

() Over Collection

NORTHERN UTILITIES, INC., NEW HAMPSHIRE DIVISION
Calculation of Distribution and Non-Distribution Revenues of the NHPUC Annual Regulatory Assessment
NHPUC Assessment Invoice dated August 19, 2020

	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021	January 2022	February 2022	March 2022	April 2022	May 2022	June 2022	Total Fiscal Year	
Distribution	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$30,747.00	$368,964.00	1
Non-Distribution	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$9,685.83	$116,230.00	2
Total		$121,298.50			$121,298.50			$121,298.50			$121,298.50		$485,194.00	

(1) The $368,964.00 for Distribution represents the amount established in Docket DG 17-070.
(2) Total Invoice amount minus Distribution amount.

Northern Utilities, Inc. -- New Hampshire Division

EEC Budget

	Residential	Low-Income	Gen Service	Total
July-21	$33,412	$24,892	$39,983	$98,287
August-21	$27,081	$33,203	$156,828	$217,112
September-21	$54,162	$66,406	$171,085	$291,653
October-21	$38,687	$47,433	$185,342	$271,462
November-21	$30,950	$37,946	$171,085	$239,981
December-21	$30,950	$37,946	$213,857	$282,753
January-22	$25,558	$12,390	$46,568	$84,517
February-22	$42,597	$20,650	$46,568	$109,816
March-22	$51,117	$24,780	$69,852	$145,749
April-22	$59,636	$28,910	$81,495	$170,041
May-22	$59,636	$28,910	$46,568	$135,115
June-22	$102,234	$49,560	$58,210	$210,004
July-22	$110,753	$53,690	$81,495	$245,938
August-22	$59,636	$28,910	$128,063	$216,609
September-22	$119,273	$57,820	$139,705	$316,798
October-22	$85,195	$41,300	$151,347	$277,842
Total	$930,878	$594,747	$1,788,053	$3,313,677

Budget with Low-Income Costs Allocated to Residential and General Service Classes

	Residential	Low-Income	Gen Service	Total
July-21	$36,541	0	$61,746	$98,287
August-21	$31,373	0	$185,739	$217,112
September-21	$63,062	0	$228,591	$291,653
October-21	$46,254	0	$225,208	$271,462
November-21	$40,169	0	$199,812	$239,981
December-21	$41,958	0	$240,795	$282,753
January-22	$29,331	0	$55,185	$84,517
February-22	$49,145	0	$60,671	$109,816
March-22	$58,389	0	$87,361	$145,749
April-22	$67,980	0	$102,061	$170,041
May-22	$66,709	0	$68,406	$135,115
June-22	$111,440	0	$98,565	$210,004
July-22	$118,357	0	$127,581	$245,938
August-22	$63,303	0	$153,306	$216,609
September-22	$126,895	0	$189,902	$316,798
October-22	$91,707	0	$186,135	$277,842
Total	$1,042,614	$0	$2,271,064	$3,313,677

EEC Charge Factor Calculation

EEC Charge Factors for Residential Customers	**Effective** November 1, 2021	
EEC Reconciliation Adjustment	($1,137)	Attachment NUI-SED-1 EEC Page 3 Nov '21 Beginning Balance
EEC Costs	$777,537	Attachment NUI-SED-1 EEC Page 3 Nov '21 Beginning Balance
EEC Performance Incentive	$48,587	Attachment NUI-SED-1 EEC Page 3 Nov '21 - Oct '22 Totals; Company Budget
EEC Low-Income Costs	$87,847	Attachmnet NUI-SED-1 EEC Page 3 Nov '21 - Oct '22 Totals; Company Budget
EEC Allocated Low-Income Performance Incentive	$5,364	Attachment NUI-SED-1 EEC Page 3 Nov '21 - Oct '22 Totals; Company Budget
Total	$918,197	
Forecasted Annual Throughput Volumes for Residential Customers	20,447,634	Attachment NUI-SED-1 EEC Page 3 Nov '21 - Oct '22 Totals; Company Forecast
Energy Efficiency Charge Factor for Residential Customers	**$0.0449**	

EEC Charge Factors for Commercial and Industrial Customers (C&I)		
EEC Reconciliation Adjustment	($279,480)	Attachment NUI-SED-1 EEC Page 4 Nov '21 Beginning Balance
EEC Costs	$1,234,814	Attachment NUI-SED-1 EEC Page 4 Nov '21 - Oct '22 Totals; Company Budget
EEC Performance Incentive	$67,041	Attachment NUI-SED-1 EEC Page 4 Nov '21 - Oct '22 Totals; Company Budget
EEC Low-Income Costs	$334,966	Attachment NUI-SED-1 EEC Page 4 Nov '21 - Oct '22 Totals; Company Budget
EEC Allocated Low-Income Performance Incentive	$18,124	Attachment NUI-SED-1 EEC Page 4 Nov '21 - Oct '22 Totals; Company Budget
Total	$1,375,466	
Forecasted Annual Throughput Volumes for C&I Customers	57,784,135	Attachment NUI-SED-1 EEC Page 4 Nov '21 - Oct '22 Totals; Company Forecast
Energy Efficiency Charge Factor for C&I Customers	**$0.0238**	

Northern Utilities, Inc.

New Hampshire Division

Calculation of the EEC Charge, a Component of the Local Distribution Adjustment Charge

To Be Effective November 1, 2021 through October 31, 2022

Residential Customers

		Beginning Balance (Over)/Under	EEC Rate per Therm	EEC Collections	EEC Costs	DSM PI	Allocated Low Income Costs	Allocated Low Income PI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-20	Actual	$106,805	$0.0499	$15,693	$73,181	$2,929	$1,176	$186	$168,585	$137,695	3.25%	$379.04	$168,964	314,514	31
September-20	Actual	$168,964	$0.0499	$20,232	$32,481	$2,929	$17,160	$196	$201,499	$185,232	3.25%	$493.45	$201,992	405,509	30
October-20	Actual	$201,992	$0.0499	$28,271	$127,745	$2,929	$1,385	$231	$306,012	$254,002	3.25%	$699.20	$306,711	566,516	31
November-20	Actual	$306,711	$0.0774	$80,520	$90,389	$2,929	$21,486	$332	$341,327	$324,019	3.25%	$863.17	$342,190	1,292,226	30
December-20	Actual	$342,190	$0.0774	$180,763	$64,517	$2,929	$2,615	$396	$231,884	$287,037	3.25%	$790.14	$232,675	2,335,492	31
January-21	Actual	$232,675	$0.0774	$236,745	$83,689	$5,057	$14,651	$752	$100,079	$166,377	3.25%	$459.25	$100,538	3,058,804	31
February-21	Actual	$100,538	$0.0774	$265,342	$98,676	$1,517	$5,488	$232	($58,890)	$20,824	3.25%	$46.57 (1)	($58,843)	3,428,187	28
March-21	Actual	($58,843)	$0.0774	$251,839	$122,027	$3,287	$18,711	$499	($166,159)	($112,501)	3.25%	($310.53)	($166,469)	3,253,751	31
April-21	Actual	($166,469)	$0.0774	$127,532	$63,474	$3,287	$2,596	$430	($224,215)	($195,342)	3.25%	($521.80)	($224,737)	1,647,540	30
May-21	Actual	($224,737)	$0.0774	$84,351	$146,008	$3,287	$4,533	$378	($154,882)	($189,809)	3.25%	($523.92)	($155,406)	1,089,621	31
June-21	Actual	($155,406)	$0.0774	$39,772	$122,835	$4,959 (1)	$1,603	($113)(1)	($65,894)	($110,650)	3.25%	$819.85 (1)	($65,074)	513,703	30
July-21	Actual	($65,074)	$0.0774	$29,128	$33,412	$3,287	$3,129	$203	($54,171)	($59,623)	3.25%	($622.79)(1)	($54,794)	376,131	31
August-21	Forecast	($54,794)	$0.0774	$27,305	$27,081	$4,769	$4,293	$295	($45,661)	($50,228)	3.25%	($138.64)	($45,800)	352,774	31
September-21	Forecast	($45,800)	$0.0774	$29,272	$54,162	$4,769	$8,900	$306	($6,935)	($26,367)	3.25%	($70.43)	($7,005)	378,189	30
October-21	Forecast	($7,005)	$0.0774	$45,507	$38,687	$4,769	$7,568	$364	($1,125)	($4,065)	3.25%	($11.22)	($1,137)	587,951	31
November-21	Forecast	($1,137)	$0.0449	$69,103	$30,950	$4,769	$9,220	$554	($24,747)	($12,942)	3.25%	($34.57)	($24,782)	1,539,048	30
December-21	Forecast	($24,782)	$0.0449	$117,580	$30,950	$4,769	$11,008	$661	($94,973)	($59,877)	3.25%	($165.28)	($95,138)	2,618,699	31
January-22	Forecast	($95,138)	$0.0449	$162,524	$25,558	$3,905	$3,773	$576	($223,849)	($159,494)	3.25%	($440.25)	($224,289)	3,619,686	31
February-22	Forecast	($224,289)	$0.0449	$175,051	$42,597	$3,905	$6,547	$600	($345,691)	($284,990)	3.25%	($710.52)	($346,402)	3,898,694	28
March-22	Forecast	($346,402)	$0.0449	$130,011	$51,117	$3,905	$7,272	$555	($413,563)	($379,982)	3.25%	($1,048.85)	($414,612)	2,895,562	31
April-22	Forecast	($414,612)	$0.0449	$98,906	$59,636	$3,905	$8,344	$546	($441,087)	($427,850)	3.25%	($1,142.89)	($442,230)	2,202,807	30
May-22	Forecast	($442,230)	$0.0449	$56,808	$59,636	$3,905	$7,072	$463	($427,961)	($435,095)	3.25%	($1,200.98)	($429,162)	1,265,203	31
June-22	Forecast	($429,162)	$0.0449	$28,229	$102,234	$3,905	$9,206	$352	($341,694)	($385,428)	3.25%	($1,029.57)	($342,724)	628,698	30
July-22	Forecast	($342,724)	$0.0449	$18,382	$110,753	$3,905	$7,603	$268	($238,577)	($290,650)	3.25%	($802.27)	($239,379)	409,403	31
August-22	Forecast	($239,379)	$0.0449	$16,443	$59,636	$3,905	$3,667	$240	($188,374)	($213,877)	3.25%	($590.36)	($188,964)	366,219	31
September-22	Forecast	($188,964)	$0.0449	$17,630	$119,273	$3,905	$7,622	$250	($75,545)	($132,254)	3.25%	($353.28)	($75,898)	392,644	30
October-22	Forecast	($75,898)	$0.0449	$27,433	$85,195	$3,905	$6,512	$298	($7,420)	($41,659)	3.25%	($114.99)	($7,535)	610,971	31
Nov 21 thru Oct 22 Totals				$918,099	$777,537	$48,587	$87,847	$5,364						20,447,634	

Forecast therm Sales from Company Forecast as seen in Attachment NUI-FXW-1.
Actual Performance Incentives includes reconciliations from prior year(s).
(1) Reflects interest adjustments associated with PI true-up and reclass of costs.

Northern Utilities, Inc.
NHPUC Docket No. DG 21-xxx
Attachment NUI-SED-1 EEC
Page 4 of 4

Northern Utilities, Inc.
New Hampshire Division
Calculation of the EEC Charge, a Component of the Local Distribution Adjustment Charge
To Be Effective November 1, 2021 through October 31, 2022
General Service Customers

		Beginning Balance (Over)/Under	EEC Rate per Therm	EEC Collections	EEC Costs	DSM PI	Allocated Low Income Costs	Allocated Low Income PI	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Prime Rate	Interest @ Prime Rate	Ending Balance plus Interest (Over)/Under	Therm Sales	# of Days
August-20	Actual	($243,312)	$0.0247	$51,545	$26,609	$4,002	$7,806	$1,234	($255,206)	($249,259)	3.25%	($686)	($255,892)	2,086,783	31
September-20	Actual	($255,892)	$0.0247	$62,445	$64,003	$4,002	$106,978	$1,223	($142,130)	($199,011)	3.25%	($530)	($142,660)	2,528,069	30
October-20	Actual	($142,660)	$0.0247	$72,461	$61,124	$4,002	$7,121	$1,189	($141,685)	($142,173)	3.25%	($391)	($142,077)	2,912,954	31
November-20	Actual	($142,077)	$0.0337	$131,454	$177,804	$4,002	$70,290	$1,087	($20,347)	($81,212)	3.25%	($216)	($20,564)	4,227,455	30
December-20	Actual	($20,564)	$0.0337	$203,275	$296,630	$4,002	$6,754	$1,023	$84,571	$32,004	3.25%	$88	$84,659	6,031,844	31
January-21	Actual	$84,659	$0.0337	$237,815	$20,764	$6,555	$33,793	$1,735	($90,309)	($2,825)	3.25%	($8)	($90,317)	7,055,251	31
February-21	Actual	($90,317)	$0.0337	$255,524	$39,131	$1,967	$12,113	$514	($292,116)	($191,217)	3.25%	($484)(1)	($292,601)	7,582,246	28
March-21	Actual	($292,601)	$0.0337	$245,940	$74,412	$4,261	$41,967	$1,118	($416,783)	($354,692)	3.25%	($979)	($417,762)	7,297,927	31
April-21	Actual	($417,762)	$0.0337	$153,469	$27,439	$4,261	$7,174	$1,187	($531,169)	($474,465)	3.25%	($1,267)	($532,436)	4,553,970	30
May-21	Actual	($532,436)	$0.0337	$120,178	$20,822	$4,261	$14,834	$1,238	($611,459)	($571,947)	3.25%	($1,579)	($613,037)	3,566,084	31
June-21	Actual	($613,037)	$0.0337	$83,292	$43,459	($6,936)(1)	$7,711	$2,096 (1)	($649,999)	($631,518)	3.25%	($2,101)(1)	($652,100)	2,471,584	30
July-21	Actual	($652,100)	$0.0337	$88,164	$39,983	$4,261	$21,763	$1,414	($672,843)	($662,472)	3.25%	($1,829)	($674,672)	2,616,202	31
August-21	Forecast	($674,672)	$0.0337	$80,069	$156,828	$6,841	$28,910	$1,985	($560,177)	($617,424)	3.25%	($1,704)	($561,881)	2,375,936	31
September-21	Forecast	($561,881)	$0.0337	$82,350	$171,085	$6,841	$57,506	$1,974	($406,825)	($484,353)	3.25%	($1,294)	($408,118)	2,443,631	30
October-21	Forecast	($408,118)	$0.0337	$104,378	$185,342	$6,841	$39,865	$1,916	($278,532)	($343,325)	3.25%	($948)	($279,480)	3,097,272	31
November-21	Forecast	($279,480)	$0.0238	$114,126	$171,085	$6,841	$28,726	$1,726	($185,227)	($232,353)	3.25%	($621)	($185,848)	4,795,193	30
December-21	Forecast	($185,848)	$0.0238	$152,513	$213,857	$6,841	$26,938	$1,618	($89,107)	($137,477)	3.25%	($379)	($89,486)	6,408,112	31
January-22	Forecast	($89,486)	$0.0238	$196,751	$46,568	$5,336	$8,617	$1,316	($224,400)	($156,943)	3.25%	($433)	($224,833)	8,266,852	31
February-22	Forecast	($224,833)	$0.0238	$199,861	$46,568	$5,336	$14,103	$1,293	($357,394)	($291,114)	3.25%	($726)	($358,120)	8,397,502	28
March-22	Forecast	($358,120)	$0.0238	$165,932	$69,852	$5,336	$17,508	$1,337	($430,018)	($394,069)	3.25%	($1,088)	($431,106)	6,971,920	31
April-22	Forecast	($431,106)	$0.0238	$129,225	$81,495	$5,336	$20,566	$1,347	($451,587)	($441,346)	3.25%	($1,179)	($452,766)	5,429,623	30
May-22	Forecast	($452,766)	$0.0238	$92,978	$46,568	$5,336	$21,838	$1,430	($470,572)	($461,669)	3.25%	($1,274)	($471,847)	3,906,651	31
June-22	Forecast	($471,847)	$0.0238	$65,592	$58,210	$5,336	$40,354	$1,541	($431,997)	($451,922)	3.25%	($1,207)	($433,204)	2,755,986	30
July-22	Forecast	($433,204)	$0.0238	$59,061	$81,495	$5,336	$46,087	$1,625	($357,723)	($395,463)	3.25%	($1,092)	($358,814)	2,481,573	31
August-22	Forecast	($358,814)	$0.0238	$60,003	$128,063	$5,336	$25,243	$1,653	($258,522)	($308,668)	3.25%	($852)	($259,374)	2,521,135	31
September-22	Forecast	($259,374)	$0.0238	$61,541	$139,705	$5,336	$50,198	$1,643	($124,034)	($191,704)	3.25%	($512)	($124,546)	2,585,748	30
October-22	Forecast	($124,546)	$0.0238	$77,679	$151,347	$5,336	$34,788	$1,594	($9,159)	($66,853)	3.25%	($185)	($9,344)	3,263,837	31
Nov 21 thru Oct 22 Totals				$1,375,262	$1,234,814	$67,041	$334,966	$18,124						57,784,134	

Forecast therm Sales from Company Forecast as seen in Attachment NUI-FXW-1. Does not include Special Contracts.
Actual Performance Incentives includes reconciliations from prior year(s).
(1) Reflects interst adjustments asoiated with PI true-up.

CALCULATION OF ENVIRONMENTAL RESPONSE COST RATE
November 1, 2021 through October 31, 2022

Total ERC Costs for the Period	$432,594	(See 2021 ERC Invoice Filing, Schedule 1)
Less Current (Over)/Under Collection (Estimated)	$3,446	(See page 2 of 2)
Total ERC Cost to be Recovered	$436,040	
Forcasted Firm Sales & Firm Transportation Volumes (Attachment NUI-FXW-2, Page 2 of 4, "Total Division" subtract "Special Contracts").	78,231,768	
ERC Recovery Rate	**$0.0056**	

Northern Utilities, Inc. - New Hampshire Division
Environmental Response Cost 12 Month Reconciliation

Month	Actual or Forecast	Beginning Balance (Over)/Under	Revenue	Prior Period ERC Costs To be recovered	Ending Balance (Over)/Under
November-'20	Actual	$21,166	$32,902	$418,530	$406,794
December	Actual	$406,794	$51,043		$355,751
January- '21	Actual	$355,751	$61,701		$294,050
February	Actual	$294,050	$67,167		$226,883
March	Actual	$226,883	$64,367		$162,516
April	Actual	$162,516	$37,834		$124,683
May	Actual	$124,683	$28,409		$96,273
June	Actual	$96,273	$18,225		$78,048
July	Actual	$78,048	$18,264		$59,784
August	Est.	$59,784	$16,645		$43,139
September	Est.	$43,139	$17,213		$25,926
October	Est.	$25,926	$22,480		$3,446

Northern Utilities, Inc.
Calculation of Lost Revenue Rate (LRR)

Line	Sector		Effective November 1, 2021	Reference
	Residential Classes- R5, R6, R10, R11			
1	Sector Ending Balance-October 31	$	22,628	Page 2a, Ln 2
2	Lost Distribution Revenue-November through October		111,533	Page 2a, Ln 4, Total
3	Interest- November through October		86	Page 2a, Ln 17, Total
4	**Total to be recovered**	**$**	**134,247**	Line 1 + Line 2 + Line 3
5	Sector Sales - Therms- November through October		20,447,634	Page 2a, Line 7
6	**Lost Revenue Rate ($ per therm)**		**$0.0066**	Line 4 / Line 5
	Commercial & Industrial Classes-G40/T40, G50/T50, G41/T41, G51/T51, G42/T42, G-52/T52			
7	Sector Ending Balance-October 31		(24,617)	Page 2a, Ln 21
8	Lost Distribution Revenue-November through October	$	61,769	Page 2a, Ln 24, Total
9	Interest- November through October	$	(178)	Page 2a, Ln 37, Total
10	**Total to be recovered**	**$**	**36,973**	Line 7 + Line 8 + Line 9
11	Sector Sales - Therms- November through October		57,784,134	Page 2a, Line 27
12	**Lost Revenue Rate ($ per therm)**		**$0.0006**	Line 10 / Line 11

Northern Utilities, Inc.
Lost Revenue Reconciliation
2021

Line	Sector / Description	Unit	Recast Nov-20	Recast Dec-20	Recast Jan-21	Recast Feb-21	Recast Mar-21	Recast Apr-21	Recast May-21	Recast Jun-21	Recast Jul-21	Recast Aug-21	Recast Sep-21	Recast Oct-21	Total
1	**RESIDENTIAL**														
2	**Beginning Balance - (Over)/Under**	$'s	$ 98,969	$ 105,697	$ 83,059	$ 44,526	$ (2,062)	$ (44,644)	$ (51,570)	$ (49,246)	$ (33,707)	$ (14,493)	$ 5,979	$ 26,715	
3	**COSTS**														
4	Lost Distribution Revenue (Page 3, Line 23)	**$'s**	$ 27,365	$ 28,485	$ 28,583	$ 28,780	$ 29,067	$ 29,453	$ 26,442	$ 26,956	$ 27,557	$ 28,245	$ 29,013	$ 8,780	$318,725
5															
6	**REVENUE**														
7	Sector Sales	Therms	1,292,226	2,335,492	3,058,804	3,428,187	3,253,751	1,647,540	1,089,621	513,703	376,131	352,774	378,189	587,951	18,314,368
8	Lost Revenue Rate	$/Therm	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	$0.0220	
9	Revenue	**$'s**	$ 20,909	$ 51,382	$ 67,293	$ 75,421	$ 71,584	$ 36,251	$ 23,978	$ 11,307	$ 8,277	$ 7,761	$ 8,320	$ 12,935	395,417
10															
11	(Over)/Under-Recovery (Exc interest)	**$**	$ 105,425	$ 82,800	$ 44,350	$ (2,115)	$ (44,580)	$ (51,442)	$ (49,107)	$ (33,597)	$ (14,427)	$ 5,990	$ 26,671	$ 22,560	
12															
13	**INTEREST**														
14	Average Monthly Balance		$ 102,197	$ 94,249	$ 63,705	$ 21,205	$ (23,321)	$ (48,043)	$ (50,339)	$ (41,421)	$ (24,067)	$ (4,252)	$ 16,325	$ 24,638	
15	Interest Rate-WSJ Prime Rate	Annual %	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16	Days per Month		30	31	31	28	31	30	31	30	31	31	30	31	365
17	Computed Interest	$'s	$ 272	$ 259	$ 176	$ 53	$ (64)	$ (128)	$ (139)	$ (111)	$ (66)	$ (12)	$ 44	$ 68	$ 352
18															
19	**Ending Balance**	**$'s**	$ 105,697	$ 83,059	$ 44,526	$ (2,062)	$ (44,644)	$ (51,570)	$ (49,246)	$ (33,707)	$ (14,493)	$ 5,979	$ 26,715	$ 22,628	
20	**COMMERCIAL & INDUSTRIAL**														
21	**Beginning Balance - (Over)/Under**	**$'s**	$ (12,347)	$ (10,783)	$ (13,578)	$ (19,216)	$ (26,322)	$ (32,427)	$ (30,070)	$ (30,985)	$ (28,400)	$ (26,000)	$ (22,590)	$ (19,059)	
22															
23	**COSTS**														
24	Lost Distribution Revenue (Page 3, Line 36)	**$'s**	$ 12,930	$ 15,335	$ 15,580	$ 15,698	$ 15,870	$ 16,101	$ 9,868	$ 10,078	$ 10,323	$ 10,604	$ 10,918	$ 3,793	147,099
25															
26	**REVENUE**														
27	Sector Sales	Therms	4,273,046	5,887,088	7,167,043	7,641,797	6,930,321	5,063,577	3,549,981	2,467,336	2,179,685	2,375,936	2,443,631	3,097,272	53,076,714
28	Lost Revenue Rate	$/Therm	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	$0.0030	
29	Revenue	**$'s**	$ 11,336	$ 18,096	$ 21,173	$ 22,747	$ 21,894	$ 13,662	$ 10,698	$ 7,414	$ 7,848	$ 7,128	$ 7,331	$ 9,292	158,619
30															
31	(Over)/Under-Recovery (Exc interest)	$'s	$ (10,753)	$ (13,544)	$ (19,171)	$ (26,265)	$ (32,346)	$ (29,987)	$ (30,901)	$ (28,321)	$ (25,925)	$ (22,524)	$ (19,003)	$ (24,557)	
32															
33	**INTEREST**														
34	Average Monthly Balance		$ (11,550)	$ (12,164)	$ (16,374)	$ (22,740)	$ (29,334)	$ (31,207)	$ (30,486)	$ (29,653)	$ (27,163)	$ (24,262)	$ (20,797)	$ (21,808)	
35	Interest Rate-WSJ Prime Rate	Annual %	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
36	Days per Month		30	31	31	28	31	30	31	30	31	31	30	31	365
37	Computed Interest	$'s	$ (31)	$ (33)	$ (45)	$ (57)	$ (81)	$ (83)	$ (84)	$ (79)	$ (75)	$ (67)	$ (56)	$ (60)	$ (752)
38															
39	**Ending Balance**	**$'s**	$ (10,783)	$ (13,578)	$ (19,216)	$ (26,322)	$ (32,427)	$ (30,070)	$ (30,985)	$ (28,400)	$ (26,000)	$ (22,590)	$ (19,059)	$ (24,617)	

Northern Utilities, Inc.
Lost Revenue Reconciliation
2022

Line	Sector / Description	Unit	Estimate Nov-21	Estimate Dec-21	Estimate Jan-22	Estimate Feb-22	Estimate Mar-22	Estimate Apr-22	Estimate May-22	Estimate Jun-22	Estimate Jul-22	Estimate Aug-22	Estimate Sep-22	Estimate Oct-22	Total
1	**RESIDENTIAL**														
2	**Beginning Balance - (Over)/Under**	$'s	$ 22,628	$ 23,539	$ 18,484.55	$ 6,899	$ (6,366)	$ (12,749)	$ (14,185)	$ (10,537)	$ (2,156)	$ 8,298	$ 5,900	$ 3,321	
3	**COSTS**														
4	Lost Distribution Revenue (Page 3a, Line 20)	**$'s**	$ 11,007	$ 12,171	$ 12,269	$ 12,466	$ 12,753	$ 13,139	$ 12,032	$ 12,547	$ 13,148	$ -	$ -	$ -	$111,533
5															
6	**REVENUE**														
7	Sector Sales	Therms	1,539,048	2,618,699	3,619,686	3,898,694	2,895,562	2,202,807	1,265,203	628,698	409,403	366,219	392,644	610,971	20,447,634
8	Lost Revenue Rate (Page 1, L. 6	$/Therm	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	$0.0066	
9	Revenue	**$'s**	$ 10,158	$ 17,283	$ 23,890	$ 25,731	$ 19,111	$ 14,539	$ 8,350	$ 4,149	$ 2,702	$ 2,417	$ 2,591	$ 4,032	134,954
10															
11	(Over)/Under-Recovery (Exc interest)	**$**	$ 23,477	$ 18,427	$ 6,864	$ (6,366)	$ (12,723)	$ (14,149)	$ (10,503)	$ (2,140)	$ 8,289	$ 5,881	$ 3,309	$ (711)	
12															
13	**INTEREST**														
14	Average Monthly Balance		$ 23,053	$ 20,983	$ 12,674	$ 266	$ (9,544)	$ (13,449)	$ (12,344)	$ (6,338)	$ 3,066	$ 7,089	$ 4,604	$ 1,305	
15	Interest Rate-WSJ Prime Rate	Annual %	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16	Days per Month		30	31	31	28	31	30	31	30	31	31	30	31	365
17	Computed Interest	$'s	$ 62	$ 58	$ 35	$ 1	$ (26)	$ (36)	$ (34)	$ (17)	$ 8	$ 20	$ 12	$ 4	$ 86
18															
19	**Ending Balance**	**$'s**	$ 23,539	$ 18,485	$ 6,899	$ (6,366)	$ (12,749)	$ (14,185)	$ (10,537)	$ (2,156)	$ 8,298	$ 5,900	$ 3,321	$ (708)	
20	**COMMERCIAL & INDUSTRIAL**														
21	**Beginning Balance - (Over)/Under**	**$'s**	$ (24,617)	$ (20,698)	$ (17,049.35)	$ (14,449)	$ (11,799)	$ (8,119)	$ (3,273)	$ (500)	$ 3,182	$ 7,285	$ 5,790	$ 4,252	
22															
23	**COSTS**														
24	Lost Distribution Revenue (Page 3a, Line 33)	**$'s**	$ 6,857	$ 7,546	$ 7,604	$ 7,721	$ 7,891	$ 8,119	$ 5,122	$ 5,332	$ 5,577	$ -	$ -	$ -	61,769
25															
26	**REVENUE**														
27	Sector Sales	Therms	4,795,193	6,408,112	8,266,852	8,397,502	6,971,920	5,429,623	3,906,651	2,755,986	2,481,573	2,521,135	2,585,748	3,263,837	57,784,134
28	Lost Revenue Rate (Page 1, L. 12)	$/Therm	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
29	Revenue	**$'s**	$ 2,877	$ 3,845	$ 4,960	$ 5,039	$ 4,183	$ 3,258	$ 2,344	$ 1,654	$ 1,489	$ 1,513	$ 1,551	$ 1,958	34,670
30															
31	(Over)/Under-Recovery (Exc interest)	$'s	$ (20,638)	$ (16,997)	$ (14,405)	$ (11,766)	$ (8,091)	$ (3,258)	$ (495)	$ 3,178	$ 7,270	$ 5,772	$ 4,239	$ 2,294	
32															
33	**INTEREST**														
34	Average Monthly Balance		$ (22,628)	$ (18,848)	$ (15,727)	$ (13,108)	$ (9,945)	$ (5,688)	$ (1,884)	$ 1,339	$ 5,226	$ 6,528	$ 5,014	$ 3,273	
35	Interest Rate-WSJ Prime Rate	Annual %	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	Total
36	Days per Month		30	31	31	28	31	30	31	30	31	31	30	31	365
37	Computed Interest	$'s	$ (60)	$ (52)	$ (43)	$ (33)	$ (27)	$ (15)	$ (5)	$ 4	$ 14	$ 18	$ 13	$ 9	$ (178)
38															
39	**Ending Balance**	**$'s**	$ (20,698)	$ (17,049)	$ (14,449)	$ (11,799)	$ (8,119)	$ (3,273)	$ (500)	$ 3,182	$ 7,285	$ 5,790	$ 4,252	$ 2,303	

Northern Utilities
Monthly and Cumulative Savings (Therms) and Lost Base Revenue
November 1, 2020 to October 31, 2021

Northern Utilities Inc.
NHPUC Docket No. DG 21-xxx
Attachment NUI-SED-1 LRR
Page 3 of 6

Line	Description	10/31/2020	Recast Nov-20	Recast Dec-20	Recast Jan-21	Recast Feb-21	Recast Mar-21	Recast Apr-21	Recast May-21	Recast Jun-21	Recast Jul-21	Recast Aug-21	Recast Sep-21	Recast Oct-21	Period Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Residential Annualized Savings 2017	70,756													
2	Residential Annualized Savings 2018	115,768													
3	Residential Annualized Savings 2019	162,615													
4	Residential Annualized Savings 2020 (Page 4, L. 1)	118,543	7,203	19,430											
5	Residential Annualized Savings 2021		-	-	1,706	3,411	4,986	6,691	8,397	10,103	11,809	13,514	15,089	16,794	92,500
6	C&I Annualized Savings 2017	265,574													
7	C&I Annualized Savings 2018	182,120													
8	C&I Annualized Savings 2019	241,161													
9	C&I Annualized Savings 2020 (Page 4, L. 19)	62,360	34019	146033											
10	C&I Annualized Savings 2021		-	-	3,535	7,070	10,332	13,867	17,402	20,937	24,472	28,006	31,269	34,804	191,694
			Nov-20	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**LBR**
11	Monthly Residential Savings (2017 - 2019)														-
12	Cumulative Residential Savings	29,095	29,095	29,095	29,095	29,095	29,095	29,095	29,095	29,095	29,095	29,095	29,095	29,095	349,139
13	Average Residential Distribution Rate (Page 5)		0.6915	0.6915	0.6915	0.6915	0.6915	0.6915	0.6108	0.6108	0.6108	0.6108	0.6108	-	
14	Lost Residential Revenue		$ 20,119	$ 20,119	$ 20,119	$ 20,119	$ 20,119	$ 20,119	$ 17,770	$ 17,770	$ 17,770	$ 17,770	$ 17,770	$ -	$ 209,567
15	Monthly Residential Savings (2020)		600	1,619	-	-	-	-	-	-	-	-	-	-	2,219
16	Cumulative Residential Savings	9,879	10,479	12,098	12,098	12,098	12,098	12,098	12,098	12,098	12,098	12,098	12,098	6,667	138,127
17	Average Residential Distribution Rate (Page 5)		0.6915	0.6915	0.6915	0.6915	0.6915	0.6915	0.6108	0.6108	0.6108	0.6108	0.6108	0.6108	
18	Lost Residential Revenue		$ 7,246	$ 8,366	$ 8,366	$ 8,366	$ 8,366	$ 8,366	$ 7,389	$ 7,389	$ 7,389	$ 7,389	$ 7,389	$ 4,072	$ 90,093
19	Monthly Residential Savings (2021)		-	-	142.14	284.28	415.48	557.62	699.76	841.90	984.04	1,126.18	1,257.39	1,399.53	7,708
20	Cumulative Residential Savings	-	-	-	142	426	842	1,400	2,099	2,941	3,925	5,051	6,309	7,708	30,844
21	Average Residential Distribution Rate (Page 5)		0.6915	0.6915	0.6915	0.6915	0.6915	0.6915	0.6108	0.6108	0.6108	0.6108	0.6108	0.6108	
22	Lost Residential Revenue		$ -	$ -	$ 98	$ 295	$ 582	$ 968	$ 1,282	$ 1,796	$ 2,397	$ 3,085	$ 3,853	$ 4,708	$ 19,066
23	**Total Residential Lost Revenue**		**$ 27,365**	**$ 28,485**	**$ 28,583**	**$ 28,780**	**$ 29,067**	**$ 29,453**	**$ 26,442**	**$ 26,956**	**$ 27,557**	**$ 28,245**	**$ 29,013**	**$ 8,780**	**$ 318,725**
24	Monthly C&I Savings (2017-2019)														-
25	Cumulative C&I Savings	57,405	57,405	57,405	57,405	57,405	57,405	57,405	57,405	57,405	57,405	57,405	57,405	57,405	688,855
26	Average Residential Distribution Rate (Page 5)		0.1976	0.1976	0.2000	0.2000	0.2000	0.2000	0.1204	0.1204	0.1204	0.1204	0.1204	-	
27	Lost C&I Revenue		$ 11,343	$ 11,343	$ 11,481	$ 11,481	$ 11,481	$ 11,481	$ 6,912	$ 6,912	$ 6,912	$ 6,912	$ 6,912	$ -	$ 103,169
28	Monthly C&I Savings (2020)		2,835	12,169	-	-	-	-	-	-	-	-	-	-	15,004
29	Cumulative C&I Savings	5,197	8,032	20,201	20,201	20,201	20,201	20,201	20,201	20,201	20,201	20,201	20,201	15,530	225,571
30	Average Residential Distribution Rate (Page 5)		0.1976	0.1976	0.2000	0.2000	0.2000	0.2000	0.1204	0.1204	0.1204	0.1204	0.1204	0.1204	
31	Lost C&I Revenue		$ 1,587	$ 3,992	$ 4,040	$ 4,040	$ 4,040	$ 4,040	$ 2,432	$ 2,432	$ 2,432	$ 2,432	$ 2,432	$ 1,870	$ 35,771
32	Monthly C&I Savings (2021)		-	-	295	589	861	1,156	1,450	1,745	2,039	2,334	2,606	2,900	15,975
33	Cumulative C&I Savings	-	-	-	295	884	1,745	2,900	4,351	6,095	8,135	10,468	13,074	15,975	63,921
34	Average Residential Distribution Rate (Page 5)		0.1976	0.1976	0.2000	0.2000	0.2000	0.2000	0.1204	0.1204	0.1204	0.1204	0.1204	0.1204	
35	Lost C&I Revenue		$ -	$ -	$ 59	$ 177	$ 349	$ 580	$ 524	$ 734	$ 979	$ 1,260	$ 1,574	$ 1,923	$ 8,160
36	**Total C&I Lost Revenue**		**$ 12,930**	**$ 15,335**	**$ 15,580**	**$ 15,698**	**$ 15,870**	**$ 16,101**	**$ 9,868**	**$ 10,078**	**$ 10,323**	**$ 10,604**	**$ 10,918**	**$ 3,793**	**$ 147,099**
37	**Total Lost Revenue**		**$ 40,296**	**$ 43,820**	**$ 44,163**	**$ 44,478**	**$ 44,937**	**$ 45,554**	**$ 36,310**	**$ 37,034**	**$ 37,880**	**$ 38,849**	**$ 39,931**	**$ 12,573**	**465,826**

Lines 1, 6: 2017 Annual Report
Lines 2, 7: 2018 Annual Report
Lines 3, 8: 2019 Annual Report
Lines 4, 9: Page 4, Lines 1, 19
Lines 5, 10: DE 17-136 Approved Savings Budget
Line 12: Lines (1 +2 +3)/12
Line 16: Line 4/12
Line 25: Lines (6 + 7 +8)/12
Line 29: Line 9/12

Northern Utilities
Monthly and Cumulative Savings (Therms) and Lost Base Revenue
November 1, 2021 to October 31, 2022

Northern Utilities Inc.
NHPUC Docket No. DG 21-xxx
Attachment NUI-SED-1 LRR
Page 3a of 6

Line	Description	10/31/2021	Estimate Nov-21	Estimate Dec-21	Estimate Jan-22	Estimate Feb-22	Estimate Mar-22	Estimate Apr-22	Estimate May-22	Estimate Jun-22	Estimate Jul-22	Estimate Aug-22	Estimate Sep-22	Estimate Oct-22	Period Annual Savings
	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	Residential Annualized Savings 2020	80,008													-
2	Residential Annualized Savings 2021	92,500	18,500	20,206											
3	Residential Annualized Savings 2022		-	-	1,706	3,411	4,986	6,691	8,397	10,103	11,809	13,514	15,089	16,794	
4	C&I Annualized Savings 2020	186,355													
5	C&I Annualized Savings 2021	191,694	38,339	41,874											
6	C&I Annualized Savings 2022		-	-	3,535	7,070	10,332	13,867	17,402	20,937	24,472	28,006	31,269	34,804	
7	Total		56,839	62,079	5,240	10,481	15,318	20,559	25,799	31,040	36,280	41,521	46,358	51,598	-
			Nov-21	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**LBR**
8	2020 Monthly Residential Savings											-	-	-	-
9	Cumulative Residential Savings	6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	6,667	-	-	-	60,006
10	Average Residential Distribution Rate (Page 5)		0.6915	0.6915	0.6915	0.6915	0.6915	0.6915	0.6108	0.6108	0.6108	-	0.6108	0.6108	
11	Lost Residential Revenue		$ 4,610	$ 4,610	$ 4,610	$ 4,610	$ 4,610	$ 4,610	$ 4,072	$ 4,072	$ 4,072	$ -	$ -	$ -	$ 39,879
12	2021 Monthly Residential Savings		1,542	1,684	-	-	-	-	-	-	-	-	-	-	3,225
13	Cumulative Residential Savings	7,708	9,250	10,934	10,934	10,934	10,934	10,934	10,934	10,934	10,934	-	-	-	96,720
14	Average Residential Distribution Rate (Page 5)		0.6915	0.6915	0.6915	0.6915	0.6915	0.6915	0.6108	0.6108	0.6108	-	0.6108	0.6108	
15	Lost Residential Revenue		$ 6,396	$ 7,561	$ 7,561	$ 7,561	$ 7,561	$ 7,561	$ 6,678	$ 6,678	$ 6,678	$ -	$ -	$ -	$ 64,234
16	2022 Monthly Residential Savings		-	-	142	284	415	558	700	842	984	-	-	-	3,925
17	Cumulative Residential Savings	-	-	-	142	426	842	1,400	2,099	2,941	3,925	-	-	-	11,776
18	Average Residential Distribution Rate (Page 5)		0.6915	0.6915	0.6915	0.6915	0.6915	0.6915	0.6108	0.6108	0.6108	-	0.6108	0.6108	
19	Lost Residential Revenue		$ -	$ -	$ 98	$ 295	$ 582	$ 968	$ 1,282	$ 1,796	$ 2,397	$ -	$ -	$ -	$ 7,419
20	**Total Lost Residential Revenue**		**$ 11,007**	**$ 12,171**	**$ 12,269**	**$ 12,466**	**$ 12,753**	**$ 13,139**	**$ 12,032**	**$ 12,547**	**$ 13,148**	**$ -**	**$ -**	**$ -**	**$ 111,533**
21	2020 Monthly C&I Savings														
22	Cumulative C&I Savings	15,530	15,530	15,530	15,530	15,530	15,530	15,530	15,530	15,530	15,530	-	-	-	139,766
23	Average C&I Distribution Rate (Page 5)		0.1976	0.1976	0.1976	0.1976	0.1976	0.1976	0.1204	0.1204	0.1204	0.1204	0.1204	0.1204	
24	Lost C&I Revenue		$ 3,069	$ 3,069	$ 3,069	$ 3,069	$ 3,069	$ 3,069	$ 1,870	$ 1,870	$ 1,870	$ -	$ -	$ -	$ 24,021
25	2021 Monthly C&I Savings		3,195	3,489											6,684
26	Cumulative C&I Savings	15,975	19,169	22,659	22,659	22,659	22,659	22,659	22,659	22,659	22,659	-	-	-	200,440
27	Average C&I Distribution Rate (Page 5)		0.1976	0.1976	0.1976	0.1976	0.1976	0.1976	0.1204	0.1204	0.1204	0.1204	0.1204	0.1204	
28	Lost C&I Revenue		$ 3,788	$ 4,477	$ 4,477	$ 4,477	$ 4,477	$ 4,477	$ 2,728	$ 2,728	$ 2,728	$ -	$ -	$ -	$ 34,360
29	2022 Monthly C&I Savings		-	-	295	589	861	1,156	1,450	1,745	2,039	-	-	-	8,135
30	Cumulative C&I Savings		-	-	295	884	1,745	2,900	4,351	6,095	8,135	-	-	-	24,404
31	Average C&I Distribution Rate (Page 5)		0.1976	0.1976	0.1976	0.1976	0.1976	0.1976	0.1204	0.1204	0.1204	0.1204	0.1204	0.1204	
32	Lost C&I Revenue		$ -	$ -	$ 58	$ 175	$ 345	$ 573	$ 524	$ 734	$ 979	$ -	$ -	$ -	$ 3,388
33	**Total Lost C&I Revenue**		**$ 6,857**	**$ 7,546**	**$ 7,604**	**$ 7,721**	**$ 7,891**	**$ 8,119**	**$ 5,122**	**$ 5,332**	**$ 5,577**	**$ -**	**$ -**	**$ -**	**$ 61,769**
34	**Total Lost Revenue**		**$ 17,863**	**$ 19,717**	**$ 19,874**	**$ 20,187**	**$ 20,644**	**$ 21,258**	**$ 17,154**	**$ 17,879**	**$ 18,725**	**$ -**	**$ -**	**$ -**	**173,301**

Line 1: Page 4, Line 18
Line 2: Total, Page 3, Line 13
Line 3: DE 17-136 Approved Savings Budget
Line 4: Page 4, Line 36
Line 5: Total, Page 3, Line 10
Line 6: DE 7-136 Approved Savings Budget
Line 9: Line 1 / 12
Line 13: Page 3, Line 20, Col. N
Line 16: Line 3/12
Line 22: Line 4/12
Line 26: Line 5/12
Line 29: Line 6/12

Northern Utilities, Inc.
2020 Residential Installed Therm Savings
Savings Annualization

Line	Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Annual Savings
	Col. A	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	**Monthly Residential Therm Savings***	**-**	**16,204**	**15,242**	**7,355**	**918**	**4,876**	**3,827**	**30,944**	**14,644**	**24,534**	**7,203**	**19,430**	**145,176**
2														
3	**Monthly Residential Therms Savings**													
4	January 2020	-	-	-	-	-	-	-	-	-	-	-	-	-
5	February 2020		1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	14,853
6	March 2020			1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	12,702
7	April 2020				613	613	613	613	613	613	613	613	613	5,516
8	May 2020					76	76	76	76	76	76	76	76	612
9	June 2020						406	406	406	406	406	406	406	2,844
10	July 2020							319	319	319	319	319	319	1,913
11	August 2020								2,579	2,579	2,579	2,579	2,579	12,893
12	September 2020									1,220	1,220	1,220	1,220	4,881
13	October 2020										2,044	2,044	2,044	6,133
14	November 2020											600	600	1,201
15	December 2020												1,619	1,619
16	**Total 2020 Therm Savings Realized in 2020**	**-**	**1,350**	**2,621**	**3,233**	**3,310**	**3,716**	**4,035**	**6,614**	**7,834**	**9,879**	**10,479**	**12,098**	**65,169**
17														
18	**2020 Residential Therm Savings Realized in 2021**	**-**	**1,350**	**2,540**	**1,839**	**306**	**2,031**	**1,913**	**18,051**	**9,762**	**18,400**	**6,003**	**17,811**	**80,008**

*Per DE 17-136 Northern Utilities, Inc 2020 Energy Efficiency Revised Annual Report filed on June 29, 2021 Page 1 of 18(Revised)

2020 C&I Installed Therm Savings
Savings Annualization

Line	Description	Actual Jan-20	Actual Feb-20	Actual Mar-20	Actual Apr-20	Actual May-20	Actual Jun-20	Actual Jul-20	Actual Aug-20	Actual Sep-20	Actual Oct-20	Actual Nov-20	Actual Dec-20	2020 Annual Savings
	Col. A	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
19	**Monthly C&I Therm Savings***	**10,885**	**3,916**	**3,966**	**2,324**	**14,685**	**4,167**	**494**	**783**	**7,393**	**13,748**	**34,019**	**146,033**	**242,412**
20														
21	**Monthly C&I Annualized Therm Savings**													
22	January 2020	907	907	907	907	907	907	907	907	907	907	907	907	10,885
23	February 2020		326	326	326	326	326	326	326	326	326	326	326	3,590
24	March 2020			331	331	331	331	331	331	331	331	331	331	3,305
25	April 2020				194	194	194	194	194	194	194	194	194	1,743
26	May 2020					1,224	1,224	1,224	1,224	1,224	1,224	1,224	1,224	9,790
27	June 2020						347	347	347	347	347	347	347	2,431
28	July 2020							41	41	41	41	41	41	247
29	August 2020								65	65	65	65	65	326
30	September 2020									616	616	616	616	2,464
31	October 2020										1,146	1,146	1,146	3,437
32	November 2020											2,835	2,835	5,670
33	December 2020												12,169	12,169
34	**Total 2020 C&I Therm Savings Realized in 2020**	907	1,233	1,564	1,758	2,981	3,329	3,370	3,435	4,051	5,197	8,032	20,201	56,057
35														
36	**2020 C&I Therm Savings Realized in 2021**	**-**	**326**	**661**	**581**	**4,895**	**1,736**	**247**	**457**	**4,929**	**10,311**	**28,349**	**133,864**	**186,355**

*Per DE 17-136 Northern Utilities, Inc 2020 Energy Efficiency Revised Annual Report filed on June 29, 2021 Page 1 of 18(Revised)

Northern Utilities, Inc.

Summary of Average Distribution Rate for Lost Revenue

Calculation of Average Distribution Rate for Lost Revenue (Detail)

Line		(1) Number of Customers	(2) Customer Charge	(3)=(1)X(2) Calculated Customer Charge	(4) Billing Determinants - Winter First Therms	(4) Billing Determinants - Winter Excess Therms	(5) Winter Distribution Rates First Therms $/thm	(5) Winter Distribution Rates Excess Therms $/thm	(6) = (4) X (5) Winter Distribution Revenue	(7) Billing Determinants - Summer First Therms	(7) Billing Determinants - Summer Excess Therms	(8) Summer Distribution Rates First Therms $/thm	(8) Summer Distribution Rates Excess Therms $/thm	(9) = (7) X (8) Summer Distribution Revenue
8	R-5 Residential, Heating	254,235	$22.20	$5,644,012	6,492,802	7,394,357	$ 0.6920	$ 0.6920	$9,609,914	2,886,762	514,633	$ 0.6099	$ 0.6099	$2,074,510
9	R-10 Residential Heating, Low Income	7,409	$8.88	$65,795	198,454	174,712	$ 0.6920	$ 0.6920	$258,231	79,240	12,894	$ 0.6099	$ 0.6099	$56,192
10	R-6 Residential, Non-Heating	13,188	$22.20	$292,765	53,533	93,914	$ 0.6470	$ 0.6470	$95,398	50,875	33,296	$ 0.6470	$ 0.6470	$54,459
11	Total Residential Service	274,832		$6,002,571	6,744,789	7,662,983			$9,963,543	3,016,876	560,823			$2,185,161
12														
13	G-40 Low Annual, High Winter Use	51,266	$75.09	$3,849,564	1,933,509	6,097,977	$ 0.1865	$ 0.1865	$1,497,872	734,511	678,865	$ 0.1865	$ 0.1865	$263,595
14	G-50 Low Annual, Low Winter Use	8,504	$75.09	$638,565	220,985	617,049	$ 0.1865	$ 0.1865	$156,293	207,033	428,694	$ 0.1865	$ 0.1865	$118,563
15	G-41 Medium Annual, High Winter Use	7,908	$222.64	$1,760,637	11,199,703	0	$ 0.2425		$2,715,928	2,549,242	0	$ 0.1895		$483,081
16	G-51 Medium Annual, Low Winter Use	3,023	$222.64	$673,041	1,711,732	1,080,841	$ 0.1712	$ 0.1399	$444,258	1,196,613	480,315	$ 0.1337	$ 0.1087	$212,197
17	G-42 High Annual, High Winter Use	391	$1,335.81	$522,302	4,239,962		$ 0.1984		$841,208	1,583,558	0	$ 0.1206		$190,977
18	G-52 High Annual, Low Winter Use	386	$1,335.81	$515,623	8,365,254		$ 0.1720		$1,438,824	7,818,964	0	$ 0.0792		$619,262
19	Total General Service	71,478		$7,959,732	27,671,145	7,795,867			$7,094,384	14,089,922	1,587,875			$1,887,676
20														
21	Total Company	346,310		$13,962,303	34,415,934	15,458,850			$17,057,927	17,106,798	2,148,697			$4,072,837

23 Notes:
24 Column (1),Column (4) and Column (7): 2018 actual billing determinants.
25 Column (2), Column (5) and Column (8): Winter and Summer distribution rates effective May 1, 2019.
26 R-11 Rate Class is closed May 1, 2017. R-11 Rate Class Customers migrated to R-6 Rate Class.

Calculation of Average Distribution Rate for Lost Revenue Winter and Summer (Summary)

Line		(10)=(3) Total Calculated Customer Revenue	(11) = (6) + (9) Total Volumetric Revenue	12=(10+(11) Total Distribution Revenue	(13)=(4)+(7) Total Annual Therms
35	R-5	$5,644,012	$11,684,424	$17,328,436	17,288,553
36	R-10	$65,795	$314,423	$380,218	465,300
37	R-6	$292,765	$149,857	$442,621	231,618
39	Total Residential Service	$6,002,571	$12,148,704	$18,151,275	17,985,471
41	G-40	$3,849,564	$1,761,467	$5,611,031	9,444,862
42	G-50	$638,565	$274,857	$913,422	1,473,762
43	G-41	$1,760,637	$3,199,009	$4,959,646	13,748,945
44	G-51	$673,041	$656,456	$1,329,496	4,469,501
45	G-42	$522,302	$1,032,186	$1,554,487	5,823,520
46	G-52	$515,623	$2,058,086	$2,573,708	16,184,218
47	Total General Service	$7,959,732	$8,982,059	$16,941,791	51,144,808
49	Total Company	$13,962,303	**$21,130,764**	$35,093,066	**69,130,279**

Based on Actual Billing Determinants for 2020 at Current Distribution Rates- Winter

	(1) Total Volumetric Revenue	(2) Total Winter therms	(3)=(1)X(2) Average Distribution Rate $/therm
R-5	$9,609,914	13,887,159	$0.6920
R-10	$258,231	373,166	$0.6920
R-6	$95,398	147,447	$0.6470
Total Residential Service	$9,963,543	14,407,772	**$0.6915**
G-40	$1,497,872	8,031,486	$0.1865
G-50	$156,293	838,034	$0.1865
G-41	$2,715,928	11,199,703	$0.2425
G-51	$444,258	2,792,573	$0.1591
G-42	$841,208	4,239,962	$0.1984
G-52	$1,438,824	8,365,254	$0.1720
Total General Service	$7,094,384	35,467,012	**$0.2000**

Based on Actual Billing Determinants for 2020 at Current Distribution Rates- Summer

	(1) Total Volumetric Revenue	(2) Total Summer therms	(3)=(1)X(2) Average Distribution Rate $/therm
R-5	$2,074,510	3,401,394	$0.6099
R-10	$56,192	92,134	$0.6099
R-6	$54,459	84,171	$0.6470
Total Residential Service	$2,185,161	3,577,699	**$0.6108**
G-40	$263,595	1,413,376	$0.1865
G-50	$118,563	635,728	$0.1865
G-41	$483,081	2,549,242	$0.1895
G-51	$212,197	1,676,928	$0.1265
G-42	$190,977	1,583,558	$0.1206
G-52	$619,262	7,818,964	$0.0792
Total General Service	$1,887,676	15,677,796	**$0.1204**
Total	**$ 21,130,764**	**69,130,279**	

NORTHERN UTILITIES, INC.- NEW HAMPSHIRE DIVISION
REMEDIATION ADJUSTMENT CLAUSE COMPLIANCE FILING
2020-2021 ENVIRONMENTAL RESPONSE COSTS
SITE SPECIFIC EXPENSES

Line	Description	Total	11/11 - 10/12	11/12 - 10/13	11/13 - 10/14	11/14-10/15	11/15-10/16	11/16-10/17	11/17-10/18	11/18-10/19	11/19-10/20	11/20-10/21	11/21-10/22	11/22-10/23	11/23-10/24	11/24-10/25	11/25-10/26	11/26-10/27	11/27-10/28
	ENVIRONMENTAL RESPONSE COST (ERC)																		
1	July 10 - June 11 Expenses Amortization (1/7)	$ 121,209	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316	$ 17,316										
2	July 11 - June 12 Expenses Amortization (1/7)	$ 159,020		$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717	$ 22,717									
3	July 12 - June 13 Expenses Amortization (1/7)	$ 175,406			$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058	$ 25,058								
4	July 13 - June 14 Expenses Amortization (1/7)	$ 40,881				$ 5,840	$ 5,840	$ 5,840	$ 5,840	$ 5,840	$ 5,840	$ 5,840							
5	July 14 - June 15 Expenses Amortization (1/7)	$ 112,198					$ 16,028	$ 16,028	$ 16,028	$ 16,028	$ 16,028	$ 16,028	$ 16,028						
6	July 15 - June 16 Expenses Amortization (1/7)	$ 2,179,885						$ 311,412	$ 311,412	$ 311,412	$ 311,412	$ 311,412	$ 311,412	$ 311,412					
7	July 16 - June 17 Expenses Amortization (1/7)	$ 54,154							$7,736	$7,736	$7,736	$7,736	$7,736	$7,736	$7,736				
8	July 17 - June 18 Expenses Amortization (1/7)	$ 283,143								$40,449	$40,449	$40,449	$40,449	$40,449	$40,449	$40,449			
9	July 18 - June 19 Expenses Amortization (1/7)	$ 203,357									$ 29,051	$ 29,051	$ 29,051	$ 29,051	$ 29,051	$ 29,051	$ 29,051		
10	July 19 - June 20 Expenses Amortization (1/7)	$ 77,165										$ 11,024	$ 11,024	$ 11,024	$ 11,024	$ 11,024	$ 11,024	$ 11,024	
11	July 20 - June 21 Expenses Amortization (1/7)	$ 118,256											$ 16,894	$ 16,894	$ 16,894	$ 16,894	$ 16,894	$ 16,894	$ 16,894
12	Subtotal (Line 1 through Line 11)	$ 3,524,674	$ 17,316	$ 40,033	$ 65,091	$ 70,931	$ 86,959	$ 398,371	$ 406,108	$ 429,241	$ 435,575	$ 421,540	$ 432,594	$ 416,566	$ 105,153	$ 97,417	$ 56,968	$ 27,917	$ 16,894
13	Add: Excess amortization from prior years (from schedule 5, Line 9)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Less: Excess amortization to be deferred (from schedule 5, Line 8)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Environmental Response cost to be recovered (ERC)	$ 3,524,674	$ 17,316	$ 40,033	$ 65,091	$ 70,931	$ 86,959	$ 398,371	$ 406,108	$ 429,241	$ 435,575	$ 421,540	$ 432,594	$ 416,566	$ 105,153	$ 97,417	$ 56,968	$ 27,917	$ 16,894
16	July 2010 - June 2011 Unamortized beginning balance		$ 121,209	$ 103,893	$ 86,578	$ 69,262	$ 51,947	$ 34,631	$ 17,316										
17	July 2011 - June 2012 Unamortized beginning balance			$ 159,020	$ 136,303	$ 113,586	$ 90,869	$ 68,151	$ 45,434	$ 22,717									
18	July 2012 - June 2013 Unamortized beginning balance				$ 175,406	$ 150,348	$ 125,290	$ 100,232	$ 75,174	$ 50,116	$ 25,058								
19	July 2013 - June 2014 Unamortized beginning balance					$ 40,881	$ 35,041	$ 29,201	$ 23,361	$ 17,521	$ 11,680	$ 5,840							
20	July 2014 - June 2015 Unamortized beginning balance						$ 112,198	$ 96,170	$ 80,141	$ 64,113	$ 48,085	$ 32,057	$ 16,028						
21	July 2015 - June 2016 Unamortized beginning balance							$ 2,179,885	$ 1,868,473	$ 1,557,061	$ 1,245,649	$ 934,236	$ 622,824	$ 311,412					
22	July 2016 - June 2017 Unamortized beginning balance								$ 54,154	$ 46,418	$ 38,681	$ 30,945	$ 23,209	$ 15,473	$ 7,736				
23	July 2017 - June 2018 Unamortized beginning balance									$ 283,143	$ 242,694	$ 202,245	$ 161,796	$ 121,347	$ 80,898	$ 40,449			
24	July 2018 - June 2019 Unamortized beginning balance										$ 203,357	$ 174,306	$ 145,255	$ 116,204	$ 87,153	$ 58,102	$ 29,051		
25	July 2019 - June 2020 Unamortized beginning balance											$ 77,165	$ 66,141	$ 55,118	$ 44,094	$ 33,071	$ 22,047	$ 11,024	
26	July 2020 - June 2021 Unamortized beginning balance												$ 118,256	$ 101,362	$ 84,468	$ 67,575	$ 50,681	$ 33,787	$ 16,894
27	Total Unamortized beginning balance		$ 121,209	$ 262,913	$ 398,287	$ 374,077	$ 415,344	$ 2,508,270	$ 2,164,053	$ 2,041,089	$ 1,815,204	$ 1,456,794	$ 1,153,509	$ 720,915	$ 304,350	$ 199,196	$ 101,779	$ 44,811	$ 16,894
28	INSURANCE/3RD PARTY EXPENSES (IE) Expenses (from schedule 2)																		
29	INSURANCE/3RD PARTY RECOVERIES (IR)																		
30	UNDER/OVER Recovery from previous year																		
31	**Total of Lines 27 through 30**		$ 121,209	$ 262,913	$ 398,287	$ 374,077	$ 415,344	$ 2,508,270	$ 2,164,053	$ 2,041,089	$ 1,815,204	$ 1,456,794	$ 1,153,509	$ 720,915	$ 304,350	$ 199,196	$ 101,779	$ 44,811	$ 16,894

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 715 therms/year

Comparison of Winter 2021-2022 vs. Winter 2020-2021

#	Item	Units	Rate	Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		55	93	124	135	101	74	581	51	21	14	12	15	21	133	715
3		Winter 2021 - 2022																
4	Customer Charge	units @	$ 22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20								
5	First	50 units @	$0.6920	$34.60	$34.60	$34.60	$34.60	$34.60	$34.60	$207.60								
6	Over	50 units @	$0.6920	$3.71	$29.50	$51.20	$58.55	$35.30	$16.47	$194.74								
7		COG 1	$0.9392	$52.00						$52.00								
8		COG 2	$0.9392		$86.99					$86.99								
9		COG 3	$0.9392			$116.45				$116.45								
10		COG 4	$0.9392				$126.43			$126.43								
11		COG 5	$0.9392					$94.87		$94.87								
12		COG 6	$0.9392						$69.31	$69.31								
13		LDAC	$0.0631	$3.49	$5.84	$7.82	$8.49	$6.37	$4.66	$36.69								
14		Summer 2022																
15	Customer Charge	units @	$ 22.20								$ 22.20	$22.20	$22.20	$22.20	$ 22.20	$22.20	$133.20	
16	First	50 units @	$0.6099								$30.50	$12.91	$8.53	$7.09	$9.07	$12.73	$80.82	
17	Over	50 units @	$0.6099								$0.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.36	
20		COG 1	$0.5176								$26.18						$26.18	
21		COG 2	$0.5176									$10.95					$10.95	
22		COG 3	$0.5176										$7.24				$7.24	
23		COG 4	$0.5176											$6.02			$6.02	
24		COG 5	$0.5176												$7.70		$7.70	
25		COG 6	$0.5176													$10.80	$10.80	
26	Summer Period Weighted Avg. COG		$0.5176															
27		LDAC	$ 0.0631								$3.19	$1.34	$0.88	$0.73	$0.94	$1.32	$8.40	
28			TOTAL	$116.01	$179.13	$232.28	$250.28	$193.35	$147.24	**$1,118.29**	$82.43	$47.40	$38.86	$36.04	$39.91	$47.05	$291.67	$1,409.96
	Base Rate Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
			% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**								
	COG Change Winter		**$ Change**	$11.50	$19.24	$25.75	$27.96	$20.98	$15.33	**$120.76**								
			% Change	10.74%	11.71%	12.13%	12.23%	11.85%	11.32%	**11.78%**								
	LDAC Change Winter		**$ Change**	-$2.59	-$4.33	-$5.80	-$6.30	-$4.73	-$3.45	**-$27.21**								
			% Change	-2.42%	-2.64%	-2.73%	-2.76%	-2.67%	-2.55%	**-2.66%**								
27				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
28		Typical Usage: therms		55	93	124	135	101	74	581	51	21	14	12	15	21	133	715
29		Winter 2020 - 2021																
30	Customer Charge	units @	$ 22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20								
31	First	50 units @	$0.6920	$34.60	$34.60	$34.60	$34.60	$34.60	$34.60	$207.60								
32	Over	50 units @	$0.6920	$3.71	$29.50	$51.20	$58.55	$35.30	$16.47	$194.74								
33		COG 1	$0.7315	$40.50						$40.50								
34		COG 2	$0.7315		$67.75					$67.75								
35		COG 3	$0.7315			$90.70				$90.70								
36		COG 4	$0.7315				$98.47			$98.47								
37		COG 5	$0.7315					$73.89		$73.89								
38		COG 6	$0.7315						$53.99	$53.99								
39	Winter Period Weighted Avg. COG		$0.7315															
40		LDAC	$ 0.1099	$6.08	$10.18	$13.63	$14.79	$11.10	$8.11	$63.90								
41		Summer 2021																
42	Customer Charge	units @	$ 22.20								$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20	
43	First	50 units @	$0.6099								$30.50	$12.91	$8.53	$7.09	$9.07	$12.73	$80.82	
44	Over	50 units @	$0.6099								$0.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.36	
45		COG 1	$0.4970								$25.14						$25.14	
46		COG 2	$0.4970									$10.52					$10.52	
47		COG 3	$0.4970										$6.95				$6.95	
48		COG 4	$0.4970											$5.78			$5.78	
49		COG 5	$0.4970												$7.39		$7.39	
50		COG 6	$0.4970													$10.37	$10.37	
51	Summer Period Weighted Avg. COG		$0.4970															
52		LDAC	$ 0.1099								$5.56	$2.33	$1.54	$1.28	$1.63	$2.29	$14.63	
53			TOTAL	$107.10	$164.23	$212.33	$228.62	$177.10	$135.37	**$1,024.74**	$83.75	$47.95	$39.22	$36.34	$40.30	$47.59	$295.16	$1,319.90
54			Change	$8.91	$14.90	$19.95	$21.66	$16.25	$11.87	**$93.55**	($1.33)	($0.55)	($0.37)	($0.30)	($0.39)	($0.55)	**($3.49)**	$90.06
55			% Chg	8.32%	9.07%	9.40%	9.47%	9.18%	8.77%	**9.1%**	-1.58%	-1.16%	-0.93%	-0.84%	-0.97%	-1.15%	**-1.18%**	6.82%

*-Note- Weighted by usage. Most recent 12 months actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 2,022 therms/year

Comparison of Winter 2021-2022 vs. Winter 2020-2021

Line	Description		Rate	Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		159	279	369	417	306	209	1,738	122	42	24	20	31	44	283	2,022
3	**Winter 2021 - 2022**																	
4	Customer Charge	units @	$ 75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$450.54								
5	First	75 units @	$0.1865	$13.99	$13.99	$13.99	$13.99	$13.99	$13.99	$83.93								
6	Over	75 units @	$0.1865	$15.60	$38.00	$54.81	$63.72	$43.11	$25.04	$240.28								
7		COG 1	$0.9551	$151.54						$151.54								
8		COG 2	$0.9551		$266.22					$266.22								
9		COG 3	$0.9551			$352.32				$352.32								
10		COG 4	$0.9551				$397.95			$397.95								
11		COG 5	$0.9551					$292.39		$292.39								
12		COG 6	$0.9551						$199.89	$199.89								
13		LDAC	$0.0360	$5.71	$10.03	$13.28	$15.00	$11.02	$7.53	$62.58								
14	**Summer 2022**																	
15	Customer Charge	units @	$ 75.09								$ 75.09	$75.09	$75.09	$75.09	$ 75.09	$75.09	$450.54	
16	First	75 units @	$0.1865								$13.99	$7.90	$4.41	$3.75	$5.85	$8.27	$44.17	
17	Over	75 units @	$0.1865								$8.70	$0.00	$0.00	$0.00	$0.00	$0.00	$8.70	
18		COG 1	$0.4554								$55.40						$55.40	
19		COG 2	$0.4554									$19.28					$19.28	
20		COG 3	$0.4554										$10.77				$10.77	
21		COG 4	$0.4554											$9.15			$9.15	
22		COG 5	$0.4554												$14.29		$14.29	
23		COG 6	$0.4554													$20.20	$20.20	
24	Summer Period Weighted Avg. COG		$0.4554															
25		LDAC	$ 0.0360								$4.38	$1.52	$0.85	$0.72	$1.13	$1.60	$10.21	
26			**TOTAL**	$261.93	$403.32	$509.49	$565.74	$435.59	$321.55	**$2,497.63**	$157.55	$103.80	$91.13	$88.71	$96.37	$105.16	$642.72	$3,140.35
	Base Rate Change Winter		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
			% Change	0%	0%	0%	0%	0%	0%	**0%**								
	COG Change Winter		**$ Change**	$33.54	$58.92	$77.98	$88.08	$64.72	$44.24	**$367.49**								
			% Change	15%	17%	18%	18%	17%	16%	**17%**								
	LDAC Change Winter		**$ Change**	-$1.78	-$3.12	-$4.13	-$4.67	-$3.43	-$2.34	**-$19.47**								
			% Change	-0.8%	-0.9%	-0.9%	-1.0%	-0.9%	-0.8%	**-0.9%**								
27				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
28		Typical Usage: therms		159	279	369	417	306	209	1,738	122	42	24	20	31	44	283	2,022
29	**Winter 2020 - 2021**																	
30	Customer Charge	units @	$ 75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$450.54								
31	First	75 units @	$0.1865	$13.99	$13.99	$13.99	$13.99	$13.99	$13.99	$83.93								
32	Over	75 units @	$0.1865	$15.60	$38.00	$54.81	$63.72	$43.11	$25.04	$240.28								
33		COG 1	$0.7437	$118.00						$118.00								
34		COG 2	$0.7437		$207.29					$207.29								
35		COG 3	$0.7437			$274.34				$274.34								
36		COG 4	$0.7437				$309.87			$309.87								
37		COG 5	$0.7437					$227.67		$227.67								
38		COG 6	$0.7437						$155.65	$155.65								
39	Winter Period Weighted Avg. COG		$0.7437															
40		LDAC	$ 0.0472	$7.49	$13.16	$17.41	$19.67	$14.45	$9.88	$82.05								
41	**Summer 2021**																	
42	Customer Charge	units @	$ 75.09								$75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$450.54	
43	First	75 units @	$0.1865								$13.99	$7.90	$4.41	$3.75	$5.85	$8.27	$44.17	
44	Over	75 units @	$0.1865								$8.70	$0.00	$0.00	$0.00	$0.00	$0.00	$8.70	
45		COG 1	$0.5291								$64.36						$64.36	
46		COG 2	$0.5291									$22.41					$22.41	
47		COG 3	$0.5291										$12.52				$12.52	
48		COG 4	$0.5291											$10.63			$10.63	
49		COG 5	$0.5291												$16.61		$16.61	
50		COG 6	$0.5291													$23.47	$23.47	
51	Summer Period Weighted Avg. COG		$0.5291															
52		LDAC	$ 0.0472								$5.74	$2.00	$1.12	$0.95	$1.48	$2.09	$13.38	
53			**TOTAL**	$230.17	$347.52	$435.64	$482.33	$374.31	$279.65	**$2,149.61**	$167.88	$107.39	$93.14	$90.42	$99.03	$108.93	$666.79	$2,816.40
54			**Change**	$31.76	$55.80	$73.85	$83.41	$61.29	$41.90	**$348.02**	($10.33)	($3.60)	($2.01)	($1.71)	($2.66)	($3.77)	**($24.07)**	$323.95
55			**% Chg**	13.80%	16.06%	16.95%	17.29%	16.37%	14.98%	**16.19%**	-6.15%	-3.35%	-2.16%	-1.89%	-2.69%	-3.46%	**-3.61%**	11.50%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 20,679 therms/year

Comparison of Winter 2021-2022 vs. Winter 2020-2021

1				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
2		Typical Usage: therms (*)		1,723	2,769	3,576	3,921	3,003	2,178	17,170	1,273	552	360	210	438	676	3,509	20,679
3	**Winter 2021 - 2022**																	
4	Customer Charge	units @	$ 222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84								
5	All	units @	$0.2425	$417.80	$671.60	$867.07	$950.83	$728.20	$528.26	$4,163.76								
6		COG 1	$0.9551	$1,645.53						$1,645.53								
7		COG 2	$0.9551		$2,645.12					$2,645.12								
8		COG 3	$0.9551			$3,415.01				$3,415.01								
9		COG 4	$0.9551				$3,744.89			$3,744.89								
10		COG 5	$0.9551					$2,868.07		$2,868.07								
11		COG 6	$0.9551						$2,080.58	$2,080.58								
12		LDAC	$0.0360	$62.02	$99.70	$128.72	$141.15	$108.10	$78.42	$618.13								
13	**Summer 2022**																	
14	Customer Charge	units @	$ 222.64								$ 222.64	$222.64	$222.64	$222.64	$ 222.64	$222.64	$1,335.84	
15	All	units @	$0.1895								$241.20	$104.63	$68.21	$39.75	$83.08	$128.04	$664.90	
16		COG 1	$0.4554								$579.63						$579.63	
17		COG 2	$0.4554									$251.43					$251.43	
18		COG 3	$0.4554										$163.93				$163.93	
19		COG 4	$0.4554											$95.52			$95.52	
20		COG 5	$0.4554												$199.65		$199.65	
21		COG 6	$0.4554													$307.70	$307.70	
22	Summer Period Weighted Avg. COG		$0.4554															
23		LDAC	$ 0.0360								$45.82	$19.88	$12.96	$7.55	$15.78	$24.32	$126.31	
24			TOTAL	$2,347.99	$3,639.06	$4,633.44	$5,059.51	$3,927.02	$2,909.91	**$22,516.94**	$1,089.29	$598.57	$467.74	$365.46	$521.15	$682.71	$3,724.92	$26,241.86
	Base Rate Change Winter		$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**								
			% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**								
	COG Change Winter		$ Change	$364.22	$1,025.81	$1,324.38	$1,452.32	$1,112.28	$806.88	**$6,085.88**								
			% Change	18.18%	38.79%	39.54%	39.78%	39.05%	37.93%	**36.61%**								
	LDAC Change Winter		$ Change	-$19.30	-$31.02	-$40.05	-$43.91	-$33.63	-$24.40	**-$192.31**								
			% Change	-0.963%	-1.173%	-1.196%	-1.203%	-1.181%	-1.147%	**-1.16%**								
25				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
26		Typical Usage: therms		1,723	2,769	3,576	3,921	3,003	2,178	17,170	1,273	552	360	210	438	676	3,509	20,679
27	**Winter 2020 - 2021**																	
28	Customer Charge	units @	$ 222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84								
29	All	units @	$0.2425	$417.80	$671.60	$867.07	$950.83	$728.20	$528.26	$4,163.76								
30		COG 1	$0.7437	$1,281.31						$1,281.31								
31		COG 2	$0.5847		$1,619.31					$1,619.31								
32		COG 3	$0.5847			$2,090.63				$2,090.63								
33		COG 4	$0.5847				$2,292.57			$2,292.57								
34		COG 5	$0.5847					$1,755.80		$1,755.80								
35		COG 6	$0.5847						$1,273.71	$1,273.71								
36	Winter Period Weighted Avg. COG		$0.6007															
37		LDAC	$ 0.0472	$81.32	$130.72	$168.77	$185.07	$141.74	$102.82	$810.43								
38	**Summer 2021**																	
39	Customer Charge	units @	$ 222.64								$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84	
40	All	units @	$0.1895								$241.20	$104.63	$68.21	$39.75	$83.08	$128.04	$664.90	
41		COG 1	$0.5291								$673.44						$673.44	
42		COG 2	$0.5291									$292.12					$292.12	
43		COG 3	$0.5291										$190.46				$190.46	
44		COG 4	$0.5291											$110.98			$110.98	
45		COG 5	$0.5291												$231.96		$231.96	
46		COG 6	$0.5291													$357.50	$357.50	
47	Summer Period Weighted Avg. COG		$0.5291															
48		LDAC	$ 0.0472								$60.08	$26.06	$16.99	$9.90	$20.69	$31.89	$165.61	
49			TOTAL	$2,003.07	$2,644.27	$3,349.10	$3,651.11	$2,848.38	$2,127.43	**$16,623.36**	$1,197.35	$645.45	$498.30	$383.27	$558.37	$740.07	$4,022.81	$20,646.17
50			Change	$344.92	$994.79	$1,284.34	$1,408.40	$1,078.64	$782.48	**$5,893.58**	($108.06)	($46.87)	($30.56)	($17.81)	($37.22)	($57.37)	**($297.89)**	$5,595.69
51			% Chg	17.22%	37.62%	38.35%	38.57%	37.87%	36.78%	**35.45%**	-9.02%	-7.26%	-6.13%	-4.65%	-6.67%	-7.75%	**-7.41%**	27.10%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 16,982 therms/year
Comparison of Winter 2021-2022 vs. Winter 2020-2021

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
1																		
2		Typical Usage: therms (*)		1,394	1,767	1,968	2,106	2,041	1,647	10,922	990	951	992	928	1,122	1,078	6,060	16,982
3	**Winter 2021 - 2022**																	
4	Customer Charge	units @	$ 222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84								
5	First	1,300 units @	$0.1712	$222.56	$222.56	$222.56	$222.56	$222.56	$222.56	$1,335.36								
6	Over	1,300 units @	$0.1399	$13.13	$65.30	$93.45	$112.73	$103.67	$48.49	$436.77								
7		COG 1	$0.8453	$1,178.25						$1,178.25								
8		COG 2	$0.8453		$1,493.46					$1,493.46								
9		COG 3	$0.8453			$1,663.52				$1,663.52								
10		COG 4	$0.8453				$1,780.00			$1,780.00								
11		COG 5	$0.8453					$1,725.28		$1,725.28								
12		COG 6	$0.8453						$1,391.87	$1,391.87								
13		LDAC	$0.0360	$50.18	$63.60	$70.85	$75.81	$73.48	$59.28	$393.19								
14	**Summer 2022**																	
15	Customer Charge	units @	$ 222.64								$ 222.64	$222.64	$222.64	$222.64	$ 222.64	$222.64	$1,335.84	
16	First	1,000 units @	$0.1337								$132.38	$127.11	$132.56	$124.04	$133.70	$133.70	$783.49	
17	Over	1,000 units @	$0.1087								$0.00	$0.00	$0.00	$0.00	$13.27	$8.51	$21.77	
18		COG 1	$0.4741								$469.41						$469.41	
19		COG 2	$0.4741									$450.72					$450.72	
20		COG 3	$0.4741										$470.07				$470.07	
21		COG 4	$0.4741											$439.85			$439.85	
22		COG 5	$0.4741												$531.97		$531.97	
23		COG 6	$0.4741													$511.20	$511.20	
24		Summer Period Weighted Avg. COG	$0.4741															
25		LDAC	$ 0.0360								$35.64	$34.22	$35.69	$33.40	$40.39	$38.82	$218.17	
26			TOTAL	$1,686.76	$2,067.56	$2,273.01	$2,413.74	$2,347.63	$1,944.83	$12,733.54	$860.07	$834.69	$860.97	$819.93	$941.97	$914.86	$5,232.49	$17,966.03
	Base Rate Change Winter		$ Change	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
			% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
	COG Change Winter		$ Change	$277.10	$351.24	$391.23	$418.63	$405.76	$327.34	$2,171.30								
			% Change	19.44%	20.23%	20.55%	20.74%	20.65%	20.01%	20.32%								
	LDAC Change Winter		$ Change	-$15.61	-$19.79	-$22.04	-$23.58	-$22.86	-$18.44	-$122.33								
			% Change	-1.10%	-1.14%	-1.16%	-1.17%	-1.16%	-1.13%	-1.14%								

				Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	June	July	August	Sept	October	Summer	Annual
27																		
28		Typical Usage: therms		1,394	1,767	1,968	2,106	2,041	1,647	10,922	990	951	992	928	1,122	1,078	6,060	16,982
29	**Winter 2020 - 2021**																	
30	Customer Charge	units @	$ 222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84								
31	First	1,300 units @	$0.1712	$222.56	$222.56	$222.56	$222.56	$222.56	$222.56	$1,335.36								
32	Over	1,300 units @	$0.1399	$13.13	$65.30	$93.45	$112.73	$103.67	$48.49	$436.77								
33		COG 1	$0.6465	$901.14						$901.14								
34		COG 2	$0.6465		$1,142.22					$1,142.22								
35		COG 3	$0.6465			$1,272.29				$1,272.29								
36		COG 4	$0.6465				$1,361.38			$1,361.38								
37		COG 5	$0.6465					$1,319.53		$1,319.53								
38		COG 6	$0.6465						$1,064.52	$1,064.52								
39		Winter Period Weighted Avg. COG	$0.6465															
40		LDAC	$ 0.0472	$65.79	$83.39	$92.89	$99.39	$96.34	$77.72	$515.52								
41	**Summer 2021**																	
42	Customer Charge	units @	$ 222.64								$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84	
43	First	1,000 units @	$0.1337								$132.38	$127.11	$132.56	$124.04	$133.70	$133.70	$783.49	
44	Over	1,000 units @	$0.1087								$0.00	$0.00	$0.00	$0.00	$13.27	$8.51	$21.77	
45		COG 1	$0.4501								$445.64						$445.64	
46		COG 2	$0.4501									$427.90					$427.90	
47		COG 3	$0.4501										$446.27				$446.27	
48		COG 4	$0.4501											$417.59			$417.59	
49		COG 5	$0.4501												$505.04		$505.04	
50		COG 6	$0.4501													$485.32	$485.32	
51		Summer Period Weighted Avg. COG	$0.4501															
52		LDAC	$ 0.0472								$46.73	$44.87	$46.80	$43.79	$52.96	$50.89	$286.05	
53			TOTAL	$1,425.27	$1,736.11	$1,903.82	$2,018.70	$1,964.73	$1,635.93	$10,684.57	$847.39	$822.52	$848.28	$808.06	$927.61	$901.06	$5,154.92	$15,839.49
54			Change	$261.49	$331.45	$369.19	$395.04	$382.90	$308.90	$2,048.97	$12.67	$12.17	$12.69	$11.88	$14.36	$13.80	$77.57	$2,126.54
55			% Chg	18.35%	19.09%	19.39%	19.57%	19.49%	18.88%	19.18%	1.50%	1.48%	1.50%	1.47%	1.55%	1.53%	1.50%	13.43%

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level
Forecast Winter 2021-2022 vs. Actual Winter 2020-2021

Residential Heating

	Winter 2020- 2021	Winter 2021- 2022
Customer Charge	$22.20	$22.20
First 50 Therms	$0.6920	$0.6920
Over 50 therms	$0.6920	$0.6920
LDAC	$0.1099	$0.0631
CGA	$0.7315	$0.9392

	Usage (Therms)	Winter 2020-2021 Bill Amount	Winter 2021-2022 Bill Amount	Total Bill		Base Rate		CGA		LDAC	
	5	$29.87	$30.67	$0.80	2.7%	$0.00	0.0%	$1.04	3.5%	($0.23)	-0.8%
	10	$37.53	$39.14	$1.61	4.3%	$0.00	0.0%	$2.08	5.5%	($0.47)	-1.3%
	20	$52.87	$56.09	$3.22	6.1%	$0.00	0.0%	$4.15	7.8%	($0.94)	-1.8%
	25	$60.54	$64.56	$4.02	6.6%	$0.00	0.0%	$5.19	8.6%	($1.17)	-1.9%
	30	$68.20	$73.03	$4.83	7.1%	$0.00	0.0%	$6.23	9.1%	($1.40)	-2.1%
	45	$91.20	$98.44	$7.24	7.9%	$0.00	0.0%	$9.35	10.3%	($2.11)	-2.3%
	50	$98.87	$106.92	$8.04	8.1%	$0.00	0.0%	$10.39	10.5%	($2.34)	-2.4%
	75	$137.21	$149.27	$12.07	8.8%	$0.00	0.0%	$15.58	11.4%	($3.51)	-2.6%
Monthly*	125	$213.88	$233.99	$20.11	9.4%	$0.00	0.0%	$25.96	12.1%	($5.85)	-2.7%
	150	$252.21	$276.35	$24.14	9.6%	$0.00	0.0%	$31.16	12.4%	($7.02)	-2.8%
	200	$328.88	$361.06	$32.18	9.8%	$0.00	0.0%	$41.54	12.6%	($9.36)	-2.8%

* Monthly amount for benchmarking purposes, does not represent the average monthly use of Northern's residential class.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical Residential Heating Bill - 133 therms/Summer

Comparison of Summer 2022 vs. Summer 2021

				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2	Typical Usage: therms(*)			51	21	14	12	15	21	133
3	**Summer 2022**									
4	Customer Charge	units @	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20
5	First	50 units @	$0.6099	$30.50	$12.91	$8.53	$7.09	$9.07	$12.73	$80.82
6	Over	50 units @	$0.6099	$0.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.36
7		COG 1	$0.5176	$26.18						$26.18
8		COG 2	$0.5176		$10.95					$10.95
9		COG 3	$0.5176			$7.24				$7.24
10		COG 4	$0.5176				$6.02			$6.02
11		COG 5	$0.5176					$7.70		$7.70
12		COG 6	$0.5176						$10.80	$10.80
13	Summer Period 2022 Avg. COG		$0.5176 *							
14		LDAC	$0.0631	$3.19	$1.34	$0.88	$0.73	$0.94	$1.32	$8.40
15		**TOTAL**		$82.43	$47.40	$38.86	$36.04	$39.91	$47.05	**$291.67**
	Base Rate Change	**$ Change**		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
		% Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
	COG Change	**$ Change**		$1.04	$0.44	$0.29	$0.24	$0.31	$0.43	**$2.74**
		% Change		1.24%	0.91%	0.73%	0.66%	0.76%	0.90%	**0.93%**
	LDAC Change	**$ Change**		-$2.37	-$0.99	-$0.65	-$0.54	-$0.70	-$0.98	**-$6.23**
		% Change		-2.83%	-2.07%	-1.67%	-1.50%	-1.73%	-2.05%	**-2.11%**
16				May	June	July	August	Sept	October	Summer
17	Typical Usage: therms			51	21	14	12	15	21	133
18	**Summer 2021**									
19	Customer Charge	units @	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$133.20
20	First	50 units @	$0.6099	$30.50	$12.91	$8.53	$7.09	$9.07	$12.73	$80.82
21	Over	50 units @	$0.6099	$0.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.36
22		COG 1	$0.4970	$25.14						$25.14
23		COG 2	$0.4970		$10.52					$10.52
24		COG 3	$0.4970			$6.95				$6.95
25		COG 4	$0.4970				$5.78			$5.78
26		COG 5	$0.4970					$7.39		$7.39
27		COG 6	$0.4970						$10.37	$10.37
28	Summer Period 2021 Avg. COG		$0.4970 *							
29		LDAC	$0.1099	$5.56	$2.33	$1.54	$1.28	$1.63	$2.29	$14.63
30		**TOTAL**		$83.75	$47.95	$39.22	$36.34	$40.30	$47.59	**$295.16**
31		**Change**		-$1.33	-$0.55	-$0.37	-$0.30	-$0.39	-$0.55	**-$3.49**
32		**% Chg**		-1.58%	-1.16%	-0.93%	-0.84%	-0.97%	-1.15%	**-1.18%**

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-40 Commercial & Industrial Bill - 283 therms/Summer

Comparison of Summer 2022 vs. Summer 2021

Line				Rate	May	June	July	August	Sept	October	Summer
1					May	June	July	August	Sept	October	Summer
2			Typical Usage: therms(*)		122	42	24	20	31	44	283
3			**Summer 2022**								
4	Customer Charge		units @	$75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$450.54
5	First	75	units @	$0.1865	$13.99	$7.90	$4.41	$3.75	$5.85	$8.27	$44.17
6	Over	75	units @	$0.1865	$8.70	$0.00	$0.00	$0.00	$0.00	$0.00	$8.70
7			COG 1	$0.4554	$55.40						$55.40
8			COG 2	$0.4554		$19.28					$19.28
9			COG 3	$0.4554			$10.77				$10.77
10			COG 4	$0.4554				$9.15			$9.15
11			COG 5	$0.4554					$14.29		$14.29
12			COG 6	$0.4554						$20.20	$20.20
13			Summer Period 2022 Avg. COG	$0.4554 *							
14			LDAC	$0.0360	$4.38	$1.52	$0.85	$0.72	$1.13	$1.60	$10.21
15				**TOTAL**	$157.55	$103.80	$91.13	$88.71	$96.37	$105.16	**$642.72**
	Base Rate Change			**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
				% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
	COG Change			**$ Change**	-$8.97	-$3.12	-$1.74	-$1.48	-$2.31	-$3.27	**-$20.89**
				% Change	-5.34%	-2.91%	-1.87%	-1.64%	-2.34%	-3.00%	**-3.13%**
	LDAC Change			**$ Change**	-$1.36	-$0.47	-$0.26	-$0.23	-$0.35	-$0.50	**-$3.18**
				% Change	-0.81%	-0.44%	-0.28%	-0.25%	-0.35%	-0.46%	-0.48%
16					May	June	July	August	Sept	October	Summer
17			Typical Usage: therms		122	42	24	20	31	44	283
18			**Summer 2021**								
19	Customer Charge		units @	$75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$75.09	$450.54
20	First	75	units @	$0.1865	$13.99	$7.90	$4.41	$3.75	$5.85	$8.27	$44.17
21	Over	75	units @	$0.1865	$8.70	$0.00	$0.00	$0.00	$0.00	$0.00	$8.70
22			COG 1	$0.5291	$64.36						$64.36
23			COG 2	$0.5291		$22.41					$22.41
24			COG 3	$0.5291			$12.52				$12.52
25			COG 4	$0.5291				$10.63			$10.63
26			COG 5	$0.5291					$16.61		$16.61
27			COG 6	$0.5291						$23.47	$23.47
28			Summer Period 2021 Avg. COG	$0.5291 *							
29			LDAC	$0.0472	$5.74	$2.00	$1.12	$0.95	$1.48	$2.09	$13.38
30				**TOTAL**	$167.88	$107.39	$93.14	$90.42	$99.03	$108.93	**$666.79**
31				**Change**	-$10.33	-$3.60	-$2.01	-$1.71	-$2.66	-$3.77	**-$24.07**
32				**% Chg**	-6.15%	-3.35%	-2.16%	-1.89%	-2.69%	-3.46%	**-3.61%**

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-41 Commercial & Industrial Bill - 3,509 therms/Summer

Comparison of Summer 2022 vs. Summer 2021

				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2	Typical Usage: therms(1)			1,273	552	360	210	438	676	3,509
3	**Summer 2022**									
4	Customer Charge	units @	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84
5	All	units @	$0.1895	$241.20	$104.63	$68.21	$39.75	$83.08	$128.04	$664.90
6		COG 1	$0.4554	$579.63						$579.63
7		COG 2	$0.4554		$251.43					$251.43
8		COG 3	$0.4554			$163.93				$163.93
9		COG 4	$0.4554				$95.52			$95.52
10		COG 5	$0.4554					$199.65		$199.65
11		COG 6	$0.4554						$307.70	$307.70
12		Summer Period 2022 Avg. COG	$0.4554 *							
13		LDAC	$0.0360	$45.82	$19.88	$12.96	$7.55	$15.78	$24.32	$126.31
14		**TOTAL**		$1,089.29	$598.57	$467.74	$365.46	$521.15	$682.71	**$3,724.92**
	Base Rate Change		**$ Change**	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
			% Change	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
	COG Change		**$ Change**	-$93.81	-$40.69	-$26.53	-$15.46	-$32.31	-$49.80	**-$258.59**
			% Change	-7.83%	-6.30%	-5.32%	-4.03%	-5.79%	-6.73%	**-6.43%**
	LDAC Change		**$ Change**	-$14.26	-$6.18	-$4.03	-$2.35	-$4.91	-$7.57	**-$39.30**
			% Change	-1.19%	-0.96%	-0.81%	-0.61%	-0.88%	-1.02%	-0.98%

				May	June	July	August	Sept	October	Summer
15				May	June	July	August	Sept	October	Summer
16	Typical Usage: therms			1,273	552	360	210	438	676	3,509
17	**Summer 2021**									
18	Customer Charge	units @	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84
19	All	units @	$0.1895	$241.20	$104.63	$68.21	$39.75	$83.08	$128.04	$664.90
20		COG 1	$0.5291	$673.44						$673.44
21		COG 2	$0.5291		$292.12					$292.12
22		COG 3	$0.5291			$190.46				$190.46
23		COG 4	$0.5291				$110.98			$110.98
24		COG 5	$0.5291					$231.96		$231.96
25		COG 6	$0.5291						$357.50	$357.50
26		Summer Period 2021 Avg. COG	$0.5291 *							
27		LDAC	$0.0472	$60.08	$26.06	$16.99	$9.90	$20.69	$31.89	$165.61
28		**TOTAL**		$1,197.35	$645.45	$498.30	$383.27	$558.37	$740.07	**$4,022.81**
29		**Change**		-$108.06	-$46.87	-$30.56	-$17.81	-$37.22	-$57.37	**-$297.89**
30		**% Chg**		-9.02%	-7.26%	-6.13%	-4.65%	-6.67%	-7.75%	**-7.41%**

*-Note- Weighted by usage. Actual Weather Normalized.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE DIVISION

Typical G-51 Commercial & Industrial Bill - 6,060 therms/Summer

Comparison of Summer 2022 vs. Summer 2021

				May	June	July	August	Sept	October	Summer
1				May	June	July	August	Sept	October	Summer
2		Typical Usage: therms(1)		990	951	992	928	1,122	1,078	6,060
3	**Summer 2022**									
4	Customer Charge	units @	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84
5	First	1,000 units @	$0.1337	$132.38	$127.11	$132.56	$124.04	$133.70	$133.70	$783.49
6	Over	1,000 units @	$0.1087	$0.00	$0.00	$0.00	$0.00	$13.27	$8.51	$21.77
7		COG 1	$0.4741	$469.41						$469.41
8		COG 2	$0.4741		$450.72					$450.72
9		COG 3	$0.4741			$470.07				$470.07
10		COG 4	$0.4741				$439.85			$439.85
11		COG 5	$0.4741					$531.97		$531.97
12		COG 6	$0.4741						$511.20	$511.20
13		Summer Period 2022 Avg. COG	$0.4741 *							
14		LDAC	$0.0360	$35.64	$34.22	$35.69	$33.40	$40.39	$38.82	$218.17
15		**TOTAL**		$860.07	$834.69	$860.97	$819.93	$941.97	$914.86	$5,232.49
	Base Rate Change	**$ Change**		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	**$0.00**
		% Change		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
	COG Change	**$ Change**		$266.44	$255.83	$353.97	$331.21	$235.41	$226.22	**$1,669.07**
		% Change		44.89%	44.20%	69.83%	67.78%	33.32%	32.85%	**46.85%**
	LDAC Change	**$ Change**		$0.10	$0.10	$0.10	$0.09	$0.11	$0.11	**$0.61**
		% Change		0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
16				May	June	July	August	Sept	October	Summer
17		Typical Usage: therms		990	951	992	928	1,122	1,078	6,060
18	**Summer 2021**									
19	Customer Charge	units @	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$222.64	$1,335.84
20	First	1,000 units @	$0.1337	$132.38	$127.11	$132.56	$124.04	$133.70	$133.70	$783.49
21	Over	1,000 units @	$0.1087	$0.00	$0.00	$0.00	$0.00	$13.27	$8.51	$21.77
22		COG 1	$0.2050	$202.97						$202.97
23		COG 2	$0.2050		$194.89					$194.89
24		COG 3	$0.1171			$116.10				$116.10
25		COG 4	$0.1171				$108.64			$108.64
26		COG 5	$0.2643					$296.56		$296.56
27		COG 6	$0.2643						$284.98	$284.98
28		Summer Period 2021 Avg. COG	$0.1987 *							
29		LDAC	$0.0359	$35.54	$34.13	$35.59	$33.31	$40.28	$38.71	$217.57
30		**TOTAL**		$593.53	$578.76	$506.90	$488.63	$706.45	$688.54	**$3,562.82**
31		**Change**		$266.54	$255.92	$354.07	$331.30	$235.52	$226.33	**$1,669.67**
32		**% Chg**		44.91%	44.22%	69.85%	67.80%	33.34%	32.87%	**46.86%**

*-Note- Weighted by usage.

NORTHERN UTILITIES, INC. -- NEW HAMPSHIRE DIVISION

Impact of Rate Changes on Residential Heating Bills by Usage Level

Forecast Summer 2022 vs. Actual Summer 2021

Residential Heating	Summer 2021	Summer 2022
Customer Charge	$22.20	$22.20
First 50 Therms	$0.6099	$0.6099
Over 50 therms	$0.6099	$0.6099
LDAC	$0.1099	$0.0631
CGA	$0.4970	$0.5176

	Usage (Therms)	Summer 2019 Bill Amount	Summer 2020 Bill Amount	Total Bill		Base Rate		COG		LDAC	
	5	$28.28	$28.15	($0.13)	-0.5%	$0.00	0.0%	$0.10	0.4%	($0.23)	-0.8%
	10	$34.37	$34.11	($0.26)	-0.8%	$0.00	0.0%	$0.21	0.6%	($0.47)	-1.4%
	20	$46.54	$46.01	($0.52)	-1.1%	$0.00	0.0%	$0.41	0.9%	($0.94)	-2.0%
Monthly*	25	$52.62	$51.97	($0.66)	-1.2%	$0.00	0.0%	$0.52	1.0%	($1.17)	-2.2%
	30	$58.70	$57.92	($0.79)	-1.3%	$0.00	0.0%	$0.62	1.1%	($1.40)	-2.4%
	45	$76.96	$75.78	($1.18)	-1.5%	$0.00	0.0%	$0.93	1.2%	($2.11)	-2.7%
	50	$83.04	$81.73	($1.31)	-1.6%	$0.00	0.0%	$1.03	1.2%	($2.34)	-2.8%
	75	$113.46	$111.50	($1.97)	-1.7%	$0.00	0.0%	$1.55	1.4%	($3.51)	-3.1%
	125	$174.30	$171.03	($3.28)	-1.9%	$0.00	0.0%	$2.58	1.5%	($5.85)	-3.4%
	150	$204.72	$200.79	($3.93)	-1.9%	$0.00	0.0%	$3.09	1.5%	($7.02)	-3.4%
	200	$265.56	$260.32	($5.24)	-2.0%	$0.00	0.0%	$4.12	1.6%	($9.36)	-3.5%

* Monthly amount for benchmarking purposes, does not represent the average monthly use of Northern's residential class.