NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

In accordance with New Hampshire Code of Administrative Rules Part Puc 1604, Full Rate Case Filing Requirements, 1604.01 (a), Northern Utilities, Inc. ("Company" or "NU") has prepared responses to the following requests as provided herein:

(Request) (Page #)

(1) (000004) The utility's internal financial reports for the following periods:
a. For the first and last month of the test year;
b. For the entire test year; and
c. For the 12 months or 5 quarters prior to the test year;

(2) (000008) Annual reports to stockholders and statistical supplements, if any, for the most recent 2 years;

(3) (000009) Federal income tax reconciliation for the test year;

(4) (000010) A detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;

(5) (000012) A detailed list of charitable contributions charged in the test year above the line showing donee, the amount, and the account charged according to the following guidelines:
a. If the utility's annual gross revenues are less than $100,000,000 all contributions of $50 and more shall be reported;
b. If the utility's annual gross revenues are $100,000,000 or more, all contributions of $2,500 and more shall be reported; and
c. The reporting threshold for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution;

(6) (000013) A list of advertising charged in the test year above the line showing expenditure by media, subject matter, and account charged according to the following guidelines;
a. If the utility's annual gross revenues are less than $100,000,000 all expenditures of $50 and more shall be reported; and
b. If the utility's annual gross revenues are $100,000,000 or more, all expenditures of $2,500 and more shall be reported;

(7) (000015) The utility's most recent cost of service study if not previously filed in an adjudicative proceeding;

(8) (000016) The utility's most recent construction budget;

(9) (000026) The utility's chart of accounts, if different from the uniform system of accounts established by the Commission as part of Puc 300, Puc 400, Puc 500, Puc 600 and Puc 700;

(10) (000049) The utility's Securities and Exchange Commission 10K forms and 10Q forms or hyperlinks thereto, for the most recent 2 years;

(11) (000050) A detailed list of all membership fees, dues, lobbying expenses and donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount, and the account charged, according to the following guidelines:

a. If the utility’s annual gross revenues are less than $100,000,000 all membership fees, dues and donations shall be reported; and

b. If the utility’s annual gross revenues are $100,000,000 or more, all membership fees, dues and donations of $5,000 and more shall be reported;

(12) (000052) The utility's most recent depreciation study if not previously filed in an adjudicative proceeding;

(13) (000053) The utility's most recent management and financial audits if not previously filed in an adjudicative proceeding;

(14) (000219) A list of officers and directors of the utility and their full compensation for each of the last 2 years, detailing base compensation, bonuses, and incentive plans;

(15) (000222) Copies of all officer and executive incentive plans;

(16) (000242) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;

b. Owned by the spouse or minor child of an officer or director; or

c. Controlled by the officer or director directly or indirectly;

(17) (000243) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $10,000,000 in annual gross revenues, a list of all payments in excess of $10,000;

b. For utilities with $10,000,001 to $100,000,000 in annual gross revenues, a list of all payments in excess of $50,000; and

c. For utilities with annual gross revenues in excess of $100,000,000, a list of all payments in excess of $100,000;

d. The reporting thresholds for a particular entity shall be on a cumulative basis, indicating the number of items comprising the total amount of expenditure.

(18) (000245) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations;

(19) (000246) Balance sheets and income statements for the previous 2 years if not previously filed with the commission;

(20) (000247) Quarterly income statements for the previous 2 years if not previously filed with the commission;

(21) (000249) Quarterly sales volumes for the previous 2 years, itemized for residential and other classifications of service, if not previously filed with the commission;

(22) (000251) A description of the utility's projected need for external capital for the 2 year period immediately following the test year;

(23) (000252) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately following the test year;

(24) (000254) The amount of outstanding short term debt, on a monthly basis during the test year, for each short-term indebtedness;

(25) (000256) If a utility is a subsidiary, a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service;

(26) (000258) Support for figures appearing on written testimony and in accompanying exhibits.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(1) The utility's internal financial reports for the following periods:

a. For the first and last month of the test year;

b. For the entire test year; and

c. For the 12 months or 5 quarters prior to the test year;

Response:

Please see PUC 1604.01(a) – 1 Attachment 1 for the internal financial reports (balance sheets and income statements) for the above requested periods.

Northern Utilities, Inc.
Inc Stmt - NH - Rate Case
G_NU_NH_IS_Rate Case

	YTD December 2019	MTD January 2020	MTD December 2020	YTD December 2020
OPERATING REVENUES				
Sales:				
Residential (480)	$34,517,227.13	$4,656,524.61	$4,164,087.50	$30,041,334.70
General Service (481)	28,306,834.03	3,465,342.14	3,205,756.33	22,321,899.94
Firm Transport Revenues (484, 489)	9,829,867.28	1,151,861.26	1,110,030.35	9,739,813.60
Sales for Resale (483)	2,870,978.98	60,384.67	42,386.44	1,107,459.45
Other Sales (495)	(3,515,439.00)	(441,271.74)	228,202.01	2,244,617.36
Total Sales	72,009,468.42	8,892,840.94	8,750,462.63	65,455,125.05
Other Operating Revenues:				
Late Charge (487)	76,773.15	14,195.89	0.00	36,760.56
Misc. Service Revenues (488)	875,754.96	69,575.00	74,500.23	852,303.57
Rent from Property (493 & 457)	200,952.00	18,219.00	18,219.00	218,628.00
Other Revenues	(311,587.39)	0.00	15,064.66	120,656.07
Total Other Operating Revenues	841,892.72	101,989.89	107,783.89	1,228,348.20
TOTAL OPERATING REVENUES	72,851,361.14	8,994,830.83	8,858,246.52	66,683,473.25
OPERATING EXPENSES				
Operation & Maint. Expenses:				
Production (710-813)	28,226,731.36	3,861,752.11	3,166,760.33	23,544,859.85
Transmission (850-857)	72,713.01	6,252.13	6,916.57	63,828.91
Distribution (870-894) (586)	3,509,448.39	310,762.01	365,844.50	3,733,377.07
Cust. Accounting (901-905)	2,768,757.96	260,924.09	267,909.80	2,608,188.94
Cust. Service & Info (906-910)	2,319,375.02	86,327.89	376,726.67	2,341,705.53
Sales Expenses (911-916)	64,467.20	3,709.06	5,985.25	69,177.75
Admin. & General (920-935)	7,679,291.15	640,946.18	591,960.68	6,740,776.50
Total O & M Expenses	44,640,784.09	5,170,673.47	4,782,103.80	39,101,914.55
Other Operating Expenses:				
Deprtn. & Amort. (403-407)	9,004,943.38	799,210.38	857,982.18	9,693,558.76
Taxes-Other Than Inc. (408)	4,306,297.50	426,424.76	130,288.38	4,867,773.94
Federal Income Tax (409)	52,380.19	362,704.17	379,787.35	(30,211.07)
State Franchise Tax (409)	(309,547.45)	114,154.90	626,862.95	(384,643.78)
Def. Income Taxes (410,411)	2,975,683.09	108,881.92	(296,802.74)	2,600,178.96
Total Other Operating Expenses	16,029,756.71	1,811,376.13	1,698,118.12	16,746,656.81
TOTAL OPERATING EXPENSES	60,670,540.80	6,982,049.60	6,480,221.92	55,848,571.36
NET UTILITY OPERATING INCOME	12,180,820.34	2,012,781.23	2,378,024.60	10,834,901.89
OTHER INCOME & DEDUCTIONS				
Other Income:				
Other (415- 421)	242,786.84	23,135.80	33,106.65	206,338.79
Other Income Deduc. (425, 426)	232,635.71	17,383.46	24,218.34	151,744.19
Taxes Other than Income Taxes:				
Income Tax, Other Inc & Ded	2,751.63	1,557.91	2,407.22	14,785.85
Net Other Income (Deductions)	7,399.50		6,481.09	39,808.75
GROSS INCOME	12,188,219.84	2,016,975.66	2,384,505.69	10,874,710.64
Interest Charges (427 - 432)	4,673,981.74	427,512.64	423,039.89	4,778,440.54
NET INCOME	7,514,238.10	1,589,463.02	1,961,465.80	6,096,270.10

Northern Utilities, Inc.
Combined Balance Sheet (NH & ME)
G_NU_BS_Rate Case

	December 2019	January 2020	December 2020
ASSETS			
UTILITY PLANT			
Gas (101-106, 114)	$622,701,812.89	$625,112,029.80	$689,321,122.58
Const. Work in Progress (107)	12,576,741.64	11,920,075.90	13,301,948.50
Total Utility Plant	635,278,554.53	637,032,105.70	702,623,071.08
Less: Accum. Depr. & Amort (108-111, 115)	(143,066,941.59)	(144,786,798.03)	(175,354,389.54)
Net Utility Plant	492,211,612.94	492,245,307.67	527,268,681.54
OTHER PROPERTY & INVESTMENTS			
Nonutility Property (121)	2,943,712.34	2,943,712.34	3,058,116.38
Less: Accum.Prov. for Depr. and Amort. (122)	(2,913,893.26)	(2,940,561.89)	(2,971,261.24)
Total Other Prop. & Invest.	29,819.08	3,150.45	86,855.14
CURRENT ASSETS			
Cash (131)	$337,596.85	($348,097.04)	$370,260.09
Other Special Deposits (134, 136)	2,500.00	2,500.00	0.00
Working Funds (135)	1,750.00	1,750.00	1,750.00
Accounts Receivable (142)	21,416,442.65	22,582,115.81	23,594,967.02
Other Accounts Receivable (143)	154,773.31	142,176.13	199,463.96
(Less) Accum. Prov. for Uncoll. Acct (144)	(441,587.83)	(413,241.54)	(1,158,007.43)
Accts Receivable-Assoc. Cos. (146)	5,559,766.01	2,176,462.67	8,913,185.12
Plant Material & Operating Supplies (154)	4,162,205.58	4,358,770.56	4,464,730.02
Stores Expense Undistributed (163)	655,825.52	707,156.07	708,099.81
Gas Stored Underground - Current	401,480.61	262,870.41	267,731.25
Liquified Natural Gas Stored and Held for Processing	46,623.05	37,671.07	40,347.69
Prepayments (165)	4,450,028.61	4,611,054.63	2,161,366.78
Accrued Revenues (173)	9,587,863.54	7,438,527.71	8,534,883.10
Miscellaneous Current and Accrued Assets (174)	5,666,175.53	4,155,487.28	4,624,272.16
Total Current Assets	52,001,443.43	45,715,203.76	52,723,049.57
DEFERRED DEBITS			
Unamortized Debt Expense (181)	1,208,586.32	1,227,818.76	1,359,851.23
Regulatory Assets (182)	23,818,108.99	14,802,640.03	27,935,356.03
Preliminary Survey Chgs (183)	663,266.65	678,848.15	861,958.45
Clearing Accounts (184)	173,313.84	1,388,507.40	203,053.82
Misc. Deferred Debits (186)	1,250,862.64	1,273,884.26	864,679.14
Unrecovered Purchase Gas Costs (191)	2,803,584.01	2,891,528.92	6,818,463.80
Total Deferred Debits	29,917,722.45	22,263,227.52	38,043,362.47
TOTAL ASSETS	$574,160,597.90	$560,226,889.40	$618,121,948.72

Northern Utilities, Inc.
Combined Balance Sheet (NH & ME)
G_NU_BS_Rate Case

	December 2019	January 2020	December 2020
LIABILITIES AND CAPITAL			
PROPRIETARY CAPITAL			
Common Stock Equity			
Common Stock of Subs, Par Value (201)	1,000.00	1,000.00	1,000.00
Other Paid-In Capital (208, 211)	200,699,000.00	200,699,000.00	207,074,000.00
Retained earnings (216)	24,380,042.44	24,013,784.57	24,453,103.55
Total Proprietary Capital	225,080,042.44	224,713,784.57	231,528,103.55
LONG TERM DEBT			
Other Long-Term Debt (224)	198,200,000.00	198,200,000.00	230,000,000.00
Total Long Term Debt	198,200,000.00	198,200,000.00	230,000,000.00
Capital Leases-Noncurrent	706,610.32	1,172,759.07	1,092,628.92
CURRENT LIABILITIES			
Accounts Payable (232)	8,651,894.04	6,297,393.62	7,178,825.54
Notes Payable (233)	28,494,680.03	28,666,839.96	26,747,021.72
Accts. Payable-Assoc. Co's (234)	6,497,178.34	6,120,881.60	7,400,408.89
Customer Deposits (235)	640,562.43	626,328.64	592,301.78
Taxes Accrued (236)	292,533.71	1,286,273.02	63,034.19
Interest Accrued (237)	1,824,919.44	2,659,886.51	2,094,466.69
Dividends Declared (238)	3,304,600.00	3,666,585.00	3,666,585.00
Tax Collections Payable (241)	94,758.52	68,278.26	174,522.35
Misc. Current Liabilities (242)	11,636,693.25	9,812,680.73	9,024,630.21
Capital Leases - Current (243)	431,168.75	535,246.32	519,504.85
Total Current Liabilities	61,868,988.51	59,740,393.66	57,461,301.22
DEFERRED CREDITS			
Other Deferred Credits (253)	35,921,433.54	19,221,777.00	40,177,075.27
Other Regulatory Liabilities (254)	21,739,717.95	21,722,427.95	21,336,059.65
Accum. Deferred Inc. Taxes - Other Prop. (282, 283)	46,747,167.58	47,241,125.14	53,374,153.90
Accum. Def. Income Taxes (282, 283)	(16,103,362.44)	(11,785,377.99)	(16,847,373.79)
Total Deferred Credits	88,304,956.63	76,399,952.10	98,039,915.03
TOTAL LIABILITIES AND CAPITAL	$574,160,597.90	$560,226,889.40	$618,121,948.72

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(2) Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;

Response:

Northern Utilities, Inc. does not make an annual report to stockholders.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(3) Federal income tax reconciliation for the test year.

Response:

Please refer to Schedule RevReq-3-22, Page 3 of 4 for the federal and state income tax reconciliation for the test year.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(4) A detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;

Response:

Please refer to PUC 1604.01(a) - 04 Attachment 1 which is the computation of Gross-Up Factor for Revenue Requirement.

NORTHERN UTILITIES, INC.
COMPUTATION OF GROSS-UP FACTOR FOR REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO	DESCRIPTION	RATE	
1	Revenue		1.0000
2	State Income Tax	7.70%	0.0770
3	Subtotal taxable income - Federal		0.9230
4	Federal Income Tax	21.00%	0.1938
5	Net Operating Income		0.7292
6	Gross-up Factor (1/Line 5)		1.3714

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(5) A detailed list of charitable contributions charged in the test year above the line showing donee, the amount, and the account charged according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000,000 all contributions of $50 and more shall be reported;

b. If the utility's annual gross revenues are $100,000,000 or more, all contributions of $2,500 and more shall be reported; and

c. The reporting threshold for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution.

Response:

There were no charitable contributions charged above the line during the test year.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(6) A list of advertising charged in the test year above the line showing expenditure by media, subject matter, and account charged according to the following guidelines;

a. If the utility's annual gross revenues are less than $100,000,000 all expenditures of $50 and more shall be reported; and

b. If the utility's annual gross revenues are $100,000,000 or more, all expenditures of $2,500 and more shall be reported

Response:

a. Please see PUC 1604.01(a) – 06 Attachment 1 for a list of advertising charged above the line greater than $50.

b. N/A.

Northern Utilities, Inc.
List of Advertising by Media and Subject Matter
2020

Advertising above the line in excess of $50

Media	Subject Matter	Account Number	Amount
Radio	Gas Connectors	30-40-24-00-909-52-00	$ 1,674
Radio	Gas Leak Response	30-40-24-00-909-52-00	1,810
Radio	Home Safety	30-40-24-00-909-52-00	1,810
Radio	Carbon Monoxide	30-40-24-00-909-52-00	1,810
Radio	Presidents Message	30-40-24-00-913-53-00	1,659
Radio	Dig Safe	30-40-24-00-909-52-00	1,810
Radio	Gas Leak Recognition	30-40-24-00-909-52-00	1,810
Radio	Pipeline Safety	30-40-24-00-909-52-00	1,810
	Subtotal - Radio Advertising		$ 14,193
Social Media	Carbon Monoxide	30-40-24-00-909-52-00	$ 59
Social Media	Home Safety Hazardss	30-40-24-00-909-01-00	140
Social Media	January Mythbuster	30-40-24-00-909-01-00	80
Social Media	Gas Connectors	30-40-24-00-909-52-00	240
Social Media	Natural Gas Appliances	30-40-24-00-909-01-00	70
Social Media	Dig Safe	30-40-24-00-909-52-00	142
Social Media	MyUnitil Energy Tools	30-40-24-00-909-01-00	60
Social Media	EE Tips - Ceiling Fans & Energy	30-40-24-00-909-01-00	50
Social Media	Gas Leak Recognition	30-40-24-00-909-52-00	180
Social Media	Gas Leak Response	30-40-24-00-909-52-00	256
Social Media	Pipeline Safety	30-40-24-00-909-52-00	240
Social Media	Home Safety	30-40-24-00-909-52-00	240
Social Media	Corrugated Stainless Steel Tubing (CSST)	30-40-24-00-909-52-00	194
Social Media	Clear meters of Snow and Ice	30-40-24-00-909-52-00	103
	Subtotal - Social Media Advertising		$ 2,054
	Grand Total		$ 16,247

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(7) The utility's most recent cost of service study.

Response:

The Company cost of service study is attached to the Testimony of Christopher Goulding and Daniel Nawazelski.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(8) The utility's most recent construction budget.

Response:

See PUC 1604.01(a) – 8 Attachments 1 for the utility’s most recent construction budget.

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Capital Budget 2021 Northern NH

Description	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions	Retirements	Salvage
Electric Totals:	0	0	0	0	0	0	0	0
Blankets:Gas	6,114,766	8,452,586	78,955	8,373,631	0	8,373,631	0	0
Communications:Gas	25,010	34,572	0	34,572	0	34,572	100	0
Distribution:Gas	13,778,675	19,046,590	265,003	18,781,587	0	18,781,587	0	0
Tools, Shop, Garage:Gas	215,547	215,547	0	215,547	0	215,547	0	0
Office:Gas	14,000	14,000	0	14,000	0	14,000	0	250
Transportation:Gas	4	4	0	4	0	4	0	0
Gas Totals:	20,148,002	27,763,299	343,958	27,419,340	0	27,419,340	100	250
Blankets:Water Heater	222,320	222,320	0	222,320	0	222,320	0	0
Hotwater Totals:	222,320	222,320	0	222,320	0	222,320	0	0
Structures:General	1,118,000	1,118,000	0	1,118,000	0	1,118,000	0	0
General/Common Totals:	1,118,000	1,118,000	0	1,118,000	0	1,118,000	0	0
Totals:	**21,488,322**	**29,103,619**	**343,958**	**28,759,660**	**0**	**28,759,660**	**100**	**250**

Capital Budget System • Report • Budget Item Requests

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Blankets:Gas**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	1	MAB21	Distribution System Improvements (Under $40,000)	414,364	572,785	0	572,785	0	572,785
A	1	MAC21	Distribution System Improvements (Under $40,000) Carryover	12,692	17,544	0	17,544	0	17,544
A	1	MBB21	New Gas Services	1,903,924	2,631,839	78,955	2,552,884	0	2,552,884
A	1	MBC21	New Gas Services Carryover	22,455	31,040	0	31,040	0	31,040
A	2	MCB21	Corrosion Control	109,514	151,384	0	151,384	0	151,384
A	1	MDB21	Abandon Gas Services	154,381	213,404	0	213,404	0	213,404
A	1	MDC21	Abandoned Gas Service Carryover	6,947	9,603	0	9,603	0	9,603
A	2	MEB21	Gas Service Upgrades (Renewals)	1,319,316	1,823,722	0	1,823,722	0	1,823,722
A	2	MEC21	Gas Service Upgrades Carryover	8,514	11,769	0	11,769	0	11,769
A	2	MFB21	Gas Meter Installation Company Driven	591,407	817,516	0	817,516	0	817,516
A	2	MFC21	Gas Meter Installation Company Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MGB21	Gas Meter Installation : Customer Driven	648,284	896,139	0	896,139	0	896,139
A	1	MGC21	Gas Meter Installation : Customer Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MHB21	Meter Purchases - Company	325,579	450,056	0	450,056	0	450,056
A	1	MIB21	Meter Purchases - Customer	384,583	531,618	0	531,618	0	531,618
A	2	MMB21	Gas Distribution System Improvements - Systems Operations	175,640	242,791	0	242,791	0	242,791
A	2	MMC21	Gas Disribution System Improvements - Systems Operations-Carryover	26,250	36,286	0	36,286	0	36,286
			Totals:	6,114,766	8,452,586	78,955	8,373,631	0	8,373,631

Capital Budget System • Report • Budget Item Requests

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Communications:Gas**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	ECG01	Replace and Upgrade Gas SCADA Master	16,556	22,886	0	22,886	0	22,886
A	2	ECG02	Provide New Gas SCADA Communications - various locations	8,453	11,685	0	11,685	0	11,685
			Totals:	25,010	34,572	0	34,572	0	34,572

Printed: 2/15/2021 2:43:24 PM

Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Distribution:Gas**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	1	JAB00	Gas Main Extensions over $40,000	1,917,085	2,650,032	265,003	2,385,028	0	2,385,028
A	1	JAC00	Gas Main Extensions carryover	45,945	63,511	0	63,511	0	63,511
A	2	JHB00	Gas Highway Projects City State	2,102,792	2,906,740	0	2,906,740	0	2,906,740
A	2	JHC00	Gas Highway Projects Carryover	7,511	10,382	0	10,382	0	10,382
A	2	JPB01	Asphalt Restoration 2020 Projects	551,350	762,144	0	762,144	0	762,144
A	3	JPB03	Distribution Gas Main Upgrades	310,419	429,100	0	429,100	0	429,100
A	2	JPB04	Farm Tap Replacement	362,196	500,672	0	500,672	0	500,672
A	2	JPB05	Regulator Station OPP/Redundancy	172,469	238,408	0	238,408	0	238,408
A	3	JPB21	Heater Replacement - Newfields Station	777,819	1,075,197	0	1,075,197	0	1,075,197
A	2	JPB22	Henry Law Ave Dover Replacement	141,665	195,827	0	195,827	0	195,827
A	2	JPB23	Plaistow System Improvement Phase 2	360,450	498,258	0	498,258	0	498,258
A	3	JPB24	Bartlett Avenue/High Street Stations Rebuild-PHASE 1	389,818	538,855	0	538,855	0	538,855
A	3	JPB25	Monroe Street Station Upgrade	271,408	375,174	0	375,174	0	375,174
A	1	JPB26	Stard Road Mini-DR Station Install	282,908	391,071	0	391,071	0	391,071
A	3	JPB27	Rutland Street Station Rebuild	338,408	467,790	0	467,790	0	467,790
A	2	JPB28	Ashbrook Rd., Exeter	154,182	213,130	0	213,130	0	213,130
A	2	JPB29	Partridge Green Replacement Rochester	633,242	875,346	0	875,346	0	875,346
A	2	JPB30	GIS Data Development - Services & Station Utilities	104,000	143,762	0	143,762	0	143,762
A	2	JPB31	AC Interference Mitigation (NH)	48,068	66,445	0	66,445	0	66,445
A	2	JPB32	Railroad Ave. Rochester	874,095	1,208,283	0	1,208,283	0	1,208,283
A	2	JPB33	Borthwick Ave. Footbridge Crossing	199,988	276,448	0	276,448	0	276,448
A	2	JPB34	Middle Road System Improvement	456,051	630,410	0	630,410	0	630,410
A	2	JPB35	Atkinson System Improvement Phase 3	995,339	1,375,881	0	1,375,881	0	1,375,881
A	1	JPC01	Rochester Reinforcement - 99 PSIG Station-Carryover	419,661	580,107	0	580,107	0	580,107
A	1	JPC02	Rochester Reinforcement Phase 3 - 99 psig Main Carryover	1,696,334	2,344,883	0	2,344,883	0	2,344,883
A	1	JPC03	Atkinson System Improvement Phase 2 Carryover	165,471	228,735	0	228,735	0	228,735
			Totals:	13,778,675	19,046,590	265,003	18,781,587	0	18,781,587

Printed: 2/15/2021 2:43:44 PM

Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Tools, Shop, Garage:Gas**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	EAG01	Tools: Normal Additions and Replacements	33,497	33,497	0	33,497	0	33,497
A	2	EAG02	Tools: Normal Additions and Replacements - Systems Operations	17,000	17,000	0	17,000	0	17,000
A	3	EAG03	Normal add & replace- tools & equipment - Metering and FS	5,050	5,050	0	5,050	0	5,050
A	2	EAG04	Mueller Equipment	110,000	110,000	0	110,000	0	110,000
A	2	EAG05	Emergency Response Trailer	30,000	30,000	0	30,000	0	30,000
A	2	EAG06	TTQM Tools for OQ Training	20,000	20,000	0	20,000	0	20,000
			Totals:	215,547	215,547	0	215,547	0	215,547

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:39:35 PM

Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Office:Gas**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	EDG01	Office Furniture & Equipment- Normal Additions & Replacements	5,000	5,000	0	5,000	0	5,000
A	3	EDG02	Chair Replacement - Year 3 of 3 Year Replacement Program	9,000	9,000	0	9,000	0	9,000
			Totals:	14,000	14,000	0	14,000	0	14,000

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:40:14 PM

Capital Budget 2021 Northern NH										
Status	Priority	Budget Number	Description **Transportation:Gas**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	FGB01	#44- Metering- Van	1	1	0	1	0	1
A	2	FGB02	#58- Manager Gas Operations- SUV	1	1	0	1	0	1
A	2	FGB03	#13- Service- Weld Truck	1	1	0	1	0	1
A	2	FGB04	#47- Distribution- Backhoe	1	1	0	1	0	1
			Totals:	4	4	0	4	0	4

Printed: 2/15/2021 2:44:09 PM

Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Blankets:Gas**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	1	MAB21	Distribution System Improvements (Under $40,000)	414,364	572,785	0	572,785	0	572,785
A	1	MAC21	Distribution System Improvements (Under $40,000) Carryover	12,692	17,544	0	17,544	0	17,544
A	1	MBB21	New Gas Services	1,903,924	2,631,839	78,955	2,552,884	0	2,552,884
A	1	MBC21	New Gas Services Carryover	22,455	31,040	0	31,040	0	31,040
A	2	MCB21	Corrosion Control	109,514	151,384	0	151,384	0	151,384
A	1	MDB21	Abandon Gas Services	154,381	213,404	0	213,404	0	213,404
A	1	MDC21	Abandoned Gas Service Carryover	6,947	9,603	0	9,603	0	9,603
A	2	MEB21	Gas Service Upgrades (Renewals)	1,319,316	1,823,722	0	1,823,722	0	1,823,722
A	2	MEC21	Gas Service Upgrades Carryover	8,514	11,769	0	11,769	0	11,769
A	2	MFB21	Gas Meter Installation Company Driven	591,407	817,516	0	817,516	0	817,516
A	2	MFC21	Gas Meter Installation Company Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MGB21	Gas Meter Installation : Customer Driven	648,284	896,139	0	896,139	0	896,139
A	1	MGC21	Gas Meter Installation : Customer Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MHB21	Meter Purchases - Company	325,579	450,056	0	450,056	0	450,056
A	1	MIB21	Meter Purchases - Customer	384,583	531,618	0	531,618	0	531,618
A	2	MMB21	Gas Distribution System Improvements - Systems Operations	175,640	242,791	0	242,791	0	242,791
A	2	MMC21	Gas Disribution System Improvements - Systems Operations-Carryover	26,250	36,286	0	36,286	0	36,286
			Totals:	6,114,766	8,452,586	78,955	8,373,631	0	8,373,631

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:39:54 PM

Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Structures:General**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	GPB01	Normal Improvements to Portsmouth Facility	18,000	18,000	0	18,000	0	18,000
A	3	GPB02	HVAC Upgrades	800,000	800,000	0	800,000	0	800,000
A	3	GPB04	Facilities Improvements - Portsmouth	300,000	300,000	0	300,000	0	300,000
			Totals:	1,118,000	1,118,000	0	1,118,000	0	1,118,000

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(9) The utility's chart of accounts, if different from the uniform system of accounts established by the commission as part of Puc 300, Puc 400, Puc 500, Puc 600 and Puc 700.

Response:

Please see PUC 1604.01(a) - 9 Attachment 1 for the chart of accounts.

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-00-00-101-00-00	NH GAS PLANT IN SERVICE	Assets
30-40-00-00-101-02-00	RIGHT OF USE ASSETS	Assets
30-40-00-00-101-02-01	CONTRA RIGHT OF USE ASSETS	Assets
30-40-00-00-101-03-00	GAS PLANT IN SERVICE - NH - CIS	Assets
30-40-00-00-101-90-00	NH GAS PLANT IN SERVICE (GA CONTRA)	Assets
30-40-00-00-106-00-00	GS CMPL CNST NT CLSS - NH	Assets
30-40-00-00-107-00-00	GAS CONST IN PROGRESS - NH	Assets
30-40-00-00-107-01-02	RWIP GAS SALVAGE	Assets
30-40-00-00-107-01-03	RWIP GAS COST OF REMOVAL	Assets
30-40-00-00-107-90-00	CONST WORK IN PROGRESS-CONST (GA) - NH	Assets
30-40-00-00-108-01-00	ACCUM DEPR GENERAL PLANT - NH	Assets
30-40-00-00-108-01-05	ACCUM DEPREC RESERVE - NH	Assets
30-40-00-00-108-04-00	ACCUMULATED DEPRECIATION - COR - NH	Assets
30-40-00-00-108-90-00	ACCUM DEPR - GENL PLANT - NH (GA CONTRA)	Assets
30-40-00-00-111-05-00	ACCUM AMORT COMPUTER SW - NH	Assets
30-40-00-00-111-05-01	COMPUTER SW RETIREMENT - NH	Assets
30-40-00-00-111-07-00	ACCUM AMORT - NH - CIS	Assets
30-40-00-00-114-00-00	GROSS PLANT ACQUISITION ADJ - NH	Assets
30-40-00-00-114-01-00	GROSS PAA - UNREGULATED - NH	Assets
30-40-00-00-131-00-01	CASH - SUSPENSE - NH	Assets
30-40-00-00-131-00-02	CASH - SUPPLY - NH	Assets
30-40-00-00-135-00-00	CASH - PETTY CASH - NH	Assets
30-40-00-00-136-00-00	MARGIN DEPOSIT	Assets
30-40-00-00-142-00-00	A/R - OTHER - NH	Assets
30-40-00-00-142-01-00	A/R- SALES - NH	Assets
30-40-00-00-142-01-01	A/R SALES SUSPENSE - NH	Assets
30-40-00-00-142-01-02	A/R- SALES - COG - NH	Assets
30-40-00-00-142-02-00	A/R MANUAL ENTRIES - NH	Assets
30-40-00-00-142-03-00	A/R SUNDRY - NH	Assets
30-40-00-00-142-03-02	A/R MISC ACCRUALS - NH	Assets
30-40-00-00-142-04-04	A/R REIMBURSABLE PROJECTS - NH	Assets
30-40-00-00-143-00-00	A/R - OTHER - NH	Assets
30-40-00-00-143-03-03	A/R DRUG SUBSIDY - NH	Assets
30-40-00-00-143-25-00	A/R CUST PURCH- WATER HEATERS - NH	Assets
30-40-00-00-144-00-00	AFDA - (BEG BAL) - DISTRIBUTION - NH	Assets
30-40-00-00-144-00-27	AFDA - NON-DISTRIBUTION - NH	Assets
30-40-00-00-144-01-00	ALLOW FOR DOUBTFUL ACCTS - NH - DISTR	Assets
30-40-00-00-144-04-00	AFDA - BEG BAL - NON DIST - NH	Assets
30-40-00-00-144-13-00	AFDA - UNBILLED REVENUE RECEIVABLE - NH	Assets
30-40-00-00-154-01-00	MATERIALS & SUPPLIES - NH	Assets
30-40-00-00-154-02-00	MATERIALS & SUPPLIES NU TRANSFER - NH	Assets
30-40-00-00-154-03-00	MATERIALS & SUPPLIES FGE TRANSFER	Assets
30-40-00-00-163-00-00	STORES EXP UNDISTRIBUTED - NH	Assets
30-40-00-00-163-01-00	STOREROOM OPERATING EXPENSE - NH	Assets
30-40-00-00-163-02-00	STOCK OVER & SHORT - NH	Assets
30-40-00-00-163-03-00	OBSOLETE STOCK - NH	Assets
30-40-00-00-163-05-00	STOREROOM - SHIPPING COSTS - NH	Assets
30-40-00-00-164-16-00	INVENTORY - NAT GAS SSNE (TENN GAS/TGP) - NH	Assets
30-40-00-00-165-01-00	PREPAID PROPERTY INSURANCE - NH	Assets
30-40-00-00-165-01-01	PREPAID INJURIES & DAMAGES INS - NH	Assets
30-40-00-00-165-02-00	PREPAID NH PUC ASSESSMENT - NH	Assets
30-40-00-00-165-04-01	FASB 87 - PREPAID PENSION - NH	Assets
30-40-00-00-165-11-00	PREPAID PROPERTY TAX - NH	Assets
30-40-00-00-165-12-00	PREPAID POSTAGE - NH	Assets
30-40-00-00-165-16-00	PREPAID HEALTH CLAIMS	Assets
30-40-00-00-165-19-00	OTHER MISC PREPAYMENT - NH	Assets
30-40-00-00-165-20-00	PREPAID GAS IRP PROGRAM - NH	Assets
30-40-00-00-173-01-00	ACCRUED REVENUE MISC	Assets
30-40-00-00-173-22-00	UNBILLED REVENUE - BASE - NH	Assets
30-40-00-00-173-28-00	ACCRUED REVENUE - RATE RELIEF - NH	Assets
30-40-00-00-173-30-00	PRICE RISK - CURRENT - NH	Assets
30-40-00-00-173-31-00	ERC SITE COSTS - CURRENT - NH	Assets
30-40-00-00-173-32-00	ACCRUED REV - WORK CAP - PEAK - NH	Assets
30-40-00-00-173-34-00	ACCRUED REV - BAD DEBT - PEAK - NH	Assets

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-00-00-173-36-00	ACCRUED REV - WORK CAP - OFF PEAK - NH	Assets
30-40-00-00-173-37-00	ACCRUED REV - BAD DEBT- OFF PEAK - NH	Assets
30-40-00-00-173-38-00	ACCRUED REV - RLIAP- NH	Assets
30-40-00-00-173-41-02	ACCRUED REVENUE EE - R - NH	Assets
30-40-00-00-173-41-06	ACCRUED REVENUE EE - CI - NH	Assets
30-40-00-00-173-77-00	ACCRUED REVENUE - RLIARA - NH	Assets
30-40-00-00-173-78-00	ACCRUED REVENUE - RATE CASE EXP - NH	Assets
30-40-00-00-173-80-00	ACCRUED REVENUE-EEBB RES - NH	Assets
30-40-00-00-173-81-00	ACCRUED REVENUE LRR - NH	Assets
30-40-00-00-173-82-00	ACCRUED REVENUE - OBF - NH - RESIDENTIAL	Assets
30-40-00-00-173-82-01	ACCRUED REVENUE - OBF - NH - C&I	Assets
30-40-00-00-173-90-00	ACCRUED REVENUE - CREDIT BALANCE RECLASS - NH	Assets
30-40-00-00-173-90-01	ACCRUED REVENUE - YEAREND FT AP ACCRUAL	Assets
30-40-00-00-174-05-00	VACATION ACCRUAL	Assets
30-40-00-00-174-25-00	INVENTORY - EXCHANGE GAS - W10	Assets
30-40-00-00-174-26-00	Inventory - Exchange Gas - Union	Assets
30-40-00-00-175-01-00	PRICE RISK ASSET - CURRENT - NH	Assets
30-40-00-00-175-02-00	PRICE RISK ASSET - NON CURRENT -NH	Assets
30-40-00-00-182-00-27	REG ASSET - NON-DIST BAD DEBT - NH	Assets
30-40-00-00-182-03-28	REG ASSET - RATE CASE - 2013 - NH	Assets
30-40-00-00-182-03-40	REG ASSET - RATE CASE - 2017 - NH	Assets
30-40-00-00-182-04-09	REGULATORY ASSET - PBOP FAS 158	Assets
30-40-00-00-182-04-10	REGULATORY ASSET - PENSION FAS 158	Assets
30-40-00-00-182-04-11	REGULATORY ASSET - SERP - NH	Assets
30-40-00-00-182-04-19	REGULATORY ASSET - OTHER PBOP	Assets
30-40-00-00-182-04-20	REGULATORY ASSET - OTHER PENSION	Assets
30-40-00-00-182-04-21	REGULATORY ASSET - OTHER SERP	Assets
30-40-00-00-182-14-00	REG ASSET - DEFERRED PANDEMIC COSTS - NH	Assets
30-40-00-00-182-15-00	REG ASSET - DEFERRED PROPERTY TAXES - NH	Assets
30-40-00-00-182-21-00	REG ASSET - WORK CAP - OFF PEAK COMM - NH	Assets
30-40-00-00-182-22-00	REG ASSET - OFF PEAK BAD DEBT - NH	Assets
30-40-00-00-182-29-00	REG ASSET - ERC COSTS - NH - VOUCHERS	Assets
30-40-00-00-182-36-00	REG ASSET - ERC - PRIOR YEAR LAYERS - NH	Assets
30-40-00-00-182-42-00	REG ASSET - ERC COSTS - NH	Assets
30-40-00-00-182-44-00	REG ASSET - PRICE RISK - NC - NH	Assets
30-40-00-00-182-50-00	REGULATORY ASSET - SFAS109 - NH	Assets
30-40-00-00-182-81-00	REG ASSET - PNGTS RATE CASE - CURRENT NH	Assets
30-40-00-00-182-82-00	REG ASSET - GRANITE RATE CASE- NH	Assets
30-40-00-00-182-99-01	REG ASSET - OCA CONSULTING COSTS	Assets
30-40-00-00-183-00-00	PREL SURVEY & INVESTIGATION - NH	Assets
30-40-00-00-184-00-00	ENG & OPER OVERHEADS - NH	Assets
30-40-00-00-184-00-02	GENERAL OVERHEADS - NH	Assets
30-40-00-00-184-02-00	TRANS EXP LIGHT VEHICLES - NH	Assets
30-40-00-00-184-03-00	HEAVY TRUCKS - NH	Assets
30-40-00-00-184-04-00	GAS EXEMPT STOCK - NH	Assets
30-40-00-00-184-06-00	SMALL TOOLS - NH	Assets
30-40-00-00-184-08-00	CASH DISCOUNTS TAKEN - NH	Assets
30-40-00-00-184-12-01	LT MAINT & PARTS - NH	Assets
30-40-00-00-184-12-02	LT LEASING - NH	Assets
30-40-00-00-184-12-03	LT FUEL - NH	Assets
30-40-00-00-184-12-04	LT TAXES, REG, INS, TOLLS - NH	Assets
30-40-00-00-184-12-05	LT OTHER - NH	Assets
30-40-00-00-184-13-01	HT MAINT & PARTS - NH	Assets
30-40-00-00-184-13-02	HT LEASING - NH	Assets
30-40-00-00-184-13-03	HT FUEL - NH	Assets
30-40-00-00-184-13-04	HT TAXES, REG, INS, TOLLS - NH	Assets
30-40-00-00-184-13-05	HT OTHER - NH	Assets
30-40-00-00-185-01-00	NONPROD - GAS OPERATIONS - NH	Assets
30-40-00-00-186-10-00	PROPERTY TAX ABATEMENT REC - LT - NH	Assets
30-40-00-00-186-20-00	LT PORTION - IRP	Assets
30-40-00-00-186-27-02	CIS REPLACEMENT - NH	Assets
30-40-00-00-186-30-00	TRANSITION COSTS - NH	Assets
30-40-00-00-186-30-01	TRANSACTION COSTS - NH	Assets
30-40-00-00-186-50-00	PLANT AND M&S ACCRUALS - NH	Assets

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-00-00-186-80-00	GAS SUPPLIER REFUND A/R - NH	Assets
30-40-00-00-190-01-99	DEF FIT - DEBIT BALANCE RECLASS	Assets
30-40-00-00-190-02-99	DEF SIT - DEBIT BALANCE RECLASS	Assets
30-40-00-00-191-10-00	UNRECOVERED GAS COSTS - OFF PEAK COMM - NH	Assets
30-40-00-00-191-20-00	UNRECOVERED GAS COSTS - PEAK COMM - NH	Assets
30-40-00-00-191-40-00	DEFERRED HEDGING COSTS - NH	Assets
30-40-00-00-227-01-00	OPER LEASE OBLIG - NONCURRENT	Liabilities
30-40-00-00-232-03-23	RETIREE HEALTH INS CONTRIBUTIONS	Liabilities
30-40-00-00-232-05-02	A/P - CUSTOMER CREDIT BALANCES-NH	Liabilities
30-40-00-00-232-15-00	ACCTS PAYABLE OTHER	Liabilities
30-40-00-00-232-21-00	CUSTOMER REFUNDS - NH	Liabilities
30-40-00-00-232-21-01	A/P - CUSTOMER DEPOSIT REFUND - NH	Liabilities
30-40-00-00-232-80-00	A/P - CDFA FOR EEBB PROGRAM	Liabilities
30-40-00-00-232-80-01	A/P - CDFA FOR EEBB PROGRAM - 2015	Liabilities
30-40-00-00-235-01-00	CUSTOMER DEPOSITS ACTIVE - NH	Liabilities
30-40-00-00-235-03-00	CUSTOMER BILLED DEPOSITS - NH	Liabilities
30-40-00-00-235-09-01	A/P-UNCLAIMED CREDIT BALANCE REFUNDS	Liabilities
30-40-00-00-236-01-30	FED INC TAX CURRENT - NH	Liabilities
30-40-00-00-236-01-31	FED INC TAX PRIOR - NH	Liabilities
30-40-00-00-236-02-30	NH INC TAX - CURRENT	Liabilities
30-40-00-00-236-02-31	NH INC TAX - PRIOR	Liabilities
30-40-00-00-236-02-40	STATE BET-CURRENT	Liabilities
30-40-00-00-236-02-41	STATE BET- NH - PRIOR	Liabilities
30-40-00-00-236-03-10	TAXES FICA-NU NH	Liabilities
30-40-00-00-236-04-10	TAXES FEDERAL UNEMPLOYMNT-NU NH	Liabilities
30-40-00-00-236-06-11	TAXES UNEMPLOYMENT-NH	Liabilities
30-40-00-00-236-76-00	ACCRUED PROPERTY TAXES - NH	Liabilities
30-40-00-00-241-19-03	SALES TAX PAYABLE -CA-GST HST	Liabilities
30-40-00-00-242-00-00	MISC ACCRUED LIABILITIES - NH	Liabilities
30-40-00-00-242-03-20	ACCRUED HEALTH INSURANCE - NH	Liabilities
30-40-00-00-242-03-25	ACCRUED DENTAL INSURANCE - NH	Liabilities
30-40-00-00-242-04-01	ACCRUED LEGAL-LOCAL-NH	Liabilities
30-40-00-00-242-04-02	ACCRUED LEGAL-CORP-NH	Liabilities
30-40-00-00-242-04-03	ACCRUED LEGAL-POWER SUPPLY-NH	Liabilities
30-40-00-00-242-04-04	ACCRUED LEGAL-REGULATORY-NH	Liabilities
30-40-00-00-242-04-08	ACCRUED LEGAL-CLAIMS AND LITIGATION	Liabilities
30-40-00-00-242-05-05	ACCRUED PUC ASSESSMENT- NH	Liabilities
30-40-00-00-242-06-00	FAS 158 ADJ-SERP CURRENT - NH	Liabilities
30-40-00-00-242-26-00	ACCRUED INCENTIVE COMPENSATION - NH	Liabilities
30-40-00-00-242-30-00	ACCRUED VACATION-NH	Liabilities
30-40-00-00-242-31-10	INSURANCE CLAIMS RESERVE - NH	Liabilities
30-40-00-00-242-33-00	UNEARNED REVENUE - UNH CONTRACT - NH	Liabilities
30-40-00-00-242-37-00	CURRENT ERC LIABILITIES - NH	Liabilities
30-40-00-00-242-90-00	REGULATORY LIABILITIES CURRENT - NH	Liabilities
30-40-00-00-242-90-01	UNDISTRIB COMMODITY SUPPLIER REFUNDS - NH	Liabilities
30-40-00-00-242-90-02	MISC REG LIABILITY - NH	Liabilities
30-40-00-00-242-90-11	ATV RECONCILIATION ACCRUAL - NH-PEAK	Liabilities
30-40-00-00-242-90-25	REG LIAB - GAS SUPPLIER REFUNDS-NH	Liabilities
30-40-00-00-242-90-43	PRICE RISK LIABILITY SHORT TERM- NH	Liabilities
30-40-00-00-243-01-00	OPER LEASE OBLIG - CURRENT	Liabilities
30-40-00-00-244-00-00	PRICE RISK LIABILITY - NH	Liabilities
30-40-00-00-244-01-00	PRICE RISK LIABILITY - NC - NH	Liabilities
30-40-00-00-252-01-00	LT REIMB CONTRIBUTIONS - NH	Liabilities
30-40-00-00-253-03-01	LT ERC COSTS - NH	Liabilities
30-40-00-00-253-04-01	FASB 87 - ACCRUED PENSION	Liabilities
30-40-00-00-253-04-03	ACCRUED SFAS 106 LIABILITY - NH	Liabilities
30-40-00-00-253-04-11	FAS 158 ADJ - PENSION - NH	Liabilities
30-40-00-00-253-04-13	FAS 158 ADJ - PBOP - NH	Liabilities
30-40-00-00-253-04-14	FAS 158 ADJ - SERP - NH	Liabilities
30-40-00-00-254-01-00	REG LIAB - PRICE RISK - NC - NH	Liabilities
30-40-00-00-254-04-00	REGULATORY LIABILITY-COST OF REMOVAL-NH	Liabilities
30-40-00-00-254-05-00	REG LIAB - FAS109 COSTS - NH	Liabilities
30-40-00-00-254-05-01	REGULATORY LIABILITY - ASC 740 - NH	Liabilities
30-40-00-00-254-05-03	REGULATORY LIABILITY-ASC 740 REV REQ	Liabilities

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-00-00-254-90-25	REG LIAB - GAS SUPPLIER REFUND	Liabilities
30-40-00-00-282-01-66	DEF FIT- R & D	Liabilities
30-40-00-00-282-02-66	DEF SIT- R & D	Liabilities
30-40-00-00-283-00-23	ACC DEF FIT-NONCURRENT 27811	Liabilities
30-40-00-00-283-00-43	ACC DEF SIT-NONCURRENT 27810	Liabilities
30-40-00-00-283-01-31	DEF FIT - ACCEL DEPR - NH	Liabilities
30-40-00-00-283-01-34	DEF FIT - SFAS 106 OPEB - NH	Liabilities
30-40-00-00-283-01-35	DEF FIT - PENSION FAS 87 - NH	Liabilities
30-40-00-00-283-01-42	DEF FIT - DEF RATE CASE COSTS - NH	Liabilities
30-40-00-00-283-01-43	DEF FIT - REMEDIATION - NH	Liabilities
30-40-00-00-283-01-51	DEF FIT - TRANSITION COSTS - NH	Liabilities
30-40-00-00-283-01-52	DEF FIT - TRANSACTION COSTS - NH	Liabilities
30-40-00-00-283-01-55	DEF FIT - OTHER - NH	Liabilities
30-40-00-00-283-01-59	DEF FIT - FASB 158 ADJ - PBOP - NH	Liabilities
30-40-00-00-283-01-60	DEF FIT- PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-01-63	DEF FIT - SFAS 158 SERP - NH	Liabilities
30-40-00-00-283-01-64	DEF FIT - INSURANCE CLAIM RESERVE - NH	Liabilities
30-40-00-00-283-01-99	DEF FIT - DEBIT BALANCE RECLASS	Liabilities
30-40-00-00-283-02-31	DEF SIT- ACCEL DEPR - NH	Liabilities
30-40-00-00-283-02-34	DEF SIT- SFAS 106 OPEB - NH	Liabilities
30-40-00-00-283-02-35	DEF SIT- PENSION FAS 87 - NH	Liabilities
30-40-00-00-283-02-42	DEF SIT- DEF RATE CASE COSTS - NH	Liabilities
30-40-00-00-283-02-43	DEF SIT- REMEDIATION - NH	Liabilities
30-40-00-00-283-02-51	DEF SIT - TRANSITION COSTS - NH	Liabilities
30-40-00-00-283-02-52	DEF SIT - TRANSACTION COSTS - NH	Liabilities
30-40-00-00-283-02-59	DEF SIT- FASB 158 ADJ - PBOP - NH	Liabilities
30-40-00-00-283-02-60	DEF SIT- PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-02-63	DEF SIT - SFAS 158 SERP - NH	Liabilities
30-40-00-00-283-02-64	DEF SIT - INSURANCE CLAIM RESERVE- NH	Liabilities
30-40-00-00-283-02-99	DEF SIT - DEBIT BALANCE RECLASS	Liabilities
30-40-00-00-283-03-03	TCJA REV REQ GROSS-UP	Liabilities
30-40-00-00-283-05-01	ACCUM DEF (ASC 740) GROSS-UP	Liabilities
30-40-00-00-283-11-38	DEF FIT - BAD DEBT- NH	Liabilities
30-40-00-00-283-11-39	DEF FIT - ACCRUED REVENUE - NH	Liabilities
30-40-00-00-283-11-41	DEF FIT- PREPAID PROPERTY TAX - NH	Liabilities
30-40-00-00-283-12-38	DEF SIT- BAD DEBT - NH	Liabilities
30-40-00-00-283-12-39	DEF SIT- ACCRUED REVENUE - NH	Liabilities
30-40-00-00-283-12-41	DEF SIT- PREPAID PROPERTY TAX - NH	Liabilities
30-40-00-00-283-91-59	DEF FIT - SFAS 158 PBOP - NH	Liabilities
30-40-00-00-283-91-60	DEF FIT - PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-91-63	DEF FIT - SFAS 158 SERP - NH	Liabilities
30-40-00-00-283-92-59	DEF SIT - SFAS 158 PBOP - NH	Liabilities
30-40-00-00-283-92-60	DEF SIT - PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-92-63	DEF SIT - SFAS 158 SERP - NH	Liabilities
30-40-01-00-431-00-99	INVENTORY FINANCE CHARGES - PEAK - NH	Expenses
30-40-01-00-921-03-00	DUES & SUBSCRIPTIONS	Expenses
30-40-01-00-923-00-02	OS LEGAL - MISC	Expenses
30-40-01-00-928-01-00	REG COMM ASSESSMENT/FEES-NH	Expenses
30-40-01-00-928-02-00	REG COMM EXP - MISC-NH	Expenses
30-40-01-00-928-03-00	REG COMM EXP - LEGAL-NH	Expenses
30-40-01-10-419-00-00	INTEREST INCOME-DMD-COM-P-NH	Revenues
30-40-01-10-431-00-00	INTEREST EXPENSE-DMD-COM-P-NH	Expenses
30-40-01-13-419-00-00	INTEREST INCOME-WC-P-NH	Revenues
30-40-01-13-431-00-00	INTEREST EXPENSE-WC-P-NH	Expenses
30-40-01-14-419-00-00	INTEREST INCOME-BAD DEBT-P-NH	Revenues
30-40-01-14-431-00-00	INTEREST EXPENSE-BAD DEBT-P-NH	Expenses
30-40-01-40-419-00-00	INTEREST INCOME-DMD-COM-OP-NH	Revenues
30-40-01-40-431-00-00	INTEREST EXPENSE-DMD-COM-OP-NH	Expenses
30-40-01-43-419-00-00	INTEREST INCOME-WC-OP-NH	Revenues
30-40-01-43-431-00-00	INTEREST EXPENSE-WC-OP-NH	Expenses
30-40-01-44-419-00-00	INTEREST INCOME-BAD DEBT-OP-NH	Revenues
30-40-01-44-431-00-00	INTEREST EXPENSE-BAD DEBT-OP-NH	Expenses
30-40-01-70-419-00-00	INT INC-SUP REF-DEMAND-NH	Revenues
30-40-01-70-431-00-00	INT EXP-SUP REF-DEMAND-NH	Expenses

Account Code	Account Description	Type
30-40-01-71-419-00-00	INT INC-SUP REF - COMMODITY - NH	Revenues
30-40-01-71-431-00-00	INT EXP-SUP REF - COMMODITY - NH	Expenses
30-40-01-72-419-10-05	INTEREST INCOME- LDAC EEC-NH	Revenues
30-40-01-72-431-10-05	INTEREST EXPENSE- LDAC EEC	Expenses
30-40-01-72-495-00-99	LDAC-EEC LOST BASE REVENUE	Revenues
30-40-01-77-419-00-00	INTEREST INCOME-RLIARA-NH	Revenues
30-40-01-77-431-00-00	INTEREST EXPENSE-RLIARA-NH	Expenses
30-40-01-78-419-00-00	INTEREST INCOME - RATE CASE EXP - NH	Revenues
30-40-01-78-431-00-00	INTEREST EXPENSE - RATE CASE EXP - NH	Expenses
30-40-01-81-419-00-00	INTEREST INCOME - LRA - NH	Revenues
30-40-01-81-431-00-00	INTEREST EXPENSE - LRA - NH	Expenses
30-40-02-00-923-30-00	MKT DEV - GENERAL -NH	Expenses
30-40-02-00-930-24-00	MISC GENERAL EXPENSES - NH	Expenses
30-40-02-50-184-07-00	WATER HEATER OVERHEADS - NH	Assets
30-40-02-50-923-06-00	USC - WATER HEATER PROGRAM (GAS)-NH	Expenses
30-40-03-00-408-03-10	TAXES FICA - NH	Expenses
30-40-03-00-408-04-10	TAXES FEDERAL UNEMPLOYMENT - NH	Expenses
30-40-03-00-408-06-11	TAXES UNEMPLOYMENT - NH	Expenses
30-40-03-00-408-08-10	TAXES STATE HEALTH - NH	Expenses
30-40-03-00-426-01-00	PENALTIES-NH	Expenses
30-40-03-00-426-10-00	DONATIONS - NH	Expenses
30-40-03-00-920-05-00	INCENTIVE COMPENSATION - NH	Expenses
30-40-03-00-926-00-00	EMPL PENSION-PAYROLL	Expenses
30-40-03-00-926-01-00	EMPL PENSION-401K	Expenses
30-40-03-00-926-02-01	FASB 87- PENSION - SERVICE	Expenses
30-40-03-00-926-02-20	FASB 87- PENSION - OTHER	Expenses
30-40-03-00-926-03-00	HEALTH INSUR MEDICAL ONLY	Expenses
30-40-03-00-926-03-01	HEALTH INS - EMP CONTR - MEDICAL ONLY	Expenses
30-40-03-00-926-03-03	HEALTH INS - DRUG SUBSIDY	Expenses
30-40-03-00-926-04-00	EMPL BENEFIT-LIFE INSURANCE	Expenses
30-40-03-00-926-06-00	EMPL BENEFITS OTHER-USC	Expenses
30-40-03-00-926-06-01	EMP BENEFITS OTHER - SHARED - NH	Expenses
30-40-03-00-926-09-00	SFAS 106- PBOP - SERVICE	Expenses
30-40-03-00-926-09-19	SFAS 106- PBOP - OTHER	Expenses
30-40-03-00-926-10-00	EMPL PENSION FUND SERVICES	Expenses
30-40-03-00-926-11-00	MISC GENERAL EXPENSE	Expenses
30-40-03-00-926-12-00	DENTAL INSURANCE	Expenses
30-40-03-00-926-12-01	DENTAL INSURANCE - EMP CONTRIBUTION	Expenses
30-40-03-00-926-13-00	AD&D INSURANCE	Expenses
30-40-03-00-926-14-00	LTD INSURANCE	Expenses
30-40-03-00-926-24-00	VISION INSURANCE	Expenses
30-40-03-00-926-24-01	VISION - EE CONTR	Expenses
30-40-08-00-419-00-00	INTEREST INCOME-MISC-NH	Revenues
30-40-08-00-419-01-00	INTEREST INCOME - HEDGING - NH	Revenues
30-40-08-00-419-09-00	INT INC-OTHER - NH	Revenues
30-40-08-00-419-09-01	INT INC - CASH POOL - NH	Revenues
30-40-08-00-421-00-00	MISC NON OPER INCOME - NH	Revenues
30-40-08-00-426-10-00	DONATIONS - NH	Expenses
30-40-08-00-427-00-00	INTEREST ON LT DEBT - NH	Expenses
30-40-08-00-428-00-00	AMORT OF DEBT EXPENSE - NH	Expenses
30-40-08-00-430-00-00	INTEREST EXPENSE - ASSOC. CO. - NH	Expenses
30-40-08-00-431-00-00	OTHER INTEREST EXPENSE - NH	Expenses
30-40-08-00-431-01-00	INTEREST EXPENSE - HEDGING - NH	Expenses
30-40-08-00-431-32-00	INT EXP-NON COMPETE LIABILITY	Expenses
30-40-08-00-457-00-01	RENTAL INCOME - GRANITE	Revenues
30-40-08-00-457-00-02	RENTAL INCOME - USOURCE	Revenues
30-40-08-00-457-00-03	RENTAL INCOME - USC	Revenues
30-40-08-00-480-00-99	CONVERTED REVENUE RESIDENTIAL NON EXT	Revenues
30-40-08-00-481-00-99	CONVERTED REVENUE COMMERCIAL NON EXT	Revenues
30-40-08-00-481-02-99	CONVERTED REVENUE INDUSTRIAL NON EXT	Revenues
30-40-08-00-481-10-01	SIMPLEX NU CONVERTED REVENUE	Revenues
30-40-08-00-481-11-01	NAT GYPSUM NU CONVERTED REVENUE	Revenues
30-40-08-00-481-12-01	FOSS NU CONVERTED REVENUE	Revenues
30-40-08-00-485-00-00	UNBILLED SALE	Revenues

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-08-00-487-00-01	LATE PAYMENT FEE - RES - NH	Revenues
30-40-08-00-487-00-02	LATE PAYMENT FEE - COMM - NH	Revenues
30-40-08-00-487-00-03	LATE PAYMENT FEE - ANCILLARY SERVICES	Revenues
30-40-08-00-488-00-03	RECONNECT FEE - NH	Revenues
30-40-08-00-488-00-04	UNAUTHORIZED USE OF GAS - NH	Revenues
30-40-08-00-488-00-05	POOL ADMINISTRATION	Revenues
30-40-08-00-488-00-06	3RD PARTY BILLING	Revenues
30-40-08-00-488-00-07	CUSTOMER TELEMETERING	Revenues
30-40-08-00-488-00-08	METER TEST REVENUE	Revenues
30-40-08-00-488-00-09	CUSTOMER RE-ENTRY FEE	Revenues
30-40-08-00-489-01-01	R-6 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-02	R-11 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-03	R-5 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-04	R-10 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-99	CONVERTED REVENUE RESIDENTIAL EXT	Revenues
30-40-08-00-489-02-99	CONVERTED REVENUE COMMERCIAL EXT	Revenues
30-40-08-00-489-03-99	CONVERTED REVENUE INDUSTRIAL EXT	Revenues
30-40-08-00-489-11-01	NAT GYPSUM NU CONVERTED REVENUE	Revenues
30-40-08-00-489-12-00	FOSS NU CONVERTED REVENUE	Revenues
30-40-08-00-489-12-01	Foss W-EXT-Excess (3)	Revenues
30-40-08-00-493-00-02	RENTAL INCOME -USOURCE	Revenues
30-40-08-00-495-10-01	UNBILLED REVENUE - SEASONALITY - NH	Revenues
30-40-08-00-495-50-00	RATE RELIEF - NU NH	Revenues
30-40-08-00-921-01-08	BANK FEES & COMMITMENT FEES - NH	Expenses
30-40-08-00-921-01-11	CREDIT RATING FEES	Expenses
30-40-08-00-923-00-00	OS- LEGAL CLAIMS AND LITIGATIONS	Expenses
30-40-08-00-923-00-01	OS LEGAL - CORP-NH	Expenses
30-40-08-00-924-00-00	PROPERTY INSURANCE	Expenses
30-40-08-00-925-00-00	D & O AND FIDUCIARY	Expenses
30-40-08-00-925-02-00	GENERAL LIABILITY	Expenses
30-40-08-00-925-02-02	GENERAL LIABILITY CLAIMS	Expenses
30-40-08-00-925-04-00	WORKERS COMPENSATION EXP	Expenses
30-40-08-00-930-02-00	TRUSTEE/REGISTRAR EXPENSE - NH	Expenses
30-40-08-01-480-01-01	R-6 W-NEXT-Customer Charge	Revenues
30-40-08-01-480-01-02	R-11 W-NEXT-Customer Charge	Revenues
30-40-08-01-480-02-01	R-5 W-NEXT-Customer Charge	Revenues
30-40-08-01-480-02-02	R-10 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-01-01	G-40 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-01-02	G-50 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-02-01	G-41 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-02-02	G-51 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-03-01	G-42 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-03-02	G-52 W-NEXT-Customer Charge	Revenues
30-40-08-01-489-01-01	R-6 W-EXT-Customer Charge	Revenues
30-40-08-01-489-01-02	R-11 W-EXT-Customer Charge	Revenues
30-40-08-01-489-01-03	R-5 W-EXT-Customer Charge	Revenues
30-40-08-01-489-01-04	R-10 W-EXT-Customer Charge	Revenues
30-40-08-01-489-02-01	G-40 W-EXT-Customer Charge	Revenues
30-40-08-01-489-02-02	G-50 W-EXT-Customer Charge	Revenues
30-40-08-01-489-03-01	G-41 W-EXT-Customer Charge	Revenues
30-40-08-01-489-03-02	G-51 W-EXT-Customer Charge	Revenues
30-40-08-01-489-04-01	G-42 W-EXT-Customer Charge	Revenues
30-40-08-01-489-04-02	G-52 W-EXT-Customer Charge	Revenues
30-40-08-01-489-11-01	Nat Gypsum W-EXT-Customer Charge	Revenues
30-40-08-01-489-12-01	Foss W-EXT-Customer Charge	Revenues
30-40-08-02-480-01-01	R-6 W-NEXT-First Step	Revenues
30-40-08-02-480-01-02	R-11 W-NEXT-First Step	Revenues
30-40-08-02-480-02-01	R-5 W-NEXT-First Step	Revenues
30-40-08-02-480-02-02	R-10 W-NEXT-First Step	Revenues
30-40-08-02-481-01-01	G-40 W-NEXT-First Step	Revenues
30-40-08-02-481-01-02	G-50 W-NEXT-First Step	Revenues
30-40-08-02-481-02-01	G-41 W-NEXT-First Step	Revenues
30-40-08-02-481-02-02	G-51 W-NEXT-First Step	Revenues
30-40-08-02-481-03-01	G-42 W-NEXT-First Step	Revenues

Account Code	Account Description	Type
30-40-08-02-481-03-02	G-52 W-NEXT-First Step	Revenues
30-40-08-02-489-01-01	R-6 W-EXT-First Step	Revenues
30-40-08-02-489-01-02	R-11 W-EXT-First Step	Revenues
30-40-08-02-489-01-04	R-10 W-EXT-First Step	Revenues
30-40-08-02-489-02-01	G-40 W-EXT-First Step	Revenues
30-40-08-02-489-02-02	G-50 W-EXT-First Step	Revenues
30-40-08-02-489-03-01	G-41 W-EXT-First Step	Revenues
30-40-08-02-489-03-02	G-51 W-EXT-First Step	Revenues
30-40-08-02-489-04-01	G-42 W-EXT-First Step	Revenues
30-40-08-02-489-04-02	G-52 W-EXT-First Step	Revenues
30-40-08-02-489-11-01	Nat Gypsum W-EXT-First Step	Revenues
30-40-08-02-489-12-01	Foss W-EXT-First Step	Revenues
30-40-08-03-480-01-01	R-6 W-NEXT-Excess	Revenues
30-40-08-03-480-01-02	R-11 W-NEXT-Excess	Revenues
30-40-08-03-480-02-01	R-5 W-NEXT-Excess	Revenues
30-40-08-03-480-02-02	R-10 W-NEXT-Excess	Revenues
30-40-08-03-481-01-01	G-40 W-NEXT-Excess	Revenues
30-40-08-03-481-01-02	G-50 W-NEXT-Excess	Revenues
30-40-08-03-481-02-02	G-51 W-NEXT-Excess	Revenues
30-40-08-03-481-12-01	Foss W-NEXT-Excess	Revenues
30-40-08-03-489-01-01	R-6 W-EXT-Excess	Revenues
30-40-08-03-489-01-02	R-11 W-EXT-Excess	Revenues
30-40-08-03-489-01-04	R-10 W-EXT-Excess	Revenues
30-40-08-03-489-02-01	G-40 W-EXT-Excess	Revenues
30-40-08-03-489-02-02	G-50 W-EXT-Excess	Revenues
30-40-08-03-489-03-02	G-51 W-EXT-Excess	Revenues
30-40-08-03-489-12-01	Foss W-EXT-Excess	Revenues
30-40-08-04-481-12-01	Foss W-NEXT-Excess (2)	Revenues
30-40-08-04-489-12-01	Foss W-EXT-Excess (2)	Revenues
30-40-08-05-481-12-01	Foss S-NEXT-Excess (3)	Revenues
30-40-08-05-489-12-01	Foss S-EXT-Excess (3)	Revenues
30-40-08-06-480-01-01	R-6 S-NEXT-Customer Charge	Revenues
30-40-08-06-480-01-02	R-11 S-NEXT-Customer Charge	Revenues
30-40-08-06-480-02-01	R-5 S-NEXT-Customer Charge	Revenues
30-40-08-06-480-02-02	R-10 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-01-01	G-40 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-01-02	G-50 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-02-01	G-41 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-02-02	G-51 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-03-01	G-42 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-03-02	G-52 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-10-01	Simplex S-NEXT-Customer Charge	Revenues
30-40-08-06-481-12-01	Foss S-NEXT-Customer Charge	Revenues
30-40-08-06-489-01-01	R-6 S-EXT-Customer Charge	Revenues
30-40-08-06-489-01-02	R-11 S-EXT-Customer Charge	Revenues
30-40-08-06-489-01-03	R-5 S-EXT-Customer Charge	Revenues
30-40-08-06-489-01-04	R-10 S-EXT-Customer Charge	Revenues
30-40-08-06-489-02-01	G-40 S-EXT-Customer Charge	Revenues
30-40-08-06-489-02-02	G-50 S-EXT-Customer Charge	Revenues
30-40-08-06-489-03-01	G-41 S-EXT-Customer Charge	Revenues
30-40-08-06-489-03-02	G-51 S-EXT-Customer Charge	Revenues
30-40-08-06-489-04-01	G-42 S-EXT-Customer Charge	Revenues
30-40-08-06-489-04-02	G-52 S-EXT-Customer Charge	Revenues
30-40-08-06-489-11-01	Nat Gypsum S-EXT-Customer Charge	Revenues
30-40-08-06-489-12-01	Foss S-EXT-Customer Charge	Revenues
30-40-08-07-480-01-01	R-6 S-NEXT-First Step	Revenues
30-40-08-07-480-01-02	R-11 S-NEXT-First Step	Revenues
30-40-08-07-480-02-01	R-5 S-NEXT-First Step	Revenues
30-40-08-07-480-02-02	R-10 S-NEXT-First Step	Revenues
30-40-08-07-481-01-01	G-40 S-NEXT-First Step	Revenues
30-40-08-07-481-01-02	G-50 S-NEXT-First Step	Revenues
30-40-08-07-481-02-01	G-41 S-NEXT-First Step	Revenues
30-40-08-07-481-02-02	G-51 S-NEXT-First Step	Revenues
30-40-08-07-481-03-01	G-42 S-NEXT-First Step	Revenues

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-08-07-481-03-02	G-52 S-NEXT-First Step	Revenues
30-40-08-07-481-10-01	Simplex S-NEXT-First Step	Revenues
30-40-08-07-481-11-01	Nat Gypsum S-NEXT-First Step	Revenues
30-40-08-07-481-12-01	Foss S-NEXT-First Step	Revenues
30-40-08-07-489-01-01	R-6 S-EXT-First Step	Revenues
30-40-08-07-489-01-02	R-11 S-EXT-First Step	Revenues
30-40-08-07-489-01-04	R-10 S-EXT-First Step	Revenues
30-40-08-07-489-02-01	G-40 S-EXT-First Step	Revenues
30-40-08-07-489-02-02	G-50 S-EXT-First Step	Revenues
30-40-08-07-489-03-01	G-41 S-EXT-First Step	Revenues
30-40-08-07-489-03-02	G-51 S-EXT-First Step	Revenues
30-40-08-07-489-04-01	G-42 S-EXT-First Step	Revenues
30-40-08-07-489-04-02	G-52 S-EXT-First Step	Revenues
30-40-08-07-489-11-01	Nat Gypsum S-EXT-First Step	Revenues
30-40-08-07-489-12-01	Foss S-EXT-First Step	Revenues
30-40-08-08-480-01-01	R-6 S-NEXT-Excess	Revenues
30-40-08-08-480-01-02	R-11 S-NEXT-Excess	Revenues
30-40-08-08-480-02-01	R-5 S-NEXT-Excess	Revenues
30-40-08-08-480-02-02	R-10 S-NEXT-Excess	Revenues
30-40-08-08-481-01-01	G-40 S-NEXT-Excess	Revenues
30-40-08-08-481-01-02	G-50 S-NEXT-Excess	Revenues
30-40-08-08-481-02-02	G-51 S-NEXT-Excess	Revenues
30-40-08-08-481-12-01	Foss S-NEXT-Excess	Revenues
30-40-08-08-489-01-01	R-6 S-EXT-Excess	Revenues
30-40-08-08-489-01-02	R-11 S-EXT-Excess	Revenues
30-40-08-08-489-01-04	R-10 S-EXT-Excess	Revenues
30-40-08-08-489-02-01	G-40 S-EXT-Excess	Revenues
30-40-08-08-489-02-02	G-50 S-EXT-Excess	Revenues
30-40-08-08-489-03-02	G-51 S-EXT-Excess	Revenues
30-40-08-08-489-12-01	Foss S-EXT-Excess	Revenues
30-40-08-09-481-12-01	Foss S-NEXT-Excess (2)	Revenues
30-40-08-09-489-12-01	Foss S-EXT-Excess (2)	Revenues
30-40-09-00-875-00-01	INTERVAL DATA NU NH	Expenses
30-40-09-00-902-00-00	CUST ACCTS METER READ EXP NH	Expenses
30-40-09-00-921-17-00	TELEPHONE SERVICE - SERVICE CENTER - NH	Expenses
30-40-10-00-403-00-00	DEPRECIATION GAS - NH	Expenses
30-40-10-00-403-24-00	DEPRECIATION GAS - NH	Expenses
30-40-10-00-404-03-00	AMORTIZATION OF COMP SOFTWARE	Expenses
30-40-10-00-404-04-00	AMORT INTANGIBLE SOFTWARE - NH	Expenses
30-40-10-00-406-00-00	AMORT-INVESTMNT TAX CREDIT - NH	Expenses
30-40-10-00-407-01-00	AMORTIZATION - EXCESS ADIT - BASE REV	Expenses
30-40-10-00-407-04-19	AMORTIZATION OF OTHER PBOP COST	Expenses
30-40-10-00-407-04-20	AMORTIZATION OF OTHER PENSION COST	Expenses
30-40-10-00-407-04-21	AMORT OF OTHER SERP COST	Expenses
30-40-10-00-407-09-01	AMORT EXP-FAS 109 REG LIABILITY - GAS - NH	Expenses
30-40-10-00-407-11-00	AMORT - NON DIST BAD DEBT REG ASSET - ME	Expenses
30-40-10-00-408-00-00	OTHER TAXES	Expenses
30-40-10-00-408-02-10	NH SURPLUS TAX	Expenses
30-40-10-00-408-02-18	NH BET TAX EXPENSE	Expenses
30-40-10-00-408-10-00	PAYROLL TAXES CAPTIALIZED - NH	Expenses
30-40-10-00-408-12-00	LOCAL OPER. PROPERTY TAX - NH	Expenses
30-40-10-00-408-12-01	LOCAL OPER PROPERTY TAX ABATEMENTS - NH	Expenses
30-40-10-00-409-01-30	FED INCOME TAX CURRENT - GAS - NH	Expenses
30-40-10-00-409-01-31	FED INCOME TAX - PRIOR - GAS - NH	Expenses
30-40-10-00-409-01-32	FED INCOME TAX - NON OPER - GAS - NH	Expenses
30-40-10-00-409-02-30	STATE INCOME TAX EXP - CURRENT - NH	Expenses
30-40-10-00-409-02-31	STATE INCOME TAX EXP - PRIOR - NH	Expenses
30-40-10-00-409-02-32	STATE INC TAX-NON OPER-CURRENT-NH	Expenses
30-40-10-00-410-01-00	DEF FIT EXP - NH	Expenses
30-40-10-00-410-01-30	DEF FIT EXP-ACCEL DEPRECIATION - NH	Expenses
30-40-10-00-410-01-34	DEF FIT EXP-SFAS 106 OPEB - NH	Expenses
30-40-10-00-410-01-35	DEF FIT EXP-PENSION FAS 87 - NH	Expenses
30-40-10-00-410-01-37	DEF FIT EXP-STOCK COMP - NH	Expenses
30-40-10-00-410-01-38	DEF FIT EXP-BAD DEBT - NH	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-10-00-410-01-39	DEF FIT EXP-ACCRUED REVENUE - NH	Expenses
30-40-10-00-410-01-41	DEF FIT EXP-PREPAID PROP TAX - NH	Expenses
30-40-10-00-410-01-42	DEF FIT EXP-RATE CASE COSTS - NH	Expenses
30-40-10-00-410-01-45	DEF FIT EXP-REMEDIATION - NH	Expenses
30-40-10-00-410-01-51	DEF FIT-TRANSITION COSTS - NH	Expenses
30-40-10-00-410-01-52	DEF FIT-TRANSACTION COSTS - NH	Expenses
30-40-10-00-410-01-64	DEF FIT-MISC - NH	Expenses
30-40-10-00-410-01-66	DEF FIT EXP- R&D	Expenses
30-40-10-00-410-02-00	DEF SIT EXP- NH	Expenses
30-40-10-00-410-02-30	DEF SIT EXP-ACCEL DEPRECIATION-NH	Expenses
30-40-10-00-410-02-34	DEF SIT EXP-SFAS 106 OPEB - NH	Expenses
30-40-10-00-410-02-35	DEF SIT EXP-PENSION FAS 87 - NH	Expenses
30-40-10-00-410-02-37	DEF SIT EXP-STOCK COMP - NH	Expenses
30-40-10-00-410-02-38	DEF SIT EXP-BAD DEBT - NH	Expenses
30-40-10-00-410-02-39	DEF SIT EXP-ACCRUED REVENUE - NH	Expenses
30-40-10-00-410-02-41	DEF SIT EXP-PREPAID PROP TAX - NH	Expenses
30-40-10-00-410-02-42	DEF SIT EXP-RATE CASE COSTS - NH	Expenses
30-40-10-00-410-02-45	DEF SIT EXP-REMEDIATION - NH	Expenses
30-40-10-00-410-02-51	DEF SIT-TRANSITION COSTS - NH	Expenses
30-40-10-00-410-02-52	DEF SIT-TRANSACTION COSTS - NH	Expenses
30-40-10-00-410-02-64	DEF SIT-MISC - NH	Expenses
30-40-10-00-410-02-66	DEF SIT EXP- R&D	Expenses
30-40-10-00-410-03-03	DEF TAX - TCJA REV REQ GROSS-UP	Expenses
30-40-10-00-411-01-00	AMORTIZATION - EXCESS ADIT - BASE REV - NH	Expenses
30-40-10-00-411-01-10	DEF TAX - DISCRETE TAX PROVISION	Expenses
30-40-10-00-421-00-01	USC BELOW THE LINE RECLASS	Expenses
30-40-10-00-426-01-01	USC BELOW THE LINE RECLASS	Expenses
30-40-10-00-426-01-02	USC PENALTIES RECLASS	Expenses
30-40-10-00-426-05-00	OTHER INCOME DEDUCTIONS - NH	Expenses
30-40-10-00-426-20-00	NIPSCO AMORTIZATION	Expenses
30-40-10-00-426-21-00	SQI METER TO CASH	Expenses
30-40-10-00-432-00-00	AFUDC-BORROWED FUNDS - NH	Expenses
30-40-10-00-485-21-00	COMMERCIAL TRANS NORMALIZATION	Revenues
30-40-10-00-485-52-00	INDUSTRIAL TRANS NORMALIZATION	Revenues
30-40-10-00-493-00-00	INTERCOMPANY RENT	Revenues
30-40-10-00-493-00-01	RENTAL INCOME - GSG	Revenues
30-40-10-00-493-00-03	RENTAL INCOME - USC	Revenues
30-40-10-00-495-00-27	ACCRUED REVENUE - NON DIST BAD DEBT	Revenues
30-40-10-00-495-10-00	UNBILLED GAS REVENUE - NH	Revenues
30-40-10-00-495-10-01	ACCRUED REVENUE - TCJA 2018	Revenues
30-40-10-00-495-10-02	UNBILLED REVENUE - SEASONALITY - NH	Revenues
30-40-10-00-495-30-00	ACCRUED REVENUE - OTHER	Revenues
30-40-10-00-813-01-00	USC-GAS PRODUCTION OTHER - NH	Expenses
30-40-10-00-851-02-00	USC- DISPATCH	Expenses
30-40-10-00-851-02-01	USC- DISPATCH - CAP	Expenses
30-40-10-00-880-02-00	USC-GAS DISTRIBUTION - NH	Expenses
30-40-10-00-880-02-01	USC-GAS DISTRIBUTION - NH-CAP	Expenses
30-40-10-00-885-06-00	UNPROD TIME/CAPITALIZED - NH	Expenses
30-40-10-00-903-06-00	USC - CUSTOMER ACCOUNTING	Expenses
30-40-10-00-904-00-00	PROVISION FOR DOUBTFUL ACCTS - DISTR - NH	Expenses
30-40-10-00-904-00-27	PROVISION FOR DOUBTFUL ACCTS - NON-DIST - NH	Expenses
30-40-10-00-920-05-00	INCENTIVE COMPENSATION CAPITALIZED	Expenses
30-40-10-00-920-09-00	PAYROLL ACCRUAL	Expenses
30-40-10-00-921-15-00	SVC CENTER CAPITALIZED- SHARED NH	Expenses
30-40-10-00-921-19-00	TELEPHONE SVS CAPITALIZED- SHARED NH	Expenses
30-40-10-00-923-02-00	OUTSIDE SERVICES-AUDIT-NH	Expenses
30-40-10-00-923-03-00	OS UNITIL SERVICE CORP-NH	Expenses
30-40-10-00-923-03-01	OS UNITIL SERVICE CORP-NH-CAP	Expenses
30-40-10-00-923-03-05	USC OUTSIDE SERVICES-DIRECT CHGS-NH	Expenses
30-40-10-00-923-03-07	DIRECT CHARGES CAPITALIZED	Expenses
30-40-10-00-923-03-08	USC ALLOCATED PBOP EXPENSE	Expenses
30-40-10-00-923-03-09	USC ALLOCATED SERP EXPENSE	Expenses
30-40-10-00-923-03-10	USC ALLOCATED PENSION EXPENSE	Expenses
30-40-10-00-923-04-00	OS OTHER	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-10-00-923-09-00	OUTSIDE SERVICES-NH	Expenses
30-40-10-00-924-00-01	PROPERTY INS CAPITALIZED	Expenses
30-40-10-00-925-02-01	GEN LIAB CAPITALIZED	Expenses
30-40-10-00-925-04-01	WORKERS COMP CAPITALIZED	Expenses
30-40-10-00-926-01-01	401K CAPITALIZED	Expenses
30-40-10-00-926-02-10	PENSION - USC ALLOC - SVC	Expenses
30-40-10-00-926-02-30	PENSION - USC ALLOC - OTHER	Expenses
30-40-10-00-926-02-99	FASB 87 - YEAR END ACCRUAL ADJ	Expenses
30-40-10-00-926-03-02	EMPLOYEE BENEFIT ACCRUAL ADJ	Expenses
30-40-10-00-926-05-00	BENEFIT COST CAPITALIZED	Expenses
30-40-10-00-926-08-00	PENSION - SVC CAPITALIZED	Expenses
30-40-10-00-926-08-12	PENSION - USC ALLOC - SVC CAPITALIZED	Expenses
30-40-10-00-926-08-20	PENSION - OTHER - CAPITALIZED	Expenses
30-40-10-00-926-08-30	PENSION - USC ALLOC - OTHER DEFERRED	Expenses
30-40-10-00-926-09-10	PBOP - USC ALLOC - SVC	Expenses
30-40-10-00-926-09-29	PBOP - USC ALLOC - OTHER	Expenses
30-40-10-00-926-11-10	SERP - USC ALLOC - SVC	Expenses
30-40-10-00-926-11-31	SERP - USC ALLOC - OTHER	Expenses
30-40-10-00-926-17-00	PBOP - SVC CAPITALIZED	Expenses
30-40-10-00-926-17-12	PBOP - USC ALLOC - SVC CAPITALIZED	Expenses
30-40-10-00-926-17-19	PBOP - OTHER - CAPITALIZED	Expenses
30-40-10-00-926-17-29	PBOP - USC ALLOC - OTHER DEFERRED	Expenses
30-40-10-00-926-18-12	SERP - USC ALLOC - SVC CAPITALIZED	Expenses
30-40-10-00-926-18-31	SERP - USC ALLOC - OTHER DEFERRED	Expenses
30-40-10-00-930-10-00	MISC EXP - PANDEMIC COSTS - NH	Expenses
30-40-10-00-930-20-00	MISC EXPENSE	Expenses
30-40-10-00-931-00-00	RENT- GARAGE SPACE - NH	Expenses
30-40-10-00-935-11-00	SVC CENTER CAPITALIZED - NH	Expenses
30-40-10-11-723-01-02	LPG EXPENSE MISC - ELECTRIC PEAK - NH	Expenses
30-40-10-13-419-00-99	WORKING CAPITAL - PEAK - NH	Revenues
30-40-10-43-419-00-99	WORKING CAPITAL - OFF PEAK - NH	Revenues
30-40-12-00-923-04-00	OS - ENGINEERING - NH	Expenses
30-40-13-00-921-03-00	DUES & SUBSCRIPTIONS - NH	Expenses
30-40-13-00-921-38-00	PC SOFTWARE & SUPPLY - NH	Expenses
30-40-13-00-923-00-02	OS LEGAL - MISC	Expenses
30-40-13-00-923-06-00	OS IRP EXPENSE-NH	Expenses
30-40-13-00-923-07-00	OS EXPENSE OTHER - NH	Expenses
30-40-13-00-928-03-00	POWER SUPPLY - LEGAL-NH	Expenses
30-40-15-00-923-00-00	OS- LEGAL CLAIMS AND LITIGATIONS	Expenses
30-40-15-00-930-20-00	MISC GENERAL EXP - STATUTORY REP FEES	Expenses
30-40-21-00-415-05-00	JOBBING	Revenues
30-40-21-00-426-05-01	OTHER INC DED - CUSTOMER RELATIONS	Expenses
30-40-21-00-431-04-00	INTEREST ON CUSTOMER DEPOSITS - NH	Expenses
30-40-21-00-903-02-00	BILLG/ACCT FORMS/SUPPLIES - NH	Expenses
30-40-21-00-903-04-00	POSTAGE - NH	Expenses
30-40-21-00-903-05-01	MISC COST OF COLLECTIONS - NH	Expenses
30-40-21-00-903-05-02	COST OF COLLECTIONS - NH	Expenses
30-40-21-00-903-05-03	SUNDRY COST OF COLLECTIONS - NH	Expenses
30-40-21-00-903-05-04	O/S VENDOR SERVICES - MAILROOM - NH	Expenses
30-40-21-00-903-08-00	MISC CUSTOMER RELATIONS - NH	Expenses
30-40-21-00-903-10-00	O/S REMITTANCE LOCK BOX	Expenses
30-40-21-00-904-00-00	PROVISION FOR DOUBTFUL ACCTS - DISTR - NH	Expenses
30-40-21-00-904-01-00	PROVISION FOR DOUBTFUL ACCTS - SUNDRY - NH	Expenses
30-40-21-00-904-99-99	BD EXP CIS CNVRTED WO	Expenses
30-40-21-00-909-01-00	NEIGHBOR HELPING NEIGHBOR	Expenses
30-40-21-00-921-01-09	CREDIT CARD FEES	Expenses
30-40-21-00-923-02-00	MISC COSTS - AFCC-NH	Expenses
30-40-21-00-923-08-00	MISC COSTS - AFCC-NH	Expenses
30-40-21-14-904-00-05	BD EXP CIS R5-W -DIST	Expenses
30-40-21-14-904-00-06	BD EXP CIS R6-W-DIST	Expenses
30-40-21-14-904-00-10	BD EXP CIS R10-W-DIST	Expenses
30-40-21-14-904-00-11	BD EXP CIS R11-W-DIST	Expenses
30-40-21-14-904-00-40	BD EXP CIS G40-W-DIST	Expenses
30-40-21-14-904-00-41	BD EXP CIS G41-W-DIST	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-21-14-904-00-42	BD EXP CIS G42-W-DIST	Expenses
30-40-21-14-904-00-50	BD EXP CIS G50-W-DIST	Expenses
30-40-21-14-904-00-51	BD EXP CIS G51-W-DIST	Expenses
30-40-21-14-904-00-52	BD EXP CIS G52-W-DIST	Expenses
30-40-21-14-904-00-65	BD EXP CIS SP CT-W-DIST	Expenses
30-40-21-14-904-99-99	BD EXP CIS CNVRTED WO	Expenses
30-40-21-44-904-00-05	BD EXP CIS R5-S-DIST	Expenses
30-40-21-44-904-00-06	AFDA R6 - RES NONHEAT - SUMMER - DIST	Expenses
30-40-21-44-904-00-10	BD EXP CIS R1-S-DIST	Expenses
30-40-21-44-904-00-11	BD EXP CIS R11-S-DIST	Expenses
30-40-21-44-904-00-40	BD EXP CIS G40-S-DIST	Expenses
30-40-21-44-904-00-41	BD EXP CIS G41-S-DIST	Expenses
30-40-21-44-904-00-42	BD EXP CIS G42-S-DIST	Expenses
30-40-21-44-904-00-50	BD EXP CIS G50-S-DIST	Expenses
30-40-21-44-904-00-51	BD EXP CIS G51-S-DIST	Expenses
30-40-21-44-904-00-52	BD EXP CIS G52-S-DIST	Expenses
30-40-21-44-904-00-65	BD EXP CIS SP CT-S-DIST	Expenses
30-40-21-44-904-04-40	AFDA G-40 - LOW ANNUAL_HIGH - SUMMER - DIST	Expenses
30-40-22-00-913-31-02	ADVERTISING-SHARED SERVICES/SAFETY	Expenses
30-40-22-00-921-24-00	SAFETY - SHARED SERVICES	Expenses
30-40-22-00-923-15-00	OS - Emergency Mgmt & Compliance	Expenses
30-40-22-00-932-01-00	MGP MAINTENANCE COSTS - NH-SHARED SEVICES/MGP	Expenses
30-40-24-00-426-02-00	SOCIAL ADVERTISING -BELOW LINE - NH	Expenses
30-40-24-00-426-04-00	CIVIC ACTIVITIES-STATE	Expenses
30-40-24-00-426-04-01	CIVIC ACTIVITIES-FEDERAL-NH	Expenses
30-40-24-00-426-10-00	COMMUNITY DONATIONS - NH	Expenses
30-40-24-00-426-16-00	COMMUNITY SPONSORSHIPS - NH	Expenses
30-40-24-00-426-17-00	OUTREACH AND EDUCATION - NH	Expenses
30-40-24-00-909-01-00	SOCIAL ADVERTISING - NH	Expenses
30-40-24-00-909-52-00	OUTREACH AND EDUCATION	Expenses
30-40-24-00-913-53-00	CUSTOMER COMMUNICATION	Expenses
30-40-24-00-923-09-00	OUTSIDE SERVICES - NH	Expenses
30-40-24-00-930-51-00	COMMUNITY SPONSORSHIPS-NH	Expenses
30-40-24-00-930-54-00	MEDIA SERVICES-NH	Expenses
30-40-24-00-930-60-00	EMERGENCY COMMUNICATIONS-NU-NH	Expenses
30-40-27-00-852-00-00	COMMUNICATION SYSTEM EXP NU NH	Expenses
30-40-27-00-935-06-01	MAINTENANCE SOFTWARE DISPATCH	Expenses
30-40-28-00-902-00-00	CUST ACCT METER READ EXP - NH	Expenses
30-40-70-00-920-00-00	A&G SALARIES - NH	Expenses
30-40-80-00-415-00-00	JOBBING REVENUE - NH	Revenues
30-40-80-00-415-06-00	MDSE ADMIN-WH	Revenues
30-40-80-00-415-08-00	INST HW (CORRECT O&M)	Revenues
30-40-80-00-415-11-00	INST FURNACE LABOR	Revenues
30-40-80-00-415-13-00	MDSE GEN OPER(correct O&M)	Revenues
30-40-80-00-415-15-00	MDSE INST B/F LB/PT	Revenues
30-40-80-00-415-70-00	JOBBING PARTS REVENUE - NH	Revenues
30-40-80-00-415-71-00	JOBBING LABOR REVENUE - NH	Revenues
30-40-80-00-415-73-00	UNH REVENUE	Revenues
30-40-80-00-416-00-00	JOBBING EXPENSE - NH	Expenses
30-40-80-00-416-73-00	UNH EXPENSE	Expenses
30-40-80-00-416-73-01	UNH EXPENSE - DIG SAFE	Expenses
30-40-80-00-416-73-02	UNH EXPENSE - HIGH RISK DIG SAFE	Expenses
30-40-80-00-416-73-03	UNH EXPENSE - SERVICE SURVEY	Expenses
30-40-80-00-416-73-04	UNH EXPENSE - MAIN SURVEY	Expenses
30-40-80-00-416-73-05	UNH EXPENSE - QUARTERLY SURVEY	Expenses
30-40-80-00-416-73-06	UNH EXPENSE - PUBLIC BUILDING SURVEY	Expenses
30-40-80-00-416-73-07	UNH EXPENSE - STAND BY FEE	Expenses
30-40-80-00-416-73-08	UNH EXPENSE OTHER-MAIN/SERVICE RELOCATES DAMAGES	Expenses
30-40-80-00-416-80-00	JOBBING PARTS EXPENSE - NH	Expenses
30-40-80-00-416-81-00	JOBBING LABOR EXPENSE - NH	Expenses
30-40-80-00-416-82-00	MDSE COST OF APPL - WH	Expenses
30-40-80-00-416-84-00	JOBBING - UNH EXPENSE	Expenses
30-40-80-00-416-85-00	EQUIPMENT TRAINING FEE FOR SERVICE	Expenses
30-40-80-00-426-00-00	PENALTIES - NH	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-80-00-426-10-00	DONATIONS - NH	Expenses
30-40-80-00-717-00-00	PROD OPER LABOR LPG - NH	Expenses
30-40-80-00-717-01-00	PROD OPER LABOR LNG - NH	Expenses
30-40-80-00-717-02-00	PROD OPER LABOR OTHER - NH	Expenses
30-40-80-00-718-00-00	DISPATCHING PRODUCTION - NH	Expenses
30-40-80-00-735-01-00	PROD OPER MISC EXPENSE - NH	Expenses
30-40-80-00-735-03-00	PROD INSPECTIONS & ALARMS LPGA - NH	Expenses
30-40-80-00-735-04-00	PROD UNPRODUCTIVE - NH	Expenses
30-40-80-00-735-05-00	PROD INSPECTIONS & ALARMS LNG - NH	Expenses
30-40-80-00-741-01-00	PROD MAINT STRUCT & IMP LNG - NH	Expenses
30-40-80-00-742-01-00	PROD MAINT E - EQUIPMENT - LNG - NH	Expenses
30-40-80-00-743-00-00	GAS SYS PRODUCTION TRAINING - NH	Expenses
30-40-80-00-769-00-00	MAINT OF SCADA - PRODUCTION - NH	Expenses
30-40-80-00-857-00-00	T&D OPER MEAS & REGULATG STN - NH	Expenses
30-40-80-00-857-96-00	MEAS+REG.STA-STORERM EXP	Expenses
30-40-80-00-870-00-00	DISTRIBUTION OPERATION SUPERVISION - NH	Expenses
30-40-80-00-874-00-00	MISC EXP MAINS AND SERVICES - NH	Expenses
30-40-80-00-874-01-00	GAS SYSTEM TRAINING - NH	Expenses
30-40-80-00-874-02-00	DISTRIBUTION VALVE MAINTENANCE-NH	Expenses
30-40-80-00-874-02-01	DISTRIBUTION INTEGRITY MANAGEMENT - NH	Expenses
30-40-80-00-874-02-02	DISTRIBUTION MANUAL UPDATES - NH	Expenses
30-40-80-00-874-03-00	UNION GAS ON CALL PAY	Expenses
30-40-80-00-874-04-00	DIG SAFE EXPENSE - NH	Expenses
30-40-80-00-874-04-01	DIG SAFE EXPENSE - HIGH RISK- NH	Expenses
30-40-80-00-874-05-00	SERVICE LINE SURVEY - NH	Expenses
30-40-80-00-874-06-00	PUBLIC BUILDING SURVEY - NH	Expenses
30-40-80-00-874-07-00	GAS MAIN SURVEY - NH	Expenses
30-40-80-00-874-08-00	HIGH RISK BRIDGE SURVEY	Expenses
30-40-80-00-874-09-00	OUTSIDE LEAK INVESIGATION	Expenses
30-40-80-00-874-10-00	CRITICAL VALVE INSPECTIONS	Expenses
30-40-80-00-874-24-00	MAINS+SERV-TRANSP	Expenses
30-40-80-00-875-00-00	REG STATION EXPENSE (GEN) - NH	Expenses
30-40-80-00-875-01-00	SYSTEM OPS STANDBY	Expenses
30-40-80-00-875-02-00	SYSTEM OPS UPRODUCTIVE	Expenses
30-40-80-00-875-03-00	SYSTEM OPS TRAINING	Expenses
30-40-80-00-875-04-00	REGULATION SUPERVISION	Expenses
30-40-80-00-875-05-00	ODORANT TESTING - NH	Expenses
30-40-80-00-875-06-00	REG STATN STANDBY/DAMAGE PREV - NH	Expenses
30-40-80-00-875-08-00	MTR & HSE REG - INVESTIGATE METER READING	Expenses
30-40-80-00-875-09-00	MTR & HSE REG - INVESTIGATE DEVICE/ERT	Expenses
30-40-80-00-875-10-00	SYSTEM CRITICAL VALVE INSPECTION	Expenses
30-40-80-00-878-00-00	METER ORDERS - GENERAL	Expenses
30-40-80-00-878-01-00	METERTURN ON & OFFS - NH	Expenses
30-40-80-00-878-02-00	METERS-REMOVES & INSTALLS - NH	Expenses
30-40-80-00-878-03-00	REPAIR FIT LEAKS - NH	Expenses
30-40-80-00-878-04-00	SERVICING GAS METER BRACKETS	Expenses
30-40-80-00-878-04-01	METER & SERVICE TRANSPORTATION EXP	Expenses
30-40-80-00-878-05-00	M&S UNPRODUCTIVE TIME	Expenses
30-40-80-00-878-05-01	M&S UNPRODUCTIVE TIME - SICK	Expenses
30-40-80-00-878-05-02	M&S UNPRODUCTIVE TIME - HOLIDAY	Expenses
30-40-80-00-878-05-03	M&S UNPRODUCTIVE TIME - VACATION	Expenses
30-40-80-00-878-05-04	M&S UNPRODUCTIVE TIME - OTHER	Expenses
30-40-80-00-878-05-05	M&S UNPRODUCTIVE TIME TRAINING	Expenses
30-40-80-00-878-06-00	METER & SERVICE SUPERVISION	Expenses
30-40-80-00-878-07-00	MTR & HSE REG - READ IN/OUTS - NH	Expenses
30-40-80-00-878-08-00	MTR & HSE REG - FIELD INVESTIGATE	Expenses
30-40-80-00-878-09-00	MTR & HSE REG - INVESTIGATE DEVICE/ERT	Expenses
30-40-80-00-878-10-00	MTR & HSE REG - CHG MTR ERT - NH	Expenses
30-40-80-00-878-13-00	MTR & HSE REG - TRAINING - EM&C NH	Expenses
30-40-80-00-878-14-00	MTR & HSE REG - MISC - EM&C NH	Expenses
30-40-80-00-878-28-00	MTR & HSE REG - TOOLS & EQUP - NH	Expenses
30-40-80-00-878-30-00	MTR & HSE REG - MTR INSTRUM - NH	Expenses
30-40-80-00-878-33-00	MTR & HSE REG - FLEET - NH	Expenses
30-40-80-00-878-80-00	MTR & HSE REG - CHG MTR ERT - NH	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-80-00-878-86-00	MTR & HSE REG - MTR INSTRUM MAINT - ME BY NH	Expenses
30-40-80-00-879-00-00	CUSTOMER LEAK INVESTIGATION - NH	Expenses
30-40-80-00-879-01-00	EASY CARE SVC PLAN BASIC NO CHARGE NH	Expenses
30-40-80-00-880-00-00	T&D OPER SYSTEM EXP - NH	Expenses
30-40-80-00-880-03-00	OTHER EXPENSES-MISC - NH	Expenses
30-40-80-00-880-04-00	METERING SYS - GAS TRAINING	Expenses
30-40-80-00-880-99-00	COMPANY USE - NH	Expenses
30-40-80-00-885-00-00	MAINTENANCE GEN SUPERVISION - NH	Expenses
30-40-80-00-885-01-00	UNPROD TIME/SICKNESS - NH	Expenses
30-40-80-00-885-02-00	UNPROD TIME/WEATHER - NH	Expenses
30-40-80-00-885-03-00	UNPROD TIME/HOLIDAYS - NH	Expenses
30-40-80-00-885-04-00	UNPROD TIME/VACATION - NH	Expenses
30-40-80-00-885-05-00	UNPROD TIME/OTHER - NH	Expenses
30-40-80-00-885-05-01	UNPROD TIME TRAINING	Expenses
30-40-80-00-886-00-00	T&D MAINT STRUCTURES & IMPROV - NH	Expenses
30-40-80-00-887-00-00	MAINT OF MAINS - NH	Expenses
30-40-80-00-887-01-00	MAINT OF MAINS LEAK REPAIR - CORROSION - NH	Expenses
30-40-80-00-887-01-01	MAINT OF MAINS TRANSPORTATION EXP- NH	Expenses
30-40-80-00-887-03-00	CORROSION MAINS - NH	Expenses
30-40-80-00-887-04-00	CORROSION BRIDGES - NH	Expenses
30-40-80-00-887-07-00	T&D MAINT OF MAINS - BRIDGE - COMMON	Expenses
30-40-80-00-889-00-00	MAINT OF REG EQUIP (DISTRICT)- NH	Expenses
30-40-80-00-890-00-00	MAINT OF REG EQUIP (INDUST) - NH	Expenses
30-40-80-00-891-00-00	MAINT OF REG EQUIP (GATE STATION) - NH	Expenses
30-40-80-00-891-01-00	MAIN DISTRI SCADA -DISTRIBUTION- NH	Expenses
30-40-80-00-892-00-00	MAINT OF SERVICES - NH	Expenses
30-40-80-00-892-01-00	CORROSION SERVICES- NH	Expenses
30-40-80-00-892-14-00	MAINT SERV- TRANSPORTATION EXP - NH	Expenses
30-40-80-00-892-15-00	MAINT SERV- 3RD PARTY BILLING- NH	Expenses
30-40-80-00-893-00-00	MAINT OF MTRS & HOUSE REGULTRS - NH	Expenses
30-40-80-00-893-04-00	MAINT METER - STOREROOM - NH	Expenses
30-40-80-00-894-00-00	T&D MAINT SYSTEM EQUIPMENT - NH	Expenses
30-40-80-00-894-01-00	MAINT OF SYSTEM OPS EQUIPMENT - NH	Expenses
30-40-80-00-902-00-00	CUST ACCTS METER READ EXP- NH	Expenses
30-40-80-00-903-00-00	CREDIT DISCONNECTION - NH	Expenses
30-40-80-00-903-03-00	CREDIT & COLLECTIONS/PYRL - NH	Expenses
30-40-80-00-903-04-01	POSTAGE - LOCAL - SHARED NH	Expenses
30-40-80-00-903-05-00	MISC CREDIT EXPENSES - NH	Expenses
30-40-80-00-907-00-00	CUSTMR SERVICE & INFO SUPRVN - NH	Expenses
30-40-80-00-908-01-00	CUSTOMER SERVICE/PAYRL - NH	Expenses
30-40-80-00-908-02-00	CUSTOMER SERVICE/MISC - NH	Expenses
30-40-80-00-911-00-00	SUPERVISION - NH	Expenses
30-40-80-00-912-00-00	SELLING EXPENSE - NH	Expenses
30-40-80-00-920-00-00	A&G SALARIES-NH	Expenses
30-40-80-00-920-05-00	OPER SUPP - ADMIN TRAINING - GAS - NH	Expenses
30-40-80-00-921-01-00	GEN OFFICE SUPPLIES & EXP - SHARED NH	Expenses
30-40-80-00-921-01-20	UNALLOWABLE MEALS EXP - NH	Expenses
30-40-80-00-921-02-00	TRAVEL & MEALS EXP - NH	Expenses
30-40-80-00-921-16-00	SERVICE CENTER EXPENSED - SHARED NH	Expenses
30-40-80-00-921-17-00	TELEPHONE SERVICE - SERVICE CENTER - NH	Expenses
30-40-80-00-921-18-00	Telephone Services - NH	Expenses
30-40-80-00-922-00-00	ADMINISTRATIVE EXPENSES TRANSFERRED - NH	Expenses
30-40-80-00-923-00-00	OS LEGAL - LOCAL-NH-DOC-ONLY	Expenses
30-40-80-00-923-18-00	O/S WORK STOPPAGE	Expenses
30-40-80-00-925-01-00	INJURIES & DAMAGES SAFETY	Expenses
30-40-80-00-926-06-00	Employee Benefits Other - NUNH	Expenses
30-40-80-00-930-01-00	GENERAL ADVERTISING-NH	Expenses
30-40-80-00-930-03-00	DUES TO ORGANIZATIONS - NH	Expenses
30-40-80-00-930-11-00	SVC CENTER CAPITALIZED - NH	Expenses
30-40-80-00-932-04-00	MAINT OF GENL PLANT - EQUIP - SHARED NH	Expenses
30-40-80-00-935-01-00	MAINT - GEN STRUC - SHARED PORTSMOUTH	Expenses
30-40-80-00-935-01-20	MAINT - GEN STRUC - SHARED PLAISTOW	Expenses
30-40-80-00-935-02-00	MAINT - OFFICE EQUIPMENT - SHARED NH	Expenses
30-40-80-11-723-01-02	LPG EXPENSE MISC - ELECTRIC- PEAK-NH	Expenses

Account Code	Account Description	Type
30-40-80-54-415-71-00	EXCESS SERVICE LABOR - NH	Revenues
30-45-00-00-142-01-00	EXT SUPPLIER 1 - A/R - NH	Assets
30-45-00-00-142-02-00	EXT SUPPLIER GLOBAL - A/R - NH	Assets
30-45-00-00-142-03-00	EXT SUPPLIER METROMEDIA - A/R - NH	Assets
30-45-00-00-142-04-00	EXT SUPPLIER SHELL - A/R - NH	Assets
30-45-00-00-142-05-00	EXT SUPPLIER SPRAGUE - A/R - NH	Assets
30-45-00-00-142-06-00	EXT SUPPLIER SANTA BUCKLEY - A/R - NH	Assets
30-45-00-00-142-08-00	EXT SUPPLIER A/R - SOUTH JERSEY - NH	Assets
30-45-00-00-142-09-00	EXT SUPPLIER A/R - GLACIAL - NH	Assets
30-45-00-00-142-10-00	EXT SUPPLIER - UGI ENERGY SVCS - A/R - NH	Assets
30-45-00-00-142-10-02	EXT SUPPLIER - REVENUE - UGI ENERGY SVCS - NH	Assets
30-45-00-00-142-25-00	EXT SUPPLIER AR - PEOPLES POWER - NH	Assets
30-45-00-00-232-01-02	EXT SUPPLY 1-REVENUE-NH	Liabilities
30-45-00-00-232-02-02	EXT SUPPLIER GLOBAL-REVENUE-NH	Liabilities
30-45-00-00-232-03-02	EXT SUPPLIER METROMEDIA-REVENUE-NH	Liabilities
30-45-00-00-232-04-02	EXT SUPPLIER SHELL-REVENUE-NH	Liabilities
30-45-00-00-232-05-02	EXT SUPPLIER - REVENUE - SPRAGUE - NH	Liabilities
30-45-00-00-232-06-02	EXT SUPPLY REVENUE-SANTA BUCKLEY-NH	Liabilities
30-45-00-00-232-08-02	EXT SUPPLY REVENUE-SOUTH JERSEY-NH	Liabilities
30-45-00-00-232-09-02	EXT SUPPLY REVENUE-GLACIAL-NH	Liabilities
30-45-00-00-232-10-02	EXT SUPPLIER- REVENUE - UGI ENERGY SVCS - NH	Liabilities
30-45-00-00-232-25-02	EXT SUPPLIER - REVENUE PEOPLES POWER-NH	Liabilities
30-47-29-50-418-05-00	WATER HEATER RENTAL BAD DEBT	Revenues
30-47-29-50-488-01-00	WATER HEATER RENTAL-REVENUE	Revenues
30-47-29-50-488-05-00	RENTAL WH BAD DEBT - NH	Revenues
30-47-29-50-894-01-00	WATER HEATER MAINTENANCE - GAS - NH	Expenses
30-47-29-50-904-05-00	BD EXP CIS WH WO	Expenses
30-47-29-50-923-06-00	USC EXPS - WATER HTR PROG - NH	Expenses
30-47-29-51-415-01-00	ANNUAL INSPECTION REVENUE - NH	Revenues
30-47-29-51-418-05-00	CLEAN & CHECK REVENUE - BAD DEBT	Revenues
30-47-29-51-488-01-00	CLEAN & CHECK REVENUE	Revenues
30-47-29-51-894-01-00	NH ANNUAL INSPECTIONS- PARTS & LABOR	Expenses
30-47-29-52-418-05-00	CONVERSION BURNER RNTL BAD DEBT	Revenues
30-47-29-52-488-01-00	CONVERSION BURNER RENTAL-REVENUE	Revenues
30-47-29-52-488-05-00	CONV BURN BAD DEBT - NH	Revenues
30-47-29-52-894-01-00	CONVERSION BURNER MAINTENANCE - NH	Expenses
30-47-29-52-904-05-00	BD EXP CIS CB WO-DIST	Expenses
30-47-29-53-418-05-00	EQUIP PROTECTION PLAN BAD DEBT	Revenues
30-47-29-53-488-01-00	EQUIP PROTECTION PLAN REV COMM	Revenues
30-47-29-53-488-02-00	EQUIP PROTECTION PLAN REV COMM	Revenues
30-47-29-53-894-01-00	EASY CARE SVC PLAN PTS & LBR	Expenses
30-47-29-53-894-02-00	NH EQUIP PROTECTION PLAN PTS & LBR	Expenses
30-47-29-53-904-05-00	BD EXP CIS EZ WO-DIST	Expenses
30-47-29-53-923-06-00	USC EXPS - EASY CARE - NH	Expenses
30-47-29-54-418-05-00	INTERIOR GAS LINE BAD DEBT	Revenues
30-47-29-54-488-01-00	INTERIOR GAS LINES REV- RESIDENTIAL	Revenues
30-47-29-54-904-05-00	BD EXP CIS GAS LINE WO	Expenses
30-47-29-55-488-01-00	ANNUAL INSPECTION REVENUE - NH	Revenues
30-47-29-56-418-01-00	NH EQUIP SALES - REVENUE	Revenues
30-47-29-56-418-01-10	NH EQUIP SALES - PARTS & LABOR	Revenues
30-47-29-60-488-00-00	EQUIP PROTECTION PLAN REVENUE - COMMERCIAL	Revenues
30-48-02-00-426-15-00	VISIBILITY - NH	Expenses
30-48-29-00-426-13-00	ADVERTISING - NH	Expenses
30-48-29-00-426-14-00	MARKET DEVELOPMENT - GENERAL - NH	Expenses
30-48-29-00-426-15-00	VISIBILITY - NH	Expenses
30-48-29-00-913-31-02	ADVERTISING	Expenses
30-48-29-00-923-00-03	MKT DEV/PROJ MGMT - NH	Expenses
30-48-29-00-923-30-00	MKT DEV - GENERAL - NH	Expenses
30-48-29-00-923-30-01	MARKETING - NH	Expenses
30-48-29-00-923-32-03	FIELD OPERATIONS/ACCOUNT MGMT-NH	Expenses
30-48-29-00-930-31-02	ADVERTISING	Expenses
30-49-01-10-480-01-01	R-6 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-480-01-02	R-11 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-480-02-01	R-5 W-NEXT-Demand Cost of Gas	Revenues

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-49-01-10-480-02-02	R-10 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-01-01	G-40 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-01-02	G-50 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-02-01	G-41 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-02-02	G-51 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-03-01	G-42 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-03-02	G-52 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-10-01	Simplex W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-11-01	Nat Gypsum W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-12-01	Foss W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-495-00-00	ACCRUED REV-PEAK-DEMAND-NH	Revenues
30-49-01-10-710-04-88	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - NH	Expenses
30-49-01-10-710-04-99	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - NH	Expenses
30-49-01-10-930-00-88	MISC OVERHEAD ALLOWANCE - DEMAND - PEAK - NH	Expenses
30-49-01-10-930-00-99	MISC OVERHEAD ALLOWANCE - DEMAND - PEAK - NH	Expenses
30-49-01-11-431-00-99	INVENTORY FINANCE CHARGES - PEAK - NH	Expenses
30-49-01-11-480-01-01	R-6 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-480-01-02	R-11 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-480-02-01	R-5 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-480-02-02	R-10 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-01-01	G-40 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-01-02	G-50 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-02-01	G-41 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-02-02	G-51 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-03-01	G-42 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-03-02	G-52 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-10-01	Simplex W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-11-01	Nat Gypsum W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-12-01	Foss W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-12-480-01-01	R-6 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-480-01-02	R-11 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-480-02-01	R-5 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-480-02-02	R-10 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-01-01	G-40 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-01-02	G-50 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-02-01	G-41 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-02-02	G-51 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-03-01	G-42 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-03-02	G-52 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-10-01	Simplex W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-11-01	Nat Gypsum W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-12-01	Foss W-NEXT-Reconciliation Costs	Revenues
30-49-01-13-480-01-01	R-6 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-480-01-02	R-11 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-480-02-01	R-5 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-480-02-02	R-10 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-01-01	G-40 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-01-02	G-50 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-02-01	G-41 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-02-02	G-51 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-03-01	G-42 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-03-02	G-52 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-10-01	Simplex W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-11-01	Nat Gypsum W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-12-01	Foss W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-495-00-00	ACCRUED REV-WORK CAPITAL-PEAK-NH	Revenues
30-49-01-14-480-01-01	R-6 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-480-01-02	R-11 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-480-02-01	R-5 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-480-02-02	R-10 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-01-01	G-40 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-01-02	G-50 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-02-01	G-41 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-02-02	G-51 W-NEXT-Bad Debt Allowance	Revenues

Account Code	Account Description	Type
30-49-01-14-481-03-01	G-42 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-03-02	G-52 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-10-01	Simplex W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-11-01	Nat Gypsum W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-12-01	Foss W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-495-00-00	ACCRUED REV-BAD DEBT-PEAK-NH	Revenues
30-49-01-15-480-01-01	R-6 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-480-01-02	R-11 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-480-02-01	R-5 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-480-02-02	R-10 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-01-01	G-40 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-01-02	G-50 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-02-01	G-41 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-02-02	G-51 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-03-01	G-42 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-03-02	G-52 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-10-01	Simplex W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-11-01	Nat Gypsum W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-12-01	Foss W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-16-480-01-01	R-6 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-480-01-02	R-11 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-480-02-01	R-5 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-480-02-02	R-10 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-01-01	G-40 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-01-02	G-50 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-02-01	G-41 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-02-02	G-51 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-03-01	G-42 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-03-02	G-52 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-10-01	Simplex W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-11-01	Nat Gypsum W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-12-01	Foss W-NEXT-Production & Storage Capacity	Revenues
30-49-01-17-480-01-01	R-6 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-480-01-02	R-11 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-480-02-01	R-5 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-480-02-02	R-10 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-01-01	G-40 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-01-02	G-50 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-02-01	G-41 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-02-02	G-51 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-03-01	G-42 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-03-02	G-52 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-10-01	Simplex W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-11-01	Nat Gypsum W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-12-01	Foss W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-42-480-01-01	R-6 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-480-01-02	R-11 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-480-02-01	R-5 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-480-02-02	R-10 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-01-01	G-40 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-01-02	G-50 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-02-01	G-41 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-02-02	G-51 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-03-01	G-42 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-03-02	G-52 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-10-01	Simplex S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-11-01	Nat Gypsum S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-12-01	Foss S-NEXT-Reconciliation Costs	Revenues
30-49-01-44-480-01-01	R-6 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-480-01-02	R-11 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-480-02-01	R-5 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-480-02-02	R-10 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-01-01	G-40 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-01-02	G-50 S-NEXT-Bad Debt Allowance	Revenues

Account Code	Account Description	Type
30-49-01-44-481-02-01	G-41 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-02-02	G-51 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-03-01	G-42 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-03-02	G-52 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-10-01	Simplex S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-11-01	Nat Gypsum S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-12-01	Foss S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-495-00-00	ACCRUED REV-BAD DEBT-OFF PEAK-NH	Revenues
30-49-01-45-480-01-01	R-6 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-480-01-02	R-11 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-480-02-01	R-5 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-480-02-02	R-10 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-01-01	G-40 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-01-02	G-50 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-02-01	G-41 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-02-02	G-51 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-03-01	G-42 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-03-02	G-52 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-10-01	Simplex S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-11-01	Nat Gypsum S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-12-01	Foss S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-47-480-01-01	R-6 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-480-01-02	R-11 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-480-02-01	R-5 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-480-02-02	R-10 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-01-01	G-40 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-01-02	G-50 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-02-02	G-51 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-03-01	G-42 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-03-02	G-52 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-10-01	SIMPLEX S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-11-01	NAT GYPSUM S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-12-01	FOSS S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-48-480-02-01	R-5 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-72-480-01-01	R-6 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-480-01-02	R-11 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-480-02-01	R-5 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-480-02-02	R-10 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-01-01	G-40 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-01-02	G-50 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-02-01	G-41 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-02-02	G-51 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-03-01	G-42 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-03-02	G-52 S-NEXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-01-01	R-6 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-01-02	R-11 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-01-04	R-10 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-02-01	G-40 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-02-02	G-50 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-03-01	G-41 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-03-02	G-51 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-04-01	G-42 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-04-02	G-52 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-495-00-99	LDAC-EEC LOST BASE REVENUE	Revenues
30-49-01-72-495-01-01	ACCRUED REVENUE-LDAC-EEC-LOW INCOME	Revenues
30-49-01-72-495-01-02	ACCRUED REVENUE-LDAC-EEC-RESIDENTIAL	Revenues
30-49-01-72-495-01-06	ACCRUED REVENUE-LDAC-EEC-SMALL C&I	Revenues
30-49-01-73-480-00-00	ERC - RECLASS FROM RCE- RPC	Revenues
30-49-01-73-480-01-01	R-6 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-480-01-02	R-11 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-480-02-01	R-5 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-480-02-02	R-10 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-01-01	G-40 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-01-02	G-50 S-NEXT-ERC (Environmental Recovery Costs)	Revenues

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-49-01-73-481-02-01	G-41 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-02-02	G-51 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-03-01	G-42 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-03-02	G-52 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-01-01	R-6 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-01-02	R-11 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-01-04	R-10 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-02-01	G-40 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-02-02	G-50 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-03-01	G-41 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-03-02	G-51 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-04-01	G-42 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-04-02	G-52 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-735-01-00	ERC AMORTIZATION - NH	Expenses
30-49-01-75-480-01-01	R-6 S-NEXT-Wells LNG	Revenues
30-49-01-75-480-01-02	R-11 S-NEXT-Wells LNG	Revenues
30-49-01-75-480-02-01	R-5 S-NEXT-Wells LNG	Revenues
30-49-01-75-480-02-02	R-10 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-01-01	G-40 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-01-02	G-50 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-02-01	G-41 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-02-02	G-51 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-03-01	G-42 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-03-02	G-52 S-NEXT-Wells LNG	Revenues
30-49-01-75-489-01-01	R-6 S-EXT-Wells LNG	Revenues
30-49-01-75-489-01-02	R-11 S-EXT-Wells LNG	Revenues
30-49-01-75-489-01-03	R-5 S-EXT-Wells LNG	Revenues
30-49-01-75-489-01-04	R-10 S-EXT-Wells LNG	Revenues
30-49-01-75-489-02-01	G-40 S-EXT-Wells LNG	Revenues
30-49-01-75-489-02-02	G-50 S-EXT-Wells LNG	Revenues
30-49-01-75-489-03-01	G-41 S-EXT-Wells LNG	Revenues
30-49-01-75-489-03-02	G-51 S-EXT-Wells LNG	Revenues
30-49-01-75-489-04-01	G-42 S-EXT-Wells LNG	Revenues
30-49-01-75-489-04-02	G-52 S-EXT-Wells LNG	Revenues
30-49-01-76-481-01-01	G-40 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-01-02	G-50 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-02-01	G-41 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-02-02	G-51 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-03-01	G-42 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-03-02	G-52 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-02-01	G-40 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-02-02	G-50 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-03-01	G-41 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-03-02	G-51 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-04-01	G-42 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-04-02	G-52 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-77-480-01-01	R-6 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-01-02	R-11 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-02-01	R-5 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-02-02	R-10 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-10-01	LI DISCOUNT - R10 - DISTRIBUTION	Revenues
30-49-01-77-480-10-02	LI DISCOUNT - R10 - SUPPLY	Revenues
30-49-01-77-481-01-01	G-40 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-01-02	G-50 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-02-01	G-41 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-02-02	G-51 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-03-01	G-42 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-03-02	G-52 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-01-01	R-6 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-01-02	R-11 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-01-04	R-10 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-02-01	G-40 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-02-02	G-50 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-03-01	G-41 S-EXT-RLIARA (Residential Low Income)	Revenues

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-49-01-77-489-03-02	G-51 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-04-01	G-42 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-04-02	G-52 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-495-00-00	ACCRUED REVENUE - RLIARA- NH	Revenues
30-49-01-77-928-03-00	REG COMM EXP - ASSESSMENTS - RLIARA	Expenses
30-49-01-78-407-01-00	AMORTIZATION OF RATE CASE COSTS - NH	Expenses
30-49-01-78-480-00-00	RCE - RECLASS TO ERC	Revenues
30-49-01-78-480-01-01	R-6 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-480-01-02	R-11 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-480-02-01	R-5 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-480-02-02	R-10 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-01-01	G-40 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-01-02	G-50 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-02-01	G-41 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-02-02	G-51 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-03-01	G-42 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-03-02	G-52 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-489-01-01	R-6 EXT-RCE	Revenues
30-49-01-78-489-01-02	R-11 EXT-RCE	Revenues
30-49-01-78-489-01-03	R-5 EXT-RCE	Revenues
30-49-01-78-489-01-04	R-10 EXT-RCE	Revenues
30-49-01-78-489-02-01	G-40 EXT-RCE	Revenues
30-49-01-78-489-02-02	G-50 EXT-RCE	Revenues
30-49-01-78-489-03-01	G-41 EXT-RCE	Revenues
30-49-01-78-489-03-02	G-51 EXT-RCE	Revenues
30-49-01-78-489-04-01	G-42 EXT-RCE	Revenues
30-49-01-78-489-04-02	G-52 EXT-RCE	Revenues
30-49-01-78-489-10-01	Simplex EXT-RCE	Revenues
30-49-01-78-489-11-01	Nat Gypsum EXT-RCE	Revenues
30-49-01-78-489-12-01	Foss EXT-RCE	Revenues
30-49-01-79-480-00-00	RECLASS TO ERC	Revenues
30-49-01-79-480-01-01	R-6 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-480-01-02	R-11 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-480-02-01	R-5 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-480-02-02	R-10 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-01-01	G-40 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-01-02	G-50 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-02-01	G-41 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-02-02	G-51 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-03-01	G-42 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-03-02	G-52 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-01	R-6 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-02	R-11 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-03	R-5 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-04	R-10 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-02-01	G-40 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-02-02	G-50 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-03-01	G-41 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-03-02	G-51 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-04-01	G-42 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-04-02	G-52 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-495-00-00	ACCD REVENUE-RATE RELIEF - NH	Revenues
30-49-01-80-495-00-00	ACC REV ON EEBB RESIDENTIAL	Revenues
30-49-01-81-480-01-01	R-6 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-480-01-02	R-11 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-480-02-01	R-5 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-480-02-02	R-10 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-01-01	G-41 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-01-02	G-50 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-02-01	G-41 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-02-02	G-51 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-03-01	G-42 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-03-02	G-52 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-02-01	G-40 NEXT-LOST REVENUE ADJ	Revenues

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-49-01-81-489-02-02	G-50 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-03-01	G-41 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-03-02	G-51 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-04-01	G-42 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-04-02	G-52 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-495-00-00	ACCRUED REV-LRA-NH	Revenues
30-49-01-82-495-00-00	ACCRUED REVEUNE - OBF - NH - RESIDENTIAL	Revenues
30-49-01-82-495-01-00	ACCRUED REVEUNE - OBF - NH - C&I	Revenues
30-49-02-50-908-29-10	Res HVAC/Appl ImplSvcs/STAT - Int	Expenses
30-49-02-50-908-29-13	Res HVAC/Appl Plan/Admin - Int	Expenses
30-49-02-50-908-29-14	Res HVAC/Appl Plan/Admin - Ext	Expenses
30-49-02-50-908-29-20	Res HVAC/Appl Marketing - Int	Expenses
30-49-02-50-908-29-21	Res HVAC/Appl Marketing - Ext	Expenses
30-49-02-50-908-29-30	Res HVAC/Appl Evaluation - Int	Expenses
30-49-02-50-908-29-31	Res HVAC/Appl Evaluation - Ext	Expenses
30-49-02-50-908-29-40	Res HVAC/Appl Rebates	Expenses
30-49-02-50-908-29-41	Res HVAC/Appl ImplSvcs/STAT - Ext	Expenses
30-49-02-50-908-29-42	Res HVAC/Appl Loans/Financing	Expenses
30-49-02-50-908-32-15	RES BEHAVIOR IMPLSVCS/STAT - INT	Expenses
30-49-02-50-908-32-16	RES BEHAVIOR PLAN/ADMIN - INT	Expenses
30-49-02-50-908-32-17	RES BEHAVIOR PLAN/ADMIN - EXT	Expenses
30-49-02-50-908-32-22	RES BEHAVIOR MARKETING - INT	Expenses
30-49-02-50-908-32-23	RES BEHAVIOR MARKETING - EXT	Expenses
30-49-02-50-908-32-32	RES BEHAVIOR EVALUATION - INT	Expenses
30-49-02-50-908-32-33	RES BEHAVIOR EVALUATION - EXT	Expenses
30-49-02-50-908-32-42	RES BEHAVIOR REBATES	Expenses
30-49-02-50-908-32-43	RES BEHAVIOR IMPLSVCS/STAT - EXT	Expenses
30-49-02-50-908-34-10	RES HPWES IMPLSVCS/STAT - INT	Expenses
30-49-02-50-908-34-13	RES HPWES PLAN/ADMIN - INT	Expenses
30-49-02-50-908-34-14	RES HPWES PLAN/ADMIN - EXT	Expenses
30-49-02-50-908-34-20	RES HPWES MARKETING - INT	Expenses
30-49-02-50-908-34-21	RES HPWES MARKETING - EXT	Expenses
30-49-02-50-908-34-30	RES HPWES EVALUATION - INT	Expenses
30-49-02-50-908-34-31	RES HPWES EVALUATION - EXT	Expenses
30-49-02-50-908-34-40	RES HPWES REBATES	Expenses
30-49-02-50-908-34-41	RES HPWES IMPLSVCS/STAT - EXT	Expenses
30-49-02-50-908-43-35	RES FINANCING - BUYDOWN/REBATES	Expenses
30-49-02-50-908-47-10	Res NewHomes/Reno ImplSvcs/STAT - Int	Expenses
30-49-02-50-908-47-13	Res NewHomes/Reno Plan/Admin - Int	Expenses
30-49-02-50-908-47-14	Res NewHomes/Reno Plan/Admin - Ext	Expenses
30-49-02-50-908-47-20	Res NewHomes/Reno Marketing - Int	Expenses
30-49-02-50-908-47-21	Res NewHomes/Reno Marketing - Ext	Expenses
30-49-02-50-908-47-30	Res NewHomes/Reno Evaluation - Int	Expenses
30-49-02-50-908-47-31	Res NewHomes/Reno Evaluation - Ext	Expenses
30-49-02-50-908-47-40	Res NewHomes/Reno Rebates	Expenses
30-49-02-50-908-47-41	Res NewHomes/Reno ImplSvcs/STAT - Ext	Expenses
30-49-02-50-908-48-14	Res Statewide Marketing - Int	Expenses
30-49-02-50-908-48-22	Res Statewide Marketing - Ext	Expenses
30-49-02-51-908-01-10	LI SINGLEFAM IMPLSVCS/STAT - INT	Expenses
30-49-02-51-908-01-13	LI SINGLEFAM PLAN/ADMIN - INT	Expenses
30-49-02-51-908-01-14	LI SINGLEFAM PLAN/ADMIN - EXT	Expenses
30-49-02-51-908-01-20	LI SINGLEFAM MARKETING - INT	Expenses
30-49-02-51-908-01-21	LI SINGLEFAM MARKETING - EXT	Expenses
30-49-02-51-908-01-30	LI SINGLEFAM EVALUATION - INT	Expenses
30-49-02-51-908-01-31	LI SINGLEFAM EVALUATION - EXT	Expenses
30-49-02-51-908-01-40	LI SINGLEFAM REBATES	Expenses
30-49-02-51-908-01-41	LI SINGLEFAM IMPLSVCS/STAT - EXT	Expenses
30-49-02-51-908-48-15	LI Statewide Marketing - Int	Expenses
30-49-02-51-908-48-23	LI Statewide Marketing - Ext	Expenses
30-49-02-52-908-21-01	C&I Edu ImplSvc/STAT - Int	Expenses
30-49-02-52-908-21-02	C&I Edu ImplSvc/STAT - Ext	Expenses
30-49-02-52-908-21-03	C&I Edu Mrkting - Ext	Expenses
30-49-02-52-908-21-04	C&I Edu Eval - Ext	Expenses
30-49-02-52-908-22-01	Res Edu ImplSvc/STAT - Int	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-49-02-52-908-22-02	Res Edu ImplSvc/STAT - Ext	Expenses
30-49-02-52-908-22-03	Res Edu Mrkting - Ext	Expenses
30-49-02-52-908-22-04	Res Edu Eval - Ext	Expenses
30-49-02-52-908-48-16	C&I Statewide Marketing - Int	Expenses
30-49-02-52-908-48-24	C&I Statewide Marketing - Ext	Expenses
30-49-02-52-908-51-10	C&I SM BUS SVCS IMPLSVC/STAT - INT	Expenses
30-49-02-52-908-51-13	C&I SM BUS SVCS PLAN/ADMIN - INT	Expenses
30-49-02-52-908-51-14	C&I SM BUS SVCS PLAN/ADMIN - EXT	Expenses
30-49-02-52-908-51-20	C&I SM BUS SVCS MARKETING - INT	Expenses
30-49-02-52-908-51-21	C&I SM BUS SVCS MARKETING - EXT	Expenses
30-49-02-52-908-51-30	C&I SM BUS SVCS EVALUATION - INT	Expenses
30-49-02-52-908-51-31	C&I SM BUS SVCS EVALUATION - EXT	Expenses
30-49-02-52-908-51-40	C&I Sm Bus Rebates	Expenses
30-49-02-52-908-51-41	C&I SM BUS SVCS IMPLSVC/STAT - EXT	Expenses
30-49-02-52-908-52-10	C&I LG BUS SVCS IMPLSVCS/STAT - INT	Expenses
30-49-02-52-908-52-13	C&I LG BUS SVCS PLAN/ADMIN - INT	Expenses
30-49-02-52-908-52-14	C&I LG BUS SVCS PLAN/ADMIN - EXT	Expenses
30-49-02-52-908-52-20	C&I LG BUS SVCS MARKETING - INT	Expenses
30-49-02-52-908-52-21	C&I LG BUS SVCS MARKETING - EXT	Expenses
30-49-02-52-908-52-30	C&I LG BUS SVCS EVALUATION - INT	Expenses
30-49-02-52-908-52-31	C&I LG BUS SVCS EVALUATION - EXT	Expenses
30-49-02-52-908-52-40	C&I Lg Bus Rebates	Expenses
30-49-02-52-908-52-41	C&I LG BUS SVCS IMPLSVCS/STAT - EXT	Expenses
30-49-02-72-908-00-50	GAS GENERAL PLAN/ADMIN - ALL INT	Expenses
30-49-02-72-908-00-61	GAS GENERAL IMPLSVC/STAT - ALL INT	Expenses
30-49-02-72-908-00-70	GAS GENERAL EVALUATION - ALL INT	Expenses
30-49-02-72-908-00-71	GAS GENERAL EVALUATION - ALL EXT	Expenses
30-49-02-72-908-00-80	GAS GENERAL MARKETING - ALL INT	Expenses
30-49-02-72-908-00-90	GAS GENERAL MARKETING - ALL EXT	Expenses
30-49-02-72-908-00-95	GAS GENERAL PLANNING&ADMIN/LEGAL - ALL EXT	Expenses
30-49-02-72-908-00-96	GAS GENERAL PLAN/ADMIN - RES INT	Expenses
30-49-02-72-908-00-97	GAS GENERAL PLAN/ADMIN - C&I INT	Expenses
30-49-02-80-495-00-01	LOAN PAYBACK-EEBB-RES	Revenues
30-49-02-80-495-00-02	LOAN WRITEOFF-EEBB-RES	Revenues
30-49-02-80-495-00-03	LOAN WRITEOFF RECOVERY-EEBB-RES	Revenues
30-49-02-80-495-20-00	EEBB - GRANT FUNDING_REIMBURSEMENT - CDFA	Revenues
30-49-02-82-495-00-01	OBF LOAN PAYBACK - RESIDENTIAL	Revenues
30-49-02-82-495-00-02	OBF LOAN PAYBACK - C&I	Revenues
30-49-02-82-495-00-03	OBF Loan Write Off - Residential	Revenues
30-49-02-82-495-00-04	OBF Loan Write Off - C&I	Revenues
30-49-02-82-495-00-05	OBF Loan Write Off - Recovery - Residential	Revenues
30-49-02-82-495-00-06	OBF Loan Write Off- Recovery - C&I	Revenues
30-49-02-82-908-00-01	OBF LOANS - RESIDENTIAL	Expenses
30-49-02-82-908-00-02	OBF LOANS - C&I	Expenses
30-49-10-10-483-02-00	SUPPLIER REFUND - RETAIL MARKETERS	Revenues
30-49-10-10-488-00-00	SUPPLIER REFUND DEMAND CREDITS	Revenues
30-49-10-10-798-06-05	ASSET MGT CR - PNGTS CASE COSTS - NH	Expenses
30-49-10-10-804-03-02	PEAK DEMAND CHARGES DEFERRED - NH	Expenses
30-49-10-10-804-90-10	SUPPLIER REFUND - DEMAND - PEAK DEMAND	Expenses
30-49-10-11-495-00-90	ACCRD REV-DEM-COMM- UNBILLED-PEAK-NH	Revenues
30-49-10-13-419-00-99	WORKING CAPITAL - PEAK - NH	Revenues
30-49-10-13-495-00-90	ACCRD REV-WORK CAP-UNBILLED- PEAK-NH	Revenues
30-49-10-14-495-00-90	ACCRD REV-BAD DEBT- UNBILLED- PEAK-NH	Revenues
30-49-10-14-904-00-99	BAD DEBT ALLOWANCE - PEAK - NH	Expenses
30-49-10-44-495-00-90	ACCRD REV-BAD DEBT- UNBILLED- OFF PEAK - NH	Revenues
30-49-10-44-904-00-99	BAD DEBT ALLOWANCE - OFF PEAK - NH	Expenses
30-49-13-10-483-00-00	SALES FOR RESALE - DEMAND - PEAK - NH	Revenues
30-49-13-10-483-02-00	COMPANY MANAGED DEMAND - PEAK - NH	Revenues
30-49-13-10-483-20-90	COMPANY MANAGED DEMAND - PEAK - NH EST	Revenues
30-49-13-10-798-06-00	CAPACITY RELEASE- PEAK - NH	Expenses
30-49-13-10-798-06-02	PIPELINE CAPACITY RELEASE - CAP ASSIGN - PEAK - NH	Expenses
30-49-13-10-798-06-08	CUSTOMER REENTRY FEE - NH	Expenses
30-49-13-10-798-60-90	CAPACITY RELEASE- PEAK - NH - EST	Expenses
30-49-13-10-799-01-02	CAPACITY MITIGATION - PEAK - NH	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-49-13-10-799-12-90	CAPACITY MITIGATION - PEAK - NH - EST	Expenses
30-49-13-10-804-01-01	TRANSPORTATION - DEMAND - PEAK - NH	Expenses
30-49-13-10-804-02-01	SUPPLY PURCHASES - DEMAND - PEAK - NH	Expenses
30-49-13-10-804-11-90	TRANSP - DEMAND - PEAK EST - NH	Expenses
30-49-13-10-804-21-90	SUPPLY PURCHASES -DEMAND- PEAK EST - NH	Expenses
30-49-13-10-807-05-00	MISC PURCHASED GAS COSTS - NH	Expenses
30-49-13-10-807-05-10	FUEL TAX RECOVERY - NH	Expenses
30-49-13-10-808-02-00	STORAGE COSTS -DEMAND - PEAK - NH	Expenses
30-49-13-10-808-20-90	STORAGE COSTS -DEMAND - PEAK EST - NH	Expenses
30-49-13-10-813-00-00	OTHER GAS SUPPLY EXPENSES - PEAK	Expenses
30-49-13-11-483-00-01	SALES FOR RESALE - COMMODITY - PEAK - NH	Revenues
30-49-13-11-483-02-00	COMPANY MANAGED COMMODITY- PEAK - NH	Revenues
30-49-13-11-483-10-90	SALES FOR RESALE COMMODITY - PEAK - NH - EST	Revenues
30-49-13-11-483-20-90	COMPANY MANAGED COMMODITY- PEAK - NH EST	Revenues
30-49-13-11-484-00-00	TRANSPORTATION CHARGES - COMMODITY - PEAK - NH	Revenues
30-49-13-11-804-01-02	TRANSPORTATION COMMODITY - PEAK - NH	Expenses
30-49-13-11-804-02-02	SUPPLY PURCHASES COMMODITY- PEAK - NH	Expenses
30-49-13-11-804-04-01	ATV RECON CHARGES - PEAK - NH	Expenses
30-49-13-11-804-04-02	ATV IMBALANCE PENALTIES-PEAK-NH	Expenses
30-49-13-11-804-12-90	TRANSPORTATION VARIABLE - PEAK EST - NH	Expenses
30-49-13-11-804-22-90	SUPPLY PURCHASES COMMODITY- PEAK EST - NH	Expenses
30-49-13-11-806-01-00	GRANITE OBA - NH - PEAK	Expenses
30-49-13-11-807-00-00	HEDGING - COMMODITY - NH - PEAK	Expenses
30-49-13-11-808-01-01	LNG VAPORIZED FOR SENDOUT-BOILOFF - PEAK - NH	Expenses
30-49-13-11-808-02-00	NAT GAS STORAGE WITHDRAWALS - NH-PEAK	Expenses
30-49-13-11-808-02-01	STORAGE COSTS - COMMODITY - PEAK - NH	Expenses
30-49-13-11-808-21-90	STORAGE WITHDRAWLS - PEAK EST - NH	Expenses
30-49-13-11-812-00-00	COMPANY USE - PEAK - NH	Expenses
30-49-21-14-904-00-01	PROVISION FOR DOUBTFUL ACCTS - CGA	Expenses
30-49-21-14-904-00-05	BD EXP CIS R5-W-NON-DIST	Expenses
30-49-21-14-904-00-06	BD EXP CIS R6-W-NON-DIST	Expenses
30-49-21-14-904-00-10	BD EXP CIS R10-W-NON-DIST	Expenses
30-49-21-14-904-00-11	BD EXP CIS R11-W-NON-DIST	Expenses
30-49-21-14-904-00-40	BD EXP CIS G40-W-NON-DIST	Expenses
30-49-21-14-904-00-41	BD EXP CIS G41-W-NON-DIST	Expenses
30-49-21-14-904-00-42	BD EXP CIS G42-W-NON-DIST	Expenses
30-49-21-14-904-00-50	BD EXP CIS G50-W-NON-DIST	Expenses
30-49-21-14-904-00-51	BD EXP CIS G51-W-NON-DIST	Expenses
30-49-21-14-904-00-52	BD EXP CIS G52-W-NON-DIST	Expenses
30-49-21-14-904-01-00	PROVISION FOR DOUBTFUL ACCTS - CGA - NH - PEAK	Expenses
30-49-21-44-904-00-02	PROVISION FOR DOUBTFUL ACCTS - CGA	Expenses
30-49-21-44-904-00-05	BD EXP CIS R5-S-NON-DIST	Expenses
30-49-21-44-904-00-06	BD EXP CIS R6-S-NON-DIST	Expenses
30-49-21-44-904-00-10	BD EXP CIS R10-S-NON-DIST	Expenses
30-49-21-44-904-00-11	BD EXP CIS R11-S-NON-DIST	Expenses
30-49-21-44-904-00-40	BD EXP CIS G40-S-NON-DIST	Expenses
30-49-21-44-904-00-41	BD EXP CIS G41-S-NON-DIST	Expenses
30-49-21-44-904-00-42	BD EXP CIS G42-S-NON-DIST	Expenses
30-49-21-44-904-00-50	BD EXP CIS G50-S-NON-DIST	Expenses
30-49-21-44-904-00-51	BD EXP CIS G51-S-NON-DIST	Expenses
30-49-21-44-904-00-52	BD EXP CIS G52-S-NON-DIST	Expenses
30-49-21-44-904-01-00	PROVISION FOR DOUBTFUL ACCTS - CGA - NH - OFF PEAK	Expenses
30-49-21-44-904-05-52	BD EXP CIS G52-S-NON-DIST	Expenses

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(10) The utility's Securities and Exchange Commission 10K forms and 10Q forms or hyperlinks thereto, for the most recent 2 years.

Response:

Northern Utilities, Inc. does not make Form 10-K or Form 10-Q filings.

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(11) A detailed list of all membership fees, dues, lobbying expenses and donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount, and the account charged, according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000,000 all membership fees, dues and donations shall be reported; and

b. If the utility's annual gross revenues are $100,000,000 or more, all membership fees, dues and donations of $5,000 and more shall be reported.

Response:

Please see PUC 1604.01(a) - 11 Attachment 1 for a list of amounts charged above the line in 2020.

Northern Utilities, Inc.
NH Division

Organization		Amount	Account Charged	Purpose
American Gas Association	$	28,609	30-40-13-00-921-03-00	Membership Dues
Northeast Gas Association		6,000	30-40-80-00-930-03-00	Membership Dues
Total	$	34,609		

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(12) The utility's most recent depreciation study if not previously filed in an adjudicative proceeding.

Response:

The Company's most recent depreciation study is filed in this proceeding. Please see the Direct Testimony of Company witness Ned Allis of Gannett Fleming.

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(13) The utility's most recent management and financial audits if not previously filed in an adjudicative proceeding.

Response:

Please see PUC 1604.01(a) – 13 Attachment 1 which is Northern Utilities Inc.'s Annual Report to Noteholders for the year ended December 31, 2020.

On October 17, 2018, the Maine Public Utilities Commission issued an Order in Maine PUC Docket 2015-00155 indicating an intent to "initiate periodic audits" of all Maine Local Distribution Companies ("LDCs") "to allow for a comprehensive, structured and in-depth examination of LDC gas supply procurement and management decisions and activities." The Commission expressly noted that its decision to conduct audits was not based on any finding or indication of LDC imprudence or poor management and "[would] not be conducted as a management audit pursuant to Title 35-A, section 113" of Maine's statutes. 2015-00155, *Inquiry into Regulatory and Rate-Setting Approaches for Natural Gas Supply Costs*, Inquiry Findings and Conclusions at 3 (October 17, 2018). The Commission first conducted an audit of Northern Utilities, Inc.'s Maine Division ("Northern Utilities Maine"). 2018-00300, *Northern Utilities Inc. Review of Gas Supply Procurement and Management Activities*, Notice of Summary Investigation (October 18, 2018). The Maine Commission's third-party consultant, Liberty Consulting Group, issued its Final Report on December 19, 2019. Though the investigation was not a "Management Audit" as that term is defined in 35-A M.R.S. § 113, the Company is providing a copy of the Final Report as Puc 1604.01(a) – 13 Attachment 2.

In Northern Utilities Maine's last rate case, 2019-00092, the Maine Commission ordered that a management audit under 35-A M.R.S. § 113 be initiated for the purpose of examining the Company's implementation of its new customer information system ("CIS"). The Maine Commission's third-party consultant, Liberty Consulting Group, issued a Final Report of its audit on February 26, 2021. The Company provides a copy of the Final Report as Puc 1604.01(a) – 13 Attachment 3. Unitil disputes the findings of the audit, and Northern Utilities Maine recently submitted extensive testimony rebutting Liberty Consulting Group's conclusions regarding, among other things, vendor selection, project and cost management, CIS implementation, and

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:
ratepayer impact. Northern Utilities Maine's June 30, 2021 rebuttal filing can be found at:

https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=111071&CaseNumber=2021-00022

Northern Utilities continues to participate actively in the audit proceeding to demonstrate that the full amount of the CIS project costs are reasonable and justifiable, and will pursue full recovery in rates of these costs.

NORTHERN UTILITIES, INC.

CERTIFICATION TO NOTEHOLDERS

I hereby certify that the accompanying Balance Sheets as of December 31, 2020 and December 31, 2019, Statements of Earnings for the years ended December 31, 2020, 2019 and 2018, Statements of Cash Flows for the years ended December 31, 2020, 2019 and 2018 and Statements of Changes in Shareholder's Equity for the years ended December 31, 2020, 2019 and 2018 were, to the best of my knowledge and belief, properly prepared and are correct.

I additionally certify that the accompanying calculation worksheets, pursuant to Sections 10.1 and 10.5 of the Northern Utilities Inc. Note Purchase Agreements, were, to the best of my knowledge and belief, properly prepared and are correct.

I also certify that I have reviewed the provisions of the Northern Utilities, Inc. Note Purchase Agreements, and to the best of my knowledge and belief the Company was, and remains in compliance with the provisions of these Agreements and no Default or Event of Default exists or occurred during the period of the financial statements ending December 31, 2020 and up to the date of this certification.

Daniel J. Hurstak
Controller

March 22, 2021

Northern Utilities, Inc.

(a) Ratio of Funded Indebtedness to Total Capitalization

The information below is being provided in accordance with Section 10.1 (a) of the Note Purchase Agreements for Northern Utilities, Inc.'s 5.29% Senior Notes, due March 2, 2020 ,3.52% Senior Notes, due November 1, 2027, 7.72% Senior Notes, due December 3, 2038, 4.42% Senior Notes, due October 15, 2044, 4.32% Senior Notes, due November 1, 2047, 4.04% Senior Notes due September 12, 2049 and 3.78% Senior Notes, due September 15, 2040.

	(Millions) As of December 31, 2020	
Funded Indebtedness [1]	$	228.6
Total Capitalization	$	460.2
Funded Indebtedness / Total Capitalization [2]		49.7%

[1] **Funded Indebtedness is Total Capitalization less Common Stock Equity as of the balance sheet date.**

[2] **Per Section 10.1(a) of the Note Purchase Agreements, Funded Indebtedness cannot exceed 65% of Total Capitalization.**

Northern Utilities, Inc.

(a) Restrictions on Dividends

The information below is being provided in accordance with Section 10.1 (a) of the Note Purchase Agreements for Northern Utilities, Inc.'s 5.29% Senior Notes, due March 2, 2020 ,3.52% Senior Notes, due November 1, 2027, 7.72% Senior Notes, due December 3, 2038, 4.42% Senior Notes, due October 15, 2044, 4.32% Senior Notes, due November 1, 2047, 4.04% Senior Notes due September 12, 2049 and 3.78% Senior Notes, due September 15, 2040. As Section 11 (f) of the Note Purchase Agreements contains cross-default provisions, the most restrictive calculation of the amount "Available for Dividends" is being provided here.

	(Millions) As of December 31, 2020	
Stated Amount	$	168.0
Add: Equity Contributions - 2020		6.4
Add: Net Income - 2020		14.7
Subtotal	**$**	**189.1**
Less: Dividends Declared / Paid - 2020		14.6
Available for Dividends [(1)]	**$**	**174.5**

[(1)] Per Section 10.5 (a) of the Note Purchase Agreements, the Company may not declare or pay any dividend (other than dividends payable solely in shares of its own common stock) or make any other distributions of cash, property or assets on any shares of any class of its capital stock or apply any of its cash, property or assets (other than amounts equal to net proceeds received from the sale of common stock of the Company subsequent to the date of the Agreements) to the purchase or retirement of, or make any other distribution, through reduction of capital or otherwise, in respect of any shares of its capital stock in excess of the amount "Available for Dividends".

Deloitte.

Deloitte & Touche LLP
200 Berkeley Street
Boston, MA 02116-5022
USA

Tel: + 1 617 437 2000
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Northern Utilities, Inc.
Hampton, NH

We have audited the accompanying financial statements of Northern Utilities, Inc. (the "Company") (a wholly-owned subsidiary of Unitil Corporation), which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of earnings, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2020, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northern Utilities, Inc. as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in accordance with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

March 22, 2021

FINANCIAL STATEMENTS
AND
INDEPENDENT AUDITORS' REPORT

NORTHERN UTILITIES, INC.
For the Period Ended December 31, 2020

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
($ in Millions)

	Year Ended December 31,		
	2020	2019	2018
Operating Revenues	**$ 155.5**	$ 166.6	$ 179.1
Operating Expenses:			
Cost of Gas Sales	**63.2**	73.3	90.7
Operation and Maintenance	**28.6**	30.6	29.5
Depreciation and Amortization	**21.6**	20.1	16.9
Taxes Other Than Income Taxes	**10.4**	9.4	8.8
Total Operating Expenses	**123.8**	133.4	145.9
Operating Income	**31.7**	33.2	33.2
Interest Expense	**10.8**	10.6	10.4
Other Expense (Income), Net	**0.6**	0.2	1.0
Income Before Income Taxes	**20.3**	22.4	21.8
Income Taxes	**5.6**	6.2	6.0
Net Income	**$ 14.7**	$ 16.2	$ 15.8

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
BALANCE SHEETS
($ in Millions)

	December 31, 2020	December 31, 2019
ASSETS:		
Current Assets:		
Cash and Cash Equivalents	$ 0.4	$ 0.3
Accounts Receivable – (Net of Allowance for Doubtful Accounts of $1.2 and $0.4)	22.8	21.1
Due from Affiliates	1.5	---
Accrued Revenue	15.2	12.4
Exchange Gas Receivable	4.4	5.5
Gas Inventory	0.3	0.4
Materials and Supplies	5.2	4.9
Prepayments and Other	2.0	1.9
Total Current Assets	51.8	46.5
Utility Plant:		
Gas	687.7	621.6
Construction Work in Progress	13.3	12.5
Utility Plant	701.0	634.1
Less: Accumulated Depreciation	145.5	112.7
Net Utility Plant	555.5	521.4
Other Noncurrent Assets:		
Regulatory Assets	27.9	23.8
Operating Lease – Right of Use Assets	1.6	1.1
Other Assets	2.1	2.1
Total Other Noncurrent Assets	31.6	27.0
TOTAL ASSETS	$ 638.9	$ 594.9

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
BALANCE SHEETS
($ in Millions, except par value and shares data)

	December 31, 2020	December 31, 2019
LIABILITIES AND CAPITALIZATION:		
Current Liabilities:		
Accounts Payable	$ 10.0	$ 11.7
Short-Term Debt	26.7	28.5
Long-Term Debt, Current Portion	---	8.1
Energy Supply Contract Obligations	4.4	5.5
Dividends Payable	3.7	3.3
Due to Affiliates	---	0.9
Environmental Obligations	0.2	0.6
Regulatory Liabilities	0.4	1.0
Other Current Liabilities	4.6	4.8
Total Current Liabilities	50.0	64.4
Noncurrent Liabilities:		
Deferred Income Taxes	42.4	36.5
Cost of Removal Obligations	29.8	30.3
Retirement Benefit Obligations	38.1	31.0
Regulatory Liabilities	15.5	15.8
Environmental Obligations	1.8	2.1
Operating Leases – Less Current Portion	1.1	0.7
Other Noncurrent Liabilities	---	0.1
Total Noncurrent Liabilities	128.7	116.5
Capitalization:		
Long-term Debt, Less Current Portion	228.6	188.9
Shareholder's Equity:		
Common Stock, $10 Par Value		
Authorized - 200 shares		
Issued and Outstanding - 100 shares	207.1	200.7
Retained Earnings	24.5	24.4
Total Shareholder's Equity	231.6	225.1
Total Capitalization	460.2	414.0
Commitments and Contingencies (Note 5)		
TOTAL LIABILITIES AND CAPITALIZATION	$ 638.9	$ 594.9

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF CASH FLOWS
($ in Millions)

	Year Ended December 31, 2020	2019	2018
Operating Activities:			
Net Income	**$ 14.7**	$ 16.2	$ 15.8
Adjustments to Reconcile Net Income to Cash Provided by (Used in) Operating Activities:			
Depreciation and Amortization	**21.6**	20.1	16.9
Deferred Tax Provision	**5.6**	6.2	6.0
Changes in Working Capital Items:			
Accounts Receivable	**(1.7)**	6.6	(1.9)
Accrued Revenue	**(2.8)**	8.2	(2.0)
Exchange Gas Receivable	**1.1**	2.0	(2.1)
Due to/from Affiliates	**(2.4)**	0.9	2.8
Accounts Payable	**(1.7)**	(4.2)	(0.8)
Regulatory Liabilities	**(0.6)**	0.6	(2.1)
Other Changes in Working Capital Items	**(1.0)**	(0.3)	1.1
Deferred Regulatory and Other Charges	**(0.8)**	0.3	1.4
Other, net	**2.7**	(0.8)	(8.6)
Cash Provided by Operating Activities	**34.7**	55.8	26.5
Investing Activities:			
Property, Plant, and Equipment Additions	**(55.4)**	(69.6)	(53.3)
Cash Used in Investing Activities	**(55.4)**	(69.6)	(53.3)
Financing Activities:			
(Repayment of) Proceeds from Short-Term Debt, net	**(1.8)**	(29.7)	55.2
Issuance of Long-Term Debt	**40.0**	40.0	---
Repayment of Long-Term Debt	**(8.2)**	(8.4)	(18.3)
Long-Term Debt Issuance Costs	**(0.2)**	(0.2)	---
Net (Decrease) Increase in Exchange Gas Financing	**(1.1)**	(2.0)	2.1
Dividends Paid	**(14.3)**	(11.8)	(11.9)
Equity Contribution	**6.4**	25.5	---
Cash Provided by Financing Activities	**20.8**	13.4	27.1
Net Increase (Decrease) in Cash and Cash Equivalents	**0.1**	(0.4)	0.3
Cash and Cash Equivalents at Beginning of Year	**0.3**	0.7	0.4
Cash and Cash Equivalents at End of Year	**$ 0.4**	$ 0.3	$ 0.7
Supplemental Cash Flow Information:			
Interest Paid	**$ 9.8**	$ 9.4	$ 10.0
Income Taxes Paid (Refunded)	**$ ---**	$ ---	$ 0.6
Non-cash Investing Activity:			
Capital Expenditures Included in Accounts Payable	**$ 0.5**	$ 0.1	$ 0.1
Right of Use Assets Obtained in Exchange for Lease Obligations	**$ 0.5**	$ 1.1	$ ---

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
($ in Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2018	$ 175.2	$ 16.1	$ **191.3**
Net Income		15.8	**15.8**
Dividends Declared ($99,881 Per Common Share)		(9.9)	**(9.9)**
Balance at December 31, 2018	$ 175.2	$ 22.0	$ **197.2**
Net Income		16.2	**16.2**
Dividends Declared ($138,510 Per Common Share)		(13.8)	**(13.8)**
Equity Contribution	25.5		**25.5**
Balance at December 31, 2019	$ 200.7	$ 24.4	$ **225.1**
Net Income		14.7	**14.7**
Dividends Declared ($146,663 Per Common Share)		(14.6)	**(14.6)**
Equity Contribution	6.4		**6.4**
Balance at December 31, 2020	$ 207.1	$ 24.5	$ **231.6**

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

NOTE 1: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations - Northern Utilities, Inc. (Northern Utilities or Company), a wholly-owned subsidiary of Unitil Corporation (Unitil), provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area and is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Maine Public Utilities Commission (MPUC). Northern Utilities' accounting policies conform with Generally Accepted Accounting Principles in the United States of America (U.S. GAAP).

COVID-19 - In December 2019, a novel strain of coronavirus (COVID-19) emerged in Wuhan, Hubei Province, China. While initially the outbreak was largely concentrated in China and caused significant disruptions to its economy, the virus spread to several other countries and infections have been reported globally. The extent to which the coronavirus affects the Company's financial condition, results of operations, and cash flows will depend on future developments, which are highly uncertain and cannot be predicted with confidence, including the duration of the outbreak, new information which may emerge concerning the severity of the coronavirus, and the actions to contain the coronavirus or treat its effect, among others. In particular, the continued spread of the coronavirus could adversely affect the Company's business, including (i) by disrupting Northern Utilities' employees and contractors ability to provide ongoing services to Northern Utilities, (ii) by reducing customer demand for electricity or gas, or (iii) by reducing the supply of electricity or gas, each of which could have an adverse effect on the Company's financial condition, results of operations, and cash flows.

Transactions with Affiliates - In addition to its investment in Northern Utilities, Unitil has interests in two other distribution utility companies, one doing business in New Hampshire and one doing business in Massachusetts, an interstate natural gas transmission pipeline company (Granite State), a service company (Unitil Service Corp.), a realty company, a power company, and a non-regulated company.

Transactions among Northern Utilities and other affiliated companies include professional and management services rendered by Unitil Service Corp. of approximately $24.8 million, $26.1 million and $23.9 million in the years ended December 31, 2020, 2019 and 2018, respectively. The Company's transactions with affiliated companies are subject to review by the NHPUC, MPUC and the Federal Energy Regulatory Commission (FERC).

In 2019 and 2020, Northern Utilities received capital contributions of $25.5 million and $6.4 million, respectively, from Unitil.

Approximately 7%, 6% and 5% of the Company's natural gas purchases for the years ended December 31, 2020, 2019 and 2018, respectively, were from Granite State.

Use of Estimates - The preparation of financial statements in conformity with U.S. GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Fair Value - The Financial Accounting Standards Board (FASB) Codification defines fair value, and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under the FASB Codification include:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 - Valuations based on quoted prices in markets that are not active or for which all significant inputs are observable, either directly or indirectly.

Level 3 - Prices or valuations that require inputs that are both significant to the fair value measurement and unobservable.

To the extent that valuation is based on models or inputs that are less observable or unobservable in the market, the determination of fair value requires more judgment. Accordingly, the degree of judgment exercised by the Company in determining fair value is greatest for instruments categorized in Level 3. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Fair value is a market-based measure considered from the perspective of a market participant rather than an entity-specific measure. Therefore, even when market assumptions are not readily available, the Company's own assumptions are set to reflect those that market participants would use in pricing the asset or liability at the measurement date. The Company uses prices and inputs that are current as of the measurement date, including during periods of market dislocation. In periods of market dislocation, the observability of prices and inputs may be reduced for many instruments. This condition could cause an instrument to be reclassified from Level 1 to Level 2 or from Level 2 to Level 3.

There have been no changes in the valuation techniques used during the current period.

Utility Revenue Recognition - Gas Operating Revenues consist of billed and unbilled revenue and revenue from rate adjustment mechanisms. Billed and unbilled revenue includes delivery revenue and pass-through revenue, recognized according to tariffs approved by the MPUC and NHPUC which determine the amount of revenue the Company will record for these items. Revenue from rate adjustment mechanisms is recognized as accrued revenue and authorized by the MPUC and NHPUC for recognition in the current period for future cash recoveries from, or credits to, customers.

Billed and unbilled revenue is recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenues are calculated. These unbilled revenues are estimated each month based on estimated customer usage by class and applicable customer rates, taking into account current and historical weather data, assumptions pertaining to metering patterns, billing cycle statistics, and other estimates and assumptions, and are then reversed in the following month when billed to customers.

A majority of the Company's revenue from contracts with customers continues to be recognized on a monthly basis based on applicable tariffs and customer monthly consumption. Such revenue is recognized using the invoice practical expedient which allows an entity to recognize revenue in the amount that directly corresponds to the value transferred to the customer.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The Company's billed and unbilled revenue meets the definition of "revenues from contracts with customers" as defined in Accounting Standards Codification (ASC) 606. Revenue recognized in connection with rate adjustment mechanisms is consistent with the definition of alternative revenue programs in ASC 980-605-25-3, as the Company has the ability to adjust rates in the future as a result of past activities or completed events. The rate adjustment mechanisms meet the criteria within ASC 980-605-25-4. In cases where allowable costs are greater than operating revenues billed in the current period for the individual rate adjustment mechanism, additional operating revenue is recognized. In cases where allowable costs are less than operating revenues billed in the current period for the individual rate adjustment mechanism, operating revenue is reduced. ASC 606 requires the Company to disclose separately the amount of revenues from contracts with customers and from alternative revenue programs.

The following table presents revenue classified by the types of goods/services rendered and market/customer type.

	Twelve Months Ended December 31,		
Gas Operating Revenues ($ millions):	**2020**	**2019**	**2018**
Billed and Unbilled Revenue:			
Residential	$ 54.5	$ 61.9	$ 61.5
C&I	91.7	106.4	105.7
Other	4.9	7.8	6.9
Total Billed and Unbilled Revenue	151.1	176.1	174.1
Rate Adjustment Mechanism Revenue	4.4	(9.5)	5.0
Total Gas Operating Revenues	**$ 155.5**	**$ 166.6**	**$ 179.1**

Retirement Benefit Costs - The Company co-sponsors the Pension Plan, which is a defined benefit pension plan. The Pension Plan was closed to new non-union employees effective January 1, 2010. The Pension Plan was closed to United Steelworkers of America Local 12012-6 employees hired subsequent to December 31, 2010 and to Utility Workers Union of America Local 341 employees hired subsequent to April 1, 2012. The Company also co-sponsors a non-qualified retirement plan, the SERP, covering certain executives of the Company, and an employee 401(k) savings plan. Additionally, the Company co-sponsors the PBOP Plan, primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of its retirement benefit obligations (RBO) based on the projected benefit obligations. The Company has recognized a corresponding Regulatory Asset, reflecting ultimate recovery from customers through rates. The regulatory asset (or regulatory liability) is amortized as the actuarial gains and losses and prior service cost are amortized to net periodic benefit cost for the Pension and PBOP plans. All amounts are remeasured annually. See Note 7 (Retirement Benefit Obligations).

Depreciation - Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's financial statements. Provisions for depreciation were equivalent

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

to an annual composite rate of 3.01%, 3.04% and 2.96% in 2020, 2019 and 2018, respectively, based on the average depreciable property balances at the beginning and end of the year. Depreciation expense for Northern Utilities was $19.4 million, $17.9 million and $16.2 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Sales Taxes - The Company bills its customers sales tax in Maine. This tax is remitted to the Maine Revenue Service and is excluded from revenues on the Company's Statements of Earnings. There is no sales tax in New Hampshire.

Income Taxes - The Company is subject to Federal and State income taxes as well as various other business taxes. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's Balance Sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes. The Company classifies penalty and interest expense related to income tax liabilities as income tax expense and interest expense, respectively, in the Statements of Earnings.

Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes, which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining current and deferred tax assets and liabilities. The Company's deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. In accordance with the FASB Codification, the Company periodically assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Unitil Corporation and its subsidiaries, including Northern Utilities, file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal and state income taxes paid by Unitil Corporation are collected from, or refunded to, Unitil Corporation's subsidiaries based on a tax sharing agreement between Unitil Corporation and each of its affiliated subsidiaries. The tax sharing agreement apportions taxes paid among Unitil Corporation and its subsidiaries as though each affiliate had filed a separate tax return.

Cash and Cash Equivalents - Cash and Cash Equivalents includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits.

Allowance for Uncollectible Accounts - The Company recognizes a provision for doubtful accounts that reflects the Company's estimate of expected credit losses for electric and gas utility service accounts receivable. The allowance for doubtful accounts is calculated by applying a historical loss rate, which is adjusted for current conditions, customer trends, or other factors such as macroeconomic conditions, to customer account balances. The Company also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by the MPUC and NHPUC to recover the costs of its energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the allowance for doubtful accounts requires judgment about the assumptions used in the analysis. The Company's experience

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

has been that the assumptions used in evaluating the adequacy of the allowance for doubtful accounts have proven to be reasonably accurate.

Accounts Receivable, Net includes $1.1 million and $0.4 million of the Allowance for Doubtful Accounts at December 31, 2020 and December 31, 2019, respectively. Unbilled Revenues, net (a component of Accrued Revenue) includes $0.1 million of the Allowance for Doubtful Accounts at December 31, 2020.

Accrued Revenue - Accrued Revenue includes the current portion of Regulatory Assets (see "Regulatory Accounting") and unbilled revenues (see "Utility Revenue Recognition"). The following table shows the components of Accrued Revenue as of December 31, 2020 and 2019.

	December 31,	
Accrued Revenue ($ millions)	**2020**	2019
Regulatory Assets – Current	**$ 8.4**	$ 5.0
Unbilled Revenues	**6.8**	7.4
Total Accrued Revenue	**$ 15.2**	$ 12.4

Exchange Gas Receivable - The Company has a gas exchange and storage agreement whereby natural gas purchases during the months of April through October are delivered to a third party. The third party delivers natural gas back to the Company during the months of November through March. The exchange and storage gas volumes are recorded at weighted average cost. Exchange Gas Receivable was $4.4 million and $5.5 million at December 31, 2020 and 2019, respectively. Although the asset management agreement associated with the exchange gas receivable may qualify as an embedded derivative because its terms contain notional amounts, the Company does not classify the agreement as a derivative because it meets the criteria for exception as a contract for normal purchases and normal sales, as such instruments are defined per the FASB Codification.

Gas Inventory - The Company uses the weighted average cost methodology to value natural gas inventory. Natural gas inventory was $0.3 million and $0.4 million at December 31, 2020 and 2019, respectively.

	December 31,	
Gas Inventory ($ millions)	**2020**	2019
Natural Gas	**$ 0.3**	$ 0.4
Liquefied Natural Gas	**---**	---
Total Gas Inventory	**$ 0.3**	$ 0.4

Materials and Supplies - Materials and Supplies consist of distribution construction and repair materials. Materials and Supplies are stated at average cost and are issued from stock using the average cost of existing stock. Materials and Supplies are recorded when purchased and subsequently charged to expense or capitalized to property, plant, and equipment when installed. Materials and Supplies were $5.2 million and $4.9 million at December 31, 2020 and 2019, respectively.

Utility Plant - The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

an allowance for funds used during construction (AFUDC). The average annualized interest rate applied to AFUDC was 2.88%, 4.32% and 2.64% in 2020, 2019 and 2018, respectively. The costs of current repairs and minor replacements are charged to operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, depreciation amounts to provide for future negative salvage value. At December 31, 2020 and 2019, the cost of removal amounts, which are recorded on the Company's Balance Sheets in Cost of Removal Obligations, were estimated to be $29.8 million and $30.3 million, respectively.

Regulatory Accounting - Northern Utilities' principal business is the distribution of natural gas and it is regulated by the MPUC and NHPUC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

	December 31,	
Regulatory Assets consist of the following ($ millions)	**2020**	2019
Retirement Benefit Obligations	**$ 21.4**	$ 16.6
Rate Adjustment Mechanisms	**7.1**	3.8
Environmental Obligations	**4.5**	5.9
Income Taxes	**0.9**	1.2
Other	**2.4**	1.3
Total Regulatory Assets	**$ 36.3**	$ 28.8
Less: Current Portion of Regulatory Assets [1]	**8.4**	5.0
Regulatory Assets - noncurrent	**$ 27.9**	$ 23.8

(1) Reflects amounts included in Accrued Revenue on the Company's Balance Sheets.

	December 31,	
Regulatory Liabilities consist of the following ($ millions)	**2020**	2019
Rate Adjustment Mechanisms	**$ 0.4**	$ 1.0
Income Taxes	**15.2**	15.4
Other	**0.3**	0.4
Total Regulatory Liabilities	**15.9**	16.8
Less: Current Portion of Regulatory Liabilities	**0.4**	1.0
Regulatory Liabilities - noncurrent	**$ 15.5**	$ 15.8

Generally, the Company receives a return on investment on its Regulatory Assets for which a cash outflow has been made. Included in Regulatory Assets as of December 31, 2020 are $4.3 million of environmental costs, rate case costs and other expenditures to be recovered over the next seven years. Regulators have authorized recovery of these expenditures, but without a return. The Company expects that it will recover all its investments in long-lived assets through its utility rates, including those amounts recognized as Regulatory Assets.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Leases - The Company records assets and liabilities on the balance sheet for all leases with terms longer than 12 months. Leases are classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The Company has elected the practical expedient to not separate non-lease components from lease components and instead to account for both as a single lease component. The Company's accounting policy election for leases with a lease term of 12 months or less is to recognize the lease payments as lease expense on a straight-line basis over the lease term. The Company recognizes those lease payments in the Consolidated Statements of Earnings on a straight-line basis over the lease term. See additional discussion in the "Leases" section of Note 2 (Debt and Financing Arrangements).

Derivatives - The Company enters into energy supply contracts to serve its customers. The Company follows a procedure for determining whether each contract qualifies as a derivative instrument under the guidance provided by the FASB Codification on Derivatives and Hedging. For each contract, the Company reviews and documents the key terms of the contract. Based on those terms and any additional relevant components of the contract, the Company determines and documents whether the contract qualifies as a derivative instrument as defined in the FASB Codification. The Company has determined that its energy supply contracts either do not qualify as a derivative instrument under the guidance set forth in the FASB Codification, have been elected as a normal purchase, or have contingencies that have not yet been met in order to establish a notional amount.

The Company previously operated a regulatory approved hedging program designed to fix or cap a portion of its gas supply costs for the coming years of service, which included use of derivative instruments. The hedging program was terminated in 2018.

Under the hedging program previously operated by the Company, any gains or losses resulting from the change in the fair value of these derivatives were passed through to ratepayers directly through the Company's Cost of Gas Clause. The fair value of these derivatives was determined using Level 2 inputs (valuations based on quoted prices in markets that are not active or for which all significant inputs are observable, either directly or indirectly), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company recorded gains and losses resulting from the change in fair value of the derivatives as regulatory liabilities or assets, then reclassified these gains or losses into Cost of Gas Sales when the gains and losses were passed through to customers through the Cost of Gas Clause.

The Company had no derivative assets or liabilities recorded on its Consolidated Balance Sheets as of December 31, 2020 and December 31, 2019. There were no losses / (gains) recognized in Regulatory Assets / Liabilities for the years ended December 31, 2020 and 2019. There were no losses / (gains) reclassified into the Consolidated Statements of Earnings for the years ended December 31, 2020 and 2019.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Energy Supply Obligations - The Company enters into asset management agreements under which it releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. The gas volumes related to these agreements are recorded in Exchange Gas Receivable on the Company's Balance Sheets while the corresponding obligations are recorded in Energy Supply Obligations.

Commitments and Contingencies - The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2020, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's Financial Statements below. See Note 5 (Commitments and Contingencies).

Environmental Matters - The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has or will recover substantially all of the costs of the environmental remediation work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2020, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 5, Commitments and Contingencies below. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

Off-Balance Sheet Arrangements - As of December 31, 2020, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements.

Concentrations of Credit Risk - Financial instruments that subject the Company to credit risk concentrations consist of cash and cash equivalents and accounts receivable. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. Accounts receivable may be affected by changes in economic conditions. However, the Company believes that the credit risk associated with accounts receivable is offset by the diversification of the Company's customer base. The Company believes it is not exposed to any significant credit risk on cash and cash equivalents and accounts receivable.

Subsequent Events - The Company has evaluated all events or transactions through March 22, 2021, the date the Financial Statements were available to be issued. During this period, the Company did not have any material subsequent events that would result in adjustment to or disclosure in its Financial Statements.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

NOTE 2: DEBT AND FINANCING ARRANGEMENTS

Long-Term Debt and Interest Expense

All the Company's long-term debt is issued under unsecured promissory notes with negative pledge provisions, which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for the Company to issue new long-term debt, covenants of the existing long-term agreements must be satisfied, including that the Company has total funded indebtedness less than 65% of total capitalization. The Company's unsecured promissory note agreements require that if it defaults on any long-term debt agreement, it would constitute a default under all its long-term debt agreements. The default provisions are not triggered by the actions or defaults of other companies owned by Unitil. The Company's long-term debt agreements also contain covenants restricting its ability to incur liens and to enter into sale and leaseback transactions, and restricting its ability to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

On September 15, 2020, Northern Utilities issued $40 million of Notes due 2040 at 3.78% and used the net proceeds from this offering to repay short-term debt and for general corporate purposes. Approximately $0.2 million of costs associated with this issuance have been recorded as a reduction to Long-Term Debt for presentation purposes on the Balance Sheets.

On September 12, 2019, Northern Utilities issued $40 million of Notes due 2049 at 4.04%. Northern Utilities used the net proceeds from this offering to repay short-term debt and for general corporate purposes. Approximately $0.2 million of costs associated with these issuances have been netted against Long-Term Debt for presentation purposes on the Company's Balance Sheets.

Details of long-term debt at December 31, 2020 and 2019 are shown in the following table:

Long-term Debt ($ millions)	December 31, 2020	2019
Senior Notes:		
5.29% Senior Notes, Due March 2, 2020	---	8.2
3.52% Senior Notes, Due November 1, 2027	**20.0**	20.0
7.72% Senior Notes, Due December 3, 2038	**50.0**	50.0
3.78% Senior Notes, Due September 15, 2040	**40.0**	---
4.42% Senior Notes, Due October 15, 2044	**50.0**	50.0
4.32% Senior Notes, Due November 1, 2047	**30.0**	30.0
4.04% Senior Notes, Due September 12, 2049	**40.0**	40.0
Total Long-Term Debt	**230.0**	198.2
Less: Unamortized Debt Issuance Costs	**1.4**	1.2
Total Long-Term Debt, net of Unamortized Debt Issuance Costs	**228.6**	197.0
Less: Current Portion	---	8.1
Total Long-Term Debt, Less Current Portion	**$ 228.6**	$ 188.9

The aggregate amount of Note repayment requirements is zero in each of 2021 – 2025 and $230.0 million thereafter.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The fair value of the Company's long-term debt is estimated based on quoted market prices for the same or similar issues, or on current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at December 31, 2020 is estimated to be approximately $286.5 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, management believes that there is no active market in the Company's debt securities, which have all been sold through private placements. If there were an active market for the Company's debt securities, the fair value of the Company's long-term debt would be estimated based on quoted market prices for the same or similar issues, or on current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt is estimated using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.) In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

Credit Arrangements

Northern Utilities' short-term borrowings are presently provided under a cash pooling and loan agreement between Unitil and its subsidiaries. Under the existing pooling and loan agreement, Unitil Corporation borrows, as required, from its banks on behalf of its subsidiaries. At December 31, 2020, Unitil had unsecured committed bank lines of credit for short-term debt aggregating $120 million. The weighted average interest rates on all short-term borrowings were 1.7%, 3.4% and 3.3% during 2020, 2019 and 2018, respectively. The Company had short-term debt outstanding through bank borrowings of approximately $26.7 million and $28.5 million at December 31, 2020 and 2019, respectively.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $5.4 million and $6.5 million of natural gas storage inventory at December 31, 2020 and 2019, respectively, related to these asset management agreements. The amount of natural gas inventory released in December 2020, which was payable in January 2021, was $1.0 million and recorded in Accounts Payable at December 31, 2020. The amount of natural gas inventory released in December 2019, which was payable in January 2020, was $1.0 million and recorded in Accounts Payable at December 31, 2019.

Leases

The Company leases some of its vehicles under operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2020, 2019 and 2018 amounted to $0.7 million, $0.5 million and $0.8 million respectively.

The balance sheet classification of the Company's lease obligations is presented in the following table:

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Lease Obligations (millions)	December 31, 2020		December 31, 2019	
Operating Lease Obligations:				
Other Current Liabilities (current portion)	$	0.5	$	0.4
Operating Leases, Less Current Portion (noncurrent portion)		1.1		0.7
Total Lease Obligations	$	1.6	$	1.1

Cash paid for amounts included in the measurement of operating lease obligations for the twelve months ended December 31, 2020 and 2019 was $0.7 million and $0.5 million, respectively, and was included in Cash Provided by Operating Activities on the Statements of Cash Flows.

The following table is a schedule of future operating lease payment obligations as of December 31, 2020. The payments for operating leases consist of $0.5 million of current operating lease obligations, which are included in Other Current Liabilities and $1.1 million of noncurrent operating lease obligations, which are included in Operating Leases, Less Current Portion, on the Company's Balance Sheets as of December 31, 2020.

Lease Payments ($000's) Year Ending December 31,	Operating Leases	
2021	$	584
2022		448
2023		382
2024		289
2025		50
2026-2030		---
Total Payments		**1,753**
Less: Interest		141
Amount of Lease Obligations Recorded on Balance Sheets	**$**	**1,612**

Operating lease obligations are based on the net present value of the remaining lease payments over the remaining lease term. In determining the present value of lease payments, the Company used the interest rate stated in each lease agreement. As of December 31, 2020, the weighted average remaining lease term is 3.5 years and the weighted average operating discount rate used to determine the operating lease obligations was 4.7%. As of December 31, 2019, the weighted average remaining lease term is 3.2 years and the weighted average operating discount rate used to determine the operating lease obligations was 4.9%.

NOTE 3: RESTRICTION ON DIVIDENDS

Under the terms of the Note Purchase Agreements relating to Northern Utilities' Senior Notes, $174.5 million was available for dividends and similar distributions at December 31, 2020. Common dividends declared by Northern Utilities are paid exclusively to Unitil Corporation.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

NOTE 4: ENERGY SUPPLY

Natural Gas Supply:

Northern Utilities' C&I customers are entitled to purchase their natural gas supply from third-party gas suppliers. Many of Northern Utilities' large, and some of its medium, C&I customers purchase their gas supply from third-party suppliers. Most small C&I customers, and all residential customers, purchase their gas supply from Northern Utilities under regulated rates and tariffs. As of December 2020, 80% of the Company's largest New Hampshire gas customers, representing 39% of the Company's New Hampshire gas therm sales, and 67% of the Company's largest Maine customers, representing 25% of the Company's Maine gas therm sales, purchased their gas supply from a third-party supplier.

The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Cost of Gas Sales in the Statements of Earnings.

Regulated Natural Gas Supply:

Northern Utilities purchases the majority of its natural gas from U.S. domestic and Canadian suppliers largely under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern Utilities arranges for gas transportation and delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of liquefied natural gas (LNG), via trucking of supplies to storage facilities within Northern Utilities' service territory.

Northern Utilities has available under firm contract 122,000 million British Thermal Units (MMbtu) per day of year-round and seasonal transportation capacity to its distribution facilities, and 4.3 billion cubic feet (BCF) of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns an LNG storage and vaporization facility. This plant is used principally during peak load periods to augment the supply of pipeline natural gas.

NOTE 5: COMMITMENTS AND CONTINGENCIES

Regulatory Matters

Overview - Northern Utilities is a New Hampshire corporation and a public utility under both New Hampshire and Maine law. Northern Utilities provides natural gas distribution services to approximately 69,400 customers in 47 New Hampshire and southern Maine communities at rates established under traditional cost of service regulation. Under this regulatory structure, the Company recovers the cost of providing distribution service to its customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. The Company's business customers are entitled to purchase their natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through the Company as the provider of basic service energy supply. The Company purchases natural gas for basic service from unaffiliated wholesale suppliers and recovers the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law. Among other things, the TCJA substantially reduced the corporate income tax rate to 21%, effective January 1, 2018. Each state public utility commission, with jurisdiction over the areas that are served by Northern Utilities, issued orders directing how the tax law changes were to be reflected in rates. Northern Utilities has complied with these orders and has made the required changes to its rates as directed by the commissions.

On November 21, 2019, FERC issued Order No. 864, a final rule on Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes. The new rule requires public utilities with formula transmission rates to revise their formula rates to include a transparent methodology to address the TCJA and future tax law changes on customer rates by accounting for "excess" or "deficient" Accumulated Deferred Income Taxes (ADIT). FERC also required transmission providers with stated rates to account for TCJA's effect on ADIT in their next rate case. The Company is complying with the new rule and there is no material effect on its financial position, operating results, or cash flows.

Base Rates - Maine - On March 26, 2020, the MPUC approved an increase to base revenue of $3.6 million, a 3.6% increase over the Company's test year operating revenues, effective April 1, 2020. The order approved a return on equity of 9.48%, and a hypothetical capital structure of 50% equity and 50% debt. As part of the order and increase in base revenue, the MPUC provided for recovery of some but not all of the Company's implementation costs associated with its customer information system pending the completion of an investigation. On March 9, 2021, the MPUC opened a new docket and issued the notice of investigation to determine the amount of customer information system costs that will be allowed in rates. The Company believes that the customer information system costs were prudently incurred and that the investigation will not have a material impact on its financial position, operating results or cash flows.

Targeted Infrastructure Replacement Adjustment - Maine - The settlement in Northern Utilities' Maine division's 2013 rate case authorized the Company to implement a TIRA rate mechanism to adjust base distribution rates annually to recover the revenue requirements associated with targeted investments in gas distribution system infrastructure replacement and upgrade projects, including the Company's Cast Iron Replacement Program (CIRP). In its Final Order issued on February 28, 2018 for Northern Utilities' 2017 base rate case, the MPUC approved an extension of the TIRA mechanism for an additional eight-year period, which will allow for annual rate adjustments through the end of the CIRP program. The Company's most recent request under the TIRA mechanism, to increase annual base rates by $1.4 million for 2019 eligible facilities, was approved by the MPUC on April 29, 2020, effective May 1, 2020.

Base Rates - New Hampshire - On May 2, 2018, the NHPUC approved a settlement agreement providing for a net annual revenue increase of $3.2 million, incorporating the effect of the TCJA, and an initial step increase to recover post-test year capital investments. The Company's second annual revenue step increase of approximately $1.4 million to recover eligible capital investments in 2018 was approved by the NHPUC effective May 1, 2019. According to the terms of the settlement agreement, Northern Utilities' next distribution base rate case shall be based on a historical test year no earlier than the twelve months ending December 31, 2020.

Financial Effects of COVID-19 Pandemic - The NHPUC has opened a proceeding to consider the revenue and cost effects on the regulated gas and electric utilities within their respective jurisdictions of the requirement to continue the availability of gas, electric and water service to customers during the COVID-19 pandemic. Among the effects under investigation are the revenue effects associated

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

with service disconnection moratoriums, the waiver of certain fees and expanded customer payments arrangements; the increased cost of customer accounts that cannot be collected, including the cost of bad debt reserves and increased working capital costs; and increased operating and maintenance costs incurred for employees to work safely and protect the public. Northern Utilities is an active participant in this proceeding, and is in full compliance with all regulatory orders governing service shut-off moratoriums and other customer service protection measures. These matters remain pending.

Northern Utilities / Granite State - Firm Capacity Contract - Northern Utilities relies on the transport of gas supply over its affiliate Granite State pipeline to serve its customers in the Maine and New Hampshire service territories. Granite State facilitates critical upstream interconnections with interstate pipelines and third party suppliers essential to Northern Utilities' service to its customers. Northern Utilities reserves firm capacity through a contract with Granite State, which is renewed annually. Pursuant to statutory requirements in Maine and orders of the MPUC, Northern Utilities submits an annual informational report requesting approval of a one-year extension of its 12-month contract for firm pipeline capacity reservation, with an evergreen provision and three-month termination notification requirement. On May 13, 2020, the MPUC approved Northern Utilities' request to extend its contract for firm transmission service on its affiliate Granite State pipeline for another year, extending the current contract for the period of November 1, 2020 through October 31, 2021.

Reconciliation Filings - Northern Utilities has a number of regulatory reconciling accounts which require annual or semi-annual filings with the MPUC and NHPUC, respectively, to reconcile costs and revenues and seek approval of any rate changes. These filings include: costs associated with energy efficiency programs in New Hampshire as directed by the NHPUC; and the actual wholesale energy costs for natural gas incurred by Northern Utilities. Northern Utilities has been and remains in full compliance with all directives and orders regarding these filings. The Company considers these to be routine regulatory proceedings and there are no material issues outstanding.

Contractual Obligations

The table below lists the Company's known specified gas supply contractual obligations as of December 31, 2020.

	Payments Due by Period						
Gas Supply Contractual Obligations as of December 31, 2020 (millions)	**Total**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026 & Beyond**
Gas Supply Contracts	**$ 542.7**	**$ 52.7**	**$ 47.0**	**$ 44.2**	**$ 35.3**	**$ 34.9**	**$ 328.6**

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company is in material compliance with applicable environmental and safety laws and regulations and, as of December 31, 2020, has not identified any material losses reasonably likely to be incurred in excess of recorded amounts. However, we cannot assure that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

Manufactured Gas Plant (MGP) Sites - Northern Utilities has an extensive program to identify, investigate and remediate former manufactured gas plant (MGP) sites, which were operated from the

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. In Maine, Northern Utilities has documented the presence of MGP sites in Lewiston and Portland, and a former MGP disposal site in Scarborough.

Northern Utilities has worked with the Maine Department of Environmental Protection and New Hampshire Department of Environmental Services (NH DES) to address environmental concerns with these sites. Northern Utilities or others have completed remediation activities at all sites; however, on site monitoring continues at several sites which may result in future remedial actions as directed by the applicable regulatory agency. In July 2019, the NH DES requested that Northern Utilities review modeled expectations for groundwater contaminants against observed data at the Rochester site. In June 2020, the NH DES coupled the submittal of the review to a proposed extension of the gas distribution system by Northern Utilities; both the review and extension are expected to be completed by the end of the second quarter of 2021. While any recommendation is subject to approval by the NH DES, the Company has accrued $0.8 million for estimated costs to complete the remediation at the Rochester site, which is included in the Environmental Obligations table below.

The NHPUC and MPUC have approved regulatory mechanisms for the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC has approved the recovery of MGP environmental costs over succeeding seven-year periods. For Northern Utilities' Maine division, the MPUC has authorized the recovery of environmental remediation costs over succeeding five-year periods.

The Environmental Obligations table below shows the amounts accrued for Northern Utilities related to estimated future cleanup costs associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the future recovery of these environmental remediation costs is expected based on regulatory precedent and established practices.

Environmental Obligations

	(millions)	
	2020	2019
Total Balance at Beginning of Period	**$ 2.7**	$ 2.0
Additions	**0.1**	0.9
Less: Payments / Reductions	**0.8**	0.2
Total Balance at End of Period	**$ 2.0**	$ 2.7
Less: Current Portion	**0.2**	0.6
Noncurrent Balance at End of Period	**$ 1.8**	$ 2.1

Litigation - The Company is also involved in other legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on its financial position, operating results or cash flows.

Market Risk - Although the Company is subject to commodity price risk as part of its traditional operations, the current regulatory framework within which the Company operates allows for full

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

collection of fuel and gas costs in rates. Consequently, there is limited commodity price risk after consideration of the related rate-making.

NOTE 6: INCOME TAXES

Provisions for Federal and State Income Taxes reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2020, 2019 and 2018 are shown in the following table:

	($000's)		
	2020	**2019**	**2018**
Current Income Tax Provision			
Federal	$ —	$ —	$ —
State	—	—	—
Total Current Income Taxes	—	—	—
Deferred Income Provision			
Federal	**3,925**	4,314	4,289
State	**1,704**	1,875	1,744
Total Deferred Income Taxes	**5,629**	6,189	6,033
Total Income Tax Expense	**$ 5,629**	$ 6,189	$ 6,033

The differences between the Company's provisions for Income Taxes and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown in the following table:

	2020	2019	2018
Statutory Federal Income Tax Rate	21%	21%	21%
Income Tax Effects of:			
State Income Taxes, net	7	6	6
Utility Plant Differences	—	—	—
Other , net	—	1	—
Effective Income Tax Rate	**28%**	**28%**	**27%**

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Temporary differences which gave rise to deferred tax assets and liabilities in 2020 and 2019, are shown in the following table:

Temporary Differences (000's)	**2020**	**2019**
Deferred Tax Assets		
Retirement Benefit Obligations	**$ 10,317**	$ 8,383
Net Operating Loss Carryforwards	**12,768**	14,985
Other, net	**183**	—
Total Deferred Tax Assets	**$ 23,268**	$ 23,368
Deferred Tax Liabilities		
Utility Plant Differences	**$ 64,195**	$ 59,785
Regulatory Assets & Liabilities	**753**	(556)
Other, net	**693**	685
Total Deferred Tax Liabilities	**65,641**	59,914
Net Deferred Tax Liabilities	**$ 42,373**	$ 36,546

In March 2020, the Coronavirus Aid, Relief and Economic Security (CARES) Act was signed into law. The CARES Act included several tax changes as part of its economic package. These changes principally related to expanded Net Operating Loss (NOL) carryback periods, increases to interest deductibility limitations, and accelerated Alternative Minimum Tax (AMT) refunds. The Company has evaluated these items and determined that these items do not have a material impact on the Company's financial statements as of December 31, 2020. Additionally, the CARES Act enacted the Employment Retention Credit (ERC) to incentivize companies to retain employees. The ERC is a 50% credit on employee wages for employees that are retained and cannot perform their job duties at 100% capacity as a result of coronavirus pandemic restrictions. The ERC is take as a credit on employment tax form 941. In the third quarter of 2020, the Company recorded an ERC of $0.2M as a reduction to employment tax expense which is recorded as a reduction to Taxes other than Income Taxes in the consolidated statement of earnings.

In December 2020, the Consolidated Appropriations Act, 2021 (CAA) was signed into law. The CAA included additional funding through tax credits as part of its economic package for 2021. The Company evaluated these items in its tax computation as of December 31, 2020 and determined that these items do not have a material impact on the Company's financial statements as of December 31, 2020.

In December 2017, the TCJA, which included a reduction to the corporate federal income tax rate to 21% effective January 1, 2018, was signed into law. In accordance with GAAP Accounting Standard 740, the Company revalued its Accumulated Deferred Income Taxes (ADIT) at the new 21% tax rate at which the ADIT will be reversed in future periods. As of December 31, 2019 and December 31, 2020 the Company had recorded a net Regulatory Liability in the amount of $15.4 million and $15.3 million, respectively, as a result of the ADIT revaluation.

Based on communications received by the Company from its state regulators in rate cases and other regulatory proceedings in the first quarter of 2018 and as prescribed in the TCJA, the recent FERC guidance noted above and IRS normalization rules; the benefit of these excess ADIT amounts will be subject to flow back to customers in future utility rates according to the Average Rate Assumption Method (ARAM). ARAM reconciles excess ADIT at the reversal rate of the underlying book/tax

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

temporary timing differences. The Company estimates the ARAM flow back period to be approximately fifteen years, for protected and unprotected excess ADIT. The Company estimates the ARAM flow back period to be approximately fifteen years, for protected and unprotected excess ADIT. As of December 31, 2020, the Company flowed back $0.1 million to customers in its Maine jurisdictions. New Hampshire liabilities will begin to flow back once rate proceedings have finalized in that jurisdiction.

The Company evaluated its tax positions at December 31, 2020 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any tax liabilities or assets as defined by the FASB Codification is required. The Company remains subject to examination by Federal, Maine, and New Hampshire tax authorities for the tax periods ended December 31, 2017; December 31, 2018; and December 31, 2019. Income tax filings for the year ended December 31, 2019 have been filed with the New Hampshire Department of Revenue Administration and the Maine Revenue Service.

NOTE 7: RETIREMENT BENEFIT OBLIGATIONS

The Company co-sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service. The Pension Plan was closed to new non-union employees effective January 1, 2010. The Pension Plan was closed to United Steelworkers of America Local 12012-6 employees hired subsequent to December 31, 2010 and to Utility Workers Union of America Local 341 employees hired subsequent to April 1, 2012.

- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) - The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.

- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) - The SERP is a non-qualified retirement plan, with participation limited to executives selected by the Board of Directors.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan costs for years ended December 31:	**2020**	2019	2018
Discount Rate	**3.25%**	4.25%	3.60%
Rate of Compensation Increase	**3.00%**	3.00%	3.00%
Expected Long-term Rate of Return on Plan Assets	**7.40%**	7.50%	7.75%
Health Care Cost Trend Rate Assumed for Next Year	**7.00%**	7.00%	7.50%
Ultimate Health Care Cost Trend Rate	**4.50%**	4.50%	4.50%
Year that Ultimate Health Care Cost Trend Rate is reached	**2029**	2024	2024

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Used to Determine Benefit Obligations at December 31:	**2020**	2019	2018
Discount Rate	**2.50%**	3.25%	4.25%
Rate of Compensation Increase	**3.00%**	3.00%	3.00%
Health Care Cost Trend Rate Assumed for Next Year	**6.60%**	7.00%	7.00%
Ultimate Health Care Cost Trend Rate	**4.50%**	4.50%	4.50%
Year that Ultimate Health care Cost Trend Rate is reached	**2029**	2029	2024

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on an assessment of current market conditions using high quality corporate bond interest rate indices and pension yield curves. The Rate of Compensation Increase assumption used in each of 2020, 2019 and 2018 was 3.00%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The following table provides the components of the Company's retirement plan costs ($000's):

	Pension Plan			**PBOP Plan**			**SERP**		
	2020	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Service Cost	**$ 1,317**	$ 1,219	$ 1,302	**$ 1,129**	$ 992	$ 1,228	**$ 120**	$ 103	$ 200
Interest Cost	**1,672**	1,786	1,601	**1,024**	1,111	1,095	**232**	235	166
Expected Return on Plan Assets	**(2,612)**	(2,338)	(2,124)	**(1,072)**	(850)	(840)	**---**	---	---
Prior Service Cost Amortization	**306**	306	306	**194**	196	278	**24**	23	78
Actuarial Loss Amortization	**1,610**	959	1,209	**191**	69	437	**438**	261	199
Sub-total	**2,293**	1,932	2,294	**1,466**	1,518	2,198	**814**	622	643
Amounts Capitalized and Deferred	**(919)**	(773)	(899)	**(620)**	(636)	(925)	**(264)**	(200)	(207)
NPBC Recognized	**$ 1,374**	$ 1,159	$ 1,395	**$ 846**	$ 882	$ 1,273	**$ 550**	$ 422	$ 436

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status ($000's):

	Pension Plan		PBOP Plan		SERP	
	2020	2019	**2020**	2019	**2020**	2019
Change in Plan Assets:						
Plan Assets at Beginning of Year	**$ 26,871**	$ 20,444	**$ 11,293**	$ 8,353	**$ ---**	$ ---
Actual Return on Plan Assets	**4,632**	5,858	**1,943**	1,934	**---**	---
Employer Contributions	**1,712**	2,561	**1,227**	1,269	**276**	253
Participant Contributions	**---**	---	**90**	51	**---**	---
Benefits Paid	**(1,764)**	(1,992)	**(584)**	(314)	**(276)**	(253)
Plan Assets at End of Year	**$ 31,451**	$ 26,871	**$ 13,969**	$ 11,293	**$ ---**	$ ---
Change in PBO:						
PBO at Beginning of Year	**$ 38,918**	$ 29,620	**$ 25,628**	$ 20,808	**$ 4,772**	$ 3,175
Service Cost	**1,317**	1,219	**1,129**	992	**120**	103
Interest Cost	**1,672**	1,786	**1,024**	1,111	**232**	235
Plan Amendments	**732**	---	**---**	---	**---**	94
Participant Contributions	**---**	---	**90**	51	**---**	---
Benefits Paid	**(1,764)**	(1,992)	**(584)**	(314)	**(276)**	(253)
Actuarial (Gain) or Loss	**6,297**	8,285	**3,318**	2,980	**1,098**	1,418
PBO at End of Year	**$ 47,172**	$ 38,918	**$ 30,605**	$ 25,628	**$ 5,946**	$ 4,772
Funded Status: Assets vs PBO	**$ (15,721)**	$ (12,047)	**$ (16,636)**	$ (14,335)	**$ (5,946)**	$ (4,772)

The increases in the PBO for the Pension and PBOP plans as of December 31, 2020 compared to December 31, 2019 reflects a decrease in the assumed discount rate as of December 31, 2020.

The funded status of the Pension, PBOP and SERP Plans is calculated based on the difference between the benefit obligation and the fair value of plan assets and is recorded on the balance sheets as an asset or a liability. Because the Company recovers the retiree benefit costs from customers through rates, regulatory assets are recorded in lieu of an adjustment to Accumulated Other Comprehensive Income/ (Loss).

The Company has recorded on its Balance Sheets as a liability the underfunded status of its retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets, net of tax, of $21.4 million and $16.6 million at December 31, 2020 and 2019, respectively, to recognize the future collection of these plan obligations in gas rates.

The Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $43.7 million and $35.9 million as of December 31, 2020 and 2019, respectively. The ABO for the SERP was $4.9 million and $3.7 million as of December 31, 2020 and 2019, respectively. For the PBOP Plan, the ABO and PBO are the same.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The Company expects to continue to make contributions to its Pension Plan in 2021 and future years at minimum required and discretionary funding levels consistent with the amounts recovered in rates for these Pension Plan costs.

The following table represents employer contributions, participant contributions and benefit payments ($000's).

	Pension Plan			PBOP Plan			SERP		
	2020	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Employer Contributions	**$ 1,712**	$ 2,561	$ 5,670	**$ 1,227**	$ 1,269	$ 1,353	**$ 276**	$ 253	$ 165
Participant Contributions	**$ ---**	$ ---	$ ---	**$ 90**	$ 51	$ 64	**$ ---**	$ ---	$ ---
Benefit Payments	**$ 1,764**	$ 1,992	$ 1,339	**$ 584**	$ 314	$ 389	**$ 276**	$ 253	$ 165

The following table represents estimated future benefit payments ($000's).

Estimated Future Benefit Payments	Pension	PBOP	SERP
2021	$ 2,164	$ 708	$ 269
2022	1,912	769	269
2023	2,444	791	268
2024	2,867	872	268
2025	2,625	999	500
2026 - 2030	$ 17,095	$ 6,746	$ 2,645

The Expected Long-Term Rate of Return on Pension Plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on Pension Plan assets is based on target investment allocation of 56% in common stock equities, 39% in fixed income securities and 5% in real estate securities. The Company's Expected Long-Term Rate of Return on PBOP Plan assets is based on target investment allocation of 55% in common stock equities and 45% in fixed income securities. The actual investment allocations are shown in the following tables.

Pension Plan	**Target Allocation**	**Actual Allocation at December 31,**		
	2021	**2020**	**2019**	**2018**
Equity Funds	56%	**58%**	54%	49%
Debt Funds	39%	**37%**	36%	40%
Real Estate Fund	5%	**4%**	9%	10%
Other[1]	---	**1%**	1%	1%
Total		**100%**	100%	100%

(1) Represents investments being held in cash equivalents as of December 31, 2020, December 31, 2019 and December 31, 2018 pending payment of benefits.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

PBOP Plan	**Target Allocation**	**Actual Allocation at December 31,**		
	2021	**2020**	**2019**	**2018**
Equity Funds	55%	**55%**	56%	53%
Debt Funds	45%	**45%**	44%	47%
Total		**100%**	100%	100%

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 7.40% for 2020. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 5 – 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

Following is a description of the valuation methodologies used for assets measured at fair value. There have been no changes in the methodologies used at December 31, 2020 and 2019. See Note 1 (Summary of Significant Accounting Policies) for a discussion of the Company's fair value accounting policy.

Equity and Fixed Income Funds
These investments are valued based on quoted prices from active markets. These securities are categorized in Level 1 as they are actively traded and no valuation adjustments have been applied.

Cash Equivalents
These investments are valued at cost, which approximates fair value, and are categorized in Level 1.

Real Estate Fund
These investments are valued at net asset value (NAV) per unit based on a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity. In accordance with FASB Codification Topic 820, "Fair Value Measurement", these investments have not been classified in the fair value hierarchy. The fair value amounts presented in the following tables for the Real Estate Fund are intended to permit reconciliation of the fair value hierarchy to the "Plan Assets at End of Year" line item shown in the "Change in Plan Assets" table above.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Assets measured at fair value on a recurring basis for the Pension Plan as of December 31, 2020 and 2019 are as follows ($000's):

Description	Balance as of December 31,	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Fair Value Measurements at Reporting Date Using		
2020				
Pension Plan Assets:				
Equity Funds	$ 18,253	$ 18,253	$ ---	$ ---
Fixed Income Funds	11,573	11,573	---	---
Total Mutual Funds	29,826	29,826	---	---
Cash Equivalents	292	292	---	---
Total Assets in the Fair Value Hierarchy	$ 30,118	$ 30,118	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	1,333			
Total Assets	$ 31,451			
2019				
Pension Plan Assets:				
Equity Funds	$ 14,711	$ 14,711	$ ---	$ ---
Fixed Income Funds	9,611	9,611	---	---
Total Mutual Funds	24,322	24,322	---	---
Cash Equivalents	160	160	---	---
Total Assets in the Fair Value Hierarchy	$ 24,482	$ 24,482	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	2,389			
Total Assets	$ 26,871			

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Assets measured at fair value on a recurring basis for the PBOP Plan as of December 31, 2020 and 2019 are as follows ($000's):

		Fair Value Measurements at Reporting Date Using		
Description	**Balance as of December 31,**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
2020				
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$ 6,258	$ 6,258	$ ---	$ ---
Equity Funds	7,711	7,711	---	---
Total Assets	$ 13,969	$ 13,969	$ ---	$ ---
2019				
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$ 4,921	$ 4,921	$ ---	$ ---
Equity Funds	6,372	6,372	---	---
Total Assets	$ 11,293	$ 11,293	$ ---	$ ---

Employee 401(k) Tax Deferred Savings Plan - The Company co-sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company common stock fund.

The Company's share of contributions to the 401(k) Plan was $1,259,300, $1,188,000 and $1,082,000 for the years ended December 31, 2020, 2019 and 2018, respectively.

Examination of Natural Gas Supply Resource Procurement and Management by Northern Utilities Inc. d/b/a Until

<u>Final Report – Public Version</u>
<u>Confidential Material Redacted</u>

Presented to:
State of Maine
Public Utilities Commission

Presented by:
The
Liberty Consulting Group

December 10, 2019

1451 Quentin Rd Suite 400, #343
Lebanon, Pennsylvania 17042

admin@libertyconsultinggroup.com

Executive Summary

The Maine Public Utilities Commission (MPUC, or the Commission) selected The Liberty Consulting Group (Liberty) to conduct an examination of the natural gas supply procurement and management protocols and practices of Northern Utilities, Inc. d/b/a Unitil (NUI, or the Company). This summary presents our principal findings, conclusions and recommendations. This following chapters of this report presents the detailed results of our examination.

We have categorized the results of our review into six overall subject areas, which, combined, encompass a broad review of the matters affecting gas supply procurement and management:

1. Organization, Staffing and Controls
2. Gas Supply Planning and Forecasting
3. Gas Supply Procurement
4. Gas Supply Management
5. Measurement and Balancing
6. Price Risk Management.

We issued 101 data requests, and conducted two rounds of interviews with Company management. We issued a draft report to the Company, whose management responded with comments and requests for the redaction of confidential information. We made changes to the report to the extent consistent with the exercise of our independent judgment.

I. Organization, Staffing and Controls

NUI provides gas distribution and supply services in New Hampshire and Maine. Unitil, NUI's parent, also owns electric distribution companies in Concord and Hampton, New Hampshire, a combination electric and gas distribution utility in Massachusetts, and an interstate gas pipeline operating in New Hampshire and Maine.

Unitil acquired NUI and the interstate pipeline from Bay State Gas Company (now d/b/a Columbia Gas of Massachusetts) in 2008. That transaction left one important gas-supply process interrelationship with the former parent -- an exchange arrangement providing access to interstate pipeline capacity under contract to NUI, but to which NUI has no physical connection.

In 1984, Unitil formed a service company to provide joint management and administrative services to its subsidiaries. Essentially all management employees work for the service company. An Energy Contracts unit within the Financial Services Division of the service company conducts the gas-supply function. Gas Operations reports to a different Vice President of the service company. It has responsibility for supply-related functions such as gas control and measurement. The interstate pipeline operates as a separate entity, but most of its employees also work for the service company.

All three jurisdictions in which Unitil's gas distribution utilities operate permit varying degrees of customer choice for electricity and natural gas supply. NUI's Energy Contracts unit works with personnel in both Gas Operations and Electric Operations to ensure delivery of third-party supplies. Energy Contracts has a more comprehensive set of planning responsibilities for the gas business. Its role includes administration associated with deliveries of third-party supplies, supply planning for customers who buy their supplies from the Company, and supply-capacity planning for both sales-service and distribution-service customers.

Qualified and experienced personnel staff Energy Contracts and Gas Operations. Performance measurement meets prevailing industry practice. However, we found a lack of written policies and procedures addressing gas-supply functions and activities (discussed below under Gas Supply Management). The lack of documented policies and procedures creates exposure to loss of continuity in understanding and executing them, particularly in a smaller organization. ***We recommended that management update personnel descriptions.***

We also found some controls weaknesses in the following areas:

- Documentation of gas supply decisions
- Limits on authority to approve transactions
- Separation of transaction-related functions
- Internal Audit examinations
- Employee acknowledgement of the Company's Code of Conduct.

We recommended that management: (a) add gas-price information, including estimated prices, to the record of daily gas-supply selections, and (b) re-examine its supply processes from a controls perspective. The process re-examination should conclude within six months of the issuance of this report, which will give management sufficient time to address the identified controls issues.

II. Gas Supply Planning and Forecasting

NUI's Integrated Resource Plan, filed in July of this year, comprehensively and clearly presented management's forecasting and supply-planning methods. We examined methods with reference to prevailing industry practices, and how and how well decisions about supply resources incorporate the results of applying those methods.

Management considered 30 years of history (the gas years of 1988/89 through 2017/18) to populate its normal- and design-weather data. The data capture effective degree-days (EDDs) by adjusting temperature data for wind speed. Separate calculations apply those parameters for the Maine and New Hampshire Divisions. Regression analysis of billing data supported the development of econometric models for forecasting numbers of customers and use per customer for each customer segment. Management made reductions to the resulting customer-segment forecasts to reflect energy-efficiency savings.

Management calculated Design Day requirements using regression analysis of actual daily throughput data, separately for each Division. Management also updated both the Residential Heating Use Per Customer model and the Peak-Day forecasting model between the 2015 IRP and the current one.

Unitil developed a comprehensive marketing program soon after it acquired NUI. That program identified customers on main but not connected, and low-use customers as targets with the highest potential. Management had also slated facilities in Maine for a Cast Iron Replacement program. Management continues special promotions and special incentives offers to prospective customers for connection in the areas affected by that program.

Energy Contracts remains informed about other company activities that might affect requirements for gas supply. Personnel gather at Seasonal Readiness Meetings to discuss new initiatives, such as a targeted area build-out. Other initiatives undergo discussion in the course of normal internal coordination.

Management inputs requirements forecasts into an optimization model. The model designs a portfolio of supply resources that provides the best fit for the input forecast. NUI uses SENDOUT, widely used for such purposes in the gas distribution business to solve for the least-cost mix of options for meeting demand, subject to user-defined constraints.

NUI has found that three pipeline options compare favorably with the alternative of relying on delivered supplies. For its seasonal and peaking requirements, management issues requests for proposals (RFPs) annually. It seeks seasonal supplies first, along with asset-management services for its legacy pipeline and storage assets. A second RFP for peaking supplies follows in mid-summer. Management has continued to discuss additional pipeline supply projects with potential offerors, and it has recently re-started work on on-system supply options.

We concluded that load-forecasting methods conformed to prevailing industry practice, but that weather-analysis methods warranted improvement. ***We recommended that NUI test the use of Monte Carlo-based weather distributions.*** Monte Carlo simulations are finding increasingly broad use in utility supply planning. ***We also recommended that management expand its analysis of additional gas-supply resources to include increased utilization of existing and newly-acquired pipeline capacity.***

III. Gas Supply Procurement

NUI's gas-supply capacity portfolio accesses the U. S. Gulf Coast, Central and Eastern Pennsylvania, Eastern Canada, and Dawn, Ontario supply sources. NUI had most of its current capacity when Unitil acquired it. Management has since renewed, converted or terminated essentially all pipeline and storage contracts then in place. The terminations sought cost reduction, or movement of receipt points closer to the NUI distribution system. NUI has also relocated its largest underground storage to Dawn, and increased capacity and maximum daily withdrawal capability.

NUI also accesses markets to supply its LNG storage and regasification facility in Lewiston, Maine. LNG enters the region at the Canaport receiving terminal in New Brunswick and at the Distrigas facility in Everett, Massachusetts. The NUI system also connects to the Maritimes & Northeast Pipeline system (M&NP); revaporized LNG from the Canaport terminal can reach NUI and other U. S. markets via M&NP pipeline facilities.

Management organizes these capacity resources into "paths" connecting each supply point to NUI's affiliated pipeline, which then delivers to the distribution system. At Lewiston, Maine, the only NUI distribution-system receipt point not served by that pipeline, NUI connects directly to M&NP, and buys supply delivered there. NUI shares all its pipeline capacity with the retail marketers who serve customers on its distribution system.

Management has sought to reduce the portion of supply bought on a delivered basis, pursuing alternatives taking the forms of pipeline connections and increases in underground storage. These resources have provided access to upstream supply points more liquid than those of New England. Capacity from such projects permits year-round use, but NUI's requirements are seasonal. Management's analysis, presented in the new IRP and in its applications for approval of participation in the new projects, holds that lower prices and greater price stability associated with access to the more-liquid supply points favor these projects over delivered supply.

NUI purchases gas supplies annually through two requests for proposals (RFPs). The first covers supplies provided as part of agreements to manage certain of NUI's capacity assets, winter-season supplies delivered through NUI's pipeline affiliate, and summer-season supplies delivered to storage-area pooling points or to injection points for storage. The second RFP covers peaking supplies delivered to the pipeline affiliate's receipt points or to NUI's receipt point on M&NP.

Management solicits offers to manage its path-based packages under asset-management agreements (AMAs) having one-year terms. Management requires asset managers to provide supply at a relevant index price, plus variable transportation and fuel charges. For each path, NUI provides the third-party managers an estimate of the amount of capacity that must be assigned to retail marketers. The third parties selected benefit in these arrangements by selling gas to NUI at agreed prices and by using any remaining capacity on the path (after meeting NUI and retail marketers' requirements) to serve other customers. NUI generally awards management of each path to the third party offering the largest asset-management fee. Over the last six years (2014-2015 through 2019-2020), asset-management revenue has covered an average of 23 percent of asset demand costs (between 11 and 36 percent in any given year).

NUI has required winter supplies significantly beyond the capacity of the capacity portfolio and pending supply projects. Management has addressed these winter needs recently with contracts for: (a) base-load supplies delivered in equal daily amounts, and (b) peaking supplies up to maximum daily quantities elected by NUI. Base-load supply contracts generally call for one delivery quantity for November through March and another for December through February. Peak-supply contracts address the five winter months.

New England gas market price volatility and constrained pipeline capacity create substantial risk for suppliers. While competition to provide commodity supply to NUI has been reasonably robust, some competitors have disappeared.

Management issues the RFP for delivered peaking service in late June or early July, with the service to begin November 1. Offerors provide the service from November 1 through the following March 31.

Management requires that prospective sellers of gas or asset-management services enter into a NAESB (North American Energy Standards Board) Base Contract for Sale and Purchase of Natural Gas with it in order to do business. Management evaluates the financial stability of those who seek to bid, but requests collateral rather than rejecting a possible supplier if it is concerned about the supplier's finances. NUI bought gas from 13 suppliers in 2018, an increase of two over the number in 2017. The top four suppliers accounted for 81.7 percent of volumes purchased.

We found NUI's management of supply procurement a notable strength. Management employed effective contracting practices, and entered contracts appropriate in meeting supply needs. ***We did, however, recommend that NUI initiate an intensive effort to reduce dependence on delivered peaking service.*** The effort should include both demand-side and supply-side options.

IV. Gas Supply Management

The challenges that NUI faces managing its gas supply include: (a) use of *multiple pipelines* to supply a *large number of delivery points*, (b) a *fragmented service territory* imposing locational requirements on deliveries, (c) a large penetration by *retail marketers*, (d) large swings in gas requirements due to high *weather variability*, and (e) NUI's *downstream location* on almost all pipelines serving, which produces narrow nominated-versus-delivered amount tolerances during the winter. We found planning, complex under these circumstances, attentive, comprehensive, and supported by appropriate systems and processes.

Operations planning begins with a general forecast to construct seasonal supply plans. The Energy Contracts staff assigns supply resources to particular delivery points. The staff then generates monthly plans that further detail and align sources and deliveries. A Daily Forecast file applies a seven-day weather forecast to generate a corresponding daily forecast of supply requirements at the pipeline delivery locations that serve NUI. Management then nominates from among the available supply resources the quantities that they want delivered to each receipt location. Management updates the Daily Forecast file every day with new weather data.

NUI's service territories, do not have robust connections among themselves. Five points of receipt bring gas into the pipeline connecting all but one of them; 38 points provide for deliveries from that pipeline. An NUI lateral connects Lewiston to the other portions of the service territory, but Lewiston depends also on winter access to an M&NP delivery point and NUI's liquefied natural gas (LNG) storage and regasification facility. Limits on the pipeline's flow capacity prohibit unlimited movement of gas from different receipt points to all the NUI points of delivery, necessitating consideration of location-specific requirements.

Management allocates shares of each NUI supply-capacity path to retail marketers in proportion to the design daily demands of each marketer's load. The marketers receive most resources directly, but NUI operates two of them -- the Lewiston LNG facility and a small storage contract and the pipeline capacity for delivering the stored gas. The marketers can trade their assigned "slices" of the NUI supply-capacity portfolio among themselves to optimize their capacity holdings, but must deliver their required amounts to specified pipeline receipt points.

NUI's primary reliance on asset-management agreements (AMAs) makes two primary activities the focus of supply-management: (a) nominating quantities for delivery to the relevant pipeline, including withdrawals from storage, under each AMA, and (b) calling on the small quantities of supply NUI manages directly as needed by marketers or NUI's system-supply customers. Management must address locational requirements first. After addressing that constraint, it can select among available resources on the basis of cost. Gas Control uses Energy Contracts' regression models relating weather conditions and sendout requirements to generate forecasts of requirements for the coming seven days, based on expected weather conditions.

NUI's lack of sizeable upstream pipeline capacity limits its occasions for secondary-market activities. Management places most available capacity into the path-based asset-management agreements, whose underlying RFPs estimate pipeline capacity required to serve NUI and retail marketer loads. Those bidding to supply asset management factor their ability to make economic use of any unused capacity into pricing their bids.

We found NUI's gas-supply management a strength, but a lack of written procedures risks operational continuity should NUI experience a loss of key skills. ***We recommended that management prepare written procedures to guide the nominations and dispatch functions.*** We also found that some short-term forecasting tools might be improved with an industry best practice known as "deep neural networks." ***We therefore recommended that management explore the application of neural network methods to short-term requirements forecasting.***

V. Measurement and Balancing

NUI's overall measurement scheme uses upstream-pipeline measurement of deliveries into NUI's pipeline affiliate (or NUI's distribution system for M&NP deliveries for Lewiston). The affiliate measures its deliveries into NUI's system; NUI, in turn, measures its deliveries to its customers. At year-end 2018, NUI's Maine Division had 34,119 active meters. NUI filed descriptions of how each of its meter types operates, and of the circumstances in which each is deployed, with its initial response in Docket No. 2018-00331, *Inquiry into Meter Testing and Standards of Local Distribution Companies*.

The interstate pipelines calibrate their meters at least annually. NUI's pipeline affiliate inspects its turbine and rotary meters monthly to verify their operation, and it calibrates its flow computers annually. NUI tests meters before installation and calibrates its largest ones quarterly. Field audits conducted each year sample the non-instrumented rotary and diaphragm meters. The audits seek to validate proper operation of the reading indexes and the automated meter reading (AMR) devices. The practice is to examine two percent of small-diaphragm meters and 25 percent of large diaphragm ones each year.

NUI's billing system identifies anomalies in billings, such as measurements showing no usage at customer locations known to be active. Upon detecting anomalies, technicians visit the meter to examine the circumstances. NUI also tests meters on customer request. NUI has identified certain meter types with known problems, replacing them as practical. Management also has a practice of retiring certain meter types to reduce the number of types in inventory. Otherwise, NUI retires meters that are more than 20 years old.

NUI takes a number of measures to reduce lost and unaccounted for (LAUF) gas. Management measures company use for office facilities and for vaporization and heaters at its LNG facility and district regulator stations. Management also installs correctors that compensate for variances in pressure and temperature for commercial and industrial customers. Another measure employed calls for checks of customer service regulators and adjustment of them on installation and routine meter changes. NUI also conducts an aggressive leak-repair program.

Management reports that most leaks occur along the cast-iron portions of its distribution system. It plots leaks on maps, to serve as a factor in planning the cast-iron replacement program. NUI has completed that replacement program in New Hampshire, now finding no leaks there. As do most gas distribution companies, NUI calculates (separately for Maine, New Hampshire, and Fitchburg) annual LAUF percentage by summing monthly calculations from July of the previous year through June of the reporting year.

Balancing consists of getting deliveries into the distribution system to match deliveries out of it. Balancing poses special challenges for NUI, because of its weather changes, penetration by retail marketers, and the company's location at downstream ends of the gas pipelines that serve it. Service interruptions on its four upstream pipelines affect it. NUI's Delivery Service Terms and Conditions provide for passing through to the marketers any flow restrictions, such as upstream imbalance warnings or operational flow orders (OFOs). Any penalties caused by marketer imbalances are passed along to the offender.

Management generally manages intra-day balancing needs by adjusting storage withdrawals for the first half of the winter, then with off-system sales in the second half. Its contracts for peaking supply and its on-system LNG facility are additional resources for addressing imbalances if necessary.

We found that NUI's metering and testing programs generally conform to prevailing industry practice. Management employed metering strategies are effective in isolating usage by customers and the Company. In particular, we found managements systems, practices and processes for balancing a strength. We had no measurement and balancing improvement recommendations

VI. Price Risk Management

NUI operated a financial hedging program when Unitil acquired it. NUI refocused the program and operated it subject to periodic review by the Commission. In early 2017, NUI petitioned the Commission to allow it to suspend the program for one year, followed by determining the best course going forward. Management also noted that it was replacing one of its gas storage contracts with a larger one that would result in an increase in the volume of gas with physically hedged pricing for the 2018-2019 Winter Period.

The next year, NUI requested that the Commission allow it to terminate the financial hedging program. The Commission approved the request, stating "the current hedging program benefits do not appear to warrant the ongoing cost …." The Commission proposed that NUI describe its price risk management objectives and actions taken to reduce customer exposure to gas price volatility in its IRP filing. Our report provides a brief history of NUI financial hedging, and reviewed the approach to inventory strategy as it relates to providing a physical hedge.

We concluded that NUI's hedging objectives have changed under Until ownership, but the Company has always stated the objective of protecting customers from natural gas price volatility. Volatility in the benchmark price for the natural gas futures contract (a monthly price at a Gulf Coast location) comprised the focus late 2008 and early 2009. Since that time, volatility in that price benchmark has generally reduced, while volatility in daily New England prices has increased.

NUI has substituted increased physical hedging and particular contracting strategies for financial hedging, but the objective is clear: to "insulate customers from the volatility of *daily* index prices".

We also found that NUI's focus on storage and contracting strategies to reduce exposure to gas-price volatility reflects its core strengths. Management has no other particular use for expertise in financial derivatives, and has chosen not to acquire it for the sole purpose of gas-price hedging.

NUI has established controls, policies and procedures that reflected the limited scope of its hedging activity. Its move to increased physical hedging and supply contracting make its processes sufficient, albeit informal. ***We recommended that additional structure be added to those functions.***

We also found that management has reviewed program results regularly, and recommended changes as market trends and program results have developed. Supply-contracting evaluations and decisions have been driven primarily by considerations of supply security and reduced operational risk, but the role of those decisions in protecting the Company's customers from price volatility has increasingly entered those deliberations as the potential benefits to price stability have been realized.

Examination of Natural Gas Supply Resource Procurement and Management by Northern Utilities Inc. d/b/a Until

Final Report – Public Version
Confidential Material Redacted

Presented to:
State of Maine
Public Utilities Commission

Presented by:
The
Liberty Consulting Group

December 10, 2019

1451 Quentin Rd Suite 400, #343
Lebanon, Pennsylvania 17042

admin@libertyconsultinggroup.com

Table of Contents

I. Organization, Staffing, and Controls

A. Background

Organization sets the basic framework for conducting and managing gas supply activities. Those activities require a trained and capable staff with particular skills and knowledge of the gas markets in which they operate. Operational policies and procedures provide definition and control to the conduct of the supply function.

We employed the following evaluation criteria:
1. Ability of the organization structure for the gas-supply function to allow effective and prompt decision-making subject to appropriate controls
2. Quality of coordination and communication of gas-supply functions and resources with related functions and groups.
3. Sufficiency of skills and experience of key managers and contributors
4. Performance assessment transparency and connection to material performance drivers
5. Sufficiency, clarity, and efficiency of policies and procedures governing supply processes
6. Comprehensiveness and sufficiency of approval processes and authority levels to enable and control needed supply commitments and expenditures
7. Adequacy of documentation to support regulatory oversight and review.

B. Findings

Unitil, the parent of Northern Utilities, Inc. (NUI), also owns electric distribution utilities in Concord and Hampton, New Hampshire, Fitchburg Gas and Electric Light Company (FG&E, a combination electric and gas distribution utility in Massachusetts), and Granite State Gas Transmission, Inc. (GSGT), an interstate gas pipeline operating in New Hampshire and Maine. NUI provides gas distribution and supply services in New Hampshire and Maine. The two smaller electric distribution companies, Concord Electric Company and Exeter & Hampton Electric Company, merged in 2002 to form Unitil Energy Systems. The Company's home office is in Hampton, New Hampshire.

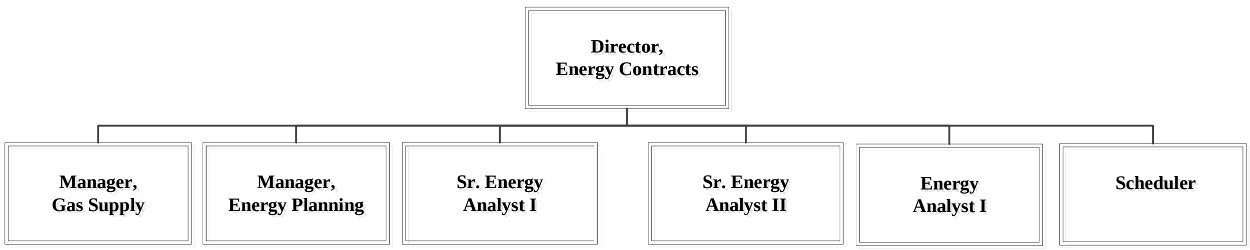
The parent owns no electricity-generating assets. Unitil sold an unregulated energy brokering and advisory business in early 2019, after which all of the operations it owns operate as fully rate-regulated businesses. Gas-supply assets include a small liquefied natural gas (LNG) storage and regasification plant in Lewiston, Maine, owned by Northern, and a small LNG plant and a propane-air peaking plant, owned by FG&E.

Unitil acquired NUI and GSGT in 2008 from Bay State Gas Company (now doing business as Columbia Gas of Massachusetts). That transaction left one important gas-supply process interrelationship with the former parent, an exchange arrangement which provides access to interstate pipeline capacity under contract to NUI, but to which NUI has no physical connection.

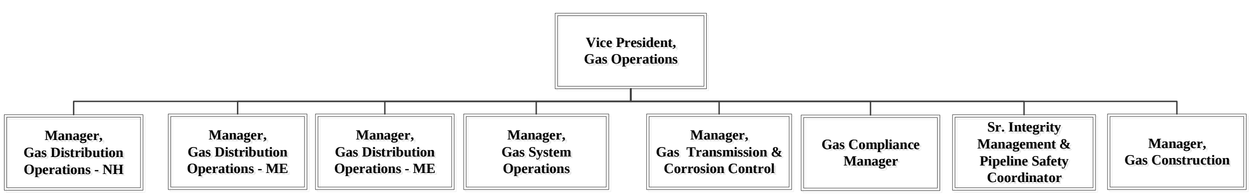
1. Organization

Unitil formed Unitil Service Corp. (USC) in 1984 to provide joint management and administrative services to its subsidiaries. Essentially all management employees work for USC. This service-company approach finds common application in holding companies operating in multiple jurisdictions or through multiple operating entities. USC provides those services at cost, which it allocates among the utilities served, pursuant to settled cost-allocation policies. The operating companies make available to each of their regulators those costs for examination and approval, if not otherwise, then at least in general rate proceedings. Each utility also has employees dedicated to its individual management and operations. Their costs get charged directly to the utility involved. Gas supply operates as one of the centrally-provided services, subject, like the others, to cost allocation.

Two key organizations under USC work together in performing the principal activities required to manage supply for NUI and for the other Unitil utilities. First, the Energy Contracts unit within USC's Financial Services Division manages the gas supply function. The diagram below shows the components of that unit. The Director, Energy Contracts reports to the Financial Services Division's Senior Vice President, Chief Financial Officer & Treasurer.



The second major organization, Gas Operations, has responsibility for gas distribution system operations, reporting under a different USC Vice President. Gas Operations is responsible for supply-related functions such as gas control and measurement. The components of that organization are shown in the diagram below. As we explain below, Energy Contracts' principal interaction with the Gas Operations organization involves Gas System Operations.



USC's Financial Services Division operates from Hampton, New Hampshire. The Gas Control personnel of the Gas Operations Division operate from the Operations Center in Portsmouth, New Hampshire. GSGT operates on a co-located basis with Unitil's Operations Center in Portsmouth, New Hampshire, but as a separate entity. Most GSGT personnel are employees of USC. The U. S. Federal Energy Regulatory Commission's Order 717, regarding standards of conduct for transmission providers, applies at the employee level, and prohibits the flow of information from transportation-function employees to market-function employees.

All three jurisdictions in which Unitil's gas distribution utilities operate permit varying degrees of customer-choice for electricity and natural gas supplies. The Unitil utilities therefore must provide various third-party administrative services, referred to as Supplier Services, and manage their systems to deliver supplies from multiple suppliers who provide electricity or gas to end users. As typical in restructured jurisdictions, Unitil retains the obligation to provide "default service," which includes the acquisition of supplies for those of its gas-system customers who do not choose competitive suppliers.

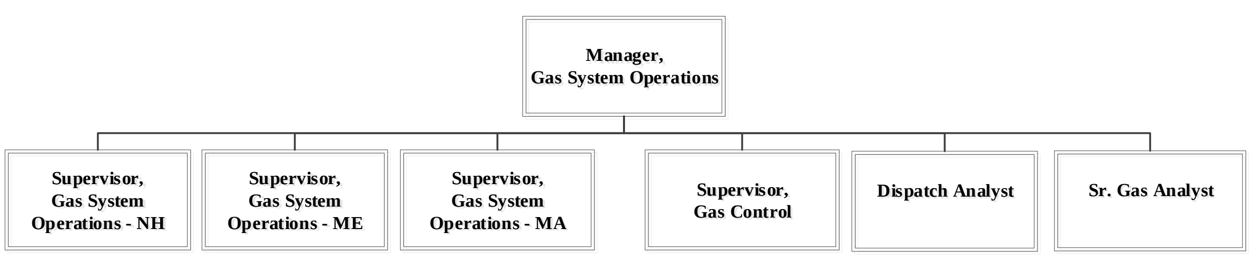
The Energy Contracts unit works with personnel in both Gas Operations and Electric Operations to ensure delivery of third-party supplies. The Manager, Energy Planning spends nearly all of his time on gas work. The electric work of Energy Contracts includes supply contract administration; the New England Independent System Operator (ISO-NE) has responsibility for power-supply planning. Thus, Energy Contracts has a more administrative role in electricity-related planning, but also responding as needed to occasional needs, such as response to regulatory initiatives (*e.g.*, renewable power supplies). Energy Contracts also buys supplies of both gas and electricity to provide default service. Two Energy Contracts personnel, the Manager, Gas Supply and the Senior Scheduler, spend 100 percent of their time dedicated to gas work. The unit dedicates two Senior Energy Analysts I to activities undertaken for electric customers. The Senior Energy Analyst II and an Energy Analyst spend about half of their time on gas work, including the Supplier Services activity.

Energy Contracts has a more comprehensive set of planning responsibilities for the gas business. Its role includes not only all of the administration associated with deliveries of third-party supplies, but also supply planning for customers who buy their supplies from the Company, and supply-capacity planning for both sales-service and distribution-service customers. The Manager, Gas Supply, and the Manager, Energy Planning, have primary responsibility for gas-supply procurement and capacity planning; the Manager, Energy Planning, and Senior Scheduler collaborate on the allocation of capacity to third-party suppliers; the Manager, Gas Supply, and the Senior Scheduler have major responsibilities for daily deliveries of system supply.

NUI serves a substantial number of "capacity-exempt" customers, for whom it does not acquire supply capacity. These customers accounted for 22 percent of distribution-system throughput for the Maine Division in 2018, and almost 29 percent of throughput for the New Hampshire Division. Distribution-system planning must account for these customers, but supply planning does not.

Energy Contracts' Manager, Gas Supply, works regularly with the Supervisor, Gas Control, to identify each day's pipeline supplies in the appropriate amounts to the Company's major delivery points into GSGT for those supplies. The Senior Scheduler must get the supplies nominated from the Company's upstream receipt points to the proper GSGT receipt points and subsequent delivery into NUI's distribution system.

The diagram below shows the organization of the Gas System Operations unit.



2. *Staffing*

a. Personnel

The Director, Energy Contracts has 25 years of utility experience, including negotiation of supply agreements, resource planning, portfolio management, and participation in regulatory proceedings. He joined the Company in 1994 and has held positions in finance and energy contracts groups. He has responsibility for supply planning and procurement for Unitil's electric distribution companies and gas distribution companies, as well as the structure and operation of the retail choice programs operated by each of the distribution companies. He also serves as a logistics section chief in the Company's emergency response organization.

The Manager of Gas Supply has spent her 20-year career at the downstream end of the gas industry in New Hampshire and Maine. She has held customer sales and service, accounting and administration, and scheduling and trading positions for a variety of participants in those markets, including pipelines and marketers, before beginning with NUI in 2010. She has held her current position since the beginning of 2013.

The Manager of Energy Planning has worked for the Company since graduating from college in 1995. He worked on supply planning, worked for Unitil's brokering business, and worked on energy supply for both the electric and gas sides of the business prior to Unitil's acquisition of NUI in late 2008. Since that time, his primary responsibilities have encompassed gas-supply planning and acquisition, including designing the capacity assignment provisions of the retail choice programs operated by each of the distribution companies. He performs yearly analyses of supplier performance, which the Company uses to assess and make changes in its gas-supply arrangements. He plays a major role in cost-of-gas proceedings before the Maine and New Hampshire Public Utility Commissions, and in other regulatory proceedings before state and federal agencies.

The Senior Scheduler has held gas scheduling positions with the Company since 2012. He has responsibility for nominating and scheduling gas on the interstate pipelines and storage facilities within the asset portfolios of NUI and FG&E. He also has a key role in implementing the capacity assignment provisions of the retail choice programs that each of the distribution companies operates and is now largely responsible for their day-to-day operations.

The Senior Energy Analyst II has worked for the Company since graduating from college in 2008. He has responsibility for natural gas demand forecasting, including long-term demand forecasts and daily operational forecasts, as well as day-to-day operations of gas and electric Supplier Services, including monthly cash-outs of third-party gas suppliers under the retail choice programs.

Outside of Energy Contracts, the Supervisor of Gas Control has important gas-supply responsibilities. She works in the Gas Operations organization and has worked in Gas Control for NUI since 1984, spanning changes in NUI ownership by different parents. During periods of cold weather, she coordinates closely with the Manager, Gas Supply in daily operation of the Company's gas-supply assets. She also provides direct supervision, coordination, and training for other Gas Control personnel.

b. Performance Measurement

Each employee receives a minimum of one written performance appraisal each year. Supervisors, managers, and Department Heads are encouraged to do written quarterly updates. Compensation adjustments tie to successful performance for specific accountabilities stated in each person's position description.

Part of the annual performance appraisal process is Goals for Next Year, which can be used to build performance and document achievement. Training is prescribed for individuals as appropriate as part of their annual performance reviews. All supervisors, managers, and Department heads receive formal training in performance management to ensure that Unitil does the best possible job of recognizing and documenting performance.

c. Position Descriptions

Unitil uses position descriptions for the jobs within each unit to provide sufficient detail about what the unit does and who has responsibility for the roles needed to accomplish unit work activities. Position descriptions describe each of the incumbent's principal accountabilities, with an estimate of what portion of time will be spent on each one. Each position description also describes the incumbent's principal challenges, decision-making authority, and required competencies. We found some of the job descriptions outdated when compared with current position responsibilities. Management agrees that an updating process is warranted.

3. *Policies and Procedures*

We found a lack of written policies and procedures addressing the gas-supply functions and activities. Incumbents are well experienced and familiar with their responsibilities. However, upon departures of key personnel, the lack of documented policies and procedures creates exposure to loss of continuity in understanding and executing them, particularly in a smaller organization. The Company's responses to our data requests in this examination provide a sound starting point for documentation. Management has agreed to develop it.

4. *Controls*

a. Documentation of Gas Supply Decisions

NUI's documentation of its gas-supply decisions takes several forms. First, for its capacity-commitment decisions (such as the decision to participate in the proposed Westbrook Xpress Project), Energy Contracts preserves its quantitative evaluations in its files. Qualitative factors generally enter final decisions, but they are not separately recorded. Rather, the Company presents all of its analysis, quantitative and qualitative, in its filings with its regulatory agencies for approval of its commitments.

Management uses the same process to document other evaluations, such as integrated resource plans, energy-efficiency programs, etc. There may be some internal analysis prior to filing, but the Company presents all evaluations, quantitative and qualitative, in its filings with its regulators, and considers those filings to be its documentation of any decisions taken as a result of those evaluations.

Management documents its commodity-purchase decisions in several ways. Annual request-for-proposals processes (RFPs) produce asset-management agreements (AMAs), winter and summer base-load purchase contracts, and contracts for delivered peaking services. Retained documentation includes all of the offers received, the Company's analysis of the offers, and the signed contracts for the offers selected. The signed contracts generally take the form of confirmations, issued under previously-executed standard contracts, such as the North American Energy Standards Board (NAESB) contract.

All of the term-purchase contracts – AMAs, base-load contracts, and contracts for delivered peaking service – use externally-determined pricing: either published index prices or the last-day-settlement price of the New York Mercantile Exchange (NYMEX) gas futures contract. Almost all use monthly prices; only a few sources, such as daily swing quantities under one AMA, use daily prices. Those daily prices are also externally-determined; they are generally also published index prices, but daily ones, rather than monthly.

Gas in storage also has an externally-determined price. NUI requires its storage asset manager to fill the storage ratably (at a uniform rate) over the storage-injection period with gas priced at a monthly index. Thus, when withdrawn, the storage gas comes to NUI at the weighted average price determined by the specified fill rate times the specified price, adjusted for any storage injection and withdrawal charges.

With this contract structure, almost all of NUI's day-to-day decisions are quantity nominations from sources with established prices. Management documents those decisions by retaining the spreadsheets containing each day's nomination information. Those spreadsheets are designed for input into the reports that the Company files with its Cost of Gas filings. Thus, its Cost of Gas filings reflects its records of sources of gas used each day. Filings with the Commissions add gas price information.

We selected at random a fall day and a spring day for identifying the nature and types of transaction records available to document supply choices available and the selections made. Conducting the supply function in the winter requires utilization of all sources, permitting fewer choices. Summer supply mostly uses base-load resources, which involve few choices that change day to day. Energy Contracts staff produced the records for the days we selected, and we confirmed that the choices made were appropriate. We also examined with Company personnel decisions made on a peak day in January 2019. Full records of the weather conditions had been saved, along with records of the decisions made. We judged those decisions to have been reasonable in the circumstances.

We had one issue with the documentation. For each of the days that we requested, a decision was made using estimated pricing. Those prices were not recorded. In comments on the draft of this report, the Company pointed out that, for the fall day, the selection was driven by locational considerations. Given the physical limits of GSGT and the Company's distribution system, not all sources can be delivered to every service area. Where the supply is needed dictates some choices.) Thus, while price might have played a role, it was not the determining factor in the choice.

On the fall day, Energy Contracts staff elected to take some daily swing gas available under two of the AMAs. One agreement provided for the gas to be priced at a daily index. Those indexes are not published until the day after transaction execution. Thus, transactions like that one must be entered on the basis of an estimated price.

Indicative prices are available each day. The Intercontinental Exchange (ICE) provides an on-line platform that shows offers and some transactions on a real-time basis. When deciding whether to enter a particular daily transaction, Energy Contracts staff generally consults ICE to view similar offers. It is likely that they did so on the day that the daily swing supply was taken, but there is no record of such action and what prices they might have observed.

In comments on the draft of this report, the Company pointed out that, due to illiquidity on their supplying pipelines, indicative pricing may or may not be available each day. Moreover, the time when Northern must make decisions can further affect the availability of indicative pricing. For example, Northern's next-day nominations to asset managers are due before 9 a.m., before active trading on ICE begins. Thus, the best pricing reference (for next day) is current-day published Gas Daily indices for nearby pipelines, such as Algonquin Gas Transmission and Tennessee Gas Pipeline. Northern also makes late-day sales between 7 and 8 a.m., when there is no activity on ICE. Spot-market purchases, which are very rare, would likely occur during business hours and ICE would be consulted if any nearby pipeline activity is posted.

The spring day presented the same documentation issue. Energy Contracts staff had decided by that time that the Company was "long" on supply at that point in the winter. Thus, on the day we selected, the staff was looking for a one-day sale to an off-system customer. Such a customer made an offer, at a price that it specified. As in the case of the fall transaction, the staff would likely have consulted ICE to see whether to accept the offer or to look for another. Whether they did, and what price information they found, was not recorded.

b. Dollar Limits on Authority to Approve Transactions

We did not initially find clear, documented definition of expenditure authority levels, which form an important measure for controlling commitments. Management advised that the Company has embedded those levels into its accounting system and specified responsibility for setting levels in its Security Administration policy. That system prevents Company personnel from approving payments in an amount that exceeds an individual's authority.

That system does not, however, address employees' ability to commit the Company to an expenditure. We learned that the authority to commit relies primarily on term:

- The Manager, Gas Supply can commit to transactions shorter than one month
- The Director, Energy Contracts can commit to any term for gas supply
- The CFO commits for any incremental supply capacity.

Company personnel are generally aware of who has what level of authority. Furthermore, we did not find any examples of employees exceeding their authority levels. We did not, however, find that those levels could be communicated explicitly to a party outside of the Company seeking some kind of commitment.

c. Separation of Transaction-Related Functions

For purposes of financial controls, companies with energy-trading operations separate transactions functions among transaction execution (front office), confirmation (middle office), and invoice verification (back office). Such separation ensures that transactions take place under controls that promote accuracy, measurement, and integrity.

NUI does not employ such a clear separation. Members of the Energy Contracts staff perform these functions together. When we raised the separation issue, management responded that Internal Audit is now reviewing needs and methods for strengthening such controls.

d. Examinations of Gas Supply by Internal Audit

As with most gas distribution utilities, supply operations and transactions bring large costs and impose risk. It is common to see periodic reviews by the internal audit function of gas supply costs and operations. We did not find that practice at NUI. Management has agreed that internal audit's 2019 activities plan will include gas supply, and that it will expand its Sarbanes-Oxley testing of financial controls to include gas supply.

e. Code of Conduct

We find use of a comprehensive code stressing the importance of ethical, objective conduct a material element in creating an effective controls environment for gas supply. Such codes should clearly specify values, expected conduct, prohibitions, and consequences. Regular acknowledgement of receipt, understanding, and acceptance of the behavioral standards and the limits such codes play an important role in ensuring that conduct regarding gas supply transactions has the objectivity and integrity necessary to optimize costs for customers.

Unitil has such a code. We found it appropriate in stressing the importance of ethical conduct, communicating appropriate values, describing promoted and prohibited behaviors, and specifying the consequences of failure to conform to expectations and requirements. Company officers acknowledge it and agree to be bound by it annually. New employees are given the code and asked to acknowledge it when they join the Company.

We did not find a requirement for annual acknowledgement by Energy Contracts staff. Management agreed that this should be done and undertook to initiate it going forward.

f. Gas Supply Risk Management

The gas-supply function presents considerable risks to Unitil as an enterprise. We examined the Company's approach to identifying and addressing these risks. We found this function to be addressed satisfactorily.

C. Conclusions

1. Organization of the gas-supply function is compact, efficient, and effective.

The Company plans for and manages a rather complicated supply system with relatively few people. Individuals' roles in supply processes are well defined, and coordination with essential functions in other organizations is well established and smooth.

The same individuals shift from an intense focus on operations in the winter to analysis, planning, and re-contracting in the spring and summer. Because the same individuals do both, operating experience is brought directly to bear on evaluation and planning going forward. As the Manager, Energy Planning is also the Company's principal witness in its gas-cost recovery proceedings, the Commission and the Company's customers have access to as much detail as they want regarding what the Company has done and what it plans to do.

Seasonal readiness meetings support higher-level coordination with other Company operations. Distribution-system planning holds these meetings in the fall and spring and other business functions attend, as well as Energy Contracts. Energy Contracts also occasionally asks distribution-system planning for analysis of particular supply problems.

2. The training and experience of gas-supply personnel is commensurate with system needs and with what we have observed at other similarly-sized entities.

The Company is fortunate to have extremely capable and highly experienced individuals in the gas-supply function. The staff is very small for the amount of work they do.

3. Performance assessment is consistent with prevailing industry practice.

Annual performance reviews with quarterly updates is the standard among most industries. Relating compensation adjustments to performance in identified accountabilities is best practice. Unitil's practice of providing formal training in performance management is a strong one.

4. Some position descriptions are out of date. *(Recommendation #1)*

The Company uses position descriptions in several ways, including comprehensive statements of an individual's role in his or her organization, and careful statements of accountabilities that can be used in performance assessment.

The Company's policy is that position descriptions are to be updated annually. Some have not been but should be. Management has agreed to do so.

5. Documentation of supply decisions is not quite adequate. *(Recommendation #2)*

The results of NUI's gas-supply evaluations are presented in various filings with the Maine and New Hampshire Public Utility Commissions: primarily Integrated Resource Plans, requests for Commission approval of long-term supply contracts, and periodic Cost of Gas filings. With the assistance of Energy Contracts staff, we examined daily records for four different days within the past gas year (November through October). Records were generally adequate to support review of the decisions made. However, we found no documentation of the estimated prices of supply options considered on the day that the choice was made.

NUI pays indexed prices for almost all its daily gas-supply transactions, with spot-market purchases (only occasionally) and off-system sales the exceptions. The gas-supply contracts, typically part of asset-management agreements, specify the indexes that apply. While the value of any of those indexes for any given day can be retrieved currently or after the fact, they are generally not settled until the day after a transaction is agreed to. Thus, agreement must occur with respect to an estimated price. Management does not retain those estimates, but should. Similarly, for the occasional off-system sale, prices at the time of the transaction can only be estimated. Those estimates are not retained, but they should be.

6. Controls are insufficiently formal. *(Recommendation #3)*

NUI employs less formal controls than we have seen elsewhere, an approach it considers generally appropriate to its small size. For example, although individuals who conduct supply processes show familiarity with procedures, they are not documented. Expenditure-authority levels exist for payments, but are not clear in limiting authority to make commitments including matters like signing gas-purchase contracts. Also, widely employed controls, such as who compares supplier confirmations to Company nominations or purchases, and who approves invoices for payment, are not applied in a structured way.

controls need to become more comprehensive and formal. Management should place less reliance on the integrity of individual staff members. When we brought our concerns in this area to the Company's attention in a Roundtable discussion., the Company provided some additional information and undertook to correct deficiencies in others.

D. Recommendations

1. Update position descriptions. *(Conclusion #4)*

Management has agreed to do this.

2. Add gas-price information, including estimated prices, to the record of daily gas-supply selections. *(Conclusion #5)*

Our review of supply-selection records for individual days did not reveal records of gas-price information, including estimated prices used to decide on daily-priced transactions, for that day in those records. We believe that information should be recorded in order to complete the transaction records.

We think the correction for this deficiency is to add another tab containing all price information to the spreadsheet that serves as the record for decisions made each day. This fix should be made immediately.

3. Re-review supply processes from a controls perspective. *(Conclusion #6)*

NUI's supply processes function smoothly and competently. We had some concerns that we shared with the Company about the controls environment for those processes, and the Company undertook to address them. We recommend that the intended solutions be reviewed after the Company has had time to implement them, which we estimate to be in about six months from the time that this report is issued.

Particular areas to be reviewed include the following:

1. The Energy Contracts unit, which conducts the gas-supply function, does not have Mission and Function statements; it uses detailed job descriptions instead. The job descriptions must

be updated, but they must also assign clear responsibilities in areas of control: the person who evaluates supply-related decisions cannot be the same person who made the decision.

2. Regarding policies and procedures, the responsibilities, accountabilities, activities, and interactions with others involved in conducting the gas-supply function are not recorded in a way that allows someone to perform the function if an incumbent is absent for some reason, or to evaluate the results. The Company's accountants and auditors can now verify that the costs produced by those processes are accurate; the question is whether they are appropriate; *i.e.*, free of mistakes and free of any possible malfeasance.
3. The processes of transaction execution, confirmation and invoice verification should be separated to ensure accuracy and integrity.
4. At the time of our review, Unitil's Internal Audit unit was due to perform a comprehensive evaluation of the gas-supply function soon. Conduct of gas-supply operations was to be examined, and strengthening controls had been identified as a key objective of that review.

II. Gas Supply Planning and Forecasting

A. Background

Ensuring sufficient supply to fill requirements at optimum prices requires sound supply planning. We applied the following criteria in examining supply planning at Northern Utilities (NUI):

1. Conformity of weather data handling and analysis methods with industry norms and unique service territory circumstances
2. Consistency of assumptions, variables and probabilities in capacity planning should comport with observable supply obligations
3. Existence of efforts appropriate to identifying and establishing alternate sources of supply.
4. Regularity and comprehensiveness of evaluations of peak-period performance
5. Strength of the correlation between the capacity portfolio and the load duration curve
6. Gas plans should be consistent with related corporate planning elements.

This chapter explores the supply-planning processes, how they produce the identification of supply requirements, and how management plans for supplying those requirements. We also generally address the relationship of supply planning to other areas of system planning, especially marketing plans.

B. Findings

The newly-filed Integrated Resource Plan comprehensively and clearly presents management's forecasting and supply-planning methods. Section V.B describes weather analysis; Section V.C. addresses Planning Standards and Design Weather; Section V.D. covers forecasts of numbers of customers, use per customer and peak-day analysis. We examined Company methods with reference to prevailing industry practices, and how and how well decisions about supply resources incorporate the results of applying those methods.

1. Weather Analysis

The Company uses 30 years of history (the gas years of 1988/89 through 2017/18) to populate its normal and design weather data. The data capture effective degree-days (EDDs) by adjusting temperature data for wind speed. Data for the Maine Division came from the Portland, Maine weather station at the Portland International Airport, and for the New Hampshire Division from the weather station at Pease International Tradeport.

Management calculated normal-year EDDs separately for its Maine and New Hampshire Divisions, by summing for each their 30-year average billing-cycle EDDs for each month. Management used a 1-year-in-30 return period to determine winter period (November through March) design-year EDDs It used normal (average) weather for summer month (April through October) determination of design EDDs. The Company calculated design-winter EDD by summing the billing-cycle EDD for each winter in the data set (1988/89 through 2017/18), then using the 30-year average and standard deviation to select the winter EDD with a once-in-30-years probability of occurrence. It then distributed the winter design EDDs among the individual winter months by multiplying the normal EDD for each winter month by an adjustment factor equal to the design-winter EDD divided by the normal-winter EDD.

2. *Requirements Forecasting*

The new IRP presents the methods for requirements forecasting and the results of applying them. The Company combined its rate classes into customer segments: residential, commercial and low-load-factor industrial, and high-load-factor commercial and industrial (C&I), driven by characteristics of their consumption. Regression analysis of billing data supported the development of econometric models for forecasting numbers of customers and use per customer for each segment. Separate equations drove the results for the Maine and New Hampshire Divisions.

Management made reductions to the resulting customer-segment forecasts to reflect energy-efficiency savings, applying separate adjustments for each segment and for each of the two Divisions. Those adjustments yielded Net Demand by segment for each Division. Adjustments to total Company-wide Net Demands for Company Use and for lost and unaccounted for gas (LAUF) yielded forecasts of Normal Year Throughput for each Division.

Planning Load comprises another important planning parameter. This parameter measures Normal Year Throughput adjusted to design weather conditions, less the projected loads of Capacity Exempt customers. The Company developed Planning Load forecasts for Design Year and Design Day conditions for both Maine and New Hampshire Divisions.

Management uses estimated Design Day requirements to calculate its need for peak-day supply capacity. It calculates Design Day requirements using regression analysis of actual daily throughput data, separately for each Division.

On January 21, 2019, the Company experienced a new system record peak-day throughput. To test its Design Day forecasting model, the Company put that day's weather conditions into it. The model ended up under-forecasting actual throughput on that day for both Divisions - - by 3.0 percent combined, by 3.8 percent for Maine, and by 2.1 percent for New Hampshire. The Company concluded that the Design Day model is "reasonably accurate, and does not show a bias towards over-predicting Design Day demand."

a. Analysis of Forecast Performance

In preparing the new IRP, management compared the forecasts of its prior IRP with actual performance. That comparison led to two modifications. First, it removed from the Residential Heating Use Per Customer model a price variable. The re-specified model more accurately predicted actual use per customer for the period between the previous IRP (2015) and the current one. Second, management updated the peak-day forecasting model to improve its performance.

The 2015 IRP comprised the most recent version as we began our field work. In reviewing it before the new one became available, we observed that actual throughput on January 2, 2014 was well below what the Company's peak-day forecasting model would have predicted. Management explained that it reviews daily forecast performance regularly, given the importance of forecasts for day-to-day operations. The Company noticed the discrepancy for that date immediately, and investigated it promptly. It found several explanatory circumstances:

- An extreme snow/blizzard event closed schools and businesses
- A large change in temperature occurred extremely quickly
- With New Year's Day the day before, resumption of normal work-day activities on January 2nd may have ramped up more slowly than usual.

b. Interaction Between Gas Supply and Marketing

The Company developed a comprehensive marketing program soon after it acquired NUI. That program identified customers on main but not connected, and low-use customers as targets with the highest potential. The Maine service territory had lower saturation than New Hampshire, thus presenting the better opportunities. Management had also slated facilities in Maine for a Cast Iron Replacement program. The Company continues special promotions and special incentives offers to prospective customers for connection in the areas affected by that program.

Management annually updates details of its marketing programs; *e.g.*, locations of special focus. The Energy Contracts unit, which is responsible for gas supply, uses these details to anticipate where additional supply might be needed.

Energy Contracts is informed when other Company activities might affect requirements for gas supply. Company personnel gather at Seasonal Readiness Meeting to discuss new initiatives, such as a targeted area build-out. Other initiatives are discussed in the course of normal internal coordination.

3. Portfolio Analysis

Gas distribution companies like NUI use three types of supply assets to meet customer demand:

- Year-round asses, primarily pipeline capacity
- Seasonal assets, typically storage facilities that are filled in summer, then re-deliver in winter
- Peaking assets, most often liquefied natural gas (LNG) storage and revaporization facilities or propane-air plants, that provide high deliverability for short periods in response to peak weather events.

Prior to Unitil's acquisition of NUI, the Company was assigned some still-operating "legacy" pipeline and storage capacity as part of the wholesale gas market restructuring required by FERC Order No. 636. This group of assets included capacity on the Iroquois Gas Transmission System (IGTS), the Tennessee Gas Pipeline system (TGP), and the Algonquin Gas Transmission Company system (AGT). Most of these assets are relatively old, considerably depreciated, and therefore, attractively priced. They comprise the foundation of NUI's supply portfolio.

Also prior to Unitil's acquisition of NUI, the Company contracted for resources known as "the Wells Replacement Contracts." Those contracts served seasonal and peaking requirements, but with supplies delivered to NUI's principal receipt points. NUI entered into them as part of a settlement regarding an LNG manufacturing and storage facility planned for installation in Wells, Maine. NUI did not actually construct the facility, choosing instead to enter three replacement contracts involving: (a) delivered pipeline supply from Duke Energy, (b) a combination liquid/vapor LNG service from Distrigas, and (c) liquid-only LNG supply from Distrigas. Distrigas owned an LNG receiving terminal located in Everett, MA. Distrigas sold the facility to ENGIE North America, Inc., which recently re-sold it to Exelon Generation Company, LLC. Constellation LNG, LLC, a subsidiary of Exelon, operates the facility.

The last of the Wells Replacements Contracts expired in late 2011. Their expiration, plus growth in NUI's load since that time, have created a significant requirement for additional supplies in both seasonal and peaking roles.

Weather is the primary driver of supply requirements for companies like NUI. Current forecasting techniques provide forecasts of daily supply requirements for most any weather, with normal-year and design-year weather used most often.

Management inputs requirements forecasts into an optimization model. The model designs a portfolio of supply resources that provides the best fit for the input forecast. NUI uses SENDOUT, widely used for such purposes in the gas distribution business. SENDOUT considers demand forecasts, available supply and delivery options, and the costs associated with them, to produce projections of costs for meeting demand with various combinations of supply options. It solves for the least-cost mix of options for meeting demand, subject to user-defined constraints. The model incorporates the legacy assets, enabling it to solve for the least-cost mix of *additional* supply options.

As the IRP notes (See, *e.g.*, Section III), NUI has limited supply options, both in number and in type. Several options for expanding U. S. pipelines to New England have been abandoned. Suppliers of regasified LNG mostly offer supply on a delivered basis.

For its seasonal and peaking requirements, NUI issues requests for proposals (RFPs) annually. It seeks seasonal supplies first, along with asset-management services for its legacy pipeline and storage assets. A second RFP for peaking supplies follows in mid-summer.

The offers that NUI receives in response to the RFPs essentially all provide supply on a delivered basis. Delivered supplies mean that the provider bears the burden of getting the gas to NUI's principal receipt points. The resulting contracts are mostly on a year-to-year basis. [redacted]

NUI has found that three pipeline options compare favorably with the alternative of relying on delivered supplies. Accordingly, the Company has entered contracts for three increments to its pipeline-capacity resources:

- 9,965 MMBtu/day on Phase III of the Portland XPress Project, scheduled to enter service in November 2020
- 7,500 MMBtu/day on the Atlantic Bridge Project, also anticipated to enter service in November 2020
- 9,965 MMBtu/day on Phase III of the Westbrook XPress Project, anticipated to enter service in November 2022.

The Company's applications for approval of its participations in the Portland XPress and Atlantic Bridge Projects have been approved by the Commission. Its application for the Westbrook XPress Project recently secured approval.

Each of these three projects would replace a portion of what NUI would otherwise require in the way of delivered supplies. The Company's analysis indicates that primary benefits these projects would bring lies in access to reliable supply points having lower and more stable pricing than is available with delivered supplies. These features make them preferable to management.

The new IRP shows changes from the Company's current winter-period mix of pipeline, storage and delivered supplies after these new projects enter service. Figure IX-1, reproduced below, shows the Company's assessment that it would require delivered supplies (seasonal and peaking) for almost 100 days under design-winter conditions, before any of the three projects goes into service. It would meet almost half of peak-day requirements with delivered supplies. Figure IX-2, also reproduced below, shows the Company's view of requirements for delivered supplies after the three new projects go into service. Those requirements drop to about 40 days, and accounts for significantly less (about one-third) of the design day. Comparison of the two figures shows that the three new projects push the Union Dawn Storage resource up in the dispatch stack, reducing considerably the requirement for delivered supplies. (As a seasonal resource, the Union Dawn Storage should be above year-round capacity, old and new, in the dispatch stack.)

Figure IX-1: Load Duration Curve, Design Winter 2019/20

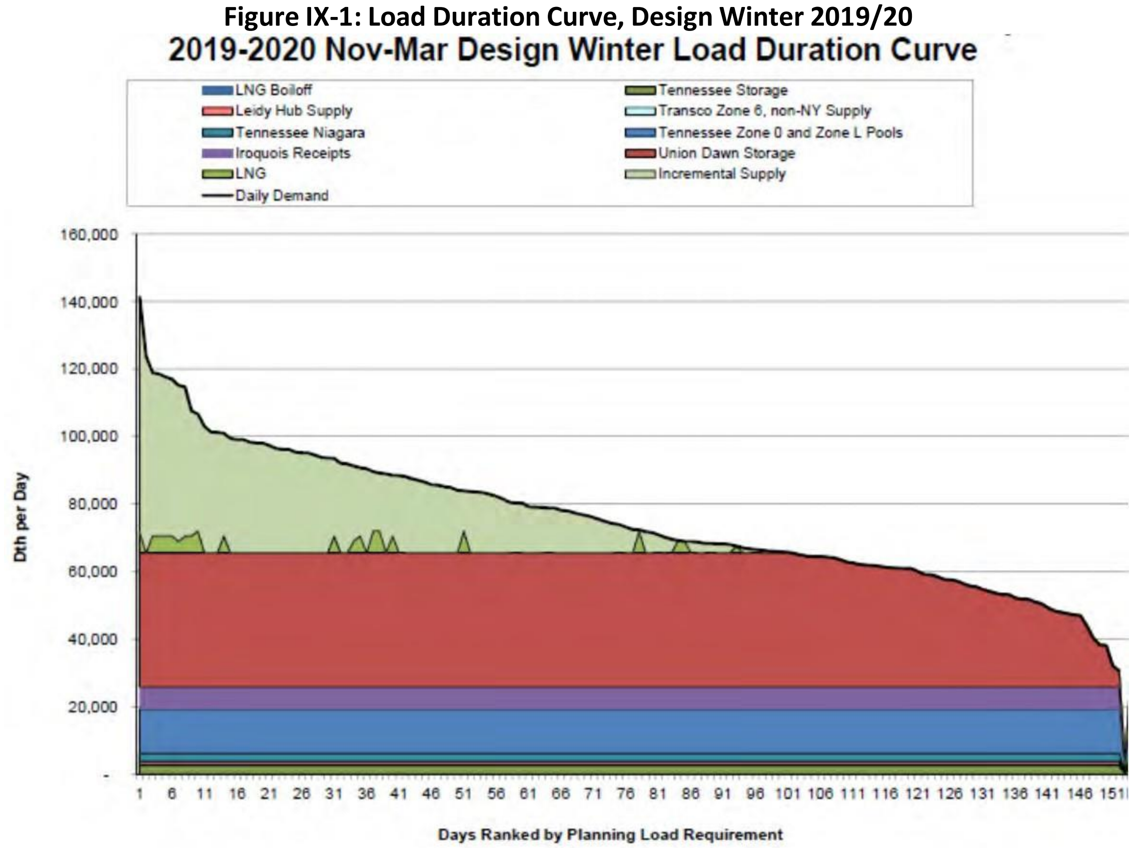
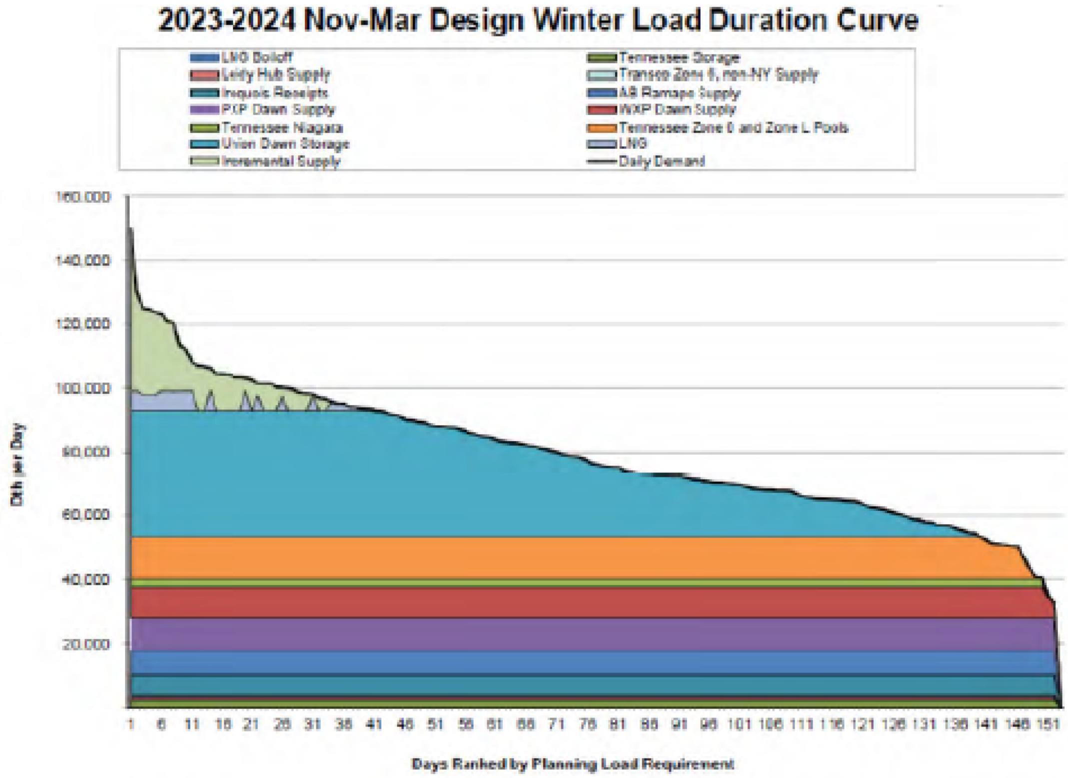


Figure IX-2: Load Duration Curve, Design Winter 2023/24



4. Development of Supply Options

Management believes that its continued dependence on delivered supplies, even after adding the three increments of pipeline capacity, entails risk. Particular concerns include constrained delivery capacity on peak days, and the limited number of offerors for delivered supplies. The Company continues to discuss additional pipeline supply projects with potential offerors, and it has recently re-started work on on-system supply options.

C. Conclusions

1. The Company's weather analysis could be improved. *(Recommendation #1)*

Management's use of averages and standard deviation in its weather analysis implies normally-distributed weather. Normal distributions have most values clustered around the mean (average), which falls in the middle of the range of values. Other values taper off symmetrically in both higher and lower directions. Standard deviation measures the dispersion of a distribution. For a normal distribution, 68 percent of values lie within one standard deviation of the mean, and 95 percent within two standard deviations.

With 2.5 percent of observations higher than two standard deviations above the mean, and 2.5 percent lower, there exists a 2.5 percent probability that a value will fall above the mean-plus-two-standard-deviations, and a 2.5 percent probability that a value will fall below mean-minus-two-standard-deviations. Analysis of design weather should focus on concern about EDD values higher than the mean plus two standard deviations. A normal distribution indicates a 2.5 percent probability of such an occurrence. That probability corresponds to a 1-in-40 chance of occurrence. If weather observations such as EDD values fit a normal distribution, the 1-in-30 standard would correspond to a probability of occurrence of 3.33 percent.

Careful studies of weather data usually show it not normally distributed; *i.e.*, values do not cluster around averages as much as they would be if normally distributed. They vary more than a normal distribution would suggest. Extreme values may occur more often than standard-deviation analysis would suggest.

Some of the analysis in the new IRP implicitly provides evidence that weather data for both Divisions does not fit a normal distribution. Recorded Peak Day EDD and Cold Snap EDD for both Divisions exceed the values calculated with the 1-in-30 standard. This demonstrates that weather more severe than would be predicted by the 1-in-30 standard has occurred in both Divisions within the past 30 years.

Industry best practice now calls for use of Monte Carlo simulation to develop distributions representing the actual occurrence of weather variables in particular locations, such as the weather stations that NUI uses for its analysis. Using such a distribution would enable management to choose for each variable values having the probability of occurrence desired for planning. Normal- and Design-Year requirements could be calculated for the weather that has actually occurred, rather than for weather that fits a normal distribution. Simulation of actual weather may also enable NUI to estimate more precisely the requirements of customers served by retail marketers. More precise estimates could enable NUI to release more of its contracted capacity to asset managers, thereby increasing the amounts they would be willing to pay for the rights to manage the assets.

2. Load forecasting methods conform to prevailing industry practice and they adequately serve the Company's needs.

Numbers of customers times use per customer for forecasting supply requirements reflects currently prevailing industry practice. Regression analysis for developing forecasting models for both parameters also finds commonly utility-industry use.

3. Management routinely evaluates the performance of its forecasting methods.

Management compares forecasts with actuals in the course of preparing succeeding IRPs. It conducts examinations of daily forecast models soon after any discrepancy occurs, given that daily operations rely on these models. This reflects an appropriate level of attention to accuracy.

4. Management adequately coordinates gas supply planning with other areas of corporate planning.

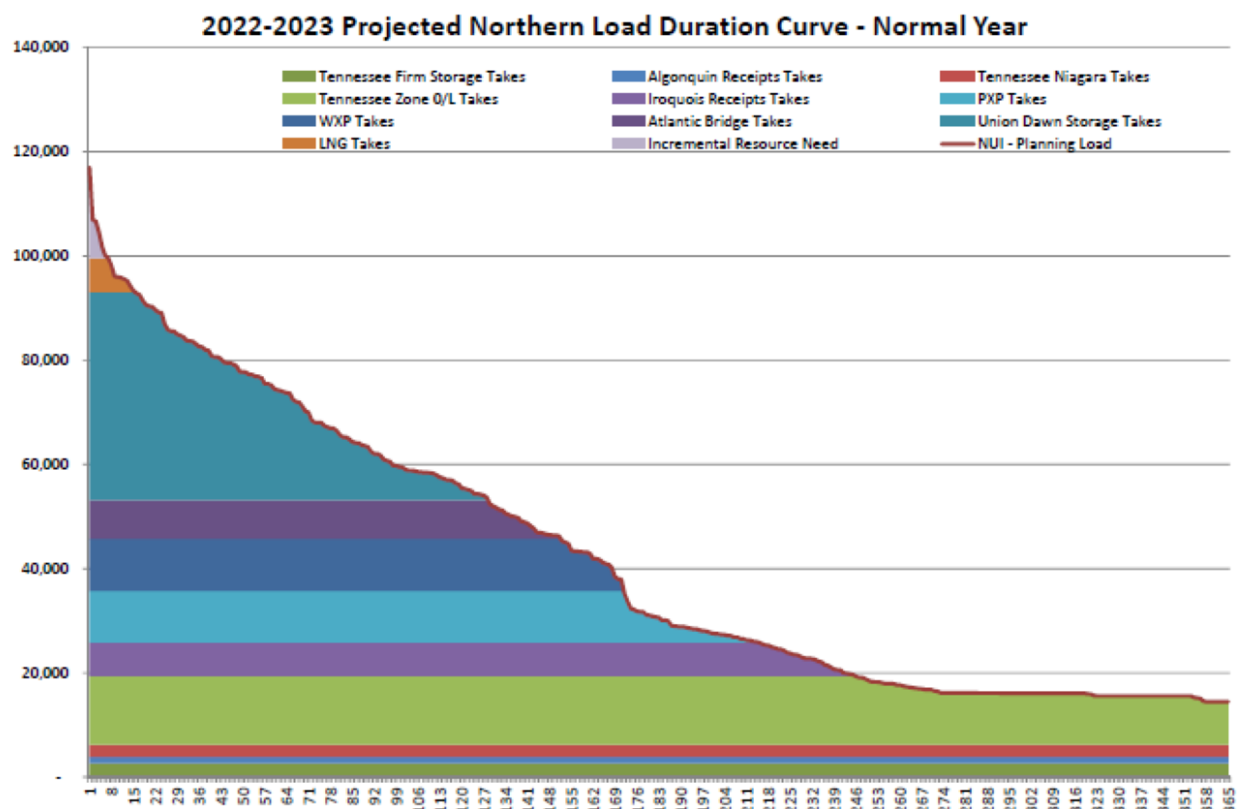
Much of this coordination takes place informally, in the course of preparation for various initiatives. The Company has two "readiness" meetings each year that inform department heads about plans that might affect them. Those gatherings engender deeper inquiry by Energy Contracts personnel into plans that might affect the gas-supply function.

5. Management should expand the scope of its resource analysis. *(Recommendation #2)*

We found the discussion in the Resource Balance (Section VII) and Incremental Resources Options (Section VIII) sections of the IRP oriented toward the peaking portion of the resource stack. We want to ensure that other parts of the Company's supply portfolio also receive attention.

We reproduce below a 365-day load duration curve (as contrasted with the 151-day durations shown in the IRP and reproduced above) that management prepared to respond to our request.

Company comments on a draft of this report noted that it does consider 365-day utilization in its supply planning, and that it provided summer-period load duration curves in the IRP. It presented winter and summer load curves were presented separately because the dispatch order changes from winter to summer. Company comments also noted that, even at 151 days of utilization, daily variability in weather can cause some non-use in winter months (warm days in November, March) and more use in shoulder summer months (cold days in April, October). Inter-seasonal variability offers another reason why Company presents seasonal load duration curves.



This more complete curve suggests the capacity of the new pipeline projects will see limited service outside of the winter season. That pipeline capacity provides 365-days-per-year capacity, but:

- PXP capacity shows use on about 215 days per year
- WXP capacity shows use on about 170 days
- Atlantic Bridge capacity shows use on about 160 days.

Local gas distribution companies outside of New England use pipeline capacity in non-winter months to fill storage. New England circumstances overall differ, because of the limited availability of in-market storage. Pipeline capacity connecting New England with other areas is not useful for filling storage in those other areas because no supplies are available to move from New England to those other areas. Imported LNG is available in New England, but regasifying it to move it to storage in other areas would add too much to its costs.

LNG facilities effectively comprise New England's in-market storage sources. Individual local gas distribution companies own all but the LNG import terminals, making them part of each owner's state-jurisdictional assets. Some LDCs "rent" space in others' LNG facilities, but we have not found such arrangements typical.

Our concern with NUI's stated approach to its resource analysis is its focus on the peaking portion of its resource requirements. How to use the available pipeline capacity when its new projects go into service should also form a focus of its supply-planning work.

The need to address both peak requirements and pipeline capacity use require joint consideration and analysis. Capacity available in the non-winter months offer a resource that can contribute to the economic viability of an LNG facility (for example, by bringing gas from a supply point with low and stable off-peak prices to a storage facility). New England's differences between summer prices and the value of gas in winter can be significant. Substituting gas bought in the summer for gas that would have been bought in the winter would likely provide considerable economic benefit. That benefit should be considered in any analysis of a new LNG facility.

D. Recommendations

1. **Test the use of Monte Carlo distributions in the Company's weather analysis.** *(Conclusion #1)*

The Company should test the use of Monte Carlo-based weather distributions in its supply planning. Formerly complex and expensive to use, Monte Carlo software has improved considerably, and is finding increasingly broad use in utility-company supply planning.

The test of whether the Monte Carlo analysis is worth what it costs to implement and operate depends on whether it makes a difference in calculated requirements for supply for system-supply customers. This population includes transportation customers for whom the Company must provide supply capacity. It can be used to calculate normal-weather requirements and design-weather requirements. It could also be used to estimate the capacity requirements of the retail marketers to whom NUI is assigning capacity. Without testing, however, it is not possible to say how this method might affect those parameters.

The Company should look into application of Monte Carlo methods soon. It should report on its plan for testing these methods in the proceeding to consider the findings of this audit (Docket No. 2018-00300) and present its results with its summer cost-of-gas filing.

2. **Expand the scope of the Company's resource analysis.** *(Conclusion #5)*

The IRP reports that the Company has engaged a consultant to

> *… help identify Non-Pipeline Supply Resources. Possible projects include adding storage to Northern's existing LNG facility in Lewiston, exploring options to construct a new LNG facility and looking for opportunities to purchase renewable natural gas (RNG).*

The scope of that work should expand to include utilization of the available capacity on the Company's newly-added pipeline capacity.

Combining the available pipeline capacity with capacity in an LNG manufacturing and storage facility is a natural choice. Using the capacity with the Lewiston facility would require installing liquefaction; any new facility would likely include liquefaction.

Scale is an important aspect of the economics of an LNG facility, suggesting that partnering with other potential users to explore a larger facility warrants consideration. An asset manager might explore combining NUI's available pipeline capacity with someone else's LNG facility. Thus, partnering with an asset manager should also be explored.

Adequate study of possibilities such as these will likely take some time. The Company should report on its results periodically, to assure its customers and the Commission that it is taking the effort seriously. Annual reports, with one of its cost-of-gas filings, should be sufficient.

III. Gas Supply Procurement

A. Background

Effective gas supply procurement requires a structured, well-controlled, rigorously executed, and transparent set of processes, critical in ensuring supply to customers at the lowest prices consistent with reliability requirements. Key elements include clear delineation of supply requirements, establishment of risk tolerances and means for ensuring satisfaction of them, a sound and objectively executed procurement processes, promoting a robust number of offerors competing for the opportunity to supply, assessment of the reliability of offers received, and competitiveness of the delivered prices of alternatives.

Gas supply planning identifies requirements for supply, and the duration of requirements (from a few peak days per year to seasonal or year-round). Planning and executing effective procurement of supply requires a sound process for identifying accessible options that can fill each requirement. Considerations include:

- Sourcing from a sufficiently broad array of supply points to provide enough diversity to assure competitive prices and protection from disruptions
- Options configured to fit the requirement
- A sufficient number of competitors to assure competitively-determined prices.

The preceding chapter of this report examined how the Company identifies its requirements for supply, and how well it addresses its concern about its limited number of supply options. This chapter turns to the processes for selecting among available capacity options, and for securing an appropriate assembly of supply sources from among them. We applied the following criteria in evaluating gas supply procurement:

1. Clarity of objectives for purchasing and price-risk-management activities, their comprehensiveness and support for meeting customer needs reliably, yet cost effectively
2. Sufficiency of focus on liquid, transparent markets in gas procurement and price risk management
3. Robustness of the range and numbers of suppliers identified and pre-qualified to meet likely needs, including short-term and emergency conditions
4. Adequacy of information maintained for identified and pre-qualified vendors
5. Analytical rigor and objective execution of offer evaluations, including application of specific criteria, weightings, responsiveness, and supplier performance history
6. Consistency of capacity contracts consistent with appropriate quality and reliability objectives
7. Promotion of the identification and use of sufficient numbers and types of vendors to ensure a sufficient range of competitive options for meeting supply needs.

B. Findings

1. *Supply Portfolio Summary*

The Company's supply capacity portfolio accesses several important supply regions:

- The U. S. Gulf Coast, via long-haul capacity on the Tennessee Gas Pipeline system (TGP)

- Central and Eastern Pennsylvania, via Texas Eastern Transmission Corporation (TXE) and the Algonquin Gas Transmission system (AGT), and via short-haul capacity on TGP, and using Company storage capacity in this region
- Pipeline supplies from eastern Canada, via TGP from the Niagara import point, and via the Iroquois Gas Transmission System (IGTS) from an import point at Waddington, NY
- The Dawn, Ontario supply point, via Enbridge, the TransCanada PipeLines system (TCPL), the Trans Quebec & Maritimes system (TQM) and the Portland Natural Gas Transportation System (PNGTS).

The Company had access to most of its still-existing capacity when Unitil acquired NUI in December 2008. Since that acquisition, NUI has renewed, converted or terminated essentially all of the pipeline and storage contracts then in place. The terminations it made sought cost reduction, moving receipt points closer to the Company's distribution system, or both. The table below, modified from one included in the Company's 2015 IRP, shows the disposition of each of the contracts from that original portfolio.

Table VI-2: Pipeline Transportation and Underground Storage Contracts by Capacity Path					**Updates by Contract Path**
Capacity Path	**Vendor**	**Contract ID**	**Receipt Zone**	**Delivery Zone**	**Contract Disposition**
Chicago Path	Vector	FT-1-NUI-0122	Alliance	Dawn	Terminated
Chicago Path	Vector	FT-1-NUI-C0122	St. Clair (Canada)	Dawn	Terminated
Chicago Path	Union	M12205	Dawn	Parkway	Converted
Chicago Path	TransCanada	41235	Union Parkway Belt	Iroquois	Converted
Chicago Path	Iroquois	R181001	Waddington	Wright	Renewed
Chicago Path	Tennessee	95196	TGP Zone 5	TGP Zone 6	Renewed
Chicago Path	Tennessee	41099	TGP Zone 5	TGP Zone 6	Renewed
Chicago Path	Algonquin	93002F	Mendon, MA	Brockton, MA	Renewed
PNGTS Year-Round	PNGTS	1997-003	Pittsburgh	Granite	Converted
Tennessee Niagara	Tennessee	5292	TGP Zone 5	TGP Zone 6	Renewed
Tennessee Niagara	Tennessee	39735	TGP Zone 5	TGP Zone 6	Renewed
Tennessee Long-haul	Tennessee	5083	TGP Zone 0	TGP Zone 6	Renewed
Tennessee Long-haul	Tennessee	5083	TGP Zone L	TGP Zone 6	Renewed
Algonquin Long-haul	Algonquin	93201A1C	Lambertville, NJ	Taunton, MA	Renewed
Tennessee Firm Storage	Tennessee	5195	TGP TGP Zone 4	TGP TGP Zone 4	Renewed
Tennessee Firm Storage	Tennessee	5265	TGP Zone 4	TGP Zone 6	Renewed
Washington 10 Path	Washington 10	01052	W10 Withdrl Meter	Vector	Terminated
Washington 10 Path	Vector Vector	CRL-NUI-1096	Alliance	Dawn	Terminated
Washington 10 Path	TransCanada	CRL-NUI-1097	Washington 10	Dawn	Terminated
Washington 10 Path	PNGTS	33322	Union Dawn	East Hereford	Renewed
Washington 10 Path		1997-004	Pittsburgh	Granite	Converted
All Capacity Paths	Granite	14-001-FT-NN	NA	Northern	Renewed

Reviews of the original capacity portfolio as those contracts expired resulted in some modifications. In particular, the Company converted the "Chicago" path in the original portfolio to today's "Dawn Storage" path. It also relocated its largest underground storage from Washington 10 to Dawn, increased it from 3.4 Bcf to 4.0 Bcf, and increased the maximum daily withdrawal capability from 34,000 Dth to 40,000 Dth. The region around Dawn, including adjacent parts of Michigan in the U. S., includes a number of gas storage facilities. Dawn operates as well as a highly active trading point, reflecting its convergence (as the new IRP depicts) for supplies from important gas-producing regions, including the Western Canadian Sedimentary Basin and the Marcellus/Utica region in Ohio, New York, Pennsylvania and West Virginia.

NUI also accesses the markets for liquefied natural gas (LNG) to supply its LNG storage and regasification facility in Lewiston, Maine. LNG enters the region at the Canaport LNG receiving terminal in New Brunswick and at the Distrigas facility in Everett, Massachusetts. (Exelon Generation Company, LLC now owns the Distrigas facility (see Chapter II)). The NUI system also connects to the Maritimes & Northeast Pipeline system (M&NP). The offshore Nova Scotia gas-producing areas have become depleted, but revaporized LNG from the large Canaport terminal in New Brunswick can reach NUI and other U. S. markets via M&NP pipeline facilities.

The following table lists the components of the Company's supply capacity portfolio, including the pending Portland Xpress and Atlantic Bridge and the proposed Westbrook Xpress Project. The table shows that all of the Company's sources involve multiple receipts and deliveries between their sources and their arrival at NUI's distribution system.

Pipeline Transportation and Underground Storage Contracts by Capacity Path

Capacity Path	Vendor	Contract ID	Contract End Date	Receipt Zone	Delivery Zone
Iroquois Receipts	Iroquois	181003	10/31/2024	Waddington	Wright
Iroquois Receipts	Tennessee	95196	10/31/2022	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Tennessee	41099	10/31/2022	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Algonquin	93002F	10/31/2020	Mendon, MA	Brockton, MA
TGP Niagara	Tennessee	5292	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Niagara	Tennessee	39735	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Long-haul	Tennessee	5083	10/31/2023	TGP Zone 0, L	TGP Zone 6
Algonquin Receipts	Texas Eastern	800384	10/31/2024	Leidy Storage	Lambertville, NJ
Algonquin Receipts	Algonquin	93201A1C	10/31/2020	Lambertville, NJ	Taunton, MA
TGP Firm Storage	Tennessee	5195	3/31/2025	TGP Zone 4	TGP Zone 4
TGP Firm Storage	Tennessee	5265	3/31/2025	TGP Zone 4	TGP Zone 6
Dawn Storage	Enbridge	LST086	3/31/2023	Dawn Hub	Dawn Hub
Dawn Storage	Enbridge	M12256	10/31/2033	Dawn Hub	Parkway
Dawn Storage	TransCanada	57901	3/31/2033	Parkway	East Hereford
Dawn Storage	TransCanada	57055	10/31/2032	Parkway	East Hereford
Dawn Storage	PNGTS	FTN-NUI-0001	10/31/2033	Pittsburg, NH	Newington, NH
Portland Xpress	Enbridge	TBD	10/31/2040	Dawn Hub	Parkway
Portland Xpress	TransCanada	TBD	10/31/2040	Parkway	East Hereford
Portland Xpress	PNGTS	TBD	10/31/2040	Pittsburg, NH	Newington, NH
Westbrook Xpress	Enbridge	TBD	10/31/2037	Dawn Hub	Parkway
Westbrook Xpress	TransCanada	TBD	10/31/2037	Parkway	East Hereford
Westbrook Xpress	PNGTS	TBD	10/31/2037	Pittsburg, NH	Newington, NH
All Capacity Paths	Granite	16-100-FT-NN	10/31/2020	NA	Northern

The Company organizes these capacity resources into "paths." The paths connect each supply point to NUI's affiliate Granite State Gas Transmission, Inc. (GSGT). GSGT then delivers to the Company's distribution system. The table below lists the paths and their maximum daily quantities.

NUI shares all its pipeline capacity with retail marketers who serve customers on its distribution system. The table indicates the method by which NUI shares each path with the marketers:

- Capacity Release: allows the marketer to directly manage the asset
- Company-Managed: the Company manages the asset, fulfilling requests of marketers for their share of that resource.

Long-Term Resources by Capacity Path

Capacity Path	Resource Type	Max Daily Quantity	Method of Assignment	Status
Iroquois Receipts Path	Pipeline	6,434	Company-managed	Existing
Tennessee Niagara Capacity	Pipeline	2,327	Capacity Release	Existing
Tennessee Long-haul Capacity	Pipeline	13,109	Capacity Release	Existing
Algonquin Receipts Path	Pipeline	1,251	Company-managed	Existing
Tennessee Firm Storage Capacity	Storage	2,644	Capacity Release	Existing
Dawn Storage Path	Storage	39,863	Capacity Release	Existing
Lewiston On-System LNG Plant	Peaking	6,500	Company-managed	Existing
Existing Long-Term Capacity		**72,128**		**Existing**
Portland XPress Project (11/2020)	Pipeline	9,965	Capacity Release	Pending
Atlantic Bridge Capacity (11/2020)	Pipeline	7,500	Capacity Release	Pending
Pending Long-Term Capacity		**89,593**		**Pending**
Westbrook XPress Project (11/2022)	Pipeline	9,965	Capacity Release	Proposed
Proposed Long-Term Capacity		**99,558**		**Proposed**

NUI has only one receipt point on its distribution system that is not served by GSGT. That one is Lewiston, Maine, where NUI connects directly to M&NP. There is currently no upstream capacity for that point; NUI buys supply delivered there. The pending Atlantic Bridge capacity will deliver to that point, allowing NUI to look for upstream resources to serve it.

2. *Capacity Contracting*

Capacity contracting decisions since the Company's acquisition by Unitil have involved renewing or converting almost all capacity resources. Management viewed the portion consisting of supplies bought on a delivered basis as too large. Management has therefore sought to pursue alternatives in the period since the acquisition. Available alternatives have come in the form of pipeline connections, plus some increase in underground storage. These resources have reduced the portion of supply acquired on a delivered basis, because they have provided access to upstream supply points which are more liquid than the ones in New England. These resources include:

- The Dawn Storage Path, which went into service in April 2018, involved re-contracting of existing pipeline capacity combined with some added capacity
- The Atlantic Bridge project, which involves added capacity on the AGT system, accessing supply points in New Jersey
- The Portland Xpress project's addition to PNGTS capacity, with upstream capacity on TCPL and Enbridge, which will provide additional access to the Dawn supply point
- The Westbrook Xpress project's addition of further capacity on PNGTS and upstream pipelines TCPL and Enbridge to access Dawn.

Acquiring capacity from such projects permits year-round use, but the Company's requirements are seasonal. Nevertheless, the new IRP suggests that the lower prices and greater price stability associated with access to the more-liquid supply points favor these projects over delivered supply.

It shows expected utilization of these resources and the legacy ones under both Normal-Year and Design-Year conditions. The Company presented detailed analysis of the benefits of the Atlantic Bridge and Portland Xpress projects in proceedings to consider whether to approve them. Recently, the Commission approved a similarly detailed analysis of the Westbrook Xpress project.

Management continues to review its remaining capacity portfolio as additional contracts expire, and as particular supply problems or opportunities present themselves. Analysis includes careful quantitative comparisons of alternatives, plus application of qualitative considerations unique to each potential opportunity presented. The IRP presents a detailed discussion of the Company's resource evaluation methods.

The Energy Contracts group is responsible for assessing opportunities. It does not prepare formal decision documents, but does preserve quantitative assessments of the alternatives it considers. When decisions lead to change, the Company presents the results of all assessments, quantitative and qualitative, in its next gas-cost-adjustment filing.

3. Commodity Purchasing

NUI purchases gas supplies annually through two requests for proposals (RFPs). The first, typically issued in mid-February, seeks proposals for particular supplies and supply services, including

- Supplies provided as part of agreements to manage certain of NUI's capacity assets
- Winter-season supplies, delivered to GSGT receipt points for re-delivery to NUI
- Summer-season supplies delivered to storage-area pooling points or to injection points for storage held by NUI.

The second RFP focuses on peaking supplies. Typically issued in June, the RFP requests supplies delivered to GSGT interconnects with PNGTS or the Company's receipt point on M&NP. These supplies are to address "demand swings and peak winter days".

a. Asset Management Agreements

Operating the many capacity paths to which the Company has access would require managing relatively small amounts of capacity on multiple pipelines every day. Management therefore simplifies its daily operating challenges by aggregating each path's components into a package. It then offers the resulting path-based packages for bid under asset-management agreements (AMAs). Management selects from among the third parties offering for each package one to operate each package. This leaves to NUI the role of ensuring accurate nominations to each package's third-party asset manager for delivery of supply using that path to NUI for meeting system-supply customer needs.

Management solicits offers to manage these path-based packages under AMAs having one-year terms. The Company requires asset managers to provide supply at a relevant index price, plus variable transportation and fuel charges associated with deliveries to the specified delivery point. For paths that go through Canada, asset managers must administer all import/export filings, and pay all duties, GST taxes and any other miscellaneous charges. For each path, NUI provides the third-party managers an estimate of the amount of capacity that must be assigned to retail marketers.

The Company requires asset managers that win the right to manage the Dawn storage asset to buy the gas that remains in storage when the manager assumes responsibility for managing its operation. The manager must then fill the storage at a cost developed as though the storage capacity had been filled ratably (uniformly) at an indexed price specified by NUI. The specified prices typically use a local index, with additions for variable injection and fuel charges. Withdrawals occur when NUI nominates them, with billing for them at inventory cost when withdrawn. At the end of the storage withdrawal season NUI repurchases any remaining inventory at the final weighted average cost.

Third parties find benefit in these arrangements by: (a) selling gas to NUI at the prices their winning offerings require, and by (b) using any remaining capacity on the path (after meeting NUI and retail marketers' requirements) to serve other customers the manager may find. Thus, for example, an asset manager who finds opportunity for storage arbitrages can do so for its own account, presumably allowing it to offer NUI better compensation for use of the asset. Management generally awards management of each "path" to the third-party offering NUI the largest asset-management "fee." NUI's view of offeror capabilities and commitment to reliable service comprise factors that can cause an award not to follow raw pricing. Over the last six years (2014-2015 through 2019-2020), asset-management revenue has covered an average of 23 percent of asset demand costs (between 11 and 36 percent in any given year).

b. Delivered Supplies

Chapter II addressed expiration of the Wells Supply Contracts, whose expiration, combined with load growth since 2008, has left a considerable requirement for supplies beyond the capabilities of the legacy capacity portfolio. The pending and proposed supply projects will address a significant part of that requirement, but the Company needs additional supplies delivered to its city gate or receipt points on GSGT in the winter months.

In recent years, this requirement has been addressed in two parts:

- Contracts for delivered "base-load" supplies; *i.e.*, those delivered in the same amounts on every day of a specified period
- Contracts for delivered "peaking" supplies; *i.e.*, committing suppliers to deliver up to a maximum daily quantity of supply as the Company calls for it.

Base-load supplies are generally seasonal. Winter-period ones provide for one quantity delivered every day for the months of November through March, and a second quantity delivered every day for the months of December through February. Summer-period ones call for constant quantities every day of the specified summer months.

i. Delivered Base-Load Supplies

The Company secures delivered base-load supplies under its annual RFP, which specifies the required delivery points and the pricing structures considered acceptable by NUI. The 2019 RFP, for example, specified the last-day settlement price of the NYMEX gas contract for each month of the delivery period – November through March or December through February – plus or minus a basis differential. Bidders specified the basis differential they were willing to accept in their offers. NUI picked the supplier with the smallest basis differential.

Also in the annual RFP are small quantities of summer-period supplies. Those supplies are to be delivered to storage-area pooling points, and a storage-injection point under contract to NUI. The 2019 RFP requested:

- 1,800 Dth/day for the months of April through December, delivered to TGP's Station 313 Pool)
- 900 Dth/day for the months of April through October, delivered to NUI's storage injection meter on the 300 Leg of TGP Zone 4.

The RFP-requested pricing for both was the last-day settlement price of the NYMEX gas contract for each month of the delivery period, plus or minus a basis differential. The RFP instructed bidders to specify the basis differential they were willing to accept.

ii. Delivered Peaking Supplies

The second RFP seeks delivered peaking supplies. For the winter of 2018-2019, the Company requested as much as 40,000 Dth/day, subject to an annual maximum of 800,000 Dth. The Company sought to reserve the power to nominate up to 40,000 Dth/day, delivered to specified delivery points. Offerors specified the maximum they would commit to providing to each of the specified delivery points. Offerors had the option of proposing either fixed pricing or a stated daily index price (such as the Algonquin City Gates price), plus a fixed demand charge that would be paid in each of the months covered by the service. For indexed pricing, qualified offerors effectively competed on the basis of the demand charge. Fixed pricing required consideration of both demand and commodity components for all offers.

In late 2018, the Company issued a special RFP for a three-, four- or five-year term, rather than the one-year term of previous contracts. Termination of gas production offshore Nova Scotia has given the Company concern about the availability of supply when NUI needs it. Management sought to consider whether entering a longer-term commitment might increase supply reliability.

The special RFP used delivery and pricing specifications similar to those of prior RFPs for this type of supply:

- Sellers specified maximum daily quantity and annual contract quantity at each of six listed delivery points
- Pricing could be at the monthly Bidweek Algonquin City Gates spot-price index, or at NYMEX last-day settle for the month in which the deliveries occurred, plus a fixed demand charge covering the entire period to be covered by the supplier's offer.

[redacted]

4. Supplier Competition

The New England market has seen multiple competitors propose additions to delivery capacity, but most projects have stalled or been abandoned. NUI has looked at each, and is participating in the pipeline projects that have survived, to meet its objective of reducing dependence on delivered supplies.

Competition to provide commodity supply has been reasonably robust, but some competitors have disappeared as market risks intensify. The New England market presents comparatively high risks for suppliers because of price volatility and constrained pipeline capacity. Those with supply available at an upstream point, but who cannot get it to a customer because of a pipeline issue, may need to secure additional supply in the market where delivery must occur, potentially facing potentially ruinous price or default risk.

a. The Annual RFP

Providing asset-management service or delivered supply to NUI requires financial resources and management skills. The following table shows how many firms competed to supply each of those services in response to NUI's last five annual RFPs. Not every competitor bid on every path. The table shows by path the lowest and highest bidder numbers. Similarly, for delivered supply not every supplier bid on delivering to every point; the table shows the range of competitors for any point.

Annual AMA and Base-Load Supply Bidder Numbers

	4/1/2015-3/31/2016	**4/1/2016-3/31/2017**	**4/1/2017-3/31/2018**	**4/1/2018-3/31/2019**	**4/1/2019-3/31/2020**
Asset Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Delivered Base-Load Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

One of the AMA opportunities involves NUI's long-haul capacity on the TGP system. That capacity accesses supply points in the U. S. Gulf Coast, near the upstream end of the TGP system, and delivers to the southern end of GSGT's pipeline system, and to GSGT at a NUI city gate in New Hampshire, both near TGP's downstream end. That AMA routinely draws the [redacted] The AMA for NUI's TGP capacity from the Niagara import point to its receipt points routinely draws the [redacted] The AMA for the Dawn Storage path (previously the Washington 10 Storage path) draws by far the largest asset-management fees, as it offers many optimization opportunities.

The competition for winter base-load supply routinely draws [redacted] Competition varies for the other delivered-supply opportunities offered in the annual RFP.

b. The Peaking RFP

The competition for delivered peaking supplies is conducted separately. The annual RFP is issued in mid-February, with contracts awarded in March. The RFP for delivered peaking service is issued in late June or early July, with the service to begin November 1. The service is provided from November 1 through the following March 31.

The peaking-service RFP traditionally provided for day-ahead nominations for the service, with a must-take provision for the nominated quantity. Beginning with the 2016 RFP (for the service period November 1, 2016 through March 31, 2017), NUI requested offers requiring day-ahead nominations, and offers allowing intra-day nominations. The following table shows the number of offers that the Company received for each type of service.

Numbers of Offers Received for Delivered Peaking Supply

	11/1/2015-3/31/2016	11/1/2016-3/31/2017	11/1/2017-3/31/2018	11/1/2018-3/31/2019
Day-Ahead Nominations	[redacted]	[redacted]	[redacted]	[redacted]
Intra-Day Nominations	[redacted]	[redacted]	[redacted]	[redacted]

As noted earlier, the Company in late 2018 issued an RFP for a multi-year delivered peaking service. [redacted]

c. Supplier Qualification

The Company requires that prospective sellers of gas or asset-management services enter into a NAESB (North American Energy Standards Board) Base Contract for Sale and Purchase of Natural Gas with it in order to do business. The Company evaluates the financial stability of any firm that wants to bid, but requests collateral rather than rejecting a possible supplier if it is concerned about the supplier's finances. For suppliers, NUI considers the physical assets that would be used to fulfill a contract. For asset managers, NUI considers a proposer's operational experience and technical capabilities. The Company says that it is willing to discuss a relationship with interested suppliers; its focus in any such discussion is to ensure that a prospective supplier understands and accepts the obligations that would come with a supply relationship with NUI. New suppliers are given relatively small opportunities to perform as tests of their suitability for a supply relationship with NUI.

As indicated in the table below, three new suppliers have been added in the last three years.

5. Supply Contracts

All of the Company's U.S. pipeline and storage capacity is on (or in) facilities regulated by the U.S. Federal Energy Regulatory Commission (FERC) Those facilities offer their services under FERC-approved tariffs, and NUI's contracts for its share of those facilities are service agreements issued pursuant to those tariffs. The only exception is the Company's LNG storage and regasification facility, which it owns. The Canadian Energy Regulator (formerly the National Energy Board) or the Ontario Energy Board regulate pipeline and storage capacity in Canada. Rates for pipeline transportation service are regulated, but rates for storage are market-based.

As noted, the Company uses the NAESB Base Contract for Sale and Purchase of Natural Gas as the basis for its relationships with all suppliers of asset-management services and natural gas. The Company uses its RFPs, and the confirmations issued when it accepts an offer for services or supply, to add specific details to govern the relationship. Those added specifics are often quite detailed as they include detailed operating provisions.

Company personnel review each year's performance under all contracts. RFPs and transaction confirmations for the succeeding year are modified to improve performance if possible. The principal objective of each year's modifications is to reduce operational risks to the Company and its customers.

6. *Suppliers*

The table below lists the Company's suppliers for 2016, 2017 and 2018. The list is in order of most supply to least for 2018.

Suppliers of Natural Gas to NUI (Dth)

Supplier	**2016**	**2017**	**2018**
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

7. *Documentation*

For decisions about capacity commitments, internal evaluations, which primarily take the form of spreadsheets comparing cost provisions of available alternatives, are annotated and saved. Details of both quantitative and qualitative evaluations are presented to the Maine and New Hampshire Public Utility Commissions in requests for approval of contractual commitments.

For decisions about commodity, the Company saves all of its RFPs, all of the responses that it receives, and all of its bid evaluations as documentation for its selections of asset managers and providers of delivered supply. Day to day, spreadsheets detailing nominations under in-force contracts are saved. Any purchases or sales outside of the AMAs and delivered-supply agreements are entered into GTRAC, which is the Company's transaction-tracking system. The spreadsheets and GTRAC are structured to support the Company's twice-yearly cost-of-gas adjustment filings.

C. Conclusions

1. We found management of supply procurement a notable NUI strength.

1 [redacted]

NUI has the benefit of a capable and experienced staff in the supply procurement function. Key personnel have deep experience in the unique circumstances of the Company's service territory, a commitment to careful analysis, and a continuing interest in evaluating performance in order to improve. Capacity options are limited, and the number of suppliers is limited for the services the Company requires, but performance in those circumstances is exceptional.

In the complex and high-risk nature of the supply environment in which the Company operates, the Company has developed supply processes well suited to that environment. Rather than try to operate a system with many small moving parts, NUI has organized its capacity portfolio into paths that connect liquid, transparent supply points to NUI's receipt points, and hires asset managers to operate each one.

For requirements that must be met with delivered supplies, the Company encourages bidders to participate by offering as much delivery-point flexibility as it can. We also believe that putting a large and diverse number of supply opportunities into one annual RFP encourages more suppliers to participate, as they can see relatively accessible opportunities to establish a relationship with NUI. We note with interest that the Company has recently attracted additional suppliers in spite of the highly-constrained and high-risk nature of the New England markets.

2. Contracting practices are effective and resulting contracts appropriate in meeting supply needs.

Analysis of the Company's results suggests that its contracting practices are highly effective. There is typically a significant spread between the highest and lowest bids. This spread indicates that the competition is extracting as much value as possible from each path.

Each year's performance is evaluated as part of preparing for the succeeding year's competitions. Any ideas for improving that performance are incorporated into the contracts for the succeeding year.

3. The Company has clear objectives for its procurement activities.

For adding to or upgrading its capacity portfolio, the Company looks for access to deep, liquid markets. It operates its existing resources to emphasize transparency and liquidity, as well.

Service competitions are structured to support price stability. RFPs specify commodity pricing related to an available index that exhibits stability, or to the last-day-settlement price of the NYMEX contract.

4. Bid evaluations are rigorous and objective.

RFPs are carefully constructed to provide unambiguous offers. Those offers are evaluated primarily on price, with a review of supply reliability and pipeline scheduling capabilities as threshold tests for an award.

5. Maintaining a sufficient number of suppliers is increasingly difficult. *(Recommendation #1)*

NUI can find abundant competitors for the right to operate its resources that access highly-liquid supply points. On the other hand, it is difficult for suppliers to compete in the highly-constrained New England gas market. With the termination of gas production offshore Nova Scotia, some suppliers for whom that was a major source may no longer participate. Other suppliers may limit their participation in order to avoid the risks of participation.

[redacted]

D. Recommendations

1. Initiate an intensive effort to reduce dependence on [redacted] delivered peaking service. *(Conclusion #5)*

NUI's multi-year contract for delivered peaking supplies make a useful time window available to pursue alternatives. That effort should begin immediately, and should have high priority.

The effort should start on the demand side. NUI currently has no curtailment plan, and it has limited information on its customers' alternate-fuel capabilities. Regarding dual-fuel capability, the Company reports "Dual fuel capability is not incorporated into the Delivery Service Terms and Conditions or the Company's planning activities in any manner."

The delivered peaking service is costly. Because its pricing under the current and recent contracts involves large demand charges assessed over all five of the winter months, all customers are paying a high price to maintain service for customers who might be willing to get off when supply costs are high. This situation begs for a thoughtful demand-response program.

There may also be other supply-side options. The new owner of the Distrigas terminal should be approached regarding supply options. It has some pipeline capacity, and provides delivered-supply services to some customers. That terminal also delivers into both the TGP and AGT pipeline systems, however, as well as into the local distribution company (National Grid). Distrigas and its LDC customer might both be possibilities for peaking-supply options.

Other LDCs have LNG facilities that have provided storage services for customers other than the owner. Among those, Southern Connecticut Gas Company, now a subsidiary of Avangrid, once offered contract peaking services through an affiliate formed to offer such services into the interstate gas markets. The large LNG facility in Providence, RI has in times past offered LNG storage services to customers other than its owner. As NUI's requirement is relatively small, and could be divided into multiple small pieces, any number of LDCs might be able to offer a portion of its requirements.

Remote peak-period supply services in the highly constrained New England gas market will present risks. NUI has several advantages in pursuing such options:

- Its connection to multiple interstate pipeline systems through affiliate GSGT
- Its ability to displace supplies entering GSGT's system to different parts of its service territory

- A highly-skilled staff who has considerable knowledge of delivery systems and issues in the New England market, and considerable experience in operating complex delivery processes.

The Company's apparent plan [redacted] is to engage a consultant to pursue on-system LNG facilities, both expansion of the current plant in Lewiston, and a new plant in another locations. While expansion of the current plant might be competitive in cost, a new facility is likely to be very costly. The Company's analysis will not be complete until it has pursued these other demand-side and supply-side options as aggressively as it is pursuing additions to its on-system plant.

IV. Gas Supply Management

A. Background

Effective gas supply management requires operation of the supply portfolio in a manner that achieves reliable deliveries to customers at the lowest overall cost. Placing delivery capacity controlled by the company, but temporarily not required for serving the company's on-system customers into secondary markets comprises a central element of effective supply management.

We applied the following criteria in evaluating supply management:

1. Scope and focus of policies and procedures for operating the gas-supply portfolio on the cost and reliability interests of on-system customers
2. Sufficiency of the operational planning structure and execution to ensure no disadvantage to customers through operating errors or omissions or supplier or pipeline penalties
3. Control of personnel with Maine-service-area-only responsibilities over actions and decisions that could disadvantage Maine customers
4. Consistency of commodity transportation costs charged to Maine customers with operations that optimize overall costs for them
5. Comprehensive, regular, accurate verification of pipeline transportation costs and consistency with services received
6. Aggressiveness of marketing of unutilized assets in line with appropriate transaction limits, controls, and risk management.

B. Findings

NUI manages its supply on an integrated basis; *i.e.*, it uses all supply assets to serve customers in both Maine and New Hampshire.NUI faces particular challenges in managing its gas supply for a number of material reasons. First, ***multiple pipelines*** transport Company supply to a large number of delivery points:

- A gate station near Lewiston, Maine, on the Maritimes & Northeast Pipeline (M&NP) system
- Four receipt points on affiliate Granite State Gas Transmission, Inc.'s (GSGT's) system in Maine and New Hampshire, and one in Massachusetts
- A gate station at affiliate Fitchburg Gas and Electric Light Company (FG&E) in Massachusetts
- Several gate stations at former parent Bay State Gas Company in Massachusetts.

Deliveries to Bay State return to NUI through an exchange agreement under which Bay State delivers supply to NUI via GSGT at connections on the Portland Natural Gas Transportation System (PNGTS).

Second, the Company's *fragmented service territory* imposes locational requirements on deliveries from particular sources of supply. Third, *retail marketers* deliver large amounts of gas to the Company's system - - roughly 40 percent in Maine and 50 percent in New Hampshire - - to serve their customers through NUI's distribution system. These volumes coming for multiple marketers complicate management and measurement accuracy. Fourth, comparatively high *weather variability* creates large swings in gas requirements, exacerbated by frequent, large daily differences between forecasted and actual weather. Fifth, the *downstream location* of the service territory on almost all of pipelines serving the Company means that, during the winter, when prompt delivery of requested gas volumes is most essential, the pipelines narrow their delivery tolerances. (Delivery tolerances refer to how close the actual quantity taken from the pipeline at the delivery point matches the quantity nominated to that point.) This means that both NUI and the retail marketers that serve customers on NUI's distribution system must take extra precautions to ensure that the supplies that they deliver to the pipelines match their customers' usage.

We found Company planning, complex under these circumstances, attentive, comprehensive, and supported by appropriate systems and processes, as we discuss below.

1. *Operations Planning*

The Company organizes its supply capacity portfolio by "path"- - each consisting of grouped capacity assets that move supply from where NUI buys or stores it to key delivery points:

- The M&NP gate station at Lewiston that delivers to NUI
- A gate station in Westbrook, Maine that serves both M&NP and PNGTS, and delivers to GSGT
- PNGTS gate stations at Eliot, Maine and Newington, New Hampshire that deliver to GSGT
- Tennessee Gas Pipeline (TGP) gate stations in Haverhill, Massachusetts, and Salem, New Hampshire that deliver to GSGT
- TGP gate stations that serve affiliate FG&E.

Other paths delivering to receipt points on GSGT support the exchange agreement with Bay State. Management must allocate the assets in each path, including those delivering to Bay State, between:

- Itself to serve its system-supply customers
- Marketers, for serving their end users.

Operations planning begins by using a general forecast to construct seasonal supply plans. The Energy Contracts staff assigns supply resources to particular delivery points, based on a rough estimate of loads expected at each point. This process produces baseline estimates of capacity amounts on each path required for its system-supply customers and marketers' customers.

The staff then reduces these seasonal plans to monthly plans, which further detail and align sources and deliveries. At the beginning of each month, the Company asks that each marketer validate its list of customers. Any changes from the prior month undergo examination for adjustment in the capacity management systems that support allocation of capacity resources.

The pipelines, including GSGT, use electronic bulletin boards (EBBs) to manage their systems. Users nominate the quantities that they want to pipeline to transport, the locations where they want to put gas in – receipt points – and the locations where they want to take gas out – delivery points. All users input this information every day, and may adjust it within each day. With this information, the pipelines can assess whether their systems are physically capable of accomplishing all the requested movements. When they get close to their physical limits, they will impose flow restrictions, such as narrowing delivery tolerances. Because NUI is near the downstream ends of the major pipelines that serve it, pipeline capacity is quite limited. As a consequence, the pipelines that serve NUI operate under operational flow orders (OFOs) for most of every winter. Those orders narrow delivery tolerances to half or less of the normal levels.

2. *Day-to-Day Operations*

A Daily Forecast file embeds the monthly plans. This file applies a seven-day weather forecast to generate a corresponding daily forecast of supply requirements at the pipeline delivery locations that serve NUI. NUI personnel then nominate from among the available supply resources the quantities that they want delivered to each receipt location. Volumes under the exchange agreement with Bay State generally comprise a base-loaded volume, which means that they don't change every day. They change seasonally, but not every day.

Management updates the Daily Forecast file every day with new weather data. An accompanying Imbalance File shows whether actual deliveries have matched requirements, and provides up-to-date assessments of surplus or shortage in deliveries.

Affiliate pipeline GSGT provides the "backbone" of the Company's distribution system. Except for FG&E in Massachusetts, the Company's service territories almost all connect to and receive deliveries by GSGT. The service territories, however, do not have robust connections among themselves.

The five points (identified earlier in this chapter) of delivery into GSGT take more than seven times more (38) delivery points to get gas from GSGT into the various segments of NUI's service territory. The Westbrook Gate Station into GSGT lies very near the pipeline's northernmost delivery point, which serves an NUI lateral connecting to the Lewiston service territory. The lateral effectively serves as an extension of GSGT, connecting Lewiston to the other portions of the service territory. That lateral does not have sufficient capacity to meet Lewiston's demand during the winter. An M&NP delivery point and NUI's liquefied natural gas (LNG) storage and regasification facility also serve the Lewiston area.

GSGT and the lateral to Lewiston connect the Maine and New Hampshire service territories to each other. That interconnection allows operation of the system on an integrated basis; *i.e.*, the Maine and New Hampshire territories operate as one system. Limits on GSGT flow capacity, however, prohibit unlimited movement of gas from different GSGT receipt points to all its points of delivery to NUI. Accordingly, location-specific requirements must be addressed before supply can flow among receipt and delivery points.

<u>a. Coordination with Retail Choice Program</u>

The Company allocates shares of each of its supply-capacity paths to retail marketers in proportion to the design daily demands of each marketer's load. Allocations take place on a "slice-of-the-system" basis. Thus, each marketer gets a proportionate share of every resource. The marketers receive most resources through direct assignment, but the Company operates two:

- The Company's LNG storage and regasification facility in Lewiston, Maine
- A small TGP storage contract and the pipeline capacity for delivering the stored gas to GSGT.

These resources do not form part of the paths operated under contract with NUI by third-party asset managers. The Company manages these two asset groups in-house and provides supply from them in response to marketers' nominations. In practice, Northern can provide any supply in response to nominations by marketers for the Company-managed resources. That is, if a marketer requests Company-managed supply, Northern can fulfill the requirement with pipeline-delivered gas, rather than gas from the two Company-managed assets.

The marketers serving end users can trade their assigned "slices" among themselves, to optimize their capacity holdings as they see fit. They must, however, deliver their required amounts to specified GSGT receipt points, thus allowing the correct amount of supply to reach each of the marketers' customers. The marketers nominate their own capacity on GSGT's system. However, GSGT's meters for delivery into NUI's distribution system do not measure volumes continuously. Thus, marketers must also report their deliveries into GSGT on NUI's Centralized Supplier Interface (CSI). All marketer nominations for their Maine supply pools go to Westbrook, and nominations for New Hampshire pools go to Newington or to Haverhill. Management can verify correct volumes to be sent to the proper NUI receipt points when marketers nominate their supplies on NUI's system.

Marketers have responsibility for ensuring deliveries for their requirements, regardless of how weather and conditions may cause them to vary from nominations. NUI's Delivery Service Terms and Conditions, part of its tariff, make clear marketer responsibilities and penalties for failure to fulfill them.

b. Nominations and Dispatch

The Company's contracts for supply resources address procedures for daily resource nominations. NUI's extensive use of asset-management agreements (AMAs) make the following the primary focuses of its supply-management activities:

- Nominating quantities for delivery to GSGT, including withdrawals from storage, under each AMA
- Calling on the small quantities of supply it manages directly, when needed by the retail marketers or the Company's system-supply customers

Management must address locational requirements first. Recall that GSGT capacity limits prevent supplies received by GSGT from being delivered to any point on GSGT's system unless locational requirements are met. After addressing that constraint, the Company can select among available resources on the basis of cost.

Gas Control prepares the Daily Forecast File. Gas Control's files contain the daily forecast parameters determined in the regression models that Energy Contracts developed and maintain. These models use historical sendout information to develop relationships between EDD (weather) and sendout. Each day, Gas Control uses those models and the weather forecast for the next seven days to forecast gas requirements over that period. Weather forecast updates occur five times per day. Cold-weather nominations for supply can change up to five times per day, in accord with industry nominations cycles: timely, evening, and three intra-day cycles.

Energy Contracts carefully coordinates its nominations work with the activities of Gas Control, which performs complementary activities that include:

- Providing daily requirements estimates to the retail suppliers for the non-daily-metered customer pools (monthly-metered customers), using an automated process based on customer-specific regression analyses conducted annually by Energy Contracts, as part of the Annual TCQ Update process required by the Delivery Service Terms and Conditions
- Operating NUI's LNG facility, and ordering additional supplies during the facility's use.

3. Management of Available Capacity

The Company uses contracts for supplies delivered to GSGT or its city gates and delivered peaking supplies as a substantial part of its supply resources. Therefore, NUI does not have the sizeable amount of upstream pipeline capacity that some other gas distributors have available for secondary-market activities. It places most of its available capacity into the path-based asset-management agreements discussed earlier. Company RFPs for asset-management services provide estimates of the amounts of its pipeline capacity required to serve its load and of the amounts required to be assigned to retail marketers. Prospective asset managers consider their ability to make economic use of any unused capacity that they estimate will be available to them when pricing their bids in competing for the right to manage a particular asset.

NUI tends to over-nominate in winter, to ensure that its customers get enough supply, and to avoid pipeline imbalance penalties. When deliveries appear to exceed requirements, the Company adjusts by reducing storage withdrawals in the first half of the winter, and engages in off-system sales in the second half.

In the past, the Company released during the summer season some pipeline capacity under its management. More recently, it has placed that capacity into one of its asset-management agreements, in an effort to recover more of the costs of the capacity through increased asset-management fees and to increase reliability.

4. Procedures and Documentation

Gas supply operations operate smoothly and confidently. All participants know their roles and responsibilities well, but no written procedures exist. The Energy Contracts staff has developed a series of spreadsheets that record various aspects of the supply-management process. The staff updates these spreadsheets daily, and retains each day's sheets for documentation purposes. The spreadsheets are structured to capture all information required for cost-of-gas filings with the Commission.

C. Conclusions

1. We found NUI gas supply management a notable strength.

Company personnel have developed systems and processes to deal with the complexities of the Company's gas-supply resources and service territories. Close coordination between Energy Contracts and Gas Control during cold-weather days results in highly-effective performance in a difficult operating environment.

The nature of the Company's service territories and the physical aspects of gas supply rule out effective operation of the Maine and New Hampshire Divisions on a segregated basis. We found it clear that the interests of on-system customers serve as the predominant drivers for supply operations in all of its service territories. Management routinely addresses the allocation of administrative costs among them to its three state jurisdictions -- Maine, Massachusetts and New Hampshire. FG&E has its own supply portfolio, but NUI allocates its gas costs between Maine and New Hampshire. Those Commissions and the Company's customers have ample opportunities to satisfy themselves regarding the rules that produce those allocations, and the results that they produce.

Physical aspects of the service territories and gas delivery systems limit choices in dispatch. After satisfying locational requirements, the Company employs economic dispatch. These processes result in the lowest possible costs to each group of customers.

The Company effectively employs its path-based, asset-management agreements to place capacity sometimes not needed. Offering the asset-management opportunity to multiple bidders encourages the extraction of maximum value for on-system customers. Those marketers who can find the most effective off-system use for capacity they manage presumably reflect the margins they gain when competing for asset-management roles.

2. **Preferable short-term forecasting tools may exist; they warrant examination.** *(Recommendation #1)*

The Company uses regression models developed in-house for short-term load forecasting (embedded in the Daily Forecast File). This approach improves on traditional methods for performing this function. Nevertheless, industry best practice for this application supplements these models with a tool known as "deep neural networks". NUI may be able to enhance its short-term forecasts, and thus improve its dispatch, by using this technique. A description of the technique and its application to short-term natural gas forecasting, is presented in a recent journal article in *Energies* by Gregory D. Merkel, Richard J. Povinelli and Ronald H. Brown. (Published: 2 August 2018).

3. **The lack of written procedures risks operational continuity, should NUI experience a loss of key skills which, while now sufficient, do not exist in reasonably large number.** *(Recommendation #2)*

The Energy Contracts and Gas Control staffs have developed efficient and effective processes for gas-supply management. That detailed knowledge of those processes is concentrated in a small group of individuals, however, presents a risk of discontinuity.

Written procedures would reduce that risk by capturing a significant share of their expertise. The potential loss of highly experienced incumbents, due to retirement, accidents or illness, or departure from the Company, should be addressed.

The solution to these concerns is to develop written procedures for daily nominations and dispatch. Much of the substance of such procedures has been developed in responding to data requests in the course of this audit. The task that remains is to complete them, and then re-format them into steps that can be followed by other persons, and by auditors.

D. Recommendations

1. **Explore the application of neural network methods to the Company's short-term requirements forecasting.** *(Conclusion #2)*

As noted above, these methods now comprise industry best practice for this function. The Company should explore their application to its Daily Load Forecast. Improved forecasts should improve dispatch, hopefully lowering the requirement for same-day and intra-day adjustments.

Evaluation of such applications can take place in short time order. We recommend that the Company report on its progress in the proceeding to consider the findings of this audit (Docket No. 2018-00300).

2. **Prepare written procedures to guide the nominations and dispatch functions.** *(Conclusion #3)*

Much of the substance of required and appropriate procedures has been developed in responding to data requests in the course of this examination. What remains is to complete them and revise them into a procedures format. We regard this recommendation as a priority. The Company should initiate this effort with dispatch, and report on its progress in the proceeding to consider the findings of this audit (Docket No. 2018-00300).

V. Measurement and Balancing

A. Background

Sound measurement methods and practices support accurate determination of total gas costs. Effective balancing minimizes penalties from delivering pipelines, and supports the appropriate distribution of gas costs among customers. We evaluated measurement and balancing under the following criteria:

1. Application of metering and testing programs conforming to industry standards and to the Company's unique circumstances
2. Design and execution of metering strategies to isolate deliveries to various customer classes and Company uses
3. Design and execution of a balancing strategy and practices appropriate for each customer class.

B. Findings

1. Management Strategies and Processes

NUI receives almost all of its gas supplies via pipeline. Affiliate Granite State Gas Transmission, Inc. (GSGT) receives most of the field purchases and storage and delivered supplies, redelivering them to NUI. The Lewiston, Maine areas comprises the principal exception; NUI receives gas there from the Maritimes & Northeast Pipeline (M&NP) directly into its distribution system. The Company also operates a small liquefied natural gas (LNG) facility in Lewiston, which receives its supplies by truck, and then delivers the regasified product into the distribution system. As discussed in Chapter IV, the Company can also supply the Lewiston, Maine area through a lateral on NUI's system, but this lateral does not have sufficient capacity to meet locational demands during the winter.

NUI delivers some of the gas that it buys for transport on its capacity on the Tennessee Gas Pipeline system (TGP) and Iroquois Gas Transmission System (IGTS) and all of the gas that it buys for delivery on its Algonquin Gas Transmission system (AGT) capacity to Bay State Gas Company receipt points in Lawrence, Agawam and Taunton in Massachusetts. Bay State, in return, delivers gas on capacity that it holds on the Portland Natural Gas Transmission System (PNGTS) to GSGT receipt points at Westbrook and Eliot, Maine, and Newington, New Hampshire, for redelivery to NUI. Bay State contracts for capacity on GSGT, which it uses to deliver to NUI. An exchange agreement negotiated as part of the sale of NUI to Unitil covers these deliveries. This exchange agreement provides access for NUI to supplies sourced on TGP and on AGT, to which NUI has no physical connection.

The overall measurement scheme uses pipeline measurement of their own deliveries into GSGT, or into NUI's distribution system in the case of M&NP delivering into Lewiston. GSGT measures its deliveries into NUI's system. NUI, in turn, measures its deliveries to its customers.

At year-end 2018, the Company's Maine Division had 34,119 active meters. Most of those (almost 33,000) consisted of diaphragm-type meters, which the Company uses for residential and small commercial and industrial (C&I) customers. The Company employs rotary meters for larger C&I customers, and turbine meters for the largest C&Is. NUI had only six turbine meters in operation at the end of 2018. The Company filed descriptions of how each meter type operates, and of the circumstances in which each is deployed, with its initial response in Docket No. 2018-00331, *Inquiry into Meter Testing and Standards of Local Distribution Companies*.

The interstate pipelines calibrate their meters at least annually. GSGT inspects its turbine and rotary meters monthly to verify their operation, and it calibrates its flow computers annually. NUI tests meters before installation, and calibrates its largest ones quarterly. Field audits conducted each year sample the non-instrumented rotary and diaphragm meters. The audits seek to validate proper operation of the reading indexes and the automated meter reading (AMR) devices. The practice is to examine two percent of small-diaphragm meters and 25 percent of large diaphragm ones each year.

NUI's billing system identifies anomalies in billings, such as measurements showing no usage at customer locations known to be active. Upon detecting anomalies, technicians visit the meter to examine the circumstances. NUI also tests meters on customer request.

NUI has identified certain meter types with known problems, replacing them as practical. Management also has a practice of retiring certain meter types to reduce the number of types in inventory. Otherwise, NUI retires meters more than 20 years old.

NUI requires its meter manufacturers to provide test data for new meters purchased. The Company sends meters removed for testing to a testing facility in Pennsylvania. Testing applies a protocol established by Unitil. In the 10 years that Unitil has owned the Company, the Maine Division has received test results for 13,358 purchased meters, and for 1,910 meters removed for testing.

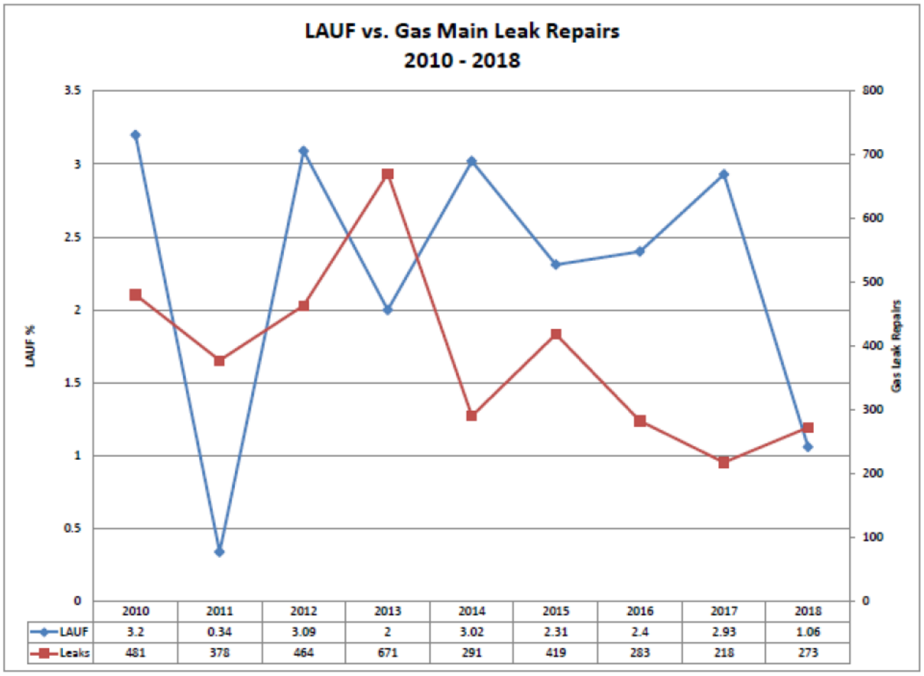
The Company generally follows manuals published by the American Gas Association (AGA) to guide meter accuracy and testing standards and protocols. Management observed that the three jurisdictions in which it operates have different requirements regarding metering standards.

2. *Lost and Unaccounted for Gas*

A variety of factors produce Lost and Unaccounted for Gas (LAUF); *e.g.*, meter accuracy, timing differences between billing measurements at upstream points and individual customer meters, company usage, measurement accuracy of LNG inventory, boil-off gas, theft, pipe leaks, and accounting differences. NUI's measures to reduce LAUF include:

- It measures Company use for domestic heat and hot water at various facilities and for vaporization and heaters at its LNG facility and district regulator stations, and deducts the measured quantities from LAUF calculations
- It installs correctors that compensate for variances in pressure and temperature for commercial and industrial customers
- It checks customer service regulators and adjusts them upon installation and routine meter changes, to ensure accurate delivery pressures, and, in turn, measurement
- It conducts an aggressive leak repair program.

The Company reports that most leaks occur along the cast-iron portions of its distribution system. Management plots leaks on maps, to serve as a factor in planning the cast-iron replacement program. NUI has completed that replacement program in New Hampshire, now finding no leaks there. While logic suggests that repairing leaks would reduce LAUF, management has found no clear correlation between leak repairs and LAUF (see the graph below), which reflects the fact that a factors beyond leaks materially influence LAUF.



NUI has organized its cast-iron replacement program by geographic areas. During work in an active area, the Company usually replaces meters as well, and upgrades service lines as necessary or appropriate.

As do most gas distribution companies, NUI calculates its annual LAUF percentage by summing monthly calculations from July of the previous year through June of the reporting year. The Company calculates LAUF separately for its Maine and New Hampshire Divisions, and for subsidiary Fitchburg Gas and Electric Light Company (FG&E) in Massachusetts.

The next table, taken from the Company's PHMSA F7100.1-1 Annual Report for the Maine Division, shows the Company's LAUF calculation for the years 2014 through 2018. NUI often appears to receive more gas than it delivers (positive LAUF) in winter, but then appears to deliver more than it receives in the spring (negative LAUF). Cycle billing produces this pattern, characteristic of most gas LDCs. For this reason, reported LAUF usually employs a 12-month calculation period.

Northern Utilities, Inc. Maine Division Lost and Unaccounted For, Company use, and Therm Factor Data								
12 Months Ending June	**Month**	**Total - ME City-Gate (MCF)**	**Therm Factor**	**Total - ME City-Gate (Dth)**	**Total System Billed Sales (Dth)**	**Company Use (Dth)**	**Lost and Unaccounted For (Dth)**	**Lost and Unaccounted For (%)**
2014	Jul-13	360,798	1.0170	366,931	361,116	37	5,778	1.60%
2014	Aug-13	373,504	1.0126	378,210	366,661	8	11,541	3.15%
2014	Sep-13	399,136	1.0281	410,352	378,996	14	31,342	8.27%
2014	Oct-13	575,408	1.0386	597,619	485,235	34	112,350	23.15%
2014	Nov-13	1,004,257	1.0272	1,031,573	843,493	173	187,907	22.28%
2014	Dec-13	1,454,069	1.0317	1,500,163	1,286,509	337	213,317	16.58%
2014	Jan-14	1,581,927	1.0386	1,642,989	1,587,741	2,465	52,783	3.32%
2014	Feb-14	1,354,980	1.0356	1,403,217	1,450,516	1,170	(48,469)	-3.34%
2014	Mar-14	1,373,442	1.0300	1,414,645	1,408,731	1,306	4,608	0.33%
2014	Apr-14	821,018	1.0312	846,634	1,008,764	933	(163,063)	-16.16%
2014	May-14	500,294	1.0371	518,855	619,888	373	(101,406)	-16.36%
2014	Jun-14	373,847	1.0438	390,221	427,439	86	(37,304)	-8.73%
2015	Jul-14	355,102	1.0396	369,164	370,442	33	(1,311)	-0.35%
2015	Aug-14	359,916	1.0408	374,600	353,033	26	21,541	6.10%
2015	Sep-14	411,741	1.0179	419,111	385,511	26	33,574	8.71%
2015	Oct-14	582,481	1.0170	592,383	514,552	112	77,719	15.10%
2015	Nov-14	1,025,629	1.0272	1,053,526	827,326	448	225,752	27.29%
2015	Dec-14	1,256,340	1.0356	1,301,066	1,222,092	976	77,998	6.38%
2015	Jan-15	1,634,539	1.0403	1,700,410	1,525,468	1,237	173,705	11.39%
2015	Feb-15	1,634,909	1.0406	1,701,286	1,710,367	2,860	(11,941)	-0.70%
2015	Mar-15	1,379,495	1.0347	1,427,364	1,499,295	2,179	(74,109)	-4.94%
2015	Apr-15	854,091	1.0266	876,810	1,052,591	1,059	(176,840)	-16.80%
2015	May-15	498,638	1.0251	511,154	590,016	245	(79,108)	-13.41%
2015	Jun-15	438,073	1.0224	447,886	462,683	80	(14,877)	-3.22%

12 Months Ending June	Month	Total - ME City-Gate (MCF)	Therm Factor	Total - ME City-Gate (Dth)	Total System Billed Sales (Dth)	Company Use (Dth)	Lost and Unaccounted For (Dth)	Lost and Unaccounted For (%)
2016	Jul-15	392,545	1.0228	401,495	398,252	28	3,216	0.81%
2016	Aug-15	387,281	1.0208	395,336	382,252	14	13,070	3.42%
2016	Sep-15	395,272	1.0212	403,652	387,311	37	16,304	4.21%
2016	Oct-15	679,374	1.0308	700,299	557,542	89	142,668	25.59%
2016	Nov-15	902,671	1.0280	927,946	778,166	381	149,398	19.20%
2016	Dec-15	1,080,621	1.0313	1,114,444	1,061,183	1,103	52,158	4.92%
2016	Jan-16	1,444,975	1.0395	1,502,052	1,363,726	1,435	136,891	10.04%
2016	Feb-16	1,280,645	1.0417	1,334,048	1,397,147	1,836	(64,935)	-4.65%
2016	Mar-16	1,104,015	1.0322	1,139,565	1,226,006	1,558	(87,999)	-7.18%
2016	Apr-16	880,207	1.0289	905,645	954,764	1,270	(50,389)	-5.28%
2016	May-16	586,114	1.0234	599,830	666,178	574	(66,921)	-10.05%
2016	Jun-16	423,131	1.0260	434,132	464,054	71	(29,993)	-6.46%
2017	Jul-16	383,017	1.0192	390,371	375,734	28	14,610	3.89%
2017	Aug-16	393,016	1.0195	400,680	404,659	26	(4,005)	-0.99%
2017	Sep-16	413,879	1.0176	421,163	393,396	29	27,739	7.05%
2017	Oct-16	658,449	1.0199	671,552	547,913	198	123,441	22.53%
2017	Nov-16	934,347	1.0215	954,435	846,936	718	106,780	12.61%
2017	Dec-16	1,435,585	1.0311	1,480,231	1,214,257	1,192	264,782	21.81%
2017	Jan-17	1,402,244	1.0337	1,449,500	1,438,474	1,601	9,426	0.66%
2017	Feb-17	1,251,854	1.0442	1,307,186	1,361,604	1,580	(55,998)	-4.11%
2017	Mar-17	1,401,927	1.0344	1,450,153	1,347,498	1,528	101,127	7.50%
2017	Apr-17	812,508	1.0258	833,470	1,034,142	1,212	(201,884)	-19.52%
2017	May-17	614,371	1.0245	629,423	702,918	640	(74,135)	-10.55%
2017	Jun-17	426,811	1.0253	437,609	444,976	380	(7,747)	-1.74%
2018	Jul-17	393,491	1.0220	402,147	445,002	27	(42,882)	-9.64%
2018	Aug-17	400,454	1.0227	409,545	397,745	27	11,774	2.96%
2018	Sep-17	403,092	1.0223	412,081	401,100	39	10,942	2.73%
2018	Oct-17	502,147	1.0249	514,651	489,750	141	24,760	5.06%
2018	Nov-17	1,046,849	1.0337	1,082,128	814,852	657	266,620	32.72%
2018	Dec-17	1,592,327	1.0360	1,649,651	1,378,493	1,182	269,975	19.58%
2018	Jan-18	1,677,857	1.0410	1,746,649	1,797,898	2,559	(53,808)	-2.99%
2018	Feb-18	1,228,124	1.0356	1,271,845	1,407,008	1,974	(137,137)	-9.75%
2018	Mar-18	1,265,450	1.0363	1,311,386	1,295,226	1,677	14,483	1.12%
2018	Apr-18	974,101	1.0346	1,007,805	1,101,347	1,234	(94,776)	-8.61%
2018	May-18	514,209	1.0266	527,887	659,106	752	(131,971)	-20.02%
2018	Jun-18	429,087	1.0326	443,076	466,445	118	(23,487)	-5.04%
2014		10,172,678	1.0323	10,501,409	10,225,089	6,937	269,384	**2.57%**
2015		10,430,953	1.0330	10,774,760	10,513,377	9,280	252,104	**2.34%**
2016		9,556,852	1.0316	9,858,444	9,636,580	8,396	213,468	**2.17%**
2017		10,128,007	1.0294	10,425,773	10,112,507	9,131	304,135	**2.92%**
2018		10,427,188	1.0337	10,778,851	10,653,973	10,386	114,492	**1.06%**

3. *Balancing*

Balancing consists of getting deliveries into the distribution system to match deliveries out of it. Effective balancing promotes: (a) getting the correct gas costs to each customer or class of customers, and (b) avoiding imbalance penalties. Balancing poses special challenges for NUI, because: (a) its service territory experiences large changes in weather, which, in turn, results in large changes in gas requirements, and (b) retail marketers supply a large portion of NUI's load. The marketers bring supplies for their customers to NUI which must then deliver those supplies to marketer customers. The next table shows, for a sample winter month (January 2018), the influence of both factors. It shows the magnitude of the load supplied by marketers, as much as one-third on some days, and it shows the impact of weather changes. Notice Column 6, which shows for that month a forecast variance range of minus 24 percent to plus 29 percent.

Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 15	Col 16
			Col 4- Col 3	(Col 4 / Col 3) - 1			Col 8 - Col 7	(Col 8 / Col7) -1		
Gas Day	**Forecast Average ME/NH EDD**	**Actual Average ME/NH EDD**	**Forecast EDD Variance (EDD)**	**Forecast EDD Variance (Percentage)**	**Forecasted Northern System Sendout (Dth)**	**Actual Northern System Sendout (Dth)**	**Forecast Sendout Variance (Dth)**	**Forecast Sendout Variance (Percentage)**	**Total System Supply**	**Imbalance (Dth)**
1/1/2018	68.0	70.3	2.3	3%	143,319	137,700	-5,619	-4%	141,034	3,334
1/2/2018	58.0	58.7	0.7	1%	124,097	131,944	7,847	6%	128,527	-3,417
1/3/2018	50.0	49.7	-0.3	-1%	109,124	112,367	3,243	3%	110,380	-1,987
1/4/2018	51.5	51.4	-0.1	0%	110,822	105,102	-5,720	-5%	115,428	10,326
1/5/2018	72.0	71.5	-0.5	-1%	144,456	138,437	-6,019	-4%	145,472	7,035
1/6/2018	75.5	75.0	-0.5	-1%	146,632	143,516	-3,116	-2%	149,039	5,523
1/7/2018	57.5	56.2	-1.4	-2%	120,565	120,460	-105	0%	132,258	11,798
1/8/2018	41.0	39.7	-1.4	-3%	96,749	100,426	3,678	4%	104,717	4,291
1/9/2018	44.5	39.8	-4.8	-11%	96,602	90,918	-5,684	-6%	92,993	2,075
1/10/2018	37.5	34.7	-2.8	-7%	89,094	85,159	-3,935	-4%	77,398	-7,761
1/11/2018	24.5	22.0	-2.6	-10%	71,332	65,508	-5,824	-8%	64,983	-525
1/12/2018	20.5	15.6	-4.9	-24%	59,691	50,784	-8,906	-15%	56,321	5,537
1/13/2018	50.5	48.4	-2.2	-4%	90,542	91,172	630	1%	91,917	745
1/14/2018	57.5	56.8	-0.7	-1%	114,825	116,497	1,672	1%	120,118	3,621
1/15/2018	53.5	52.8	-0.7	-1%	115,179	119,964	4,786	4%	119,654	-310
1/16/2018	40.0	38.8	-1.3	-3%	93,172	94,830	1,658	2%	93,500	-1,330
1/17/2018	42.0	41.7	-0.3	-1%	93,964	94,994	1,030	1%	98,057	3,063
1/18/2018	44.5	44.9	0.3	1%	99,262	95,161	-4,101	-4%	92,782	-2,379
1/19/2018	38.5	37.0	-1.6	-4%	88,611	84,789	-3,822	-4%	84,510	-279
1/20/2018	30.0	28.8	-1.3	-4%	67,172	71,443	4,271	6%	68,287	-3,156
1/21/2018	32.5	31.1	-1.5	-4%	73,485	71,656	-1,829	-2%	79,185	7,529
1/22/2018	33.0	42.7	9.7	29%	80,509	95,592	15,083	19%	83,898	-11,694
1/23/2018	27.0	33.8	6.8	25%	71,362	84,713	13,351	19%	67,275	-17,438
1/24/2018	46.5	46.2	-0.3	-1%	97,494	100,221	2,727	3%	101,875	1,654
1/25/2018	55.0	52.5	-2.6	-5%	116,912	112,865	-4,047	-3%	108,780	-4,085
1/26/2018	44.0	42.8	-1.2	-3%	98,311	98,791	480	0%	84,235	-14,556
1/27/2018	26.5	22.3	-4.3	-16%	63,862	63,186	-676	-1%	67,641	4,455
1/28/2018	32.5	28.1	-4.5	-14%	72,875	72,224	-651	-1%	72,566	342
1/29/2018	44.5	44.0	-0.5	-1%	95,659	95,525	-134	0%	94,640	-885
1/30/2018	48.0	49.5	1.5	3%	102,212	110,823	8,611	8%	107,877	-2,946
1/31/2018	41.0	40.3	-0.7	-2%	94,744	93,817	-926	-1%	99,101	5,284

NUI's location at or near the downstream ends of the gas pipelines that serve it compounds the problem. As a consequence of NUI's location, service interruptions almost anywhere on any of the four upstream pipelines that serve NUI adversely affect it. All four operate under flow restrictions for much of every winter. The four are TGP, M&NP, PNGTS and AGT, the latter through the exchange agreement with Bay State. “Upstream” refers primarily to upstream of GSGT, which delivers to NUI; however, the Union Gas system, TransCanada PipeLines (TCPL) and Trans Quebec & Maritimes (TQM) are upstream of PNGTS, and deliveries to PNGTS can be affected by interruptions on those systems. TCPL and IGTS are upstream of some of the Company’s TGP capacity.

NUI’s service territory consists of several areas in Maine and New Hampshire - - areas minimally or not at all connected to each other. GSGT serves as the link among them, except for the area around Lewiston, which M&NP facilities serve directly. This configuration imposes some locational needs on which sources can go to which portions of the territory, but NUI manages balancing by considering the system as an integrated whole.

Balancing starts with annual resource acquisition, which results in asset-management agreements and commodity-supply contracts tailored to the Company’s load forecast. Monthly plans assign portions of the Company’s pipeline capacity to retail marketers and asset managers, then Energy Contracts develops detailed plans for the Company’s own load. Energy Contracts and Gas Control then manage supply resources for the Company-supplied load day-to-day. That process begins with an Imbalance file that shows daily and cumulative balances for the current month. If the Company is short at a point, it orders extra supplies for the next day.

Retail marketers have responsibility for their own load forecasts for Daily Metered customer pools; Northern estimates daily demand for marketers’ Non-Daily Metered customer pools. Northern communicates its estimates to the marketers daily. Retail marketers have responsibility to get enough supply to NUI’s city gates to meet their customers’ requirements. The marketers nominate into GTRAC, NUI’s system for matching marketer deliveries from GSGT to the Company’s system, to their customers’ consumption. NUI’s Delivery Service Terms and Conditions provide that any flow restrictions, such as upstream imbalance warnings or operational flow orders (OFOs), are passed along to the marketers. Any penalties caused by marketer imbalances are passed along to the offender.

The Company generally manages intra-day balancing, which might occur due to changes in the weather or supply problems from a particular source, with adjustments to storage withdrawals for the first half of the winter, then with off-system sales in the second half. The Company’s contracts for peaking supply and its on-system LNG facility are additional resources for addressing imbalances if necessary.

C. Conclusions

1. Metering and testing programs generally conform to prevailing industry practice.

In interviews and in response to our data requests, the Company emphasizes that its metering and measurement practices conform to the regulations of the three states in which it operates (Maine, Massachusetts and New Hampshire). We found its practices generally conforming to prevailing industry practice.

We understand that the metering and testing programs of all of the gas LDCs operating in Maine, and the relationship of those programs to industry practice, are being explored in Docket No. 2018-

00331. NUI is participating actively in this proceeding, and anticipates additional protocols to ensure meter accuracy.

2. The Company's metering strategies are effective in isolating usage by customers and the Company.

NUI's distribution system consists of multiple groups of customers that are not connected to each other, but are connected to GSGT. GSGT has a relatively large number (38) of delivery points into NUI's system, each of which is metered. That large number of metering points, most of which are serving defined groups of customers, provides a lot of disaggregated data on customer usage.

The Company is also careful to measure its own usage. Taken together, this large amount of measurement data relative to the number of users provides confidence that usage information is accurate.

3. NUI's systems, practices and processes for balancing are a strength.

NUI's location, system configuration and supply resources present significant challenges for balancing. NUI has made significant investments of time and talent to address these challenges. The Company's objective in making this investment has been to facilitate balancing by all, rather than collecting penalties.

D. Recommendations

Liberty has no recommendations in this area.

VI. Price Risk Management

A. Background

Price-risk management programs, including physical and financial hedging, can comprise an important element in effective gas-supply procurement and management. We evaluated this subject using the following criteria:

1. Focus and clarity of objectives
2. Correlation between hedging instruments selected and attainment of program objectives
3. Sufficiency of policies and procedures in reflecting knowledgeable assessment of program risks, and careful design of elements to control risks
4. Completeness and effectiveness of administration of controls
5. Frequency and scope of program results review and modifications made to improve results.

NUI operated a financial hedging program when Unitil acquired the Company in 2008. NUI refocused the program, and operated it subject to periodic review by the Commission until 2017. Early in that year, the Company petitioned the Commission to allow it to suspend the program for one year, allowing option contracts held at that time to expire, followed by determining the best course going forward. The Company also noted that it was replacing one of its gas storage contracts with a larger one that would result in an increase in the volume of gas with physically hedged pricing for the 2018-2019 Winter Period.

The next year, the Company requested that the Commission allow it to terminate the financial hedging program. The Commission approved the Company's request, stating "the current hedging program benefits do not appear to warrant the ongoing cost …." The Commission went on to say

> *The Commission would propose that Northern include in its integrated resource planning filing an in depth discussion of its price risk management objectives and a description of actions it has taken, or will take, to reduce customers' exposure to gas price volatility from year to year, including whether or not use of financial instruments may be warranted.*

In this chapter, we provide a brief history of the Company's financial-hedging program, and then review the Company's approach to inventory strategy as it relates to providing a physical hedge.

B. Findings

1. *The Initial Hedging Program*

At the time that Unitil acquired the Company, NUI was operating a hedging program that was initially approved in 2003. That program's portfolio approach employed both physical and financial hedging to fix the prices of 70 percent of its winter supply requirements and 40 percent of its needs for May and October. The financial portion of the program used futures contracts.

When Unitil assumed control of the program, it added more structure to the financial-hedging component. Forty percent of futures contracts purchased to hedge NUI's non-storage pipeline supplies were bought pursuant to a time-based strategy: equal amounts were purchased in each of the 12 months of the year prior to the year being hedged. Up to another 30 percent of non-storage supplies could be bought with "price-triggered" hedges: purchases structured to acquire an additional 10 percent of non-pipeline supplies when certain price targets were reached. Taken together, the time-based and price-triggered hedges could result in 70 percent of non-storage supplies being hedged.

a. 2010 Program Changes

The price-based part of the program produced repeated losses, due to generally falling NYMEX prices. In its order approving NUI's 2007-2008 Winter Period CGF rates, the Commission required NUI to file a detailed evaluation of the effectiveness of the hedging program since its inception. That proceeding began with testimony from witnesses for NiSource, which owned the Company before Unitil acquired it.

The evaluation was filed after Unitil acquired the Company. In its April 2009 Annual Report on Financial Hedging Activity for November 2008 through April 2009, NUI reported that the program had not provided as much price stability as originally expected. In August, NUI filed a proposed program redesign, with three primary changes:

1. The introduction of a price ceiling above which purchases of futures contracts would be deferred until prices fell below the ceiling
2. The complete elimination of the price-based component of the existing program
3. A process that provided for sales of futures contracts that appreciated above a specified percentage.

NUI updated its program redesign in February 2010. To the three changes listed above, it added

> *… adoption of a portfolio approach to hedging whereby Northern would combine its physically hedged supplies with its financial hedges to begin each peak season with approximately 70 percent of the supply requirements available under a fixed-price. The remaining supply (approximately 30%) would be purchased at market prices throughout the peak period*

The Company also proposed to modify the hedging plan schedule. Rather than buy hedges over the 12 months prior to the start of each six-month cost-of-gas period, the Company proposed to submit a hedging plan once a year, providing a 12-month purchasing schedule with an 18-month window to implement the plan. Each plan filing would outline a three-year schedule of projected hedging activity that would include a three-year projection of sendout requirements, the peak-season resources expected to provide fixed pricing (storage and fixed-price contracts), and the financial hedging volumes required to meet the fixed-price supply quantity target. Hedging activity would continue into the delivery season if necessary to: (a) make purchases postponed due to limits imposed by the price ceiling, and (b) sell appreciated contracts under the appreciation rule.

The Commission approved NUI's proposals.

b. 2013 Program Changes

Two years later, in the spring of 2012, the Commission noted the price stability and low prices in the markets for natural gas, and directed NUI to propose changes to the hedging program. The Company worked with a brokerage firm to develop a new approach to hedging, which involved protecting against price "spikes", rather than trying to reduce price volatility.

Protection against price spikes could be achieved by purchasing options, particularly "call" options, which give the holder the right to buy at a specified price, irrespective of what was happening to market prices. In this way, the Company could effectively "cap" the prices that it would pay for gas, while preserving the opportunity for lower prices if market prices went down. This approach also had the advantage of requiring much smaller cash outlays than buying futures contracts.

NUI's proposals retained the 70-percent target, which it had inherited from NiSource. That target would apply to winter-season commodity requirements, rather than all 12 months, and it would be attained using both physical and financial hedges. By that time, physical storage provided approximately 50 percent of winter-season requirements, leaving only 20 percent to be hedged financially. Northern picked a type of option that suited its use in the financial segment of the Company's hedging program. The financial hedges would be "out-of-the-money" call options, *i.e.*, options providing the right to purchase at a specified price (the "strike" price) that was above the current price.

NUI proposed to continue to submit annual hedging plans with its off-peak cost-of-gas (CGF) filings. The plans would include calculations to determine the number of call options to be purchased for the current hedging period and the two succeeding ones, which would provide a three-year projection of expected hedging activity.

The Commission approved the revised program.

c. 2016 Program Changes

In the hedging plan for the 2017/2018 period (submitted in February 2016), NUI proposed an increased hedging budget in order to set the strike prices for the call options closer to futures contract prices. The options purchased in previous hedging plans had been too far "out of the money", and thus had expired without any benefit to the Company's gas costs. The Company had analyzed recent experience and current market conditions, and recommended paying more for options in order that the strike prices might be set closer to levels suggested by current futures contracts.

The Commission approved the Company's proposal for one year, but required the Company to file an evaluation of actual results of this program compared with what would have happened if the budget had not been increased.

d. Program Suspension and Termination

The following year, NUI reported that the options contracts under the old budget had indeed expired worthless, but it appeared that the ones with strike prices closer to futures prices were also going to expire worthless, due to the general stability of prices. NUI recommended that the program be suspended for a year, and then decide how to proceed.

NUI also reported that it had replaced an expiring storage contract with a larger contract, thereby increasing the proportion of its supplies covered by a physical hedge (buying gas at summer prices to be consumed the following winter).

The Commission approved suspension of the program, but directed further discussions to consider whether changes to the program should be made. By the next year (2018), all parties were largely agreed that, in the current period of stable gas prices, the benefits of the financial hedging program were not worth its costs. The Commission approved NUI's proposal to terminate the financial hedging program, but ordered

> *The Commission would propose that Northern include in its integrated resource planning filing an in depth discussion of its price risk management objectives and a description of actions it has taken, or will take, to reduce customers' exposure to gas price volatility from year to year, including whether or not use of financial instruments may be warranted.*

2. *Alternative Methods of Price Risk Management*

The Company has been sensitive to the high level of price volatility in the Northeast gas markets, and interested parties' and the Commission's interest in protecting its customers from the effects of that volatility. The Company's preferred approach to addressing that volatility has been by way of its physical procurement strategies, however. In particular,

- The Company's most-recent replacement of an expiring storage contract increased the storage quantity by 15 percent
- The Company structures its delivered supply and LNG contracts to be priced with respect to a monthly index, rather than daily ones
- Longer term, it is adding pipeline capacity that will connect its service territory with supply points that are more liquid and have more stable – and lower – pricing.

On the latter point, pipeline-capacity additions include participation in the Portland Express Project, the Atlantic Bridge Project and Phase III of the Westbrook Xpress Project. If the first two successfully enter service, the Company's proposed addition of capacity through the Westbrook Xpress Phase III Project will reduce its purchases of delivered supply to only about one percent of its total annual supplies.

3. *Program Management*

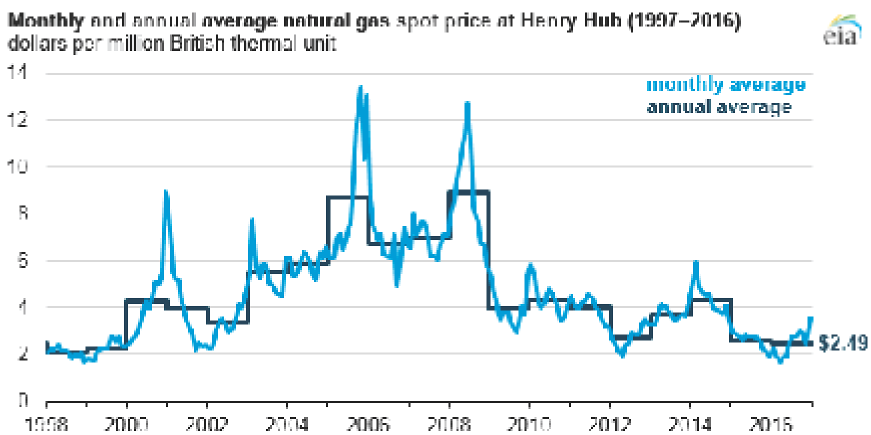
NUI had formal procedures governing operation of its financial hedging program, but the program's small size allowed it to be conducted and managed without a separate structure. The Company's Chief Financial Officer first, and then the Director of Energy Contracts, sent written instructions to execute trades to a broker who had worked with NiSource initially, and then continued working with NUI after Unitil acquired the Company. Both the Energy Contracts group and the Company's Treasury Department received daily and monthly statements of the Company's positions. Prior to converting to options contracts, Energy Contracts calculated margin-call exposure associated with futures contracts daily, and then submitted it to the Finance Department daily. Energy Contracts coordinated payment requests for margin account funding with the Director of Finance. A Senior Treasury Analyst contacted the broker for any requests to withdraw excess margin funds. The Company filed a Summary Transaction Report with the two PUCs each month.

C. Conclusions

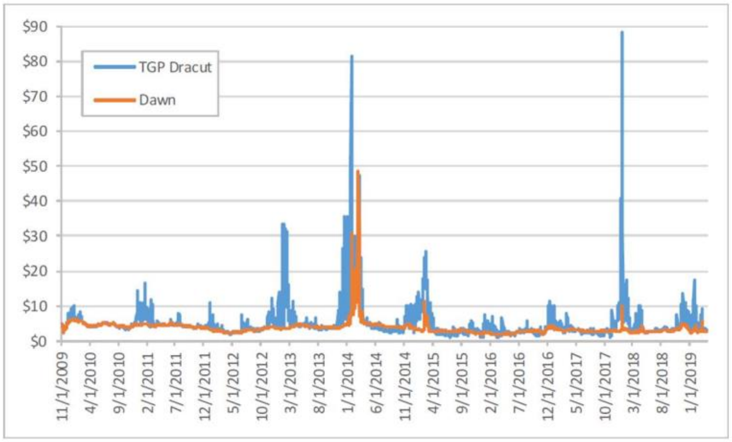
1. The objectives of NUI's hedging program have changed over the period that Unitil has owned the Company.

The stated objective of the hedging program has always been to protect NUI's customers from the consequences of natural gas price volatility. In late 2008 and early 2009, when Unitil took the program over from NiSource, the focus was volatility in the Henry Hub price. The hedging program that Unitil took over used gas futures contracts to reduce the consequences of that volatility. Gas futures contracts provide the right to buy a stated quantity at a stated price for a selected month at the Henry Hub location.

Unitil's principal change to the program, substituting call options on futures contracts for the contracts, was an effort to address the same objective – volatility in the Henry Hub price – at less cost, and with less requirement for credit support. While the level of Henry Hub prices has fluctuated somewhat since 2008, the general trend has been toward less volatility. The following chart, taken from a recent report by the U. S. Department of Energy's Energy Information Administration (EIA), illustrates this trend.



Over the same period, volatility in daily prices in the New England region has increased. The reasons for this increased volatility are well known -- increased demand for gas without corresponding increases in gas-supply capacity. The chart below, taken from NUI's recently-filed Integrated Resource Plan, illustrates this trend, using the daily spot price at TGP's Dracut location.



NUI has substituted increased physical hedging and particular contracting strategies for financial hedging, but the objective is clear: to "insulate customers from the volatility of *daily* index prices". (Emphasis added). As the Company has also stated.

> *As feasible Northern structures its Delivered Supply and LNG contracts to be indexed to monthly rather than daily prices, in order to insulate customers from daily index pricing, which can become extreme particularly on very cold days when delivered peaking supplies are needed.*

2. NUI's selection of hedging "instruments" reflects core strengths of its operations.

We noted earlier NUI's strengths in: (a) knowledge of the gas-supply infrastructure in its region, (b) knowledge of the operational risks of that infrastructure, (c) structuring its supply contracts and asset-management agreements to reduce risk, and (d) effective operation of its gas-supply resources. The Company's focus on storage and contracting strategies for reducing its customers' exposure to gas-price volatility reflects those strengths. The Company has no other particular use for expertise in financial derivatives, and chooses not to acquire it for the sole purpose of gas-price hedging.

3. Controls, policies and procedures have reflected the Company's approach to hedging.

During the period of financial hedging, the Company established controls, policies and procedures that reflected the limited scope of the hedging activity. The activity was conducted by the Director of Energy Contracts, in cooperation and coordination with Treasury and Finance. With the move to increased physical hedging and supply contracting, Energy Contracts' normal processes of analysis and approval are considered sufficient. As noted in the chapter on Organization, Staffing and Controls, those processes have been in place, if somewhat informal. Liberty has recommended that additional structure be added to those functions.

4. Company personnel have reviewed program results regularly, and have recommended changes as market trends and program results have developed.

NUI began examining the results of the financial-hedging program as soon as it took the program over from NiSource, and made several recommendations for program improvements before recommending that it be terminated. The Commission remarked favorably on NUI's program evaluations and recommendations for improvement multiple times over the period that the financial-hedging program operated.[2]

NUI's supply-contracting evaluations and decisions over the period have been driven primarily by considerations of supply security and reduced operational risk. The role of those decisions in protecting the Company's customers from price volatility has increasingly entered those deliberations, however, as the potential benefits to price stability have been realized. Price risk management has now been recognized as a feature of the Company's physical procurement strategies.[3]

D. Recommendations

Liberty has no recommendations in this area.

[2] See, *e.g.*, Order, dated April 28, 2017, in Docket No. 2017-00028, *NORTHERN UTILITIES, INC. d/b/a UNITIL, Proposed Cost of Gas Factor for May 2017 - October 2017*, at page 7, and Order, issued in Docket No. 2016-00025, *NORTHERN UTILITIES, INC. d/b/a UNITIL, Proposed Cost of Gas Factor for May 2016 – October 2016*, on April 29, 2016, at page 6.
[3] See, *e.g.*, *2019 Integrated Resource Plan*, at page VI-115.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Philip L. Bartlett, II
CHAIRMAN

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Randall D. Davis
COMMISSIONERS

Harry Lanphear
ADMINISTRATIVE DIRECTOR

March 9, 2021

Harry Lanphear
Administrative Director
Maine Public Utilities Commission
18 State House Station
Augusta, ME 04330

Re: Public Utilities Commission, Investigation of Inclusion of CIS Implementation Costs in Rates of Northern Utilities, Inc. d/b/a Unitil (35-A M.R.S. § 1303(2)), Docket No. 2021-00022

Dear Harry:

Please find enclosed The Liberty Consulting Group's report of its audit of the implementation of Northern Utilities, Inc. d/b/a Unitil's customer information system.

Sincerely,

Katie M. Gray
Deputy General Counsel

Final Report
Management Audit of Implementation of Northern Utilities, Inc. d/b/a Unitil's Customer Information System

Presented to:

State of Maine
Public Utilities Commission

Presented by:

The
Liberty Consulting Group

February 26, 2021

1451 Quentin Rd Suite 400, #343
Lebanon, Pennsylvania 17042

admin@libertyconsultinggroup.com

Table of Contents

I. Objectives and Scope

A. Work Scope and Objectives

The Maine Public Utilities Commission (Commission) retained The Liberty Consulting Group (Liberty) to conduct a management audit examining Unitil's implementation of a Customer Information System (CIS) and a Meter Data Management System (MDMS) for its operating utilities, which include Northern Utilities' natural gas operations in Maine. The audit focused on evaluating the:

- Reasonableness of service company (Unitil Service Corporation) decisions and process underlying and producing the implementation
- Selection of external vendors and consultants employed to plan, execute, and oversee implementation
- Effectiveness and efficiency of management of CIS/MDMS planning and implementation
- Assessment of project scope, schedule, and cost reasonableness.

B. Background to the Audit

Unitil began in early 2012 a process to replace its CIS and billing system (termed "SunGard" or "HTE") used for operations across its New England service territory at each of its utility operations:

- Northern Utilities: natural gas service to 67,862 customers in Maine and New Hampshire
- Unitil Energy: electricity service to 76,564 customers in New Hampshire
- Fitchburg Gas and Electric Light Company: provider of electric and natural gas service to customers in New Hampshire (29,565 electric, 16,049 natural gas).

As of 2012, Unitil had used HTE for more than 14 years. Its vendor announced at the time plans to end support for continued use of the system. Unitil began exploration of how to implement a new, system-wide CIS consisting of the following components:

- Base CIS capabilities
- A new MDMS
- A new customer portal
- 34 sub-systems to facilitate usage of the overall package of software and systems.

The first plans for implementation of what Unitil termed its "COSMOS" project called for initial work to design and describe full needs and requirements and to prepare a Request for Proposals which Unitil Service Corporation would issue to vendors - - to begin in March of 2012. The initial COSMOS schedule called for the new systems to begin operation ("Go-Live") in April 2015. Delays extended this date by 27 months - - to July 2017. Changes in outside resources and significant cost increases accompanied the delayed implementation - - the initially expected cost of $11.5 million eventually grew by more than three times, to $36.8 million by the July 2017 Go-Live date. The first management-approved budget of $12.7 million came in February 2013.

Commission Docket No. 2019-00092, which addressed a Northern Utilities rate filing, first reviewed recovery of Maine customers' 22 percent share of new system costs. Parties in that docket expressed concerns that information provided by Unitil did not sufficiently explain and justify the substantial cost increases associated with the implementation. The Commission Order in that docket initiated a management audit to "examine all aspects of Unitil's CIS implementation" and "provide a basis upon which the Commission may decide the prudence" of amounts expended on the new system in excess of its originally-proposed $12.7 million cost.

C. Audit Methods and Work Activities

CISs comprise a key component of modern utility operations, supporting a wide variety of customer service functions. These functions including billing, collections, customer call center operations, customer communications, and field operations, among others. Well-managed utilities recognize that close attention to the proper scope, approach, governance, and staffing (by vendors and employees) of CIS projects comprise central element in completing implementation of these systems successfully. MDMSs also play a critical role, importing, validating, scrubbing, and processing meter data for use in billing customers and management analysis.

CIS implementations present complex and difficult projects. Typical issues utilities have faced with them include ambitious or insufficiently detailed scope, optimistic timelines, underestimation of governance needs, incomplete or inconsistent project reporting, late identification of resource needs, ineffective vendor management, slow recognition and response to emerging problems and lags in making progress timely and efficiently, and incomplete or overlapping testing of capabilities and functionality before Go-Live.

We created an engagement work structure designed to provide a comprehensive foundation for forming conclusions in the three key areas set forth in the RFP:

1. The reasonableness of overall management of implementation and of decision-making methods, protocols, processes, timeliness, and effectiveness
2. Management's hiring and use of vendors and consultants
3. Management's decisions and their impacts on project scope, schedule, and costs.

Our work plans provided for an examination extending across the entire COSMOS implementation life cycle - - from Business Case development through post Go-Live operation. We examined the reasonableness of project scope, schedule, and cost. We organized our evaluation according to the following areas:

- *One: CIS Business Case*
- *Two: Selection of Software and Service*
- *Three: Governance and Project Management*
- *Four: Resource Management*
- *Five: Vendor Management*
- *Six: Scope/Change Order Management*
- *Seven: Schedule/Timeline Management*
- *Eight: Cost Management*
- *Nine: Risk Management*
- *Ten: Test Plan Management*
- *Eleven: Go-Live*
- *Twelve Post Go-Live Management*

We examined how activities in each area affected performance effectiveness, efficiency, and timeliness across all phases of CIS planning, development, and execution. We evaluated overall management of the project including the decision-making protocols and processes, to determine whether the project scope, schedule, and costs were reasonable.

This report presents the results of our examination, major work elements of which comprised:

- An initial project kick-off meeting supported by a detailed presentation by company and external personnel most familiar with the CIS implementation

- 19 interviews with management and vendors, conducted in successive rounds, as we gained knowledge from other field work underway
- 189 data requests, also conducted in successive rounds, as we learned more about the major components of the CIS implementation
- A review of critical project scoping and definition materials
- Review of project cost and schedule tracking materials as well as change orders used to justify changes in scope, schedule, and costs.

D. COSMOS Project Summary

In early 2012, Unitil began the process of developing a replacement for its legacy customer information and billing system, known as SunGard or HTE, for all of Unitil's operating utilities. The system's vendor, SunGard, declared in 2010 that HTE had reached its "end of life," meaning that SunGard would soon cease providing support for the system. This system had been in place since the mid-1990s; Unitil deemed it functionally obsolete.

Unitil brought in an individual consultant employed by a firm it described as familiar with utility-industry CIS implementations, to assist with identifying the scope of the project, and its key objectives. Management formed a working group, which reported to a Steering Committee. Supported by the outside consultant, this group solicited proposals from a range of firms offering to provide CIS development and implementation services. Unitil ultimately selected Systems & Software (S&S), a subsidiary of an entity commonly known as Harris (N. Harris Computer Corporation, governed by Toronto Exchange listed Constellation Software, Inc.). The Unitil CIS would employ a Systems & Software product known as enQuesta. Management believed that Systems & Software's New England base would make it "a nimble, responsive and dedicated partner." Unitil signed a contract with Systems & Software in May 2013. For the COSMOS project's companion, MDMS element, Unitil selected Harris division SmartWorks, employing a product known as MeterSense.

Management revised the original project cost estimate of $11.5 million to $12.7 million in February 2013 and lengthened the original schedule by six months. The 29-month project schedule then applicable included the following:

- 2 months of planning and a project kick-off
- 2 months of discovery
- 8-month design phase
- 5-month development phase
- 7 months of testing
- 3 months of preparation, data conversion, and transition to meet a Go-Live Date of March 30, 2015
- 2 months of post Go-Live support.

Major schedule slippage began in the project's first stages. With progress lagging, management engaged Grant Thornton, self-billed as an "independent audit, tax and advisory firm," in July 2014 to assist with certain testing, data conversion, and internal control design issues. By October 2014, the COSMOS project was 8 months behind schedule (some 20 months into the work). With project schedule continuing to lag, in January 2015 Unitil extended the planned Go-Live Date, but by only 6 months - - to October 2015.

In April 2015, just six months before the expected Go-Live Date, Grant Thornton offered what Unitil termed a "mid-cycle" project review, assessing project status and risks. Grant Thornton recommendations coming before the Unitil Board of Directors in July 2015 stated that "Unitil must manage the work plan actively and aggressively every day," requiring it to:

- Take control of the work plan
- Update, expand and validate the work and test plans
- Strengthen project management and streamline reporting structure.

During the same presentation, Unitil project leadership told the Board that it had taken ownership of the plan, was reorganizing and adding resources, and was obtaining commitment from the software vendor to add resources and improve quality control. Shortly thereafter, Unitil asked Grant Thornton to undertake project functions originally within the Systems & Software Statement of Work. Shortly thereafter, in October 2015 (the then-scheduled Go-Live date) actual expenditures of $13.6 million already surpassed the project budget of $12.7 million. Management responded by extending the schedule again, pushing the Go-Live Date out by 16 months - - to April 30, 2017. Actual Go-Live did not happen until July 5, 2017.

In summary, initially planned as a 29-month, $11.5 million implementation, including post-implementation activities, the COSMOS project stretched to 58 months in duration and $36.8 million in costs. The next table compares planned and actual project activity durations.

Comparison of Planned versus Actual Schedule Duration

Project Activity	**Duration** (months)	
	Original	**Actual**
Planning & Kick-Off	2	2
Discovery	2	2
Business Process Analysis & Design	8	16
Development	5	10
Testing	7	21
Pre-Go-Live Preparation	1	1
Go-Live	2	3
Post Implementation Activities	2	3
Total	**29**	**58**

II. Conclusions

A. Overall Summary

The COSMOS project exceeded schedule and budget by large margins for reasons substantially affected by Unitil's lack of experience in implementing systems of this type, a weak vendor selection process, undue optimism in the selected vendor's ability to complete implementation for the very low levels of work planned, delays in vendor performance, and material gaps in providing for project governance and management. It should have completed implementation sooner and for substantially lower costs, through avoidance of delays, avoidance of work duplication by vendors, and inefficiencies involved with a mid-stream vendor change.

Management did, however, notably succeed in avoiding the cutover and early operations problems that have plagued a number of other CIS implementations in the industry. Added efforts to ensure a smooth cutover and effective initial operation took time and effort, but provided for effective, albeit delayed implementation. The introduction of Unitil's enQuesta CIS and SmartWorks MDMS produced minimal impact to the customer experience or to customer service operational performance. We credit those results to comprehensive and effective training, a well-planned transition, and adequate post go-live support.

Project reporting comprised an area of performance that we found particularly lacking and incomplete. The resulting gaps make it difficult to track costs by cause and to measure the amount by which avoidable project costs resulted from decisions or performance not in accord with good utility practice. Nevertheless, it is possible to assess the costs resulting from ineffective decisions and management possible at a global level. The most fundamental driver of cost increases came from the decision to select Systems & Software on a fixed-price basis, for a cost of $4.4 million, which eventually became $7.1 million.

This decision did not recognize the implications of the extremely low number of hours underlying the Systems & Software bid. With consultation from an outside individual lacking significant experience in CIS implementation, Unitil failed to recognize that Systems & Software could not conceivably perform the full scope of development work and provide for effective testing and project management for a small fraction of the hours (and thus the costs) proposed by leading firms. However, at project completion, the total dollars paid to Systems & Software did end up amounting to about the same as the costs proposed by two first-tier CIS bidders (one offering the CIS platform and the other serving as implementer) in 2012.

We did find that Systems & Software experienced problems, charged for change orders ordinarily considered as part of base work, and failed to manage the project effectively. However, even more effective performance would not have produced total development, testing, and project management costs less than those charged by Systems & Software, were there no other implementation costs to consider. However, Unitil found itself required to retain another firm (Grant Thornton) mid-course to move the project adequately to completion. Unitil committed initially to another $3.3 million for this consultant - - an amount that increased dramatically to $8.1 million. Back at the time of Systems & Software's selection, sounder recognition than Unitil had of the work needed to implement the system would have led to costs in the range of those offered by the other two, top-tier combinations (either by retaining one of them or working with Systems & Software to create a more appropriate work scope and costs). In the second place, Unitil hired Grant Thornton without competition. To this day, the experience of the personnel Grant Thornton provided to the project remain unclear. Moreover, Grant Thornton provided little detail explaining the many hours its consultants charged, and project cost reporting does little to close that gap. Competition for the services provided by Grant Thornton would also likely have produced a more CIS-experienced team. Unitil should also have managed Grant Thornton's costs better.

Two central project cost assessment observations result from Unitil's vendor selection and utilization. First, it unexpectedly took Systems & Software and Grant Thornton together to perform the services needed to complete the COSMOS project. Second, they accomplished this result with:

- Material gaps in Systems & Software performance
- Inherent inefficiencies from "changing horses mid-stream" to strengthen project management and testing performance and planning
- Repetition and duplication of effort by Grant Thornton of work performed by Systems & Software
- Weak management of performance and charges by Grant Thornton, who came to the project without a strong CIS implementation background.

Unitil should not have paid twice for the overlap in scope between Systems & Software and Grant Thornton or the other inefficiencies involved. We compared the combined charges of Systems & Software and Grant Thornton ($15.2 million in total) against the amounts of the other two first-tier bidding combinations. The higher of their two bids was $8.1 million - - $7.1 million less than the $15.2 million.

Failing the ability to use project documentation to assess cost growth by root cause, we consider it reasonable to begin by targeting the excess of Systems & Software plus Grant Thornton costs over the higher bid of the two other, first-tier combinations as the base measure of costs that Unitil could have avoided had it either selected one of them, or begun COSMOS after working with Systems & Software to develop a suitable project scope, cost, and schedule baseline. The gap in Systems & Software's 2012-proposed resource commitments was so clear, Unitil should have undertaken such efforts. We consider the selection of one of those firms clearly more appropriate, but cannot conclude that selecting Systems & Software after successful efforts to adjust scope and price would have been demonstrably imprudent.

Moving from our base calculation, we considered the fact that scope changes could well have affected the costs of the others as well, but not so substantially, given the allowances made in their bids and in their extensive levels of experience in implementing energy utility CISs. A 25 percent contingency added to the $8.1 million offer we used as a baseline produces an amount of about $2.0 million. We consider this an appropriate amount to add for cost risk and for addressing Unitil's focus on ensuring that pre-Go-Live activities like testing would smooth the transition to the new CIS. Note that allowing 25 percent exceeds the 20 percent contingency factor we have seen used in other CIS implementation projects. That $2.0 million reduces our base calculation of excess costs to $5 million.

Our review of other vendor contracts did not show any of them having individual cost growth that caused concern in terms of overall cost growth. Internal employee costs comprised the remaining major cost source. However, Unitil did not commit a large internal project management team, thus mitigating the impact on strictly time-based internal employee activities. Moreover, their costs for training and testing certainly contributed strongly to the smooth transition to the new CIS and MDMS. We therefore did not ultimately question the internal costs that reflect the many hours spent by employees in these activities.

In summary, reducing the excess of combined Systems & Software plus Grant Thornton costs over 125 percent of the larger of the two bids by first-tier vendor combinations leaves $5 million as the expected value by which sound performance by Unitil would have reduced implementation costs.

We do believe that the better decision would have been not to choose Systems & Software, but we cannot find selecting this vendor imprudent per se. What did fail to meet good practice, however, was for an inexperienced owner, using a CIS-inexperienced consultant to begin and continue on the project without recognizing how unrealistic Systems & Software's resource commitments were, to continue on that course for so long with problems continuing, to manage the work so loosely, and then to make a sole-source selection of a firm (also without demonstrated experience) to assist late in the project and to do so with so little detail to justify the large cost increases for its services.

Unitil may not have proven successful had it worked with Systems & Software at the outset to set a more defined and appropriate scope. It may not even have wanted to had it believed that vendor's costs likely to match or exceed those of the first tier bids. Whatever the outcome, we believe the proper comparative measure is an actual 2012 bid from a first-tier bidder, adjusted to reflect uncertainty. Finally, using the Systems & Software charges alone (without the addition of costs from Grant Thornton) is equally invalid - - there was no prospect for securing the systems ultimately delivered for the bid costs of Systems & Software.

B. Specific Conclusions

1. Unitil structured and initiated the CIS project with an insufficiently developed understanding of expected work scope and resultingly unrealistic budget expectations.

Limited definition of project scope before Systems & Software contract signing eventually produced an essentially doubling of the design, development, and testing effort, substantially delaying the project schedule to accommodate the Grant Thornton transition, additional custom coding, configuration, testing, and resolution of testing issues and code defects required for successful completion prior to Go-Live Date. It was unrealistic to expect reasonably complete design, development, testing and project management for the effective numbers of hours underlying Systems & Software's fixed-fee offer. Bids by two other combinations that Unitil evaluated as finalists made proposals essentially tripling the number of hours required. Both, unlike Systems & Software, operated as major CIS implementers in the investor-owned electric and gas utility industry. Systems & Software, by contrast, provided CIS-related services primarily in the water industry at that time.

2. Unitil's use of a consultant without substantial CIS-definition, scoping, and vendor selection experience contributed to the selection of Systems & Software without first establishing an effective scope, schedule, and budget foundation.

Unitil clearly lacked a solid understanding of project scope and work requirements as it began a search for vendors to employ. It reached out to a firm to assist it in scoping and vendor selection, but did not end up with a firm possessing reasonably broad CIS implementation experience. More significantly, the consultant that the firm provided to Unitil to help guide identification of project requirements prior to CIS and MDMS vendor selection had not done a CIS vendor selection - - as he acknowledged to Unitil before his formal engagement.

Development of the work scope for the vendor RFP confirmed a lack of understanding of the full scope of CIS implementation requirements. As a result, Unitil lacked a detailed CIS requirements baseline for use in defining and assessing the reasonableness of project schedules and budgets eventually received from RFP responders. The RFP listed some 700 functional requirements - - less than a third of the typical 2,400 provided by established CIS selection vendors. Unitil thus began the project with inadequately defined requirements, which contributed both to ill-defined and under-scoped project requirements and an unsound basis for assessing bidder responses.

Moreover, we did not find the documentation evaluating, comparing, and making a recommendation from among the responding vendors either clear or convincing. Nor do the memories of those remaining at Unitil provide useful clarity. The documentation we did see appeared to be partial, and, to the extent it pointed in any direction, it showed the selected vendor at or below average in all non-cost categories except for functional requirements. Unitil could not provide clear documentation of the vendor cost evaluation. We did not find documentation or recollection of a clear, defensible vendor evaluation supporting Systems & Software selection over offerors with much more experience in the relevant utility market.

The information that remains available demonstrates a peculiar and what should have to Unitil proved a disconcerting Systems & Software combination of high hourly rates and a low number of total hours (see the following table). The net effect was an extraordinarily low comparative cost - - notably so in comparison with offerors having far more experience in working with investor-owned electric and gas utilities in CIS development and implementation.

Implementation Services Cost Comparison

Cost Item	Systems & Software	Oracle/Deloitte	SAP/Deloitte
Total cost	$3,910,080	$8,112,568	$7,293,474
Total hours	24,438	67,668	66,988
Blended Cost per hour	$160.00	$118.89	$108.88

The Systems & Software bid proved so large an outlier from those of the other qualified offerors that it should have raised questions and resulted in a deeper analysis before selecting Systems & Software. Specifically, detailed questioning and clear justification should have been required to validate the vendor's ability to accomplish this complicated project with only a third of the effort of the two other bidders. Unitil should have considered the mismatch, as Deloitte, a very highly experienced CIS project management and system implementer, bid two comparatively scoped first tier utility industry CIS solutions. We found no documentation addressing the evaluation of this significant variance in estimated effort. Moreover, it is clear that such inquiries could not have produced a soundly based comfort in the executability of the Systems & Software offering, but rather, at most, agreement on a much clearer, more detailed and comprehensive scope, and pricing at least generally in line with those of the top-tier offerors.

We do not argue in the abstract the ability of Systems & Software to perform capably, but its claimed ability to do so for 1/3 the hours of far more experienced offerors should either have led Unitil to select one of the other two finalists, or to work carefully with Systems & Software to give the firm a more realistic grasp of needs that the other two firms, probably well better then Unitil, had from their past experience.

In any event, Unitil engaged Systems & Software on a fixed-price basis for the sum of $4.4 million for the software and project management services. It eventually paid Systems & Software a total amount of $7.1 million - - interestingly an amount in the range of the bids of the other two, first-tier bidders in the business. A more curious owner and a more experienced CIS selection consultant would clearly have undertaken significantly more work to produce a sound working basis with Systems & Software - - thus avoiding many of the gaps, barriers, and problems that Unitil had to address throughout the first years of the project. A “tight” and more comprehensive Statement of Work (SOW) with Systems & Software would have minimized the need for change orders during the course of development. To show their magnitude, Unitil approved 139 Systems & Software change orders totaling more than $2.4 million.

3. Unitil began the project and continued under it for several years without clear, consistent, or independent project governance.

Unitil did not have a governance plan setting forth defined roles and responsibilities. Such a plan is essential for large and experienced owners - - it has all the more importance for ones like Unitil. The lack of development and execution of such a plan comprised a significant management failing, and one all the more surprising to have resulted following advice from an outside consultant during the project’s first, definitional stages. Failing a more clearly established governance role and body, the Unitil Board of Directors appears to have provided the top-level oversight (independent of project leadership) that existed. According to project documentation, however, the Board reviewed and discussed the project infrequently, suggesting inconsistent independent oversight, given the lack of a high-level oversight role from below that level. The project developed clear progress delays and cost issues in its early stages. The lack of rigorous, continual outside oversight encourages such problems to persist and to grow, as they in fact did.

We did not find clear definition of Steering Committee and Stakeholder Committee responsibilities, nor does the available documentation show attentive execution of consistent roles. Incomplete documentation of their activities corroborates the lack of clarity in roles and responsibilities and suggests a weak influence on the course of project events. Moreover, participants changed with exceptional frequency and it appears that the Steering Committee stopped meeting altogether in mid-2015, at which point the Stakeholder Committee commenced meetings. Even the Stakeholder Committee meetings stopped in the fall of 2016 - - well before project go-live in July 2017.

4. No formal approach to documentation or close management of project schedule appears to have occurred for an extended time.

From pre-start justification and definition to project end, tracking and documentation failed to conform to a reasonable standard of regularity, completeness, or action-orientation. The nature of data and narrative reported, combined with duplication in status reports, led to a lack of clear and concise project status documentation. As late as October 2016, Stakeholder Committee minutes documented, "Concerns around the status report providing the level of detail to understand what is happening during the project."

The Systems & Software project manager created the CIS plan using MS Project in June 2013, with the expectation that weekly updates would follow regularly. The "final" version of the Systems & Software MS Project plan was last updated in April 2015, according to documentation management provided. Status reports indicate the first plan Grant Thornton developed was ready to be baselined (with schedule mapped out using clearly defined due dates and a final deadline) in November 2015. Management could not provide the requested MS Project copy of this plan. Interviews with project team members and Grant Thornton consultants indicated that weekly project status spreadsheets guided the management of the project. However, the weekly project status spreadsheets that Unitil provided did not display an integrated project schedule. Their use of stand-alone spreadsheet tabs for each of the primary project schedule categories did not provide an effective alternative.

Others have used schedule tools like MS Project to highlight delays and project slippage. Relying instead on high-level reporting in Excel format here sacrificed key information and analysis for identifying, measuring, and addressing gaps in resources and impact to the schedule's critical-path activities. The lack of critical path analysis that applied here obscured understanding of true schedule status, the causes of delays, the locations and magnitudes of overloads on resources, and where effective recovery action could be brought to bear. Unitil did not insist on regular communication and use of a tool, such as MS Project, to provide early warnings about schedule slippage. Even highly experienced owners and implementers use such methods to manage effectively, even though they begin projects like the one at issue here with much greater experience. The resulting failure to set clear expectations and monitor delivery of them inevitably tends to aggravate schedule loss and expand cost growth unnecessarily on projects like COSMOS.

5. Retaining and outside consultant mid-course made sense, but the sole-source selection was not a strong one, nor did it correct project gaps with efficiency.

Grant Thornton, whose project management services Unitil did not initially anticipate needing at all, began providing project management services under a contract with a value of $3.3 million. Unitil eventually paid Grant Thornton $8.1 million, as the project schedule extended 29 months following the firm's mid-2015 review. As did the Systems & Software contract, the Grant Thornton arrangement also produced a large increase over initial amounts:

- Grant Thornton by $4.8 million - - from $3.3 million to $8.1 million.
- Systems & Software by $2.7 million - - from $4.4 million to $7.1 million.

The combined payments to the two firms ($15.2 million) represent $7.1 million more than the higher of the other two finalists for similar services. It is reasonable to conclude that Unitil could not have finished the project for less than the general magnitude of bids by two other very highly experienced combinations, who represented leaders in the most relevant market. It is equally clear however, that choosing one of them, even with a reasonably significant level of cost increases to address unknowns and changes would have produced far less than the $15.2 million in combined payments to Systems & Software and Grant Thornton. Even allowing a 25 percent adder for changes and unknowns to the higher of those two other bids leaves $5 million in unexplained Systems & Software plus Grant Thornton costs.

It is that difference that we attribute to the need for disruptive, mid-course correction and the use of less experienced outside firms (both Systems & Software and to Grant Thornton) for the type of work involved.

Before retaining Grant Thornton, Unitil did not seek proposals from multiple vendors for the services involved. The selection appears to have resulted primarily from a relationship created in providing Unitil with accounting and tax services to the Unitil financial organization, headed by the Senior Vice President – Chief Financial Officer. This sole source selection came despite a lack of substantial Grant Thornton direct experience in the CIS implementation context. Unitil had, but did not even return to review the project management services bids it received under the 2012 vendor selection RFP. The Controller and Chief Accounting Officer, who assumed more leadership for the project at the time Grant Thornton was brought in, indicated a lack of knowledge that such bids even existed. The Oracle/Deloitte bid (ranked second in in the CIS Selection process) included a separate project management services bid. Deloitte had substantial experience in CIS implementation and providing large-scale project management services across many industries. Deloitte's project management services bid was half that of Grant Thornton's bid, as seen in the table below, compared with other project management services bids from the 2012 CIS RFP selection process:

Project Management Offering Price Comparison

Company	Bid/SOW Cost
2015 Sole Sourcing	
Grant Thornton	$3.3 Million
2012 Vendor RFP	
Deloitte/Oracle	$1.6 Million
CIBER/SAP	$264,000
Deloitte/SAP	$818,400

Grant Thornton's initial compensation level exceeded other bids for project management services received during the CIS selection process many times over. That gap, very large at the outset, expanded greatly over the remainder of the project. By the end of the project, Grant Thornton billed $8.1 million, $4.8 million over its initial fee basis.

6. Training was comprehensive and effective.

Unitil prepared and delivered complete and comprehensive training to end users ahead of enQuesta go-live. The training plan was co-written by Unitil staff and Grant Thornton consultants. Training benefited from an extended schedule following the decision to delay go-live until July 5th. This 3-

month period was used to finish preparing training manuals, job aids, and system and user documentation.

7. Post Go-Live support was well-planned and delivered.

Unitil prepared and delivered complete and comprehensive training to end users ahead of enQuesta go-live. Unitil's post go-live planning and management of defect resolution and staff to manage these defects kept backlog within manageable levels. Unitil went live with few defects requiring later resolution. Defects discovered internally after go-live and in response to customer inquiries and complaints were managed through Unitil's established defect resolution process. Unitil was able to correct defects without noticeable impact on customer billing or customer satisfaction.

8. Customer Experience and performance was not impacted by the deployment.

Liberty's review of Unitil's customer service performance prior to, during, and following the enQuesta go-live shows a high level of service with no apparent service degradation. While call volumes increased slightly in 2017, regulatory complaints remained low, call handling service levels exceeded goal, most bills were issued on time, and very few bills were estimated.

III. Findings

A. Summary

We present below the key findings supporting our conclusions about COSMOS project decisions, organization structures, resource planning (internal and vendor), scheduling, design, development, testing, training, conversion, and go-live. These findings address how project management organizations, resources, and activities served to:

- Define project scope, cost, quality, and schedule objectives
- Manage resource application
- Ensure effective and efficient vendor performance
- Monitor and influence schedule progress
- Control scope and change orders
- Manage costs, risks, and quality.

We offer our findings in the following categories, which comprehensively address the key aspects of COSMOS planning, development, and implementation through and in the initial phases immediately following Go-Live:

- CIS Business Case
- CIS Selection
- Grant Thornton Selection
- Governance
- Project Management
- Resource Management
- Vendor Management
- Cost Management
- Scope Control
- Change Order Management
- Schedule Management
- Risk Management
- Test Management
- Go-Live Management
- Post-Go-Live Management

Well-managed CIS implementations center around a customer-service delivery vision that includes clearly defined objectives and a full understanding of how the CIS solution will support that vision. The initial phase includes the application of a well-structured and defined set of methods for selecting the vendor or vendors who will provide the software solution and the professional and project management services associated with doing so. The development vendor's work should operate under a scope defined sufficiently to allow for a reasonably fixed price for a set of well-defined services, milestones, and deliverables.

Working with the vendor, the owner must establish a firm and final solution design that includes clear and comprehensive descriptions of business processes, pre- and post-implementation roles and organizations, and identification of associated business changes. These factors provide a baseline that first supports development of the definition and design of the system's technical components and functionality. The foundation established thereafter supports careful, complete conversion of data from legacy to new systems, for designing and executing a testing program that will validate new system functionality, and for designing and delivering the training needed to permit effective use of the new system.

Implementing and testing solution design includes:

- Business process assessment and re-engineering
- Data conversion to allow data existing in legacy systems to undergo successful processing in the new system

- Hardware and software configurations
- Go-Live acceptance criteria
- Pre-Go-Live testing to ensure satisfaction of those criteria
- Training of system users, and
- Post go-live transition plans.

Late-stage preparation for Go-Live includes assessment of the system and its user organizations and resources, user acceptance testing, a "Go/No-Go" decision to go live, migration to production, and end user training. Post-Go-Live activities focus on monitoring and resolving known issues deferred until after Go-Live and promptly detecting and responding to any further issues identified post Go-Live, in order to transition into ongoing support mode.

Effective CIS implementation depends on quantitative objectives to track performance in meeting goals for schedule, cost and quality. Additionally, management should monitor performance and progress on achieving the goals and assess whether the project has the required resources necessary to achieve the goals.

B. Management's Business Case for New CIS

A sound justification process should precede all major projects and programs. For those like Unitil's COSMOS project, the prevailing utility industry approach employs the business case analysis to justify proceeding. This approach evaluates costs, benefits, and risks of options, and offers the rationale for the solution adopted, comparing it with potential alternatives. Obsolescence drove Unitil's decision, but did not obviate the need for:

- Identifying and evaluating those options that did remain
- Carefully choosing from among them
- Documenting project
    - *Approach*
    - *Direction*
    - *Structure*
    - *Scope*
    - *Objectives*
    - *Deliverables*
    - *Budget*
    - *Schedule*
    - *Execution Risks*
    - *Organization*
    - *Needed Skills*
    - *Contributors*
    - *Resource Numbers*
    - *Systems & Tools*

Whether called a business case or something else, and whether for an optional or compelled project, documentation of effective justification, scope, and requirements provides a primary means for securing executive support and funding and for setting the parameters that will guide continuous monitoring and evaluating execution success and threats, and influencing project activities to maximize quality, cost, and schedule success.

Specific purposes that a business case serves include:

- Validating through analysis of needs, potential solutions, and their comparative costs, benefits, and risks
- Ensuring team and corporate alignment on the business problem, its solution, and the needs and challenges for executing it
- Identifying project team structure, roles, and those of the resulting system's business owner
- Formalizing budget approval requirements and methods

- Providing a baseline for assessing potential changes to scope, capabilities, cost, and schedule changes allocation if later questioned
- Providing a source, for keeping project efforts aligned with expectations and intentions, while supporting a properly controlled means for changing them.

Unitil management did not create a business case or something of similar purpose and scope before embarking on the COSMOS project. Management cited functional obsolescence of the HTE and vendor issuance of an end-of-life notice as reasons. Therefore, management developed items normally part a formal business case (*e.g.*, cost estimates, timelines, and staffing) only after project commencement. We found that more evolutionary approach problematic, as compared with the benefits that a "from the start" approach offers. The lack of documentation and the inability of those still at Unitil to fill in the gaps even partially from memory, combined with the course of the project through its first years, indicate well less than the required early definition, structure, and attention.

Our inquiries disclosed no detailed information about the development of the initial project budget. Interviews disclosed that the then-vice president of IT developed it, but we could not determine what that budget included or the structure, methods, and details of its creation.

Well-expressed and comprehensive statements of project goals provide a tangible statement of what a project like COSMOS can and should achieve. These statements comprise an important component of a business case, setting project expectations and intentions. A June 2012 senior management meeting presentation these desired outcomes:

- Future proofing
  - M&A, regulatory
- Agility: Configuration over customization
- Enhance customer experience
- Optimize operations
  - Customer Self-Service
  - Mailing costs
  - Call times & call volumes
  - Debt collections
  - General process efficiencies.

The same 2012 presentation also offered these "Keys for Success:"

- *Collaboration*
- *Capture permanent improvement*
- *Creativity*
- *Understanding other department/function impacts*
- *Building for the future/crafting the future vision*
- *Cost*
- *Participation*
- *Team contributions*
- *Meeting deadline*
- *Flexibility/willingness to change*
- *Seamless to the customer*
- *Simplicity and consistency across sites*

A subsequent, July 2013 Project Charter presented project goals and objectives in the following words:

Unitil is seeking a replacement system, or more importantly a comprehensive solution that addresses the concerns of the current CIS environment and yields significant improvements by providing a Modern Rate and Billing engine efficiently supporting:

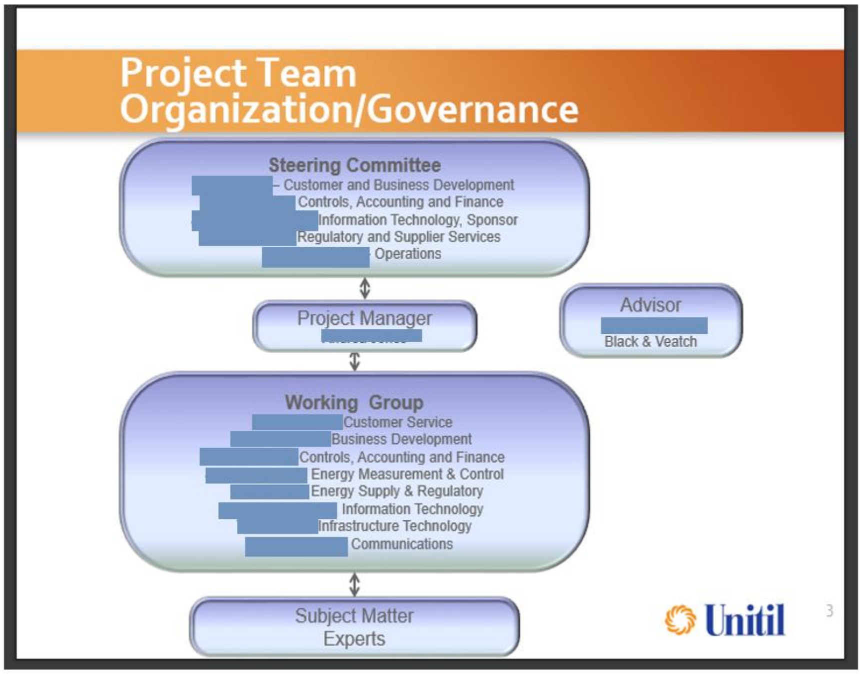
- *Deregulated markets*
- *Multi-customer aggregations (entire towns in some cases)*
- *Retail choice*
- *Purchase of Receivables legislation*
- *Customer specific contracts*
- *Various customer switching policies*
- *Net Metering*
- *Multiple jurisdictions*
    - Gas (MA, NH, ME)
    - Electric (MA, NH)
- *Decoupling*
- *Alternative Rate Structures (e.g. Time of Use)*
- *Improving controls and auditability of the entire meter to cash cycle*
- *Bringing full-range functionality commensurate with expected capabilities in contemporary systems to replace the limited functionality now in place for*
    - meter data management
    - meter asset management
    - integrated service order management initiation, tracking and closeout
- *Offering new capabilities in customer care, relationship management, business development, and advanced alternative rate offerings*
- *Providing new and requisite functionality to support the development and cultural engagement around utility best practices*
- *Providing streamlined data flows among all applications and modules*
- *Supporting customer interactions with a rich and full array of immediately available information and self-service functionality relevant to the customer to enhance their experience with Unitil*
- *Providing a modern, configurable user interface with the ability to perform self-directed ad-hoc reporting.*

The Project Charter statement of goals and objectives, developed after Implementation Kickoff, focused on functional requirements while the senior management presentation expressed desired outcomes for future proofing, agility, enhancing customer experience, and optimizing operations. Later in the implementation, project goals emphasized achieving accuracy (“balance to the penny”) and minimizing complaints to regulators (zero complaints).

C. CIS Selection

A Project Team brought together in 2011 evaluated CIS and MDMS software and services vendors. The following chart depicts this organization.

CIS Selection Project Team Organization Chart



The working group researched best practices for successful CIS projects. Some team members attended CSWeek, an annual international conference to advance utility customer service through the delivery of educational opportunities, forums for networking and sharing of innovative best practices. Guiding principles reportedly referenced included:

- Customizing versus configuration with zero modifications
- Employing third-party implementers and consultants who know CIS products
- Effecting strong governance and project management
- Regularly updating the project plan
- Strongly vetting requirements to produce a clear statement of work accompanied by a fixed-fee contract.

1. CIS Evaluation and Selection Consultant

The project team sought to secure outside expertise to assist in defining project requirements and in retaining a vendor to implement a CIS solution for Unitil. These vendor-retention services included Request for Proposal (RFP) development, bidder evaluation, and selection advice. Such CIS selection consultants provide a framework and often templates for the selection process, assist in development and completion of evaluation worksheets, conduct reference checking, and perform site visits, among other activities.

We consider the following a reasonably typical and useful expression of a qualifications statement for a CIS Selection Consultant (this one involving a gas utility), describing the required skills and experience as follows:

> *Proposers must have a proven track record with CIS selection projects within the gas utility marketplace. Specifically, Proposers must have (i) at least 10 years of experience in pre-RFP requirements gap analysis and requirements gathering, (ii) the assembly and issuance*

of RFPs, (iii) the evaluation of commercially available CIS solutions and system integrators, and (iv) the negotiation and approval of final contract(s) associated with a project with this scope in the utility industry.

Unitil's IT department was arranging in September 2011 with an information and technology firm predominantly serving government to provide assistance in COSMOS vendor selection. The firm did not appear to have direct CIS development experience but had experience with Smart Grid and smart meter work, including its integration with CISs (which is, for example, a function of an MDMS). The consultant offered by the outside firm moved to another firm (also one without extensive CIS development experience).

Unitil has stated that the firm to which this individual moved had familiarity with CIS implementations in the utility industry, making the consultant it used capable of assisting to determine project scope and key details, and to develop the vendor RFP and assist in evaluating responses to it and selecting the winner. We do not consider the firm to which he went, and from which he presumably derived support and assistance, at that time to have considerable CIS implementation or CIS vendor selection experience. Nor did the individual himself. He directly acknowledged not having performed a CIS vendor selection process. The consultant actually first delivered (in November 2011) a sample Request for Proposals and Project Plan not for the CIS, but for the MDMS, asserting relevance of MDMS functional requirements to CIS.

Unitil did not seek proposals from other vendors to provide the services at issue. Moreover, while there was a request for additional detail about the individual consultant's experience, no responsive documentation or verbal recollection about closure of that request appears to exist. We did not find the individual selected by Unitil either a specialist in CIS solution implementation or experienced in CIS vendor selection. Even more telling than the corporate and individual backgrounds came with the list of functional requirements eventually underlying the RFP that Unitil issued. It contained less than a third of the entries one might normally expect, perhaps adding color to the first offering of MDMS materials as relevant to the COSMOS CIS aspects.

The next table compares aspects of experience and content in providing CIS vendor-selection services.

Utility Industry CIS Evaluation and Selection Vendors

Criterion	Top 3 Vendors	Unitil's Consultant
Experience		
CIS software and services selection	More than 30 years	No prior CIS selection service
Comprehensive industry specific software and systems requirements	More than 30 years	No resume available
In depth CIS application experience	More than 30 years	No resume available
Clarity of Approach, Methods, Tools (to assist in CIS vendor selection)		
Templates	Templates for business case evaluation and vendor selection	Provided some templates; evaluation workbook not completed; did not include all evaluation factors

References	Structured, categorized reference checking, site visits, budgeting, and due diligence	Reference calls free form in nature
Site Visits	Structured, categorized results	Site visits free form in nature
Bid Scoping/Modification	Clear focus, analysis, documents	None documented
Bid Price Evaluation	Transparent, analytical, documented	No documentation of evaluation
Comprehensive list of functional requirements	Over 2,600 functional requirements	RFP and evaluation included approximately 700 functional requirements
Established databases for estimating CIS budget and timeline	Yes	No
Review of CIS SOW	Details include pricing by modification, interface, for example.	Limited pricing of modifications and interfaces. Functional requirements noted as "included in fixed price "or "needs further definition."
CIS Evaluation Agreement		
Price of Engagement	$248,500	$204,793
Consultant Deliverables	28	6

2. *Evaluation and Selection of the CIS Implementer*

Unitil worked with the selection consultant to prepare an RFP soliciting proposals for implementing a new CIS solution. Gartner, whose work Unitil referenced, has for many years ranked providers of a range of applications (including utility CISs). It uses what it terms a "magic quadrant" to assess ability to deliver versus completeness of vision, as the accompanying diagram depicts.

Gartner Magic Quadrant

The RFP went to fifteen CIS and two MDMS vendors in late May 2012. Unitil received nine written proposals, providing a sound mix of two of Gartner's CIS leaders (SAP and Oracle), Harris solutions, the parent of the vendor ultimately chosen (not rated by Gartner) and lesser-known solutions. Two firms made offerings using one of the lead platforms (Oracle) and three did so using another lead platform (SAP).

Unitil disqualified one vendor for failing to meet minimum requirements. Unitil, working with its selection consultant, narrowed the field to three candidates (Oracle/Deloitte, SAP/Deloitte, and Systems & Software). After preliminary evaluations, Unitil and its selection consultant then participated in site demonstrations, follow up meetings, conference calls, and reference checking with and involving the remaining vendor candidates.

Unitil management did not complete an evaluation sheet accounting for all the factors deemed relevant. Its consultant, however, evaluated the eight remaining proposals in tabular form, with Systems & Software scoring third, including consideration of comparative costs. Like Systems & Software, the top finisher was a non-top-tier firm (Cayenta) that offered comparatively very low costs. A top-tier bidder (SAP/Deloitte) also finished ahead of Systems & Software despite having very much higher costs.

Weighting of comparative costs generally results from a transparent arithmetic calculation of some sort. We could not derive that calculation here, nor could Unitil explain it. In any event, it is clear that the evaluation ranked Systems & Software even lower than third when considering all non-cost factors together. The next table shows where its offering ranked in those categories - - average or below in all other categories, except Functional Requirements. It is curious to find so high a comparative ranking in this last category, given its lack of investor-owned electric/gas utility experience compared with the first-tier offerings and the project-long challenges Systems & Software had in satisfying Unitil's functional requirements.

Comparative Systems & Software Offering Rankings

Criterion	Rank	vs. Best	vs. Average	vs. Median
Functional Requirements	2	99.2%	104.4%	102.7%
Technical Requirements	4	90.9%	100.0%	100.0%
Quality of Proposal	4	60.0%	82.8%	100.0%
Bidder Quals & Experience	6	67.6%	87.2%	83.6%
Project Management	4	67.4%	88.3%	100.0%
Roadmap	6	86.7%	95.9%	89.7%

Its unexceptional ratings in other areas contrasted with a very low offered cost as compared with the top-tier offerings. Systems & Software bid a peculiar combination of high hourly rates and a low number of total hours. The net effect was an extraordinarily low comparative cost - - providing clear indication of the lack of a common understanding of the expected services and deliverables. The next table summarizes these cost-affecting parameters. We created it using a blended rate per hour calculated by applying the hours and implementation service costs of the bidders shown.

Implementation Services Cost Comparison

	Systems & Software	Oracle/Deloitte	SAP/Deloitte
Total cost	$3,910,080	$8,112,568	$7,293,474
Total hours	24,438	67,668	66,988
Blended Cost per hour	$160.00	$118.89	$108.88

An effective selection process requires sound evaluation of the full scope of services and deliverables offered, with a plan and risk analysis for addressing services not included in particular offerings. Here, the Systems & Software bid proved so large an outlier as to raise substantial questions that required deeper analysis of the very low hours proposed by Systems & Software.

We found the top-tier offerings in line, with the second-place finalist (Oracle/Deloitte) proposing nearly three times the hours of Systems & Software. Unitil should have considered the mismatch, coming from first-tier, very highly experienced providers in the investor-owned utility business, material enough to warrant further investigation before proceeding with the Systems & Software offering as made.

A Steering Committee meeting in November 2012 considered the recommendation to select the offering of Systems & Software. The evaluation considered the SAP offering the least attractive, given perceived complexity of the product. With Oracle/Deloitte and Systems & Software thus remaining, the recommendation documentation did not provide a final evaluation sheet. Unitil's selection consultant presented the accompanying chart. It appears to recommend Systems & Software based on the variation in cost of the Systems & Software bid as compared to the Oracle bid. However, we could not determine its calculation basis, nor could anyone remaining at Unitil explain its formulation or intended contribution.

Cost Impact on Recommendation

10 yr COO	Oracle	S&S
Oracle > 4 Million	0	10
Oracle >2 Million	3	7
Oracle >1 Million	6	4
If cost were the same	8	2

9 26 Oct, 2012 Unitil

The next table shows Unitil's reported decision criteria forming the basis for the recommendation and summary comparisons between Oracle/Deloitte and Systems & Software.

Recommendation Decision Criteria

Criteria	Oracle	S&S
Rates	Best rate module for administering difficult and complex rates	Demonstrated can develop what is needed
Third Party	More mature/Large deregulation market experience	• Gas only 3rd party experience • Demonstrated can develop what is needed
CSR Interface	Not as intuitive	• CSR preference – user friendly • Best customer experience
Customer Self Service (Web & Mobile)	• Requires future version(s) • Lagging in customer facing functionality	• Advanced customer facing functions • CSS capability includes chat and SMS
Culture	• Difficult communication through sales process • Poor Listeners, want to "manage"	• Very responsive through sales process • Better Listeners, engaged • More comfortable cultural fit
Reporting	Better business analytics	Cognos – Good, but more complex
Roadmap	• Industry leader in rates • Enhance customer interaction functionality	• Social Media, Rich Customer Functionality • Enhanced scalability
Enhancements & Upgrades Model	• Unitil developed (internal resources) • Core changes on Oracle's upgrade schedule, not Unitil's	• Vendor (external resources) • Smaller more nimble - responding to Unitil changes

The recommendation noted the ability to use Systems & Software for ***customization***, rather than the industry trend of ***configuration*** without core code development. The customization approach relies on writing new code (*e.g.*, programs, class files, scripts) in the software to meet user-specific requirements. Configuration instead uses application-embedded tools to tailor capabilities to specific requirements without the need for writing code. Customization requires greater effort and more risk, given the need for programmers to work outside the application. Custom code has a greater tendency to lose functionality following application upgrades. Configuration has become favored in large part because it works from within the application. It therefore requires less effort and produces less risk by providing in-application tools to make changes in the manner expressly intended by application design.

The evaluation team recognized that Systems & Software served in the public sector and primarily at water utilities. The team learned that SEMCO, an investor-owned natural gas distribution utility serving 430,000 customers in Michigan and Alaska, had used the Systems & Software solution to implement a new CIS. A site visit to SEMCO produced the observations shown in the table below.

SEMCO Site Visit Notes	
Pros	Cons
• Very responsive to regulatory changes - - will respond to "showstopper" immediately • "80% spot on" identifying requirements in first round • Collections experienced most improvements - - ultimately reduced staff by 5 or 6 • On-screen icon alerts that customer registered account online • Payment by phone or web will generate e-mail confirmation number to customer • Representative with company old and new system took six months to get comfortable with system. • Billing edit criteria screens very flexible - - many options to pull exceptions for daily work • Edit exceptions went way down after a modification including using the degree day for consumption parameter calculations	• Can only process payments with future if made via the web • No CSR date/time stamp unless work order issued to create activity • Missing three core criteria areas (Rate engine, 3rd Party Billing and Net metering); will need development of modification; will require CIS team to drive development and testing; this approach creates risks • "Recreating the wheel" - - "Is this where we want to spend our time and resources?" • May end up with something that looks and functions like existing system, with some improvements. If so, better to work with H T E to improve the SunGard system? • "We don't know what we don't know." Design may neglect critical process or future requirements - - could be costly mistakes. • Can system keep pace with "ever increasing regulations?" Is S&S keeping up with the industry changes or relying on Unitil to drive the future regulatory requirements and system improvements?

The cons appear to us to outweigh the pros materially. Moreover, they raise fundamental questions about the application of the Systems & Software offering to the needs of Unitil as an electric and gas utility. The CIS Replacement Recommendation to Senior Management contained recommendations to mitigate risk. The next table identifies Systems & Software risks, mitigation, and provides our observations about management's application of them.

Systems & Software Risk Mitigation Strategy

Risk	Mitigation	Liberty Observations
Vendor development more extensive than estimated, affecting implementation schedule	Perform Technical Review – (Completed) and define financial penalties for missed delivery dates	Financial penalties were initially established but later waived.
Premature end-of-life for enQuesta product	Create financial obligations from vendor for an extended period	Contract included an escrow section
Regulatory changes requiring product enhancements	Negotiate cost ceiling or sharing or other protections	Protections not negotiated; S&S received $160 firm rates for change orders.
Overall project break-down despite assurances of success	Milestone-based, performance payment plan with recovery options for major failures to perform	Milestone payment plan included in SOW, but later changed to flat payment per month - - not tied to performance

3. *Statement of Work*

The process of estimating project costs by the leading CIS implementation providers has become increasingly accurate within the industry, therefore eliminating much of the need for change orders to produce the functionality sought by Unitil. A sound, comprehensive, detailed, and clear SOW forms a key to that elimination. After closing in on a preferred vendor, selection consultants typically guide the due diligence needed to examine the details of the vendor solution, confirm solution scope adequacy, and tailor the SOW accordingly. Typically, this multi-day detailed review of the vendor product takes place in workshops with the vendor, using the utility's detailed requirements, scripts and other information as guides.

This review often results in the identification of required product modifications, interfaces, conversion items, configuration items, business process work arounds, and related additions, deletion, alterations, and clarifications. The vendor then uses a hopefully detailed list of agreed upon changes to update its pricing. The company then reviews the updated pricing document, with pricing agreement using a clearly changed SOW.

We requested all Systems & Software cost sheets; Unitil provided only the bid costs, despite the fact that the final contract reflects an increase of approximately $63,000. Unitil's scope confirmation process did not materially change project scope from that requested in the RFP. Only two modifications and one system interface were added to the Systems & Software SOW.

The Systems & Software SOW defines modifications and interfaces as follows:

> *"Modification" shall be defined as custom code that is inserted into the standard system or code that is extended from the standard system in the form of interfaces, API's, etc. All modifications developed for Unitil will be rolled into the base system at the next major release. "Interface" is the passing of data between two separate and distinct systems; can be accomplished via real time or in batch mode.*

The City of Anaheim employed Systems & Software in a similar capacity in roughly the same time frame. Unitil's project team considered the City a comparable client for use in comparing lessons learned in addressing Systems & Software work changes and go-live circumstances and needs, using the City's experience in making recommendations to the Steering Committee. The next table compares the City's and Unitil's SOW.

Comparison of S&S SOW for Unitil vs. City of Anaheim

SOW Additional Costs	Unitil	City
Modification number	2	25
Modification cost	$61,400	$144, 642
Effective $/Modification	$30,700	$5,786
Interface number	1	17
Interface costs	$6,400	$126, 900
Effective $/Interface	$6,400	$7,465
Cost Standard reports & Cognos BI	$12,800	Included

The City established a fixed price SOW with Systems & Software for a broader range of modifications and interfaces than did Unitil. The City SOW's larger number of modifications and interfaces produced a more realistic cost for services and fewer change orders. In contrast, Unitil's SOW fees included minimal numbers of modifications and interfaces, which ultimately contributed significantly to the $2.4 million in change order costs. Unitil's and its CIS selection consultant's lack of experience resulted in a project SOW that was under-scoped and under-budgeted.

A clear example shows in the vendor evaluation documents. Numerous evaluation notes indicated Systems & Software could not accommodate the complexity required to accommodate utility-rates requirements. Despite that fact, we did not find documentation addressing how the Systems & Software undertaking conformed to the need to develop custom modifications that would support Unitil's customer rate and billing requirements, calculations, and support.

D. Grant Thornton Selection

In mid-2015, Unitil decided that the needs of the COSMOS project exceeded the capability of the resources it was bringing to bear. Up until that point, Systems & Software was managing the project working with a Unitil project manager. Unitil retained Grant Thornton to expand the project's capabilities, explained as follows at the August 2015 Steering Committee meetings:

> *Based on the information available to management at that time, the Company decided that additional support was necessary to match the complexity of the project and enable the current resources (internal and external to Unitil) to focus their efforts on specific areas of the project within their respective areas of expertise.*

Grant Thornton provided both project management and testing-related services. Utilities implementing large projects, such as a CIS, but without sufficient internal project management resources contract with an outside firm to provide such services. In this instance, as detailed in the Grant Thornton SOW, project management services were defined as assisting Unitil with certain activities including CIS and MDMS implementation, project management, program management support, work stream support, quality review, oversight and management of testing.

Management justified retaining Grant Thornton on a sole-source selection using the following criteria:

Grant Thornton Engagement Criteria

Criterion	Liberty Observations
Familiarity with Unitil resulting in a "low" learning curve and the ability to contribute without significant project delay	Grant Thornton had provided Unitil tax services, tax audits, and consulting services related to risk and internal control; no documentation evidenced Grant Thornton work with CIS or IT projects
Ability to provide the resources who had extensive CIS and/or systems implementation experience	No documentation supports CIS or other systems implementation experience No resumes were reviewed to determine experience of personnel providing project management and testing services
Management's knowledge that Grant Thornton's fees for professional services were reasonable as compared to other professional services firms	Unitil used bids for integrated audit services, not CIS work, from 2014

The Systems & Software contract (see *Section C.3* above) included project management services. Management stated a desire to permit Systems & Software to focus on the software implementation, instead of managing the project, even though it made no adjustment to Systems & Software compensation for reducing its project management undertaking.

Customary practice would call for more than management's sole-source retention by a senior Unitil executive, particularly of a firm without substantial experience in project management services in the CIS implementation context. We found no documentation justifying the decision or explaining the lack of a more competitive procurement process.

The 2012 RFP under which Unitil selected Systems & Software produced some discrete project management services quotations. The senior executive who selected Grant Thornton said he did not know of them. Oracle/Deloitte, who finished second in the CIS Selection process had presented a separate project management services bid. Deloitte has substantial CIS implementation experience and is experienced in providing large-scale project management services across many industries. The next table compares other project management services quotations under the 2012 RFP process.

Comparison of Management Services Cost Quotations

Entity	Bid/SOW Cost
Grant Thornton	$3.3 Million
Deloitte/Oracle	$1.6 Million
CIBER/SAP	$264,000
Deloitte/SAP	$818,400

By the end of the project, Grant Thornton billed $4.8 million over its initial compensation amount, producing a total of $8.1 million in payments from Unitil.

E. Governance

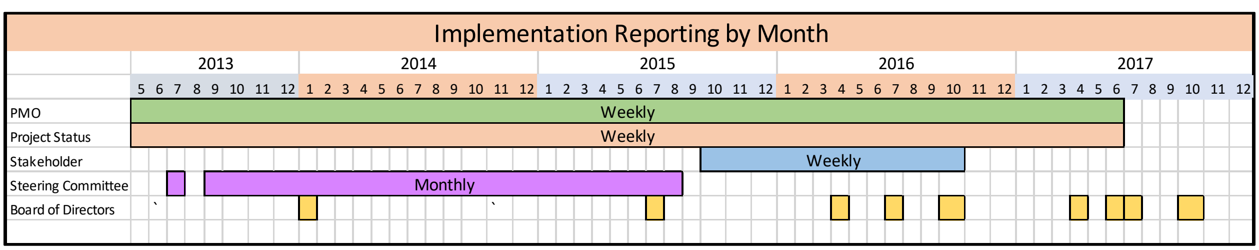
Project governance comprises a project's strategic management and governance functions and the decision-making layers responsible for providing project oversight and managing project direction, risks, budget, schedule and approach. A suitably layered project governance structure and resources provide a timely and comprehensive basis for securing senior level guidance and support. Governance involves organizations and measures that include oversight committees, steering committees, technical committees, project status reports, and required approvals. The oversight layers should consist of senior executives not directly responsible for or assigned to the project, thus bringing an arms-length, objective perspective to the project and seasoned executive input, advice and guidance to support the project sponsors. The decision-making layers should be responsible for providing day-to-day project oversight and managing project direction, risks, budget, schedule and approach.

Unitil did not have a governance plan with defined roles and responsibilities.

1. *Project Oversight*

Projects of this type generally employ an executive champion who serves as a sponsor and mentor for the project team. This executive role has particular value when, as often occurs, support from a particular department or manager has become problematic. The Vice President – Information Technology served as the initial Project Sponsor, as documented in the Communication Plan, Project Kick-Off, Project Charter, and status reports. The same individual was listed as having a project leadership role (Project Director). This position also showed as part of the Steering Committee, producing a less than an arm's-length separation from the project. Unitil's Controller later took this role, but we found no mention of the change or its reasons in status reports or presentations. Interviews confirmed that the Project Sponsor had asked the Controller to step into a leadership role on the project at the 2015 mid-project review.

The Board of Directors appears to have been the source of high-level oversight. According to project documentation, the Board reviewed and discussed the project infrequently, as seen in the chart below, suggesting intermittent, inconsistent independent oversight of the project.



It is also not evident that the Steering Committee and Stakeholder Committee roles had clear definition or consistent execution. We found documentation of their activities incomplete. Participants changed with exceptional frequency, and it appears that the Steering Committee stopped meeting in mid-2015, at which point the Stakeholder Committee commenced its meetings. However, the Stakeholder Committee stopped meeting in the fall of 2016, well before project Go-Live in July 2017.

2. *Project Quality Assurance*

Utilities implementing projects of this type, size, complexity, and risk typically create an independent quality assurance function to provide regularly unbiased evaluations of progress, problems, and risks. This outside function provides a direct, independent line of communication with senior leadership not beholden to project management. Such a quality assurance function does not displace the observations and insights of those within the project organization, but rather supplements them, to ensure that problems, gaps, delays, and barriers are identified and mitigated as quickly and effectively as possible.

The Stakeholder minutes indicated a non-project Business Owner was not satisfied that the level of project communication provided sufficient information about the project. The Controller indicated she should meet with the Grant Thornton lead for the workstream involved. Stakeholder oversight depends on information comprehensively, commonly, and transparently provided to all members on a common basis.

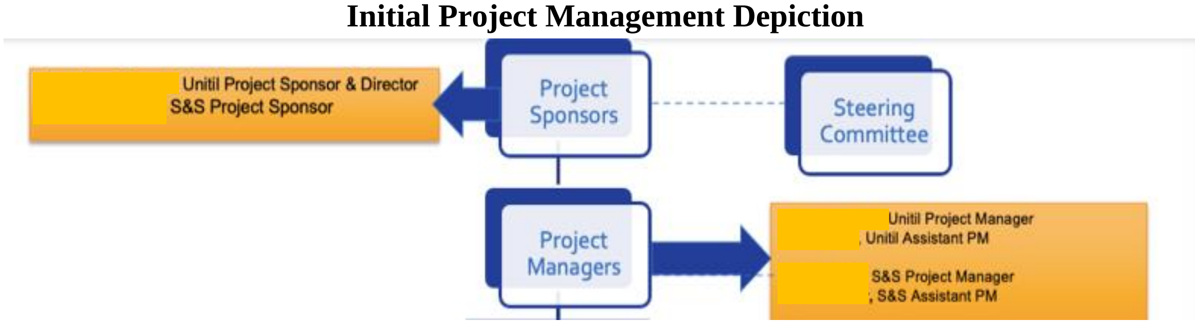
Grant Thornton's scope included the provision of quality management services. However, our review did not identify documentation of Grant Thornton quality assurance reviews. Management statements at interviews indicated that Grant Thornton did so, but we found the documentation presented limited to a few pages in Steering Committee reports at mid project review and at Go-Live. We did not find evidence that it carried out this role in a regular, comprehensive, structured, and appropriately documented manner. Moreover, with a PMO and testing role, Grant Thornton did not have a status that ensured a perspective independent of project management.

3. Project Management

The principle of "unity of command" comprises a best practice for project management. It means that each individual resource (employee, vendor, or contractor) should receive direction from one manager and remain answerable to that manager. A lack of unity that leads to multiple sources of assigning tasks and responsibilities inevitably tends to produce confusion and conflicts affecting cost, schedule, and quality. A project can operate under the direction of more than one "project manager." This approach requires clear roles and responsibilities that do not overlap, and it also requires a resource above them sufficiently engaged in project details to resolve potential confusion or conflict, and to ensure a vision that recognizes the need to harmonize their efforts.

The COSMOS project initially had two project managers, one from Systems & Software and one from Unitil. The next chart shows a simplification of the organization approach to project management presented at the Project Kickoff.

Initial Project Management Depiction



The Systems & Software SOW defines the following project management roles.

Description of Project Roles

Title	Role Description
Project Sponsor	• Secures spending authority and resources for the project. • Acts as a vocal and visible champion, legitimizes the project's goals and objectives. • Keeps abreast of major project activities. • Provides support for the Project Director and Project Manager.
Project Director *(note: this individual was also the Project Sponsor)*	• Provides a single point of accountability to deliver the project in accordance with the project commitments. • Has full project authority, within the limits of the established budget and company operating policies, to manage and direct assigned project resources and make decisions regarding the project direction. • Establishes the project resource assignments and ensures that the project is properly managed and staffed. • Chairs and participates in Steering Committee meetings and decisions. • As needed, participate in project planning (high level) and the development of the Project Plan. • Provides as needed support for the Project Manager. • As needed, assists with major issues, problems, and policy conflicts; removes obstacles. • Approves scope changes; signs off on major deliverables; and signs off on approvals to proceed to each succeeding project phase.
Unitil Project Manager	• Day-to-day management of the project and project teams. • Day-to-day management of the vendor(s). • Lead risk assessments and manage the identification and tracking processes. • Oversight/update of the project risk/issue/defect logs and make recommendations as needed. • Manage the project contracts to ensure vendor compliance. • Oversee, track, inspect, and manage the vendor project deliverables. • Development of a weekly report that outlines the status of the project. • Present reports to the Steering Committee on a bi-monthly basis. • Provide project improvement recommendations on a monthly basis. • From time to time support the Unitil with issues that may be escalated between the Vendor and the Unitil. Offer opinion regarding the issues root cause and the responsible party to correct the issue. • Day-to-day management of the detailed project schedule.
S&S Project Manager	• The Project Manager will be responsible for managing the implementation of enQuesta. The Project Manager will work closely with Unitil's Project Manager to ensure that the project is completed on time.

Other Systems & Software SOW content further defines project roles and responsibilities. Systems & Software had responsibility for managing the project on behalf of Unitil. Systems & Software had responsibility for maintaining the schedule using MS Project as the tool. Each of the two project managers had responsibility for weekly and monthly status reports, weekly team meetings, and the monthly Steering Committee presentations. Each project manager had various responsibilities (some overlapping), regarding risk, project schedule, deliverable acceptance, and direction of team members.

The Systems & Software SOW required both Unitil and Systems & Software to have a dedicated Project Manager. However, status reports indicate both Unitil and Systems & Software project managers also had substantial other responsibilities that prevented deep engagement in project details on a real-time basis.

The project referenced setting up a PMO in the Project Charter, responsible for managing and tracking the progress of the project as reported through weekly PMO status reports. However, the PMO structure itself was not defined as such in any of the organization charts provided as project documentation until mid-2015, when Grant Thornton was contracted to provide project management and other services for COSMOS.

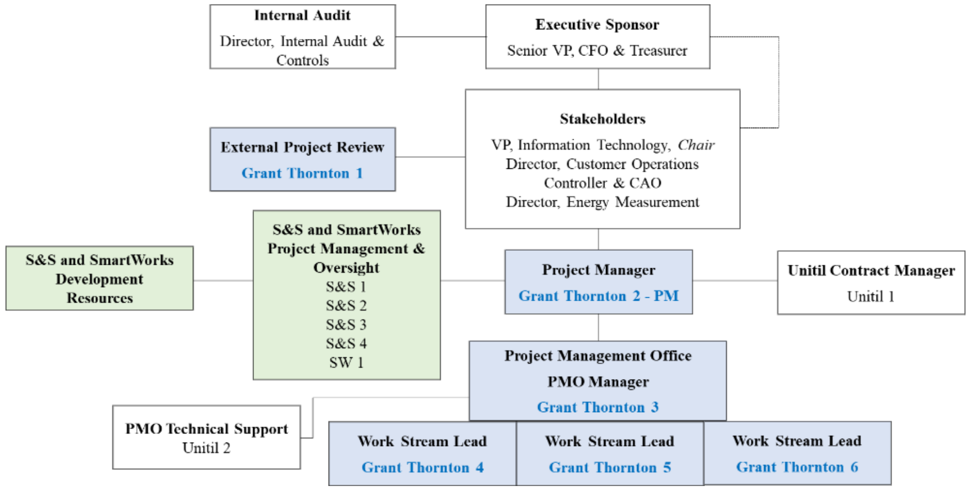
Use of a structured PMO in the utility industry elevates the importance and contribution of project management. It recognizes the value in creating a staff specializing in project management processes, techniques, and thinking. These offices standardize processes and tools and assemble forms of expertise focusing on the management of project activities. They typically bring a strengthened form of project management to a wide range of project types and sizes. Not all utilities formalize them to the same extent or use them across the same breadth of activities. Moreover, even the largest utilities contract out project management services on complex or “one-off” projects.

For COSMOS, per the Grant Thornton SOW, its services were defined as assisting Unitil with certain activities including CIS and MDMS implementation, project management, program management support, work stream support, quality review, oversight and management of testing.

The number of project managers expanded with the addition of Grant Thornton personnel to the project managers for Systems & Software and Unitil. That addition was not accompanied by a documented project description of the Grant Thornton project management role or about any changes in the project management roles of Systems & Software and Unitil. The Systems & Software SOW remained the most current documentation. However, an organization chart came following the Grant Thornton mid project review. This chart also identified a changed project sponsor, again without documentation to support that change. The chart shows a Grant Thornton individual designated “Project Manager” with persons designated as project managers explicitly for Systems & Software and Unitil reporting to him and a Project Management Office (PMO), headed by a four Grant Thornton individuals (a PMO Manager and three workstream managers reporting to him) reported to the Grant Thornton Project Manager.

This change following Grant Thornton’s 2015 arrival appears to have unified project management responsibility in a way that did not exist at project inception. There was no individual between the Grant Thornton Project Manager and the Stakeholders, as compared with a box showing joint (Systems & Software and Unitil) project managers and joint project sponsors above them.

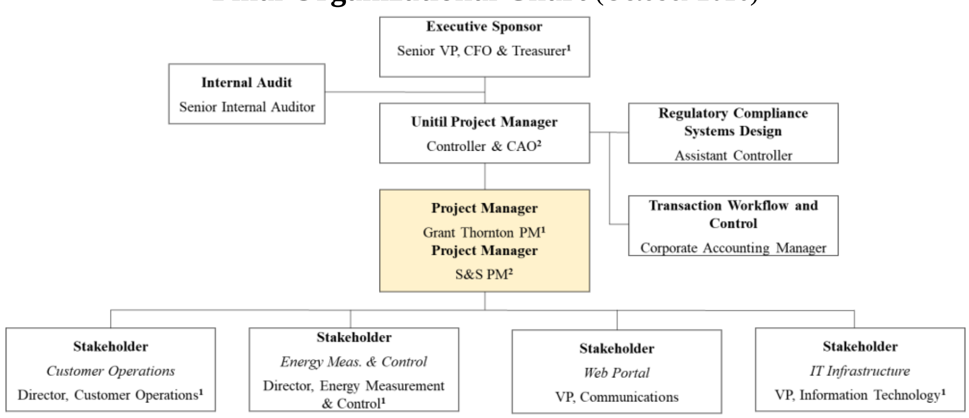
Organizational Chart After Mid-Project Review



External resources are shown in the two shaded boxes (green for Systems & Software, blue for Grant Thornton).

However, in October 2016, the final organization chart reinserts the VP Controller as a Unitil Project Manager to whom reported Grant Thornton and Systems & Software project managers shown in a single box. The placement of the Unitil project manager above the other two does nominally indicate unity of command but begs the question of removal from Grant Thornton in that role and moving the Systems & Software project manager to an apparently lateral level of authority rather than subservience to the Grant Thornton project manager. We could not confirm the reason for the change. Moreover, our review of project reporting and interviews support a conclusion that Unitil did not maintain consistently through the project a single source of project management responsibility and accountability at the day-to-day, dedicated level.

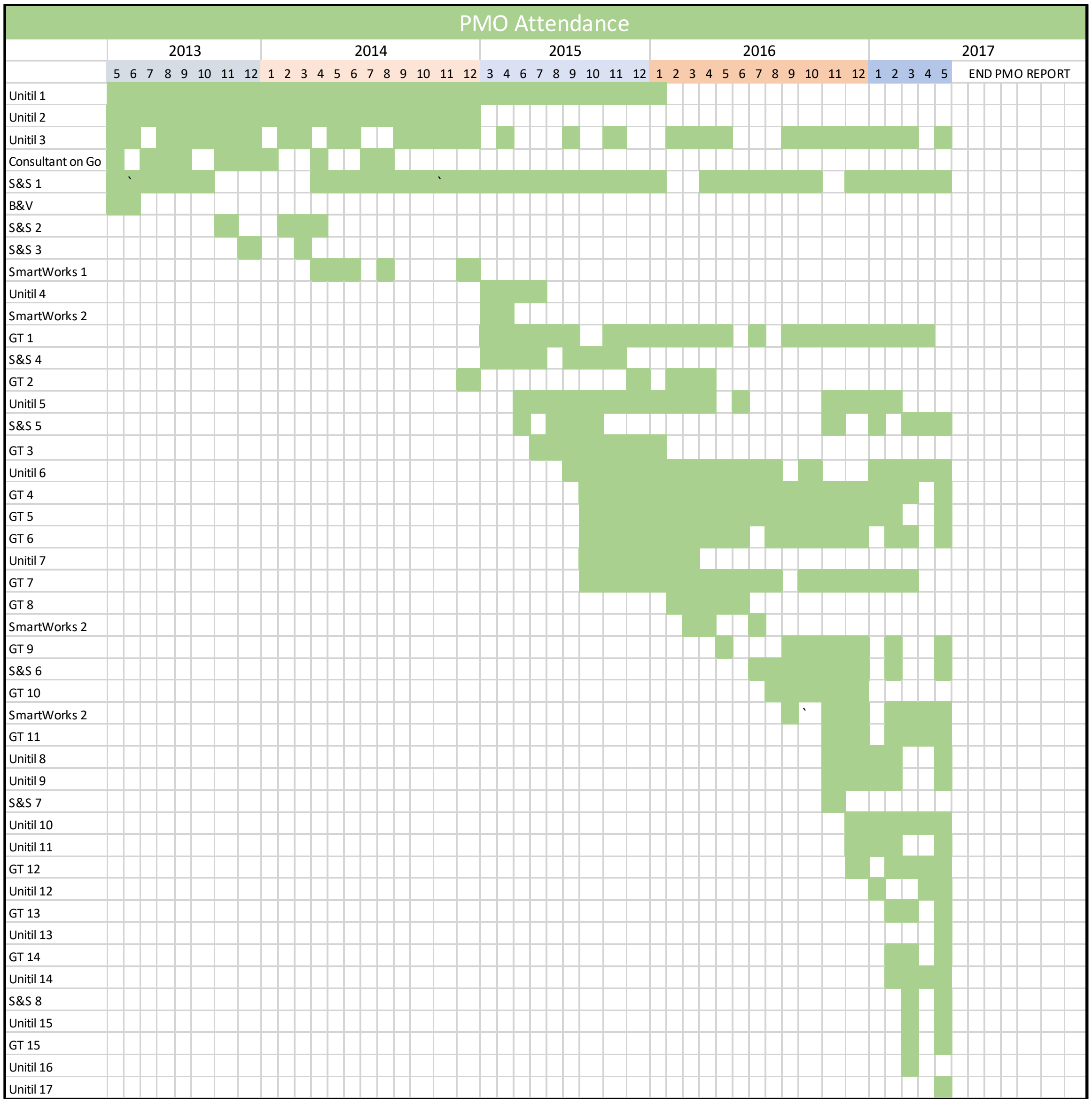
Final Organizational Chart (October 2016)



Note 1 designates personnel from the previous chart who maintained the same role, while note 2 designates personnel who are shown in the previous chart and had a change in role. External resources are shown in the yellow shaded box.

The PMO held weekly meetings and each week produced a PMO report. Using these reports, in months they were available, Liberty compiled the chart below to indicate turnover and lack of continuity at these meetings. Only two PMO members attended from beginning to end. The amount of knowledge transfer provided with each change was not documented. A large number of Grant Thornton personnel cycled in and out of the PMO during its tenure on the project.

PMO Meeting Summary



We did not find documentation addressing the performance of the Grant Thornton PMO. Unitil personnel we interviewed stated that Grant Thornton provided feedback orally. Following Go-Live, the COSMOS project organization completed formal hand-off to the Business Process Managers responsible for using the systems on October 6, 2017. Grant Thornton continued to bill the project through the end of 2017. We could not find documentation addressing the PMO roles and responsibilities from July 2017 to year-end 2017.

4. Status Reporting

High quality and consistent project reporting plays a central role in effectively managing large, complex projects - - in two particularly critical ways. First, it permits project management to track and evaluate progress and compare it to the current plan, expectations, and metrics. Significant projects tend to evolve over time as they face changing external circumstances and internally driven challenges. Current, high-quality, comprehensive, and issue-focused reporting allows project management to track progress using objective dimensions, assess changes, identify risks, and create and monitor the effectiveness of mitigation measures. In so doing, such reporting also provides a record of key decisions made, the course of cost, schedule, and quality progress, actions taken, and their level of success. Well-run utilities understand their need to demonstrate the prudence of large investments that customer rates will recover, along with the importance of such documentation in making decisions and actions transparent and understandable.

Second, good reporting informs top leadership and other key stakeholders of project progress and serves to keep them actively involved in the project. The information provided should contain the details necessary to allow stakeholders, given their role and level of management, to provide timely input and observations, make well-informed decisions about any needed changes, and in general have comfort that they know what they need to maintain adequate overall project oversight.

As we found with governance, the level, quality, and consistency of reporting varied over the course of the project, at times and in ways not conforming to expected practice. The Business Process Analysis phase defined and communicated a detailed project plan and charter. However, we did not find initial status reporting comprehensive, clear, concise, and (most importantly) actionable. It appears the same audience received multiple status reports. Not all reports were shared across all the parties represented in project management, resulting in a diminution of transparency. The Systems & Software SOW presented a variety of templates for status reporting, but we did not find them routinely used.

Grant Thornton's assumption of PMO responsibility brought significant improvement in reporting quality. However, we still did not observe the use of Key Performance Indicators (KPIs) which the industry typically uses to track progress. Moreover, we did not observe regular or consistent evaluations of progress against the new project plan delivered in December 2016. Robust reporting of risks or mitigation strategies also varied in the status reports, lacking continuity from one report to the next.

An October 2016 Stakeholder Meeting discussed concern about whether status reporting was providing the level of detail needed to understand project status, issues, and actions. Grant Thornton had already been onboard for a year or so in project management, giving the stakeholders time to identify such concerns and for Grant Thornton to address them. It would be natural to expect that Grant Thornton would have placed a high priority on learning about and responding early to the concerns of those exercising off-project oversight roles.

Overall, we found from pre-project business case components to the end of the project a lack of reasonably expected consistency, breadth and depth, clarity, and actionability of documented project tracking, analysis, and corrective action planning, execution, and effectiveness monitoring.

Our concern lies not so much in volume, but more in clarity and conciseness in timely identification and analysis of project status information and corrective action needs.

5. *Resource Management*

Managing staffing effectively on a project like COSMOS requires ensuring that the right people in the right numbers with the right skills and tools perform the right tasks at the right time, ably, and efficiently. Successful outcomes require effective staff management. Unitil displayed material gaps in efforts to staff the project appropriately.

Projects like COSMOS require significant numbers of experienced resources. One common way of assessing the quality of vendor and consultant experience is to question the extent to which key staff members that have worked on projects of similar size and complexity and then to ensure their actual engagement as outlined. Systems & Software offered resumes in their proposal but did not assign many of them to the Unitil project. We had difficulty in assessing the background and experience of the Grant Thornton resources as well. Seeking to validate management's statements that Grant Thornton team members had CIS experience, our data request for resumes produced this response:

> *Third-party professional services firms were expected to assign qualified individuals to the project. The experience of third-party personnel was discussed; however, Unitil does not have the resumes for third-party personnel (e.g., Systems and Software, Grant Thornton) who held roles as Project Managers and/or Project Leads.*

The best we can make of this response is that Grant Thornton's resources were experienced enough because they were expected to be. The lack of availability of those resumes now calls into question the degree to which Unitil ever examined closely the backgrounds they "expected" to get.

During the CIS implementation, Systems & Software was expected to staff the project with team members who had skills that aligned with their role on the project. With resume documentation not available, it is not known if some of the delays by Systems & Software were the result of a lack of skills for the role they were asked to do. Systems & Software also had a major leadership organizational change at a time when Unitil was pressing it to find a solution to continuous delays. Unitil reported that initially the leadership changes were positive. However, within a few months delays in deliverables returned.

Unitil's internal project managers and leads also did not have experience with a project of this type, size, or complexity. Taken alone, that fact might not have been of singular importance, but it emphasized the need for due diligence regarding the experience levels and skills of Systems & Software and Grant Thornton. Unitil reassigned its original project manager after Grant Thornton arrived. No documentation supports that change and interview responses seeking such support did not produce clear responses.

Typical CIS projects involve an auditing-type activity that reviews mock conversions and ensures that financial and non-financial controls and targets are met. Many CIS projects use a project accountant to provide financial reporting independent of the project team. Unitil instead staffed the project teams and governance largely with employees from its accounting and finance departments or by Grant Thornton personnel. The CIS process owner, VP External Affairs and

Customer Relations, engaged early in the project and not again until right before Go-Live. This executive's lack of regular engagement between these two points caused a knowledge and experience gap that Customer Service staff who work with CIS processes daily could have provided the project team. Post-project feedback and lessons learned documentation supports the existence of this gap.

Comments from some status reports indicate the existence of resource constraints.

> *There is a resourcing constraint across all Functional Areas as we will be creating integration test scripts as we continue to work through Functional Testing. In most cases, the same resources are also responsible for testing Letters/Notices, Reports and Interfaces as well as core enQuesta functionality and Regression testing. Based upon the development/delivery schedule for Reports & Interfaces, and the completion of Regression testing, the timing of integration test script creation overlaps with testing.*

However, we could not conclude that lingering unavailability of project resources drove extension of the schedule. In Stakeholder meeting minutes identifying resource constraints, we saw references to Grant Thornton's assignment of one of its consultants to fill the position. Thus, the impact of internal resource limitations came in the form of the incremental costs of using outside consulting resources.

F. Vendor Management

Effective contract management begins with creating a sound definition of the professional services to be acquired, including clearly defined deliverables, accountabilities and quality standards, and proceeds to incorporate effective processes for measuring and reporting performance to support efforts to ensure the cost, time, and quality effectiveness of those services.

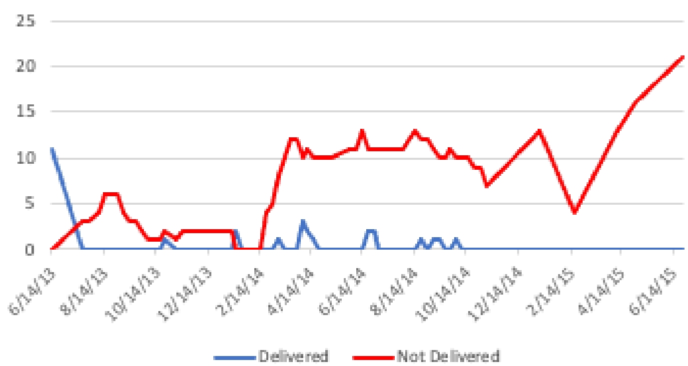
The initial Systems & Software SOW included a tight payment-by-deliverable fixed fee contract. That approach was nominally functional, but soon undercut because the Statement of Work failed to address sufficiently the full scope of requirements for the project. Consequently, major additional work requirements contributed to transforming the Systems & Software payment schedule. The change replaced payment after completion of key deliverables to monthly payments not tied to deliverables. A change order was created at the time of the extension and $595,000 was added to S&S fees, with the money remaining in the contract spread equally across the project's estimated remaining months.

Our inquiries did not produce regular reports or logs detailing deliverable acceptance issues or, as a result, status, quality, and consequences for the Systems & Software contract. Management stated that project status reports comprised the only source of tracking deliverable status. The Milestone (a group of deliverables) Acceptance forms were provided, and any detail was stored in SharePoint. See section *J. Risk Management* for information about SharePoint access.

Effective project management requires managing vendors and contractors to schedule, like other resources - - identifying problems, and developing, executing, and tracking mitigation plans to address any delays. Management has stated that Unitil actively monitored and tracked all aspects of the CIS implementation project. However, we did not find documentation indicating efforts to subject Systems & Software's performance as the project implementer to formal written analysis or evaluation by Unitil. To the extent that management did develop concerns with Systems & Software's performance, they are described minimally in Stakeholder status reporting (see Stakeholder Meeting Summary below). Clearly, those concerns did arise, as evidenced by the 2015 retention of Grant Thornton to assess the project and then to assume responsibility for project management.

PMO status reports show Systems & Software missing deliverable dates as early as September 2013. We did not find nominal documentation of missed deliverables in the PMO report accompanied by analysis of materiality, root causes, threats created, or mitigation plans or actions intended. The June 2015 report, the last status of its kind produced, listed 21 late Systems & Software deliverables. The next graph shows the fall in deliverables made and the increase in those late through June 2015.

Scheduled and Actual Deliverables (through June 2015)



Stakeholder meeting minutes do note Systems & Software's performance and contract issues in the months after the mid-2015 period reflected in the preceding graph. A September 2016 letter from Unitil's president to Systems & Software's president provides some specific documentation about these issues. It came well after the issues with Systems & Software were first identified and documented by the Stakeholder Meeting minutes.

Stakeholder Meeting Summary

Meeting	Notes
10-13-15	First Stakeholder meeting and S&S discussion. Discuss Harris contract strategy. S&S wanted move to time and materials pricing, Unitil VP - IT denies. Contacting attorney for negotiations
10-20-15	S&S not comfortable committing to schedule, given insufficient information/involvement with schedule conversations. Change orders submitted for past work to be discussed with larger contract change in November
12-9-15	Change orders requiring extra cost after approval discussed. VP -IT to follow up
12-16-15	Deliverables broken out to those completed and payable in 2015 ($350,000) and those separated for future payment after testing ($128,000). New proposal from S&S received previous Friday; call with Unitil counsel
1-27-16	Meeting with S&S to review new organizational structure
2-9-16	Leadership reorganization S&S
3-23-16	Expect update on progress diagnosing incidents and delivery dates for fixes released for retest by Unitil
4-13-16	Improvement in code and performance by S&S
8-3-16	Grant Thornton going to S&S to review development processes and identify improvements
9-14-16	S&S meeting produces commitment to additional resources; outstanding code not to be delivered until Jan. 2017, surprising Unitil; discussed lack of transparency and urgency. Stressed ensuring status report color coding accurately reflects progress against schedule
9-21-16	Unitil explores phased implementation approach. Concern that apparent progress after S&S meetings followed by performance regression
9-28-16	S&S meeting commits to all code delivered by Jan 2017; weekly schedule to be developed, discussed with S&S to address timing and delivery.

These notes confirm a continuing inability of Systems & Software to meet schedule dates. We observed that Systems & Software continues to miss deadlines through the present, as it works on the CIS enhancement projects that Unitil has continued to undertake since Go-Live.

We did not find evidence regarding acceptance of any of Grant Thornton's expected deliverables. We expected to find them as a measure of Unitil's diligence in managing the provision of services with such a large dollar value. The information to which management referred our inquiry about them consisted of more than 300 status reports and presentations, but did not identify any that specifically addressed Grant Thornton deliverables acceptance.

G. Scope/Change Management

The scope management process needed for a project like COSMOS should monitor and limit scope creep. It requires documenting, tracking, and approving/disapproving requested project changes. Levels of authority for authorizing changes typically depend on the degree of change involved.

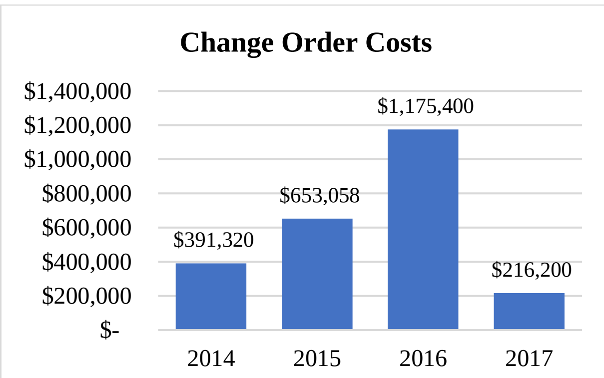
The Systems & Software SOW and the Project Charter detailed the means for processing and managing change orders. The change control process required that requests affecting project scope, schedule or cost must receive the approval of the Project Sponsor. A review of the approved change requests does not show evidence of approval by the Project Sponsor continuously through the project. Beginning in October 2016, the Assistant Controller began approving change orders, ultimately in violation of the expressed policy in the Project Charter.

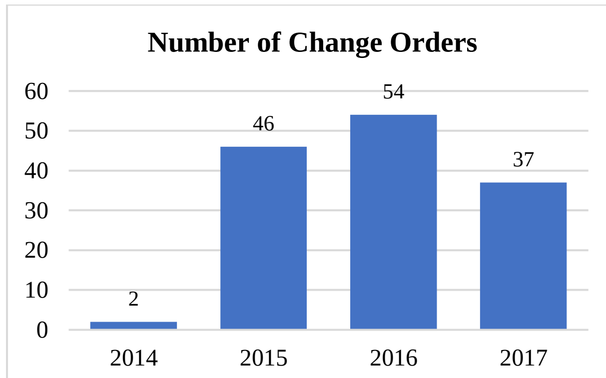
Stakeholder meetings addressed the change order process, change order approvals, issues of and change order approval matters (*e.g.*, Systems & Software work starting or completing before change order approval). The September 14, 2016 Stakeholder Meeting reviewed the change order process, noting "All CO's need to be complete and signed off before the work is started by Systems & Software."

Unitil approved 139 Systems & Software (CIS) and MeterSense (MDMS) change orders during the project totaling $2.4 million in additional fees. Systems & Software change order fees totaled more than half of the original $4.4 million fixed fee contract.

Change order volume and cost increased significantly from 2014 to 2016, as seen in the charts below. In 2017, Unitil approved $75,480 in 18 change orders leading up to go-live. Another 19 change orders totaling $140,720 were approved post go-live from July through November.

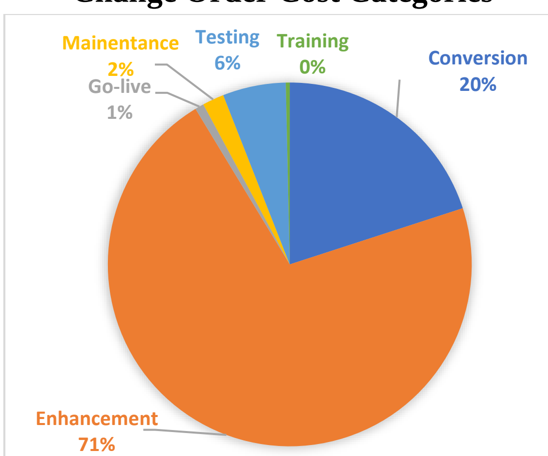
Change Order Details





The majority of change order costs represent enhancements to the software. However, 20 percent of change order costs were incurred to support additional conversion activities.

Change Order Cost Categories



Data conversion's primary objective seeks to convert required master and transactional data from legacy systems to the new solution, in this case from the legacy HTE system to new enQuesta.

Best practice in CIS implementations does not limit the number of data conversions, but instead calls for completing as many conversions as necessary and agreed to by both vendor and client.

A review of the Systems & Software SOW confirms that change orders were not needed for conversion. The detailed conversion deliverable, as listed in the Systems & Software's Information System Agreement Cost Sheet does not specify a set number of conversions, but rather lists conversion, priced at $450,000, as included in the fixed price implementation cost. The detailed deliverable description says:

> *Completion of Data Conversion Design Specifications/Detailed Data Mapping (Target System) and testing. Successful completion of all data conversion execution and cleanup and delivery of all data conversion deliverables.*

The SOW obligates Unitil to assist Systems & Software in completing a Data Conversion Plan to "establish the number of pre-install conversions and dates to ensure conversion success."

Systems & Software originally developed the Conversion Plan with review by Grant Thornton and Unitil. This plan covered four data conversions as in scope and two more for mock Go-Live and Go-Live. The Conversion Plan, like the other plans created after the SOW is signed, is not a contract. Unitil approved $487,200 in change orders for conversion-related activities that were marked as "included" in the SOW.

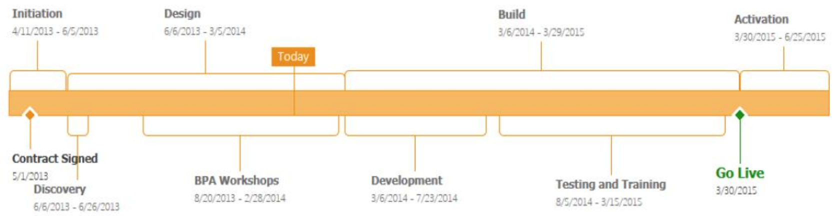
The Systems & Software SOW did not sufficiently define project scope. This lack of definition was a primary driver of Systems & Software's issuing 139 change orders totaling $2.4 million over the life of the project, including scope changes leading up to and following the Go-Live date. Project documentation does not demonstrate change order approval in the manner prescribed by the project charter. Moreover, examination of the Systems & Software SOW and its detailed deliverables for data conversion indicate Unitil should not have paid for conversion change orders, as the fixed-price contract included them.

H. Schedule/Time Management

A project like COSMOS should operate under a detailed project plan updated weekly. Good practice calls for the creation of a master, detailed schedule at initiation, supported by an appropriate schedule tool (for example, MS Project). Gantt or PERT charts should exist and undergo continual updating to support effective tracking, monitoring, and reporting of progress. Identification and assessment of critical path activities is important in analyzing downstream impacts of current sources of delay and in making adjustments to address slippage.

The Systems & Software project manager created the CIS plan using MS Project in June 2013. In October 2013, a high-level schedule timeline (see the following chart) came before the Steering Committee without detail about activities and completion. This same high-level timeline was presented to the Board in January 2014.

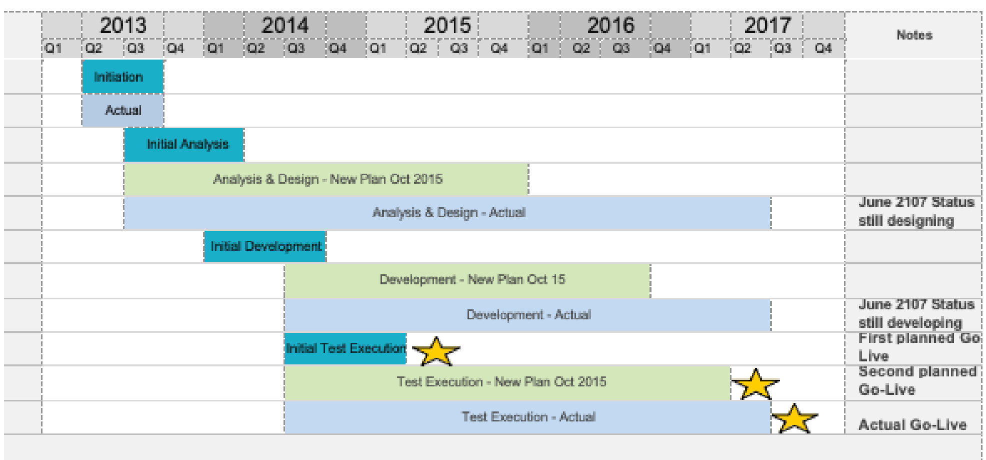
2013 Project Schedule



The expectation was that Systems & Software would update this plan weekly. The final version of the Systems & Software MS Project plan underwent its last update in April 2015. Status reports indicate the first plan developed by Grant Thornton was ready to be baselined in November 2015. We requested, but did not receive, the Grant Thornton integrated MS Project plan; management instead provided a PDF snapshot of the project at one point in time, and no documentation confirming that the MS Project plan was updated weekly, as expected. Interviews with project team members and Grant Thornton consultants indicated that project management used weekly project status spreadsheets to manage the project. However, the weekly project status spreadsheets did not contain an integrated project schedule - - instead presenting stand-alone spreadsheet tabs for each of the primary schedule categories.

Use of a tool like many others have employed (*e.g.*, MS Project) would have helped project management more timely and effectively address delays and project slippage. The initial Systems & Software timeline (teal), the Grant Thornton October 2015 plan (green), and actual schedule (light blue) and Go-Live dates (stars) for the four major tasks (initiation, analysis, development, test execution) are presented and contrasted in the following diagram.

Overall Project Timeline

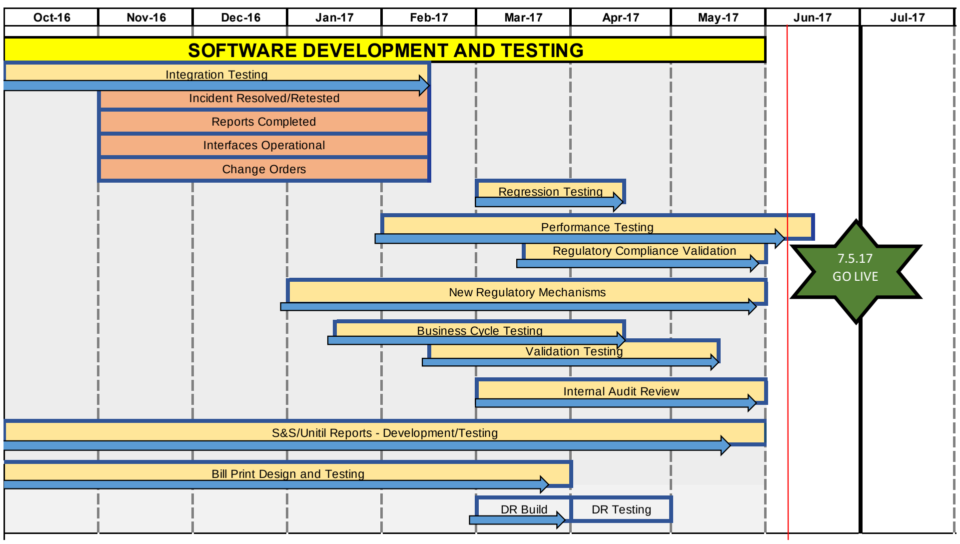


Reliance on high-level reporting in Excel format sacrificed key information and analysis useful in identifying gaps in resources and impacts to critical path. Status reports showed the timeline at a very high level and in Excel format. The lack of critical path analysis obscures understanding of true schedule status, what is driving delays and resource overload, and where action can be taken to recover. Unitil did not insist on the daily use of a tool, such as MS Project, that provides early warnings about schedule slippage.

Meeting minutes of a September 2016 Stakeholder meeting noted a desire to "…enforce more monitoring of the schedule and be able to raise concerns immediately when project is in trouble." Notes of that meeting also observed, very late in the project, that, "Currently the schedule is static, but a new schedule will be created once a decision is made about the implementation approach." We requested all project schedules but did not receive this one in response.

Minutes from the last, October 2016 Stakeholder meeting noted that progress would be shown on a Gantt chart that can be reviewed weekly. The next diagram shows the Gantt chart.

Project Timeline - - October 2016 to July 2017



This schedule shows software development and testing completion at the end of May 2017, well after code development was previously reported as complete. The June 6, 2017 status report showed five open interface development and testing issues with the last interface deployment scheduled for June 28, 2017. The June 2017 status report also documented regression testing as 95 percent complete, while the chart above shows completion in mid-April.

No integrated project plan existed; instead, management employed individual spreadsheets detailing task progress on a stand-alone basis. Therefore, presentation of the Gantt chart weekly offered only a static picture requiring manual updates that made it difficult to synchronize with project status reports and other project documentation. The examples cited in the previous paragraph show the mismatches that resulted. The use of an integrated project schedule, updated daily via a project management tool, would have substantially enhanced project management.

I. Cost Management

COSMOS experienced an extraordinary budget and cost history. At project inception, Unitil planned an $11.5 million project, with a scheduled Go-Live date in October 2015. Management extended that date into 2017 following the July 2015 project review. By that time, to-date expenditures of over $11 million had already consumed essentially all of the original $11.5 million expected cost. In fact, actual expenditures had already reached (given actual project status) an unrealistically high 90 percent of the modest 2013 increase (about 10 percent) to the approved budget. The next 2 ½ years would see expenditures of $26.8 million, more than twice the amounts spent in the first two years. At the end of 2017, project cost totaled over $36 million - - more than three times the initial budget.

The next table summarizes this project's budget and cost history.

Project Budget/Cost History

Category	Yearly Spends							Total	
	2012	2013	2014	2015	2016	2017	2018	$	%
Internal Labor	583,512	998,775	1,611,856	2,027,418	2,347,617	2,950,744	84,273	*10,604,195*	29%
Contractors	241,258	713,966	1,340,211	4,343,340	7,593,614	6,920,740	74,108	*21,227,237*	59%
Purchases	43,080	1,801,200	497,773	854,100	235,185	892,706	31,055	*4,355,099*	12%
Year Total	*867,850*	*3,513,941*	*3,449,840*	*7,224,858*	*10,176,416*	*10,764,190*	*189,436*	36,186,531	100%
To-Date Total	*867,850*	*4,381,791*	*7,831,631*	*15,056,489*	*25,232,905*	*35,997,095*	*36,186,531*	*36,186,531*	100%
	Budgets							Change	
Approved	11,500,000	12,670,000	12,670,000	18,300,000	22,000,000	29,800,000	29,800,000	159%	
Remaining	10,632,150	8,288,209	4,838,369	3,243,511	(3,232,905)	(6,197,095)	(6,386,531)		

Unitil has continued to authorize and average of about $1.4 million in yearly expenditures to enhance the enQuesta system following its actual Go-Live date of July 2017.

The data show a continuing struggle by management in securing a sound view of expected project costs. Total costs grew by a factor of three over five years and budgets could not even keep up with costs already incurred, yet alone those to go. The project began with an expected cost (in 2012) of $11.5 million and grew through its last, 2017 iteration to $29.8 million, an increase of 159 percent. As late as 2015, several years into the project, the budget stood at half of final costs. The preceding table shows a continuing inability to produce a realistic view of eventual costs. Less than 20 percent of the then-current budget remained in 2015. Even more significantly, 2016 produced a budget increase of 20 percent (to $22 million), but to-date expenditures by year end had already exceeded that increased budget by 15 percent. An even larger increase in 2017 (by 35 percent to $29.8 million) proved no more meaningful - - to-date costs for the year exceeded the budget by 21 percent. These numbers underscore what appears an abandonment of the use of budgets to manage costs, as opposed to management of costs against a realistic budget (even one incorporating a reasonable degree of "stretch").

Effective cost management requires that project management establish detailed budgets, track costs regularly, assess cost progress against clear deliverables, milestones, and expectations, assess the causes of variances, and respond to adverse cost trends and circumstances. It takes regular, comprehensive, and cause-based reporting to manage costs effectively. Regular reporting also needs to make costs, trends, causes, and concerns transparent to those outside the project as well - - typically an oversight committee for projects like this one.

These elements of effective cost control apply on all projects; they become all the more critical for a project facing such rapid and large increases and operating steadily and under transparently unrealistic budgets. The circumstances should have produced close and continuing scrutiny at the highest levels. We did not find reporting of project costs a formal part of Steering Committee or Board of Director reporting. Several years into the project, the October 2015 Stakeholder meeting minutes note that:

> *The Team Lead-Energy Management and Control brought up the idea of discussing the budget. He thought that would be one of the items discussed at this weekly meeting, as it plays that into the decision-making process. VP-Controller commented that the expenditures are discussed monthly and are available monthly for groups to see what they are spending. He will additionally email out relevant information to the group.*

The lack of clarity and focus on budget and cost reporting reoccurred the next month, with the November 2015 Stakeholder meeting having "[d]iscussed budget relative to the stakeholder's group role. Decision made to have Mark clarify role of members as it relates to budget."

Costs for outside contractors ($21.2 million) comprised about 60 percent of total project costs, roughly double the costs of internal labor. Payments to the two largest contractors accounted for close to three quarters of contractor costs:

- Grant Thornton: $8.1 million
- Systems & Software: $7.2 million.

The original Systems & Software contract amount was $4,445,160 plus expenses. Systems & Software was paid an additional $2,720,309 (change order fees) for a total of $7,165,469. Unitil management's comments about the Systems & Software team and costs are below.

> *During the project, S&S augmented its original project team with additional onsite and offsite staff. The Company was not billed for additional services provided by S&S, and as such does not have an estimate of the value of such services. The additional resources were provided by S&S to Unitil at no additional cost.*

The nature of a fixed fee contract like that with Systems & Software (not unusual for such work) makes the vendor responsible for any added resources needed to perform the agreed scope of work. Systems & Software was compensated for any out-of-scope items and an extension of the schedule. At go-live, Unitil's "build" of enQuesta became Systems & Software's newest release of enQuesta software. In effect, a smaller utility secured not an "off-the-shelf solution" that would have eased its engagement and management needs greatly, but rather a highly customized solution. Unitil essentially drove design of the vendor's product, investing in Systems & Software's development of a solution not only tailored to Unitil's needs, but producing a new release for Systems & Software. We explain later the commendable success experienced in supporting the customer experience at a comparatively high level upon and after Go-Live. Our fundamental concern about the project lies not in "gold plating," but rather in:

- The unrealistic expectation that a non-top-tier firm could bring off that result for the extraordinarily low costs it proposed
- The inefficiency suffered when Unitil found it necessary mid-course to bring in another outside firm to supply what Systems & Software was responsible for but not supplying as planned
- The use of an outside firm without substantial experience in managing even on target CIS projects, let alone ones experiencing large cost and schedule troubles

- The failure to hold that second outside firm, whose costs grew substantially, to effective cost management.

As initially projected, Grant Thornton's fees for its SOW were $3,250,000 plus expenses and plus a 3.5 percent administrative fee. We have not seen the use of administrative fee adders for work of this type. The agreement with Grant Thornton (from September 2015) states that, "*If it appears that the estimated fee will be exceeded, we will consult with you so that you will have a better understanding of our fees before we continue.*" An interview with the senior Unitil executive responsible for retaining and managing Grant Thornton's work stated that this consultation occurred at meeting discussions not reduced to any memorialization. Such an informal approach does not conform to good utility practice when increases prove material.

Grant Thornton received an additional $4,848,573, producing a total of $8,108,574 (153 percent above the base fee). Management has not produced any documentation to support the increased fees. Moreover, Unitil could not rely on the Grant Thornton invoices to explain or justify the fees charged with a helpful level of consistency. About 44 percent of the contractor's invoices as contained in the company files presented hours by staff, without any statement of activities performed, or project responsibilities. The next table shows what comprised the more "detailed" Grant Thornton invoices. Management says that it regularly received detail like that shown below, but its files do not contain it.

Sample of "Detailed" Grant Thornton Invoicing

January 2017 Project and Testing Management Fee Detail

	1/2	1/9	1/16	1/23	1/30	Hours	Rates	Fees
Chris Lilley		6	1	1		8	$ 285	$ 2,280.00
Bob Hersh	2	3				5	$ 285	$ 1,425.00
Boyd Graham	36	52	43	16	3	150	$ 230	$ 34,500.00
Tom Friedman	6	29	27	5		67	$ 230	$ 15,410.00
Paul Goldenberg	32	40	40	40	16	168	$ 205	$ 34,440.00
Larry Swanson	7	32	34	32	16	121	$ 205	$ 24,805.00
Nick Morteo	34	18	44	42	16	154	$ 205	$ 31,570.00
Brian Fellman	32	40	42	40	18	172	$ 205	$ 35,260.00
Maura MacDonald	36	42	46	46	19	189	$ 170	$ 32,130.00
Laura Kenney	40	16	41	43		140	$ 140	$ 19,600.00
April Gammal	36	48	40	44	16	184	$ 140	$ 25,760.00
Ash Rao					16	16	$ 140	$ 2,240.00
Nick Pate	34	40	40	40	18	172	$ 140	$ 24,080.00
Cory Whited	43	46	45	46	18	198	$ 115	$ 22,770.00
Total						1744		$ 306,270.00

The remaining 56 percent of Grant Thornton provided even less detail (see the example below).

Undetailed Grant Thornton Invoice Example

GrantThornton

Grant Thornton LLP
75 State St # 13
Boston, MA 02109-1827

T 617.723.7900
F 617.723.3640
www.GrantThornton.com

Req# 171832
6/5/17 DCF

This address should be used for correspondence only
For all payments, kindly use remittance instructions below

To: Unitil Service Corp.
Attn: Larry Brock
6 Liberty Lane West
Hampton, NH 03842-1704

Date: May 19, 2017

Bill Number: 953181537 **Client-Assignment Code:** 1289093-35252

Professional services rendered in connection with CIS implementation PMO.	$	283,235.00
Expenses, including an administrative expense charge of 3.5%		63,985.91
Total Amount of Bill:	**$**	**347,220.91**

Terms: As agreed upon
Federal ID No. 36-6055558

Finally, no invoices were provided that supported five other payments to Grant Thornton that totaled $32,173.

J. Risk Management

Effective project management requires careful and continuous risk identification, description, quantification, and planned mitigation, and documentation of the results of mitigation activities performed. The project charter documented a risk management process for identifying and documenting risks. We found the Initial Risk Register well developed, identifying risks and assigning them priorities, owners, mitigation, and dates. Management moved this initial risk register to an online SharePoint site. Grant Thornton in assuming PMO management, added a "risk/issue" section to the weekly Status Report, replacing the risk register. These risks could change from week to week; *i.e.*, we did not find consistency or tracking of risk opening, status, mitigation, or closing.

K. Test Plan and Management

CIS implementation projects rely heavily on pre-operation testing to ensure delivery of expected CIS solution capabilities and functionality. Defects and gaps will certainly result during development; extensive testing to identify them and subsequent efforts to resolve and retest them prove essential to successful CIS implementation.

1. Test Plan Strategy

Systems & Software developed the initial test plan. Management has stated that the original plan remained unchanged throughout project duration. We observed, however, that a "Grant Thornton Testing Strategy After the Project Reset" presented in October 2015 added new testing principles, which included:

- Adding Systems & Software test quality assurance staff to permit pre-testing of changes more effectively before deployment into the testing environment
- Strengthening and simplifying test-phase entrance and exit criteria, ensuring that functional testing would meet exit criteria before entering integration testing
- Finance and accounting testing and internal audit validation separate from the overall test plan
- Fully testing the new COSMOS environment (enQuesta, MeterSense and its integrated components) at the conclusion of Integration Testing
- Performing dry run "Go Live" testing after completion of Integration Testing with subsequent lockdown (code freezing and configuration control) of the final, approved production system.

Status reports and presentations we reviewed indicated a high level of software defects or errors. For example, the report of the July 13, 2016 Stakeholder meeting noted that, "*Testing progress slowed due to number of blocked test cases resulting from a high number of open incidents*."

In summary, the Systems & Software scope included responsibility for executing testing activities. With development and testing activities not proceeding well, Unitil turned to Grant Thornton and its testing strategy. Unitil received no price relief from Systems & Software for the insertion of Grant Thornton and its resulting charges to Unitil. We acknowledge value added by Grant Thornton, but it clearly came at the cost of repeating Systems & Software planning and testing work and with the inefficiency inherent in making major mid-course adjustments. Thus, Unitil bore avoidable added costs, again as a result of its unreasonable expectations about the ability of Systems & Software to perform all that Unitil expected for the price that Systems & Software had offered.

2. Test Methods

Unitil has credited its information-systems testing methods as a key attribute of its CIS implementation:

> *Unitil's standard practice when implementing new information systems is to establish a separate hardware/software "test" environment into which the base version of the vendor's (or internally developed) software is loaded in preparation for custom configuration and testing in accordance with Unitil's business process requirements. While the new software is under development in the test environment, Unitil begins extensive functional, integration, regression, performance and business cycle testing of the system.*

Creation of a separate testing environment comprises standard procedure, not a novel approach, for implementing software of the type relevant here. Moreover, testing while new software remains under development presents a high-risk approach. While reported as beneficial for the schedule, Systems & Software did not meet the testing objectives and testing exit criteria. The project schedule included a mandatory code freeze, but project management did not enforce it. We observed the release of multiple code changes right up to the system launch, without testing to assess the impact of the fixes on previous testing.

Management has also reported that:

> *The information system testing methodology used at Unitil is proprietary and owned by Unitil to achieve its unique audit, financial and regulatory compliance business objectives… It is written into Unitil's Information Technology Application Change Management policy.*

Unitil's 2016 Application Management and Change Control Policy expresses the following testing directives: (a) testing for completeness and accuracy, (b) documentation of test plans and results prior to deployment, and (c) Internal Audit review and validation of test results before the system goes into production. While sound, we do not find such elements unique to Unitil; typical CIS methods include these expectations.

A senior member of Unitil's management team and Project Lead in the COSMOS project said in an interview that, "Unitil wants things perfect, we balance to the penny, wanted it absolutely perfect." Financial controls typically comprise an element of CIS implementation, in balance with nonfinancial controls. The next table shows a matrix that we consider reasonably typical. It summarizes financial and non-financial controls and targets from the 2012 CSWeek Best CIS Implementation winner.

CIS Implementation Controls Sample

Control Type	Control	Criticality	Target	Actual
Non Financial	Person	Critical	99%	100.0
	Premise	Critical	99%	99.4
	Account	Critical	99%	100.0
	Item	Critical	99%	100.0
	Meter	Critical	99%	100.0
	Register	Critical	99%	100.0
	Service Point	Critical	99%	99.9
	Service Agreement	Critical	99%	99.9
	Landlord	Non-Critical	95%	100.0
	Customer Contacts	Non-Critical	95%	100.0
Financial	Meter Read	Critical	99%	100.0
	Register Read	Critical	99%	100.0
	Bill (Count & Amount)	Critical	99%	100.0
	Payment (Count & Amount)	Critical	99%	100.0
	Adjustment (Count & Amount)	Critical	99%	99.5
	Financial Transactions	Critical	99%	100.0
	Deposits	Critical	99%	100.0
	Balance	Critical	99%	100.0
	Collection Agency Referral	Non-Critical	95%	100.0

Unitil has also observed that its CIS implementation included 20 data conversions. This conversion work followed a Systems & Software change order that produced additional fees for the vendor. We find full conversions typically preformed regularly throughout a project, according to a schedule mutually agreed upon by the client and implementer. For more information about conversion costs see Section *G. Scope/Schedule Management*.

The Systems & Software test plan methods included Systems & Software testing of its code. However, no plan existed for Unitil to perform unit testing, a material part of the process for accepting deliverables from Systems & Software. The Systems & Software SOW said,

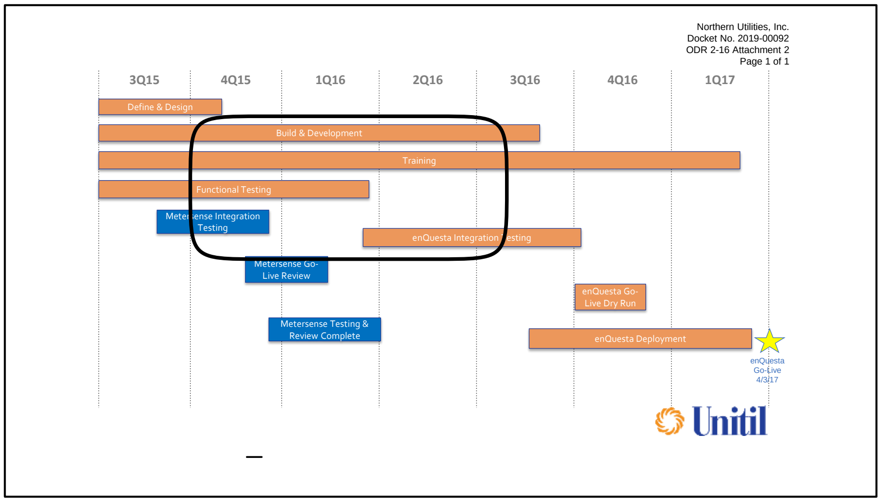
> *All components defined in the Functional Specifications are delivered to Unitil. Each modification must have been successfully tested by Unitil to ensure compliance with the Functional Specifications.*

We found no documentation about when Unitil unit-tested the code, which occurs typically at deliverable acceptance. The Deliverable Acceptance forms provided did not include detail supporting the unit-testing of the code.

3. *Test Phase Overlap*

Both the original Systems & Software and the later Grant Thornton test plans intended to do functional and integration testing before development completion. The next diagram shows the plan Grant Thornton first provided; it indicates planned overlap in testing phases.

Grant Thornton Initial Test Plan



The diagram shows considerable overlap of the various testing work streams involved, with identified defects undergoing remediation through code changes, and with subsequent test phases underway executed. This approach creates the risk of failing to examine interconnected features and functionality properly. Testing in separate test environments should be limited to features and functionality that are truly independent of each other.

Overlapping testing in different environments inevitably produces the identification of “bugs” introduced to the other environments, which can create additional correction work. Sound testing runs the unit testing, functional testing, integrated testing, and user acceptance testing one after another - - not in parallel. Otherwise, such bugs may not be appropriately tested if not tested in all other environments.

To avoid parallel testing, “Build & Development” completion and unit and functional testing should occur prior to integration testing. In the diagram above, Systems & Software continues code development until near the end of 3Q16 at which point Functional Testing has been completed and Integration testing is nearly complete. Our review of project status reports indicated instances of uncompleted unit tests that affected the scope of integrated testing. The status reports documented code that was not received and tested prior to the start of these integrated testing cycles. The reports show lack of adherence to the good practice of completing unit and functional testing prior to beginning integrated testing cycles.

Unitil considers the four and one-half year duration of COSMOS appropriate, in significant part because it "demanded perfection," tasking Grant Thornton to execute a more rigorous test plan and an enhanced PMO. We did not find in the RFP to which Systems & Software responded or in the SOW governing its work language indicating unique or unusually high client expectations compared to what we normally have seen. Management has stated that testing beyond the normal and its quest for perfection had material schedule extension and cost increase consequences. We conducted our examination of project documentation and our interviews with this asserted higher standard in mind. Here, we found testing in line with a typical CIS project with the exception of user acceptance testing. We did not find reason to believe that unusually high standards imposed by Unitil had material cost or schedule consequences.

We reviewed the Grant Thornton Principles of Testing (Section 11.a), which re-expressed testing expectations. We did not find provisions outside those typical of CIS implementation. Moreover, there was a failure to achieve some principles fully, for example:

- Code development and testing continued up until one month prior to Go-Live
- Functional testing exit criteria were not met
- Integration testing exit criteria were not met
- Readiness Testing, which included participation by the business owners, was not documented in status reports
- Situational testing approved by Change Request 67 was never included in test plans or in status reports.

Management reported completion of functional, integration, regression, and interfaces testing to the Board of Directors in April 2017. Changes to software code were reported to be "locked down" with no changes anticipated. Subsequent Status Reports in April through June tell a different story. The final PMO meeting on May 2, 2017 produced the statement that, "[Name excluded] *stressed the action plans are down to a matter of days. The mindset should change to closing out the work efforts. The next couple of weeks will determine if things will fall off go live and become work arounds.*" The final project status report of June 6, 2017 documented the existence of continuing development, testing, and integration tasks.

L. Go-Live Preparation & Project Readiness

Preparation of system users and the Customer Service organization prior to Go-Live comprises an essential element in effectively transitioning to a new CIS. End-user training and support comprise central elements of that preparation. Training should address technical (application) requirements and changes in business processes. Training materials, post Go-Live support details, and system usage documentation require regular updating and communication to all end-users before Go-Live. Following Go-Live, management should monitor support processes and action plans created to address any issues encountered. Appropriate support covers trouble-shooting, live assistance, defect tracking and resolution, and communication of workaround options. System work arounds pending permanent solution require documentation, communication to all users, and monitoring.

1. *Organization Change Management*

In March 2013, Unitil contracted with Consultants On The Go LLC to provide Organizational Change Management services, specifically bid for COSMOS. The Organization Change Management Statement of Work assumed a 24-month project and a fixed-price contract to provide:

- Organizational Change Management Leadership
- Executive Leadership Interviews and Change Assessments
- Organization Change Management Strategy (including Communication Strategy)
- Monthly Communication Plan
- Sponsor Roadmap
- Change Management Training for executives, core team/SME's, managers, and supervisors.

Over the course of six to eight months, the OCM consultant delivered the services listed above, as documented in Steering Committee meeting minutes and presentations. The OCM Strategy and Communications Plan and Sponsor Roadmap were presented and approved by September 2013. OCM training for managers and supervisors took place in mid-October. In December, Change Management for Change Agent training was delivered to Project Team members and Steering Committee members received Managing Change for Leaders training.

Following the training, the OCM consultant worked with Unitil on a monthly basis to create Project COSMOS related articles and communications in the Unitil employee newsletter. A bi-monthly manager and supervisor "Change Forum" was also created to encourage continuing dialog among the management team.

Consultant On The Go provided organizational change management services for the first 24 months of the project, working under a fixed-price contract. When the Project COSMOS schedule was extended as a result of the mid-project review, Consultant On The Go's contract was not extended.

After the Grant Thornton project restructuring in mid-2015, Grant Thornton consultants assumed responsibility for Organizational Change Management. In February 2016, another Change Management Plan was created and employees, managers, and stakeholder committee members were asked to complete change assessment surveys and participate in workshops and recurring change management meetings. Communications were planned and the SharePoint project site was updated.

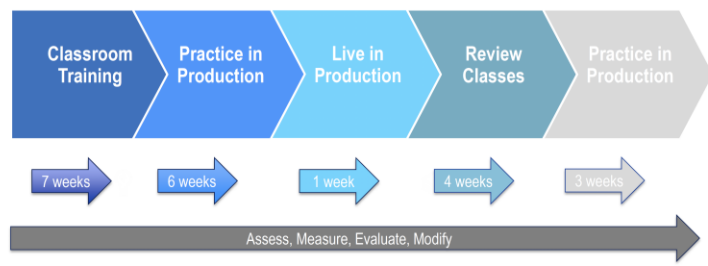
While Grant Thornton did assume responsibility for organizational change management, the Grant Thornton Change Management Plan did not build on the prior consultant's change management strategy or deliverables; rather, Grant Thornton developed from scratch another plan with similar activities, duplicating prior work.

2. *Training*

To prepare and train users on use of the new system, Unitil developed a comprehensive training strategy combining instructor-led training, self-training, and applied learning. Customer Service representatives, as deeply engaged system users, received more intensive training, which incorporated two training simulation exercises called "Practice in Production" and "Live in

Production." During Practice in Production sessions, employees listened to pre-recorded customer calls and practiced responding to the recorded customer inquiries by navigating and interacting with the new system. Live in Production was a parallel training exercise in which one employee served the customer using the existing customer system (HTE) while the other listened to the same call and practiced serving the same customer using the new enQuesta system. To make this possible, Unitil conducted a data conversion (from HTE to enQuesta) immediately prior to the training so employees could train with the most current version of system data. Both of these simulation exercises allowed employees to practice using the new system and apply their learning by listening to actual customer inquiries. Parallel training also provided an opportunity to test the system in a production-like simulation prior to Go-Live. The following diagram summarizes Unitil's training strategy.

Training Strategy Summary



Training for enQuesta users commenced on April 25, 2017 with a class of Customer Service representatives. Unitil had previously conducted training class dry-runs to prepare and train project team members and project coordinators. Management provided training at several locations to accommodate all users with minimum travel. Classroom training extended over a seven-week period followed by six weeks of Practice in Production and a week of Live in Production. Customer Service representatives then went back into classes to review and refresh. Another three weeks of Practice in Production strengthened knowledge and familiarity with the system.

At the end of training, employees evaluated the training received and provided feedback regarding readiness. Nearly all (98 percent) completing surveys indicated they felt prepared for Go-Live launch.

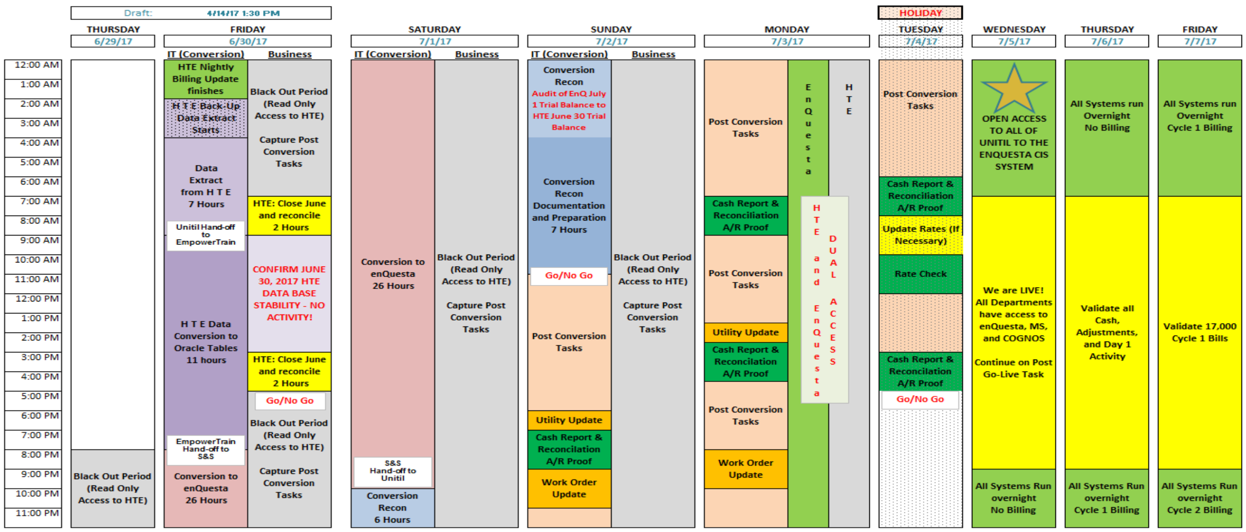
3. Go-Live Planning

Planning assumed a July 5, 2017 cutover. A "cutover plan" documented project tasks remaining to complete testing, documentation, training, planning, and communication. The cutover plan included detailed Go-Live preparation steps, Go-Live tasks, and the first 100 days of post-go live activities.

The project team conducted a dry-run of Go-Live in April 2017, letting participants practice tasks and develop a better understanding of required time to perform Go-Live tasks. Unitil continued to operate its HTE System as a back-up, permitting it to serve as a backup should a decision to postpone Go-Live occur.

Unitil develop a Go-Live plan and 5-day launch sequence to guide project launch. The plan sequenced Go-Live implementation of enQuesta over the Fourth of July weekend, beginning with monthly close-out in HTE on Friday June 30, 2017. Management planned conversion activities for early Saturday morning, followed by post-conversion tasks on Sunday, Monday, and Tuesday. Unitil planned to go live with enQuesta on Wednesday, July 5, 2017.

Go-Live Launch Sequence



4. Project Readiness

Before transitioning a new system into production, practice calls for satisfaction of an objective set of criteria to determine system and organizational readiness and to verify completion of all that needs to be in place. The go/no-go decision point stands as one of the most important decisions in the project lifecycle. The wrong decision can produce significant negative business impact if there remain material unresolved defects, poorly designed applications, insufficient training, inadequate systems security, or poorly-communicating interfaces, to cite some examples.

Ideally, an independent resource, well versed in CIS implementations, should conduct an assessment of Go-Live readiness - - project managers, systems integrators, software vendors, and company personnel bring a risk of bias or influence from the pressure to implement on time.

Project readiness (or Go-Live) acceptance criteria, should undergo thorough review as part of the readiness assessment, with all information shared with the project steering committee and project sponsor responsible for the go/no-go decision, and with complete identification and communication of known risks and mitigation methods or work arounds. At a minimum, a readiness assessment should confirm the following:

- Complete and successful testing
- Staff in place and trained
- Conversion and cutover plans practiced and perfected
- Post Go-Live support planned and ready to go

The Systems & Software Statement of Work defined both the "Go Live Criteria" and "Post Implementation Criteria" for the project. Grant Thornton also outlined testing acceptance and readiness criteria. MeterSense, the MDMS application used separately defined readiness criteria. Unitil deployed MeterSense ahead of the CIS application (enQuesta). The next table summarizes the Go-Live criteria for the COSMOS project, with our observations about their satisfaction.

COSMOS Go-Live Criteria

S&S	Grant Thornton	Liberty Observations
Successful completion of all functional tests, all integration tests, all performance tests and signed off all user acceptance tests.	All test cases and business scenarios are tested	User Acceptance documentation was incomplete.
All requirements in the Functional requirements delivered, with any exceptions agreed to by both S&S and Unitil via the Change Order process.	All critical reports are created	Change Orders document many exceptions to the Functional requirements.
Successful simulation dress rehearsal and integration tests.	System interfaces are developed, tested, and working effectively.	Late development and testing of interfaces with no documentation of completion.
The data conversion has been balanced / adequately explained to Unitil's satisfaction.	The data conversion from HTE to enQuesta is sufficiently tested and can be reliably repeated	Conversion was balanced for financial and nonfinancial items.
CIS testing that parallels a production sample of all customer types, meter reads will be compared to the legacy calculations and the new system calculations. The results are expected to be exact or explained to Unitil's satisfaction.	Business Cycle testing is complete	Weekly status reports are discontinued before Business Cycle Testing is documented as complete.
No Priority 0 or Priority 1 defects unless Unitil and S&S mutually agree to proceed.	All 0 and 1 priority incidents that are required for go live are closed or a manual work-around is developed to meet the business requirement	59 Open Priority 0 and 1 incidents (June 6, 2017 project status). Grant Thornton memo indicates Unitil business leaders have signed off on necessary work arounds for go-live.
Mutually agreed upon Priority 2 defects.		
Post-implementation support plan in place with a staffing plan.	A sufficient plan and organization is in place to support enQuesta and other new applications after go live either through in-house resources or 3rd party vendors such as S&S	100 day-plans with staffing plans On-site support by S&S and Grant Thornton and other vendors at go-live.
	User security is in place and tested	Security testing appears to have been completed prior to go-live.
	End user training is delivered, and users can effectively operate enQuesta	Comprehensive User Training was delivered.
	A Cutover Plan is in place that outlines the detailed steps necessary for: • Pre-launch • Launch sequence at go live • Post launch (first 100 days)	Detailed launch sequence and cutover plan.
	Organizational Readiness • Staffing plans are sufficient and new employees are on-boarded • 100 days plans from each department are in place and are reasonable	Post go-live 100-day plans for key business areas include staffing plans.

	Unitil has the necessary technology infrastructure in place to effectively operate all new applications	Performance testing was completed prior to Go-Live.
	Internal Audit review is complete and without significant issue	Internal Audit documented its review in the 6/20/17 Memo.

Unitil executive management conducted a Readiness Assessment meeting on June 26, 2017 to discuss project status, review Internal Audit and Grant Thornton Readiness Assessment results, and outline the senior management and Board Communication Plan to set expectations for Go-Live. This review included a synopsis of the Incident Resolution Plan, which defined post Go-Live support and problem escalation processes. The team also identified post Go-Live activities to be conducted to validate customer invoices.

Ultimately, Senior Management made the decision to go live, informing the Audit Committee of the Unitil Board of Directors on June 26, 2017. The decision was based on COSMOS project readiness, as assessed by:

- Unitil Internal Audit
- Grant Thornton
- Systems & Software
- Deloitte

Internal Audit conducted audits of data conversion, internal controls, and monthly business process testing. Business Process Testing consisted of a series of activities testing rates, account reconciliation, cash receipt processing and reconciliation, transaction processing, and month-end activities and reconciliation. Internal Audit validated Go-Live readiness through its validation of the busines process testing. A June 20, 2017 Audit memo stated:

> *Internal Audit supports management's assertion that the design of their business process testing was adequate to validate the Company's readiness to Go-Live with enQuesta.*

Grant Thornton and Systems & Software also completed system readiness reviews. Grant Thornton's readiness memo documents its criteria for system assessment, primarily consisting of project milestone completions, cutover, launch and post launch plans development, and organizational readiness as defined by sufficient staffing and support plans in place.

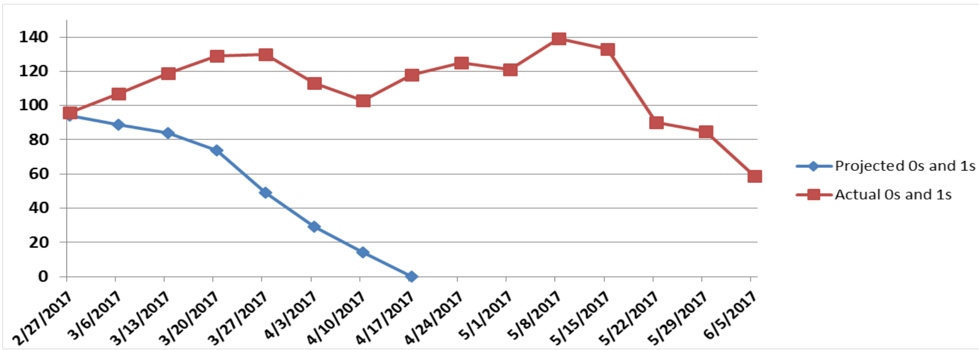
Unitil's financial auditor, Deloitte, also conducted a review of the enQuesta deployment's financial compliance with reconciliation and reporting requirements.

Grant Thornton's readiness criteria included completion of Regression Testing; *i.e.*, completion of all test cases and business scenarios and closure of all 0 and 1 priority incidents required for Go-Live (or a satisfactory manual work-around in place to the underlying business requirement. Grant Thornton evaluated Regression Testing readiness as "meeting expectations" and noted that:

> *Several incidents remain that will either be completed before Go Live or deferred to the Post Go Live phase. Unitil business leaders have signed off on necessary workarounds for Go Live.*

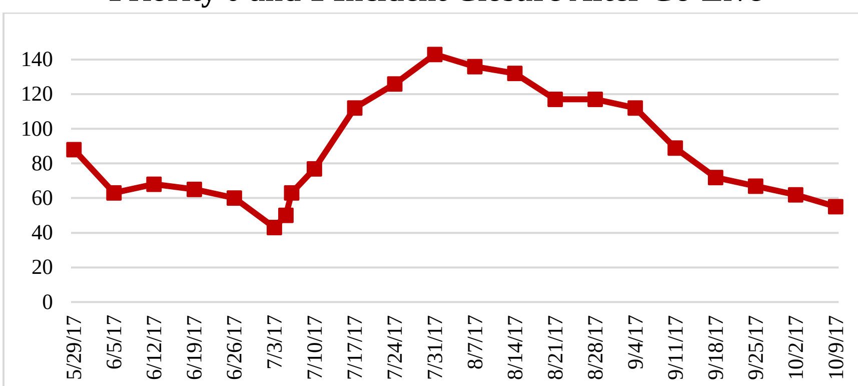
Project documentation shows a number of open priority 0 and 1 incidents at Go-Live. The last project status report documents project progress as of June 6, 2017. Of note, 95 percent of 2,500 planned test cases showed as complete, leaving 114 open test cases and 59 priority 0 and 1 incidents for completion prior to the July 5th launch. The next graph shows the unresolved priority 0 and 1 incidents as of June 16, 2017.

Priority 0 and 1 Incident Closure Up to Go-Live



Our examination of the analysis of the project incident log from the end of May through early September 2017 shows priority 0 and 1 incidents unclosed at Go-Live.

Priority 0 and 1 Incident Closure After Go-Live



Additional priority 0 and 1 incidents were logged following Go-Live, peaking at the end of July 2017. At the end of post Go-Live (100 days), Unitil reported 55 unresolved priority 0 and 1 incidents, back in line with the number of incidents reported in the June 6 status report, before Go-Live. The following table defines incident priority categorization.

Incident Priorities

#	Priority	Description	Response Time
0	Showstopper	Customer down or cannot run critical Billing or C&C process	15 Minutes
1	High	Business critical, but not preventing all users from getting work done (*e.g.*, a particular update that cannot be run needs to be run before the next business day.)	1 Hour
2	Medium	Issue has a work around usable until issue resolution. (*e.g.*, particular work order cannot be updated)	4 Hours
3	Low	Cosmetic issue or requested functionality to be considered for a future version. (*e.g.*, columns displayed on a particular screen)	24 Hours

Management built three go/no-go decision points into the launch sequence for Go-Live:

- Day 1, following HTE data conversion to Oracle
- Day 3 following conversion of HTE data to enQuesta
- Day 5 following post-conversion tasks.

However, the detailed cutover plan did not include them, nor did other project documentation confirm them, making it unclear whether these decision points were discussed or considered during launch.

Conversion ended on Saturday July 1 at 7:00pm, taking a total of 45 hours to complete. Post-conversion activities continued through Monday July 3. The "My Unitil" website went live on Tuesday July 4 at 7:00 pm. Conversion validation activities were conducted on July 5 and 6. Cycle 1 bills were run on the evening of July 6 and validated over the weekend. Unitil validated successive billing cycles through July 21.

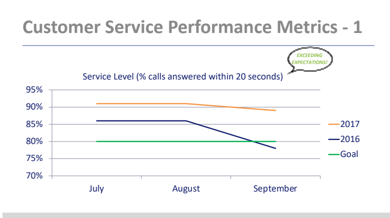
M. Post Go-Live Management

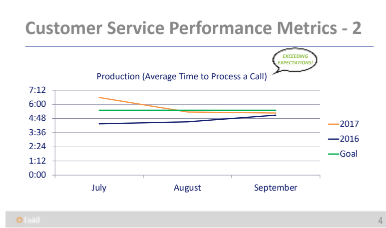
Following Go-Live, post Go-Live support processes require monitoring, with action plans created and executed to address any issues encountered. System work arounds require careful documentation and communication to all users, followed by monitoring pending completion of a permanent solution.

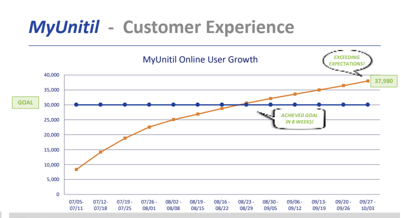
Project performance metrics, referred to commonly as Key Performance Indicators (KPIs), help to ensure a transition that minimizes billing problems, delays in handling customer inquiries, and customer complaints. Monitoring performance through the use of KPIs includes setting targets (the desired level of performance) and tracking performance and progress against targets. Unitil tracked post-go live performance through the following KPIs:

- Complaints to Regulators
- Call Center Service Level
- Average Call Time
- MyUnitil Online User Growth
- Customer Satisfaction.

Unitil's performance following Go-Live, as measured by these KPIs, proved generally positive, as the following graphs demonstrate.







1. *Post Go-Live Support*

At Go-Live, Unitil's "build" of enQuesta became Systems & Software's newest release of enQuesta software. Unitil's HTE-to-enQuesta conversion Go-Live Incident Resolution Plan detailed accountability for addressing the incidents during and after business hours through the first 100 days, and post 100 days. Unitil contracted with Systems & Software and Grant Thornton to provide on-site support in July and August, with a commitment from Systems & Software to continue incident resolution until zero incidents.

A Command Center and Incident Analysis Team, manned with Grant Thornton individuals, had responsibility for classifying and routing incidents.

After the post Go-Live period (100 days), Unitil made problem resolution part of the everyday workload, with incident support moving to Unitil's Trouble Ticketing System (TESS). Unitil released temporary staffing and project management transitioned to business process managers.

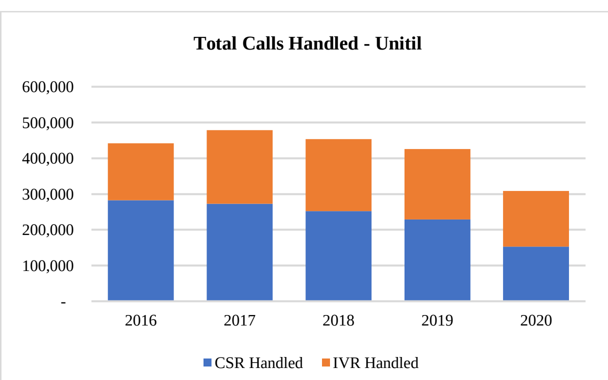
As part of project wrap-up, Unitil solicited feedback about the project from various business groups in August, following Go-Live. A review of this feedback reveals the following themes:

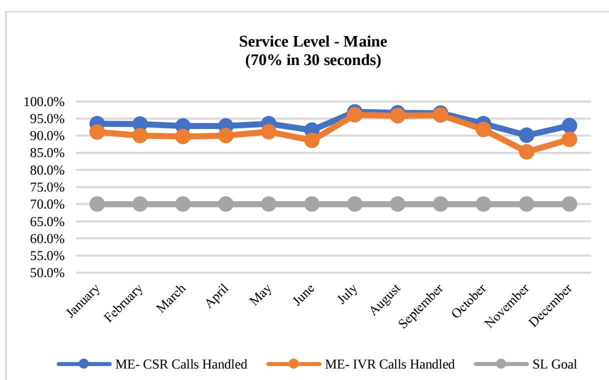
- Business Owners and operations were not involved early enough in the project
- Early project lacked Executive Sponsorship and underestimated effort
- Go-live issues
- Testing gaps/completeness.

Capturing lessons learned is an important step in project management. Unitil captured its lessons learned as part of the post-project review process. A best practices approach is to capture lessons learned throughout the project lifecycle, not just at completion. It is important to capture both successes and failures on projects and to leverage these lessons in future projects so any failed lessons can be avoided.

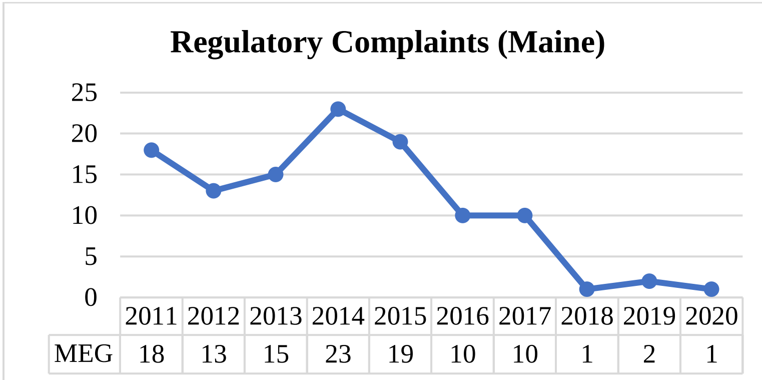
2. *Post Go-Live Customer Service Performance*

A review of total customer calls handled prior to, during, and following the enQuesta go-live shows slightly increased call volumes during 2017, with IVR calls hitting a 5-year peak in 2017 (note that IVR calls include the October 2017 storm). In Maine, service level remained well above goal during 2017 for CSR and IVR handled calls.





A review of Unitil's Maine Regulatory Complaints shows a steady decline since 2014 with minimal complaints registered in 2017 and very few in years 2018, 2019, and 2020 (October).



Unitil Maine issues more than 400,000 bills each year to customers. Since enQuesta's deployment, Unitil Maine experienced very few estimated bills or re-bills as seen in the following table.

Post-Implementation Rebills and Estimated Bills

Year	Rebills	Estimated Bills
2017 July to Dec	211	132
2018	1,653	263
2019	640	347
2020 (Jan to July)	348	405

Since enQuesta go-live, Unitil has issued most bills to customers within a day of obtaining the meter reading. The following table shows the number of bills issued by day following the meter reading.

Post-Implementation Billing Dates

	2017	2017%	2018	2018%	2019	2019%	2020	2020%
1 Day--->	172,388	87.6%	359,703	89.3%	392,432	95.6%	242,251	99.4%
2 Days--->	21,533	10.9%	31,731	7.9%	17,325	4.2%	1,019	0.4%
3 Days--->	1,928	1.0%	7,998	2.0%	244	0.1%	233	0.1%
4 Days--->	155	0.1%	410	0.1%	98	0.0%	135	0.1%
5 Days--->	211	0.1%	83	0.0%	70	0.0%	56	0.0%
6 Days--->	32	0.0%	442	0.1%	30	0.0%	31	0.0%
7 Days--->	19	0.0%	910	0.2%	23	0.0%	20	0.0%
8 to 14 Days--->	55	0.0%	1,318	0.3%	70	0.0%	69	0.0%
Over 14 Days--->	393	0.2%	8	0.0%	9	0.0%	2	0.0%
Total	**196,714**	**100.0%**	**402,603**	**100.0%**	**410,301**	**100.0%**	**243,816**	**100.0%**

Liberty's review of Unitil's customer service performance prior to, during, and following the enQuesta go-live shows a high level of service with no apparent service degradation. While call volumes increased slightly in 2017, regulatory complaints remained low, call handling service levels exceeded goal, most bills were issued on time, and very few bills were estimated.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(14) A list of officers and directors of the utility and their full compensation for each of the last two years, detailing base compensation, bonuses and incentive plans.

Response:

Attachment 1 **CONFIDENTIAL** lists the officers of Northern Utilities, Inc. ("Northern"). These officers receive no direct compensation from Northern for their services. Rather, each officer of Northern is an employee of Unitil Service Corp. ("Unitil Service"), and their entire compensation for all job responsibilities is paid through Unitil Service. Accordingly, the annual compensation listed on Attachment 1 for each officer in 2019 and 2020 is the *total* amount received from Unitil Service.

All officers' compensation is allocated to Unitil Corporation's subsidiaries through the Unitil Service billing system. Accordingly, approximately 19.85% of the total compensation was allocated to Northern - NH in 2019, and approximately 20.18% was allocated to Northern - NH in 2020.

The compensation listed for officers Meissner, Black, Brock, Collin, Hevert, LeBlanc and Vaughan is reported in Unitil Corporation's 2021 Proxy Statement, filed with the federal Securities and Exchange Commission. The amounts listed for officers Diggins, Eisfeller, Furino, Hurstak, Letourneau and Whitney are not reported, and is non-public, confidential information. A Motion for Confidential Treatment of this information, pursuant to Puc 203.08, is included with Northern's Petition.

Attachment 2 lists the directors of Northern and the total annual compensation for each person in 2019 and 2020. As is the case with Northern's officers, Northern's Board of Directors receives no direct compensation from Northern. All Directors' compensation in 2019 and 2020 was allocated to Unitil Corporation's subsidiaries through the Unitil Service billing system, with amounts allocated to Northern – NH using the same percentages as indicated above for the allocation of compensation for Northern's officers.

REDACTED

Northern Utilities, Inc.

Officers Compensation

Test Year		**2019**			**2020**		
Name	**Title**	**Base Salary**	**Incentive Cash**	**Restricted Stock**	**Base Salary**	**Incentive Cash**	**Restricted Stock**
Meissner	President	$ 572,000.00	$ 459,677.00	$ 938,737.48	$ 597,740.00	$ 527,956.00	$ 998,567.35
Black	Sr. VP	$ 292,600.00	$ 139,732.00	$ 478,707.57	$ 301,378.00	$ 145,422.00	$ 126,721.74
Brock [1]	VP and Controller / Sr. VP	$ 264,546.00	$ 115,144.00	$ 119,852.61	$ 286,000.00	$ 131,479.00	$ 126,721.74
Collin [2]	Sr. VP	$ 122,667.00	$ 232,943.00	$ 215,086.85	N/A	N/A	N/A
Diggins [3]	Treasurer	[redacted]			[redacted]		
Eisfeller	VP						
Hevert [4]	Sr. VP	N/A	N/A	N/A	$ 153,910.00	N/A	N/A
Hurstak [5]	Controller	[redacted]			[redacted]		
Furino	VP						
LeBlanc	VP	$ 211,550.00	$ 88,153.00	$ 60,156.55	$ 224,125.00	$ 90,120.00	$ 74,338.39
Letourneau	VP	[redacted]			[redacted]		
Vaughan [6]	*Sr. VP & Treasurer*	*$ 330,000.00*	*$ -*	*N/A*	*$ 339,900.00*	*$ 210,870.00*	*$ 62,727.53*
Whitney	Secretary	[redacted]			[redacted]		
OFFICERS' TOTAL CALENDAR YEAR 2019 / OFFICERS' TOTAL CALENDAR YEAR 2020		**$ 2,523,963.00**	**$ 1,307,762.00**	**$ 1,976,128.43**	**$ 3,010,829.00**	**$ 1,424,509.00**	**$ 1,673,255.90**

1 - Brock - VP & Controller in 2019; Sr VP in 2020
2 - Collin - Retired in May 2019
3 - Diggins - Treasurer in 2020
4 - Hevert - Sr. VP in July 2020; no Incentive Cash or Restricted Stock Award
5 - Hurstak - Controller in March 2020; no Incentive Cash or Restricted Stock Award
6 - Vaughan - Sr VP & Treasurer in Jan 2019; Resigned in March 2020

PUC 1604.01(a) - 14 - Attachment 2

Northern Utilities, Inc.

Directors' Compensation

Test Year	**2019**			**2020**		
Name	**Cash Retainer**	**Common Stock**	**Restricted Stock Units**	**Cash Retainer**	**Common Stock**	**Restricted Stock Units**
Robert V. Antonucci [1]	$ 77,000	$ -	$ 69,977	$ 40,500	$ 23,780	$ -
Winfield S. Brown [2]	N/A	N/A	N/A	$ 76,000	$ 69,973	$ -
David P. Brownell [1]	$ 77,000	$ -	$ 69,977	$ 40,500	$ 23,780	$ -
Mark H. Collin	$ 44,388	$ 46,893	$ -	$ 73,000	$ 69,973	$ -
Lisa Crutchfield	$ 88,500	$ -	$ 69,977	$ 90,500	$ -	$ 69,961
Albert H. Elfner, III [1]	$ 73,000	$ -	$ 69,977	$ 39,500	$ 23,780	$ -
Suzanne Foster	$ 71,000	$ 69,958	$ -	$ 76,000	$ 69,973	$ -
Edward F. Godfrey	$ 74,500	$ -	$ 69,977	$ 80,500	$ 69,973	$ -
Michael B. Green	$ 105,500	$ -	$ 69,977	$ 110,500	$ -	$ 69,961
Thomas P. Meissner, Jr. [3]	N/A	N/A	N/A	N/A	N/A	N/A
Eben S. Moulton	$ 72,000	$ -	$ 69,977	$ 79,000	$ -	$ 69,961
M. Brian O'Shaughnessy [1]	$ 71,000	$ -	$ 69,977	$ 37,500	$ 23,780	$ -
Justine Vogel	$ 71,000	$ 69,958	$ -	$ 76,000	$ 69,973	$ -
David A. Whiteley	$ 88,500	$ -	$ 69,977	$ 90,500	$ 69,973	$ -

[1] Antonucci, Brownell, Elfner, and O'Shaughnessy retired from the Board in April 2020.

[2] Winfield S. Brown joined the Board in January 2020.

[3] Employee directors are not compensated for board service.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(15) Copies of all officer and executive incentive plans.

Response:

Incentive plans in which officers and executives participate include the following:

Management Incentive Plan – Attachment 1
Unitil Corporation Second Amended and Restated 2003 Stock Plan – Attachment 2

UNITIL CORPORATION MANAGEMENT INCENTIVE PLAN
(amended and restated as of June 5, 2013)

The purpose of the Unitil Corporation Management Incentive Plan (the "Plan") is to provide key management employees of Unitil Corporation and its subsidiaries identified on Exhibit A attached hereto (collectively, the "Corporation") with significant incentives related to the performance of the Corporation and thereby to motivate them to maximize their efforts on the Corporation's behalf. The Plan is further intended to provide the Corporation's key management employees with competitive levels of total compensation when considered with their base salaries.

I. PARTICIPATION

Key management employees of the Corporation who are selected by the Compensation Committee (the "Committee") of the Corporation's Board of Directors (the "Board") for participation shall participate in the Plan (each such participating key management employee, a "Participant") for the applicable Performance Period(s) (as defined below). Each Participant in the Plan for a Performance Period shall be notified of such Participant's selection, such Participant's Target Incentive Award (as defined below) and the specific Performance Objectives and Performance Standards (each as defined below) upon which such Participant's Incentive Awards (as defined below), if any, shall be based. The Participants in the Plan for the applicable Performance Period shall be documented.

II. TARGET INCENTIVE AWARD

The Committee shall establish an individual targeted award (the "Target Incentive Award") under the Plan for each Participant for each Performance Period, expressed as a percentage of the Participant's base salary (prior to reduction under the Corporation's 401(k) retirement plan or cafeteria plan, "Base Salary") earned during the applicable Performance Period. The Target Incentive Awards for all Participants for the applicable Performance Period shall be documented.

III. PERFORMANCE PERIOD

The Performance Period is the period during which performance will be measured for determining the amounts of Participants' awards under the Plan ("Incentive Awards"). The Performance Period for the Plan shall be the calendar year.

IV. PERFORMANCE OBJECTIVES

Prior to the beginning of each Performance Period, or as soon thereafter as practicable, the Committee shall establish, based in part upon the recommendations of the Corporation's Chief Executive Officer (the "CEO"), objectives for the performance of the Corporation for the next following Performance Period, deemed necessary for the Corporation to achieve its strategic plans ("Performance Objectives"), the achievement of which or failure to achieve will result in the payment of Incentive Awards, as described in Section VIII, Determination of Incentive Awards. The Performance Objectives for the applicable Performance Period shall be documented.

V. PERCENTAGE WEIGHTING

Coincident with the establishment of the Performance Objectives for a particular Performance Period, the Committee shall, based in part upon the recommendations of the CEO, determine the relevant weights (the "Percentage Weightings") to be assigned to each of the Performance Objectives established for such Period, based on the relative impact of each Performance Objective on the Corporation's performance. The Percentage Weightings for the applicable Performance Period shall be documented.

VI. PERFORMANCE STANDARDS

Prior to the beginning of each Performance Period, or as soon thereafter as practicable, the Committee shall, based in part upon the recommendations of the CEO, establish the Performance Standards for each Performance Objective. The Performance Standards for the current Performance Period shall be documented. Performance Standards shall be set for the following three levels of achievement - "Threshold," "Target" and "Maximum."

A. **Threshold:** The minimum level of performance required for an Incentive Award to be paid. No Incentive Award shall be paid for performance below this level. Achievement of the Threshold level shall result in a payment equal to 50% of the amount of the Target Incentive Award for the Performance Objective, as adjusted by the applicable Percentage Weighting.

B. **Target:** The expected level of performance required, for which an Incentive Award in an amount equal to 100% of the Target Incentive Award shall be paid for the Performance Objective, as adjusted by the applicable Percentage Weighting.

C. **Maximum:** The maximum level of performance, for which an Incentive Award in an amount equal to 150% of the amount of the Target Incentive Award shall be paid for the Performance Objective, as adjusted by the applicable Percentage Weighting. Achievement of a result greater than the Maximum level shall not increase the amount of the Incentive Award.

VII. CONTROLLING THRESHOLD(S)

The Committee may, based in part upon the recommendations of the CEO, establish minimum organization performance level(s) for each Performance Period ("Controlling Threshold(s)") that must be satisfied by the Corporation for Incentive Awards to be paid; provided, however, that a Controlling Threshold need not be established for any particular Performance Period. The Controlling Threshold(s) for the applicable Performance Period shall be documented.

VIII. DETERMINATION OF INCENTIVE AWARDS

As soon as practicable following the completion of a Performance Period, the Committee shall determine the degree of satisfaction of the Performance Objectives and the amounts of the Incentive Awards payable in accordance with the Plan, if any. The amount of the Incentive Award earned by each Participant shall depend upon the degree of achievement of the

Performance Standards for each Performance Objective and the Percentage Weighting assigned thereto. If an achievement level falls between the Threshold and Target levels or between the Target and Maximum levels, the Incentive Award shall be linearly extrapolated between the two levels. Award calculations will be applied to Base Salary earned during the applicable Performance Period. Subject to the payment limitations in paragraph X below and notwithstanding anything else to the contrary contained in the Plan, the Committee shall have absolute discretion with respect to the payment of Incentive Awards, including but not limited to the amount to be paid and whether or not payment will be made, on the basis of business conditions.

IX. PLAN ADMINISTRATION

The Plan shall be administered by the Committee. The Committee shall, in its sole discretion, interpret the Plan, prescribe, amend and rescind any rules and regulations necessary or appropriate for administration of the Plan and make such other determinations and take such other actions as it deems necessary or advisable for such purposes. Any interpretation, determination or other action made or taken by the Committee shall be final, binding, and conclusive. The Committee may rely upon the advice, counsel, and assistance of the CEO in performing its duties under the Plan.

X. PAYMENT OF INCENTIVE AWARDS

Payment of each Participant's Incentive Award shall be made as soon as practicable following the end of the applicable Performance Period, but not prior to January 1 or later than March 15 of the calendar year following the Performance Period (the "Incentive Award Payment Date"); provided, however, that notwithstanding anything to the contrary contained in the Plan, no Incentive Award shall be paid to any individual who is not employed by the Corporation on the applicable Incentive Award Payment Date, unless due to the individual's death, disability (entitlement to benefits under the Corporation's Long-Term Disability Plan, "Disability") or retirement at or after attaining age 55. Incentive Award payments made due to the Participant's death, Disability or retirement at or after attaining age 55 shall be made on the applicable Incentive Award Payment Date. All Incentive Awards shall be paid in a lump sum in cash, less any amounts required for federal, state and local income and payroll tax withholdings.

XI. DISCIPLINARY ACTION

Notwithstanding anything to the contrary contained in the Plan, a Participant whose performance rating for a Performance Period is "Does Not Meet Expectations" (pursuant to the Corporation's Salary Administration Policy) shall not receive an Incentive Award for such Performance Period.

XII. TERMINATION OF EMPLOYMENT

If a Participant ceases to be employed by the Corporation (a) by reason of his death, Disability or retirement at or after attaining age 55, the Participant's Incentive Award for the Performance Period in which his employment terminates shall be calculated using the Participant's Base Salary earned prior to his termination of employment, or (b) other than by reason of his death, Disability or retirement at or after attaining age 55, the Participant's Incentive Award for the Performance Period in which his employment terminates shall be forfeited.

XIII. FUNDING

No funds shall be set aside or reserved for payment of Incentive Awards under the Plan, and all obligations of the Corporation under the Plan shall be unfunded and shall be paid from the general assets of the Corporation.

XIV. NOT EXCLUSIVE METHOD OF INCENTIVE

The Plan shall not be deemed to be an exclusive method of providing incentive compensation for employees of the Corporation nor shall it preclude the Board from authorizing or approving other forms of incentive compensation therefor.

XV. NO RIGHT TO CONTINUED PARTICIPATION

Participation in the Plan by an employee in any Performance Period shall not be held or construed to confer upon such employee the right to participate in the Plan in any subsequent Performance Period.

XVI. NO RIGHT TO CONTINUED EMPLOYMENT

None of the establishment of the Plan, participation in the Plan by a Participant, the payment of any Incentive Award hereunder or any other action pursuant to the Plan shall be held or construed to confer upon any employee the right to continue in the employ of the Corporation or affect any right which the Corporation may have to terminate at will the employment thereof.

XVII. NONTRANSFERABILITY OF AWARDS

Except by operation of the laws of descent and distribution, no amount payable at any time under the Plan shall be subject to alienation by anticipation, sale, transfer, assignment, bankruptcy, pledge, attachment, charge or encumbrance of any kind nor in any manner be subject to the debts or liabilities of any person, and any attempt to so alienate or subject any such amount shall be void.

XVIII. AMENDMENT AND TERMINATION

The Board may amend or terminate the Plan at any time; provided, however, that no amendment or termination of the Plan shall adversely affect the entitlement of a Participant to payment of any Incentive Award which has been determined by the Committee prior to such amendment or termination, although the Board may amend or terminate the rights of any Participant under the Plan at any time prior to the determination of the amount of the Incentive Award to be paid thereto for a Performance Period.

XIX. EFFECTIVE DATE

The Plan shall be effective June 5, 2013 and shall continue in effect until terminated by the Board.

Exhibit A
Participating Subsidiaries

Unitil Energy Systems, Inc.

Fitchburg Gas and Electric Light Company

Unitil Service Corp.

Usource LLC

Northern Utilities, Inc.

Granite State Gas Transmission, Inc.

Unitil Corporation
Second Amended and Restated
2003 Stock Plan

Effective: April 19, 2012

Unitil Corporation
Second Amended and Restated
2003 Stock Plan

ARTICLE 1

Establishment, Objectives, and Duration

1.1 Establishment of the Plan. Unitil Corporation, a corporation organized and existing under New Hampshire law (the "Company"), hereby establishes an incentive compensation plan to be known as the "Unitil Corporation Second Amended and Restated 2003 Stock Plan" (hereinafter referred to as the "Plan"). The Plan permits the grant of Shares and Restricted Stock Units. The Plan first became effective on January 1, 2003 and was previously known as the "Unitil Corporation 2003 Restricted Stock Plan." On March 24, 2011, the Plan was amended and restated to permit the granting of Restricted Stock Units, to change the name of the Plan to the "Unitil Corporation Amended and Restated 2003 Stock Plan," and to make other non-material revisions. The Plan, as further amended, restated and renamed, will become effective on April 19, 2012 if approved by the Company's shareholders at the Company's 2012 Annual Meeting of Shareholders. The Plan shall remain in effect as provided in Section 1.3 hereof.

1.2 Objectives of the Plan. The objectives of the Plan are to optimize the profitability and growth of the Company through incentives which are consistent with the Company's goals and which link the personal interests of Participants to those of the Company's shareholders; to provide Participants with an incentive for excellence in individual performance; and to promote teamwork among Participants.

1.3 Duration of the Plan. The Plan shall remain in effect, subject to the right of the Board to amend or terminate the Plan at any time pursuant to Article 14 hereof, until all Shares subject to it shall have been purchased or acquired according to the Plan's provisions.

ARTICLE 2

Definitions

Whenever used in the Plan, the following terms shall have the meanings set forth below, and, when the meaning is intended, the initial letter of the word shall be capitalized:

2.1 "Affiliate" means any parent or subsidiary of the Company which meets the requirements of Section 424 of the Code.

2.2 "Award" means, individually or collectively, an award under this Plan of Shares or Restricted Stock Units.

2.3 "Award Agreement" means an agreement entered into by the Company and each Participant setting forth the terms and provisions applicable to Awards made under the Plan.

2.4 "Board" means the Board of Directors of the Company.

2.5 "Change in Control" means the satisfaction of any one or more of the following conditions (and the "Change in Control" shall be deemed to have occurred as of the first day that any one or more of the following conditions shall have been satisfied):

(a) the Company receives a report on Schedule 13D filed with the Securities and Exchange Commission pursuant to Rule 13(d) of the Exchange Act, disclosing that any person, group, corporation or other entity is the beneficial owner, directly or indirectly, of 25% or more of the outstanding Shares;

(b) any "person" (as such term is used in Section 13(d) of the Exchange Act), group, corporation or other entity other than the Company or a wholly-owned subsidiary of the Company, purchases Shares pursuant to a tender offer or exchange offer to acquire any Shares (or securities convertible into Shares) for cash, securities or any other consideration, provided that after consummation of the offer, the person, group, corporation or other entity in question is the "beneficial owner" (as such term is defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of 25% or more of the outstanding Shares (calculated as provided in paragraph (d) of Rule 13d-3 under the Exchange Act in the case of rights to acquire Shares);

(c) consummation of a transaction which involves (1) any consolidation or merger of the Company in which the Company is not the continuing or surviving corporation, or pursuant to which Shares of the Company would be converted into cash, securities or other property (except where the Company's shareholders before such transaction will be the owners of more than 75% of all classes of voting securities of the surviving entity); or (2) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all the assets of the Company.

(d) there shall have been a change in a majority of the members of the Board within a 25-month period, unless the election or nomination for election by the Company's shareholders of each new director was approved by the vote of at least two-thirds of the directors then still in office who were in office at the beginning of the 25-month period.

2.6 "Code" means the Internal Revenue Code of 1986, as amended from time to time.

2.7 "Committee" means (i) the Compensation Committee of the Board, as specified in Article 3 herein, or (ii) such other Committee appointed by the Board to administer the Plan (or aspects thereof) with respect to grants of Awards except (a) as may be prohibited by applicable law, the Company's Articles of Incorporation or the

Company's By-Laws or (b) as may conflict with the authority that the Board has delegated to another Committee appointed by the Board.

2.8 "Company" means Unitil Corporation, a corporation organized and existing under New Hampshire law, and any successor thereto as provided in Article 17 herein.

2.9 "Consultant" means an independent contractor who is performing consulting services for one or more entities in the Group and who is not an employee of any entity in the Group.

2.10 "Director" means a member of the Board or a member of the board of directors of an Affiliate.

2.11 "Director Participant" means a Participant who receives an Award for his or her services as a Director.

2.12 "Disability" shall have the meaning ascribed to such term in the long-term disability plan maintained by the Company, or if no such plan exists, at the discretion of the Committee.

2.13 "Dividend Equivalents" shall have the meaning ascribed to such term in Section 7.5 hereof.

2.14 "Employee" means any employee of the Group, including any employees who are also Directors.

2.15 "Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time, or any successor act thereto.

2.16 "Fair Market Value" means as of any date, the closing price based upon composite transactions on a national stock exchange for one Share or, if no sales of Shares have taken place on such date, the closing price on the most recent date on which selling prices were quoted. In the event the Company's Shares are no longer traded on a national stock exchange, Fair Market Value shall be determined in good faith by the Committee.

2.17 "Group" means the Company and its Affiliates.

2.18 "Named Executive Officer" means a Participant who, as of the date of vesting of an Award, is one of the group of "covered employees," as defined in the regulations promulgated under Code Section 162(m), or any successor section.

2.19 "Nonemployee Director" shall have the meaning ascribed to such term in Rule 16b-3 of the Exchange Act.

2.20 "Outside Director" shall have the meaning ascribed to such term under the regulations promulgated with respect to Code Section 162(m).

2.21 "Participant" means a current or former Employee, Director, or Consultant who has outstanding an Award granted under the Plan.

2.22 "Performance-Based Exception" means the performance-based exception from the tax deductibility limitations of Code Section 162(m).

2.23 "Period(s) of Restriction" means the period (or periods) during which the transfer of Shares or Restricted Stock Units are limited in some way (based on the passage of time, the achievement of performance goals, or upon the occurrence of other events as determined by the Committee, at its discretion), and the Shares or Restricted Stock Units are subject to a substantial risk of forfeiture.

2.24 "Plan" shall have the meaning ascribed to such term in Section 1.1 hereof.

2.25 "Restricted Stock" or **"Restricted Share"** means an Award of Shares granted to a Participant pursuant to Article 6 herein subject to a Period(s) of Restriction.

2.26 "Restricted Stock Unit" means an Award granted to a Participant pursuant to Article 7 herein.

2.27 "RSU Election" shall have the meaning ascribed to such term in section 7.1 hereof.

2.28 "Shares" means the shares of common stock (no par value) of the Company.

2.29 "Termination of Service" means, (i) if an Employee, termination of employment with all entities in the Group, (ii) if a Director, termination of service on the Board and the board of directors of any Affiliate, as applicable, and (iii) if a Consultant, termination of the consulting relationship with all entities in the Group; provided, however, that if a Participant serves the Group in more than one of the above capacities, Termination of Service shall mean termination of service in all such capacities; provided, however, that with respect to any Restricted Stock Units that constitute deferred compensation for purposes of Code Section 409A, the term Termination of Service shall mean "separation from service," as that term is used in Code Section 409A.

ARTICLE 3

Administration

3.1 The Committee. The Plan shall be administered by the Committee. To the extent the Company deems it to be necessary or desirable with respect to any Awards made hereunder, the members of the Committee may be limited to Nonemployee Directors or Outside Directors, who shall be appointed from time to time by, and shall serve at the discretion of, the Board.

3.2 Authority of the Committee. Except as limited by law or by the Articles of Incorporation or the By-laws of the Company, and subject to the provisions herein, the

Committee shall have full power to select the persons who shall participate in the Plan; determine the sizes of Awards; determine the terms and conditions of Awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to Participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to Participants; and (subject to the provisions of Article 14 herein) amend the terms and conditions of any outstanding Award to the extent such terms and conditions are within the discretion of the Committee as provided in the Plan. Further, the Committee shall make all other determinations which may be necessary or advisable for the administration of the Plan. As permitted by law, the Committee may delegate its authority as identified herein.

3.3 Decisions Binding. All determinations and decisions made by the Committee pursuant to the provisions of the Plan and all related orders and resolutions of the Board shall be final, conclusive and binding on all persons, including the Company, its shareholders, Affiliates, Participants, and their estates and beneficiaries.

ARTICLE 4

Shares Subject to the Plan and Maximum Awards

4.1 Number of Shares Available for Grants.

(a) Subject to adjustment as provided in Section 4.2, the maximum number of Shares available for Awards to Participants under the Plan shall be 677,500 Shares. The 677,500 Shares referred to in the immediately preceding sentence includes 177,500 Shares initially made available for Awards to Participants under the Plan and 500,000 Shares added to the Plan as of April 19, 2012. To the extent all or any portion of an Award expires before vesting, is forfeited, or is paid in cash, the Shares subject to such portion of the Award shall again be available for issuance under the Plan. For avoidance of doubt, if Shares are returned to the Company in satisfaction of taxes relating to a Restricted Stock Award, such issued Shares shall not become available again under the Plan.

(b) The maximum aggregate number of Shares or Restricted Stock Units that may be granted in any one calendar year to any one Participant shall be 20,000, subject to adjustment in accordance with Section 4.2.

4.2 Adjustments in Authorized Shares. In the event of an equity restructuring (within the meaning of Financial Accounting Standards Board Accounting Standards Codification Topic 718, Stock Compensation) affecting the Shares, such as a stock dividend, stock split, spin off, rights offering, or recapitalization through a large, nonrecurring cash dividend, the Committee shall authorize and make an equitable adjustment to the number and kind of Shares that may be delivered pursuant to Section 4.1 and, in addition, may authorize and make an equitable adjustment to the Award limit set forth in Section 4.1(b). In the event of any other change in corporate capitalization, such as a merger, consolidation, reorganization or partial or complete liquidation of the Company, the Committee may, in its sole discretion, authorize and make such proportionate adjustments, if any, as the Committee shall deem appropriate to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kind of Shares or Restricted Stock Units that may be delivered pursuant to Section 4.1 and in the Award limit set forth in Section 4.1(b). The number of Shares or Restricted Stock Units subject to any Award shall always be rounded to the nearest whole number, with one-half (1/2) of a share rounded up to the next higher number.

ARTICLE 5

Eligibility and Participation

5.1 Eligibility. Persons eligible to participate in this Plan include all Employees, Directors and Consultants of the Group.

5.2 Actual Participation. Subject to the provisions of the Plan, the Committee may, from time to time, select from all eligible Employees, Directors and Consultants those to whom Awards shall be made and shall determine the nature and amount of each Award.

ARTICLE 6

Stock Awards

6.1 Grant of Stock Awards. Subject to the terms and provisions of the Plan, the Committee, at any time and from time to time, may grant Shares to Participants in such amounts as the Committee shall determine and subject to any restrictions the Committee may deem appropriate.

6.2 Stock Award Agreement. Each grant of Shares shall be evidenced by an Award Agreement that shall specify the Period(s) of Restriction, if any, the number of Shares granted, and such other provisions as the Committee shall determine.

6.3 Transferability. Except as provided in this Article 6, the Shares granted herein may not be sold, transferred, pledged, assigned or otherwise alienated or hypothecated until the end of any applicable Period(s) of Restriction established by the Committee and specified in the Award Agreement.

6.4 Restrictions.

(a) Subject to the terms hereof, the Committee shall impose such conditions and/or restrictions on any Shares granted pursuant to the Plan as it may deem advisable and as are expressly set forth in the Award Agreement including, without limitation, a requirement that Participants pay a stipulated purchase price for each Share, restrictions based upon the achievement of specific performance goals (Company-wide, divisional, and/or individual), time-based restrictions, and/or restrictions under applicable federal or state securities laws. For purposes of Awards granted under this Article 6, the period(s) that the Shares are subject to such conditions and/or restrictions shall be referred to as the “Period(s) of Restriction.”

(b) The Participant shall execute appropriate stock powers in blank and such other documents as the Committee shall prescribe.

(c) Subject to restrictions under applicable law or as may be imposed by the Company, Shares covered by each Award made under the Plan shall become freely transferable by the Participant after the last day of any applicable Period(s) of Restriction.

6.5 Voting Rights. During any Period(s) of Restriction, subject to any limitations imposed under the By-laws of the Company, Participants holding Shares granted hereunder may exercise full voting rights with respect to those Shares.

6.6 Dividends and Other Distributions. During any Period(s) of Restriction, Participants holding Shares granted hereunder may be credited with regular dividends paid with respect to the underlying Shares while they are so held. The Committee may apply any restrictions to the dividends that the Committee deems appropriate and as are expressly set forth in the Award Agreement. Without limiting the generality of the preceding sentence, if the grant or vesting of Shares granted to a Named Executive Officer is designed to comply with the requirements of the Performance-Based Exception, the Committee may apply any restrictions it deems appropriate to the payment of dividends declared with respect to such Shares, such that the dividends and/or the Shares maintain eligibility for the Performance-Based Exception.

ARTICLE 7

Restricted Stock Units

7.1 Grant of Restricted Stock Units. Subject to the terms and provisions of the Plan (a) the Committee, at any time and from time to time, may grant Restricted Stock Units to Participants in such amounts as the Committee shall determine and (b) to the extent permitted by the Committee, Director Participants may elect to receive Restricted Stock Units in lieu of Shares (an “RSU Election”) that such Director Participant otherwise would receive for services on the Board. Each Restricted Stock Unit Award shall be evidenced by an Award Agreement that shall specify the Period(s) of Restriction/vesting schedule (if any), the number of Restricted Share Units granted, and such other provisions as the Committee shall determine. A Restricted Stock Unit is a notional unit of measurement denominated in Shares (*i.e.*, one Restricted Stock Unit is equivalent in value to one Share), which represents an unfunded, unsecured right to receive Shares or a cash amount equal to the Fair Market Value of the Shares that would have been received (as specified in the applicable RSU Agreement) on the terms and conditions set forth herein and in the applicable RSU Agreement.

7.2 RSU Elections. Any RSU Election will be made in the manner determined by the Committee. Notwithstanding the foregoing, an RSU Election shall only be effective if (a) the RSU Election was made in the calendar year prior to the calendar year in which the services to which the Shares and Restricted Stock Units relate are performed, (b) the RSU Election was made within 30 days of a Director Participant first becoming eligible to participate in the Plan and such RSU Election is limited to compensation earned following the date of such election, or (c) the Committee determined the RSU Election otherwise constitutes a compliant deferral election under Code Section 409A. Once a Director Participant makes an RSU Election, such election shall remain in place until revoked or changed by the Director Participant in accordance with procedures determined by the Committee. Any such revocation or change will only be effective with respect to Shares and Restricted Stock Units relating to service in calendar years following such revocation or change, unless otherwise provided by the Committee.

7.3 Vesting. The Committee shall, in its discretion, determine any vesting requirements with respect to a Restricted Stock Unit Award, which shall be set forth in the Award Agreement. The requirements for vesting of a Restricted Stock Unit Award may be based on the continued service of the Participant for a specified time period (or periods) and/or on the attainment of a specified performance goal (or goals) established by the Committee in its discretion. A Restricted Stock Unit Award may also be granted on a fully vested basis, with a deferred payment date as may be determined by the Committee or elected by the Participant in accordance with the rules established by the Committee.

7.4 Settlement of Restricted Stock Units. Restricted Stock Units shall be settled (*i.e.*, paid out) at the time or times determined by the Committee and set forth in the Award Agreement, which may be upon or following the vesting of the Award. Restricted Stock Units that constitute deferred compensation for purposes of Code Section 409A shall only be settled on dates or events that comply with Code Section 409A. If Restricted Stock Units are settled in cash, the payment with respect to each Restricted Stock Unit shall be determined by reference to the Fair Market Value of one Share on the day immediately prior to the settlement date. Restricted Stock Unit Award Agreements may provide for payment to be made in cash or in Shares, or in a combination thereof.

7.5 Dividend Equivalents. Restricted Stock Units may be granted, at the discretion of the Committee, with or without the right to receive Dividend Equivalents with respect to the Restricted Stock Units. A Dividend Equivalent is an unfunded, unsecured right to receive (or be credited with) an amount equal to the regular cash dividend payments (if any) the Participant would have been entitled to had he or she held the number of Shares underlying the Restricted Stock Units on the record date of any regular cash dividend on the Shares. The Committee may apply any terms, restrictions or conditions on the Dividend Equivalents as it deems appropriate (including, without limitation, deferring payment of the Dividend Equivalents until the related Restricted Stock Units are settled or converting Dividend Equivalents to additional Restricted Stock Units). Any such terms, restrictions or conditions shall be set forth in the Restricted Stock Unit Award Agreement.

7.6 No Rights as Stockholder. The Participant shall not have any voting or other rights as a stockholder with respect to the Shares underlying Restricted Stock Units until such time as Shares may be delivered to the Participant pursuant to the terms of the Award.

ARTICLE 8

Termination of Service

Each Award Agreement shall set forth the effect that Termination of Service shall have upon that Award. Such provisions shall be determined in the sole discretion of the Committee, need not be uniform among all Awards issued pursuant to the Plan, and may reflect distinctions based on the reasons for Termination of Service; provided, however, that the following shall automatically apply to the extent different provisions are not expressly set forth in a Participant's Award Agreement:

(a) Upon a Termination of Service for any reason other than death, retirement or Disability, all unvested Restricted Shares shall be forfeited as of the termination date.

(b) Upon a Termination of Service as a result of the Participant's death, retirement or Disability, all unvested Restricted Shares shall vest as of the termination date.

ARTICLE 9

Restrictions on Shares

All Shares issued pursuant to Awards granted hereunder, and a Participant's right to receive Shares upon vesting or settlement of an Award, shall be subject to all applicable restrictions contained in the Company's By-laws, shareholders agreement or insider trading policy, and any other restrictions imposed by the Committee, including, without limitation, restrictions under applicable securities laws, under the requirements of any stock exchange or market upon which such Shares are then listed and/or traded, and restrictions under any blue sky or state securities laws applicable to such Shares.

ARTICLE 10

Performance Measures

If an Award is subject to Code Section 162(m) and the Committee determines that such Award should be designed to comply with the Performance-Based Exception, the performance measure(s), the attainment of which determine the degree of vesting, to be used for purposes of such Awards shall be chosen from among earnings per share, economic value added, market share (actual or targeted growth), net income (before or after taxes), operating income, return on assets (actual or targeted growth), return on capital (actual or targeted growth), return on equity (actual or targeted growth), return on investment (actual or targeted growth), revenue (actual or targeted growth), share price, stock price growth, total shareholder return, or such other performance measures as are duly approved by the Committee and the Company's shareholders.

ARTICLE 11

Beneficiary Designation

Subject to the terms and conditions of the Plan and the applicable Award Agreement, each Participant may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom Shares under the Plan are to be transferred in the event of the Participant's death. Each such designation shall revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing during the Participant's lifetime with the party chosen by the Company, from time to time, to administer the Plan. In the absence of any such designation, Shares shall be paid to the Participant's estate following his death.

ARTICLE 12

Rights of Participants

12.1 Continued Service. Nothing in the Plan shall:

(a) interfere with or limit in any way the right of the Company to terminate any Participant's employment, service as a Director, or service as a Consultant with the Group at any time, or

(b) confer upon any Participant any right to continue in the service of any member of the Group as an Employee, Director or Consultant.

12.2 Participation. Participation is determined by the Committee. No person shall have the right to be selected to receive an Award under the Plan, or, having been so selected, to be selected to receive a future Award.

ARTICLE 13

Change in Control

Upon the occurrence of a Change in Control, unless otherwise specifically prohibited under applicable laws, or by the rules and regulations of any governing governmental agencies or national securities exchanges, any restrictions and transfer limitations imposed on Restricted Shares shall immediately lapse and any unvested Restricted Stock Units shall immediately become vested.

ARTICLE 14

Amendment or Termination

The Board may at any time and from time to time amend or terminate the Plan or any Award hereunder in whole or in part; provided, however, that no amendment which requires shareholder approval in order for the Plan to continue to comply with any applicable tax or securities laws or regulations, or the rules of any securities exchange on which the securities of the Company are listed, shall be effective unless such amendment shall be approved by the requisite vote of shareholders of the Company entitled to vote thereon; provided further that no such amendment or termination shall adversely affect any Award hereunder without the consent of the Participant.

ARTICLE 15

Withholding

15.1 Tax Withholding. The Company shall have the right to deduct or withhold, or require a Participant to remit to the Company, an amount sufficient to satisfy any taxes required by federal, state, or local law or regulation to be withheld with respect to any taxable event arising in connection with an Award.

15.2 Share Withholding. Participants may elect, subject to the approval of the Committee, to satisfy all or part of such withholding requirement by having the Company withhold Shares having a Fair Market Value equal to the minimum statutory total tax which could be imposed on the transaction. All such elections shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

ARTICLE 16

Indemnification

Each person who is or shall have been a member of the Committee, or of the Board, shall be indemnified and held harmless by the Company to the fullest extent permitted by applicable law against and from any loss, cost, liability, or expense that may be imposed upon or reasonably incurred by him or her in connection with or resulting from any claim, action, suit, or proceeding to which he or she may be a party or in which he or she may be involved by reason of any action taken or failure to act under the Plan and against and from any and all amounts paid by him or her in settlement thereof, with the Company's approval, or paid by him or her in satisfaction of any judgment in any such action, suit, or proceeding against him or her, provided he or she shall give the Company an opportunity, at its own expense, to handle and defend the same before he or she undertakes to handle and defend it on his or her own behalf. The foregoing right of indemnification is subject to the person having been successful in the legal proceedings or having acted in good faith and what is reasonably believed to be a lawful manner in the Company's best interests. The foregoing right of indemnification shall not be exclusive of any other rights of indemnification to which such persons may be entitled under the Company's Articles of Incorporation or Bylaws, as a matter of law, or otherwise, or any power that the Company may have to indemnify them or hold them harmless.

ARTICLE 17

Successors

All obligations of the Company under the Plan with respect to Awards granted hereunder shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation, or otherwise, of all or substantially all of the business and/or assets of the Company.

ARTICLE 18

Miscellaneous

18.1 Gender and Number. Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine; the plural shall include the singular and the singular shall include the plural.

18.2 Severability. In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

18.3 Requirements of Law. The granting of Awards and the issuance of Shares under the Plan shall be subject to, and may be made contingent upon satisfaction of, all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

18.4 Governing Law. To the extent not preempted by federal law, the Plan, and all agreements hereunder, shall be construed in accordance with and governed by the laws of the state of New Hampshire.

18.5 Section 409A Compliance. To the extent applicable, it is intended that the Plan and all Awards of Restricted Stock Units comply with the requirements of Section 409A, and the Plan and the Restricted Stock Unit Award Agreements shall be interpreted accordingly.

(a) If it is determined that all or a portion of a Restricted Stock Unit Award constitutes deferred compensation for purposes of Code Section 409A, and if the Participant is a “specified employee” (as defined in Code Section 409A(a)(2)(B)(i)) at the time of the Participant’s separation from service (as that term is used in Code Section 409A), then, to the extent required under Section 409A, any Shares or cash that would otherwise be paid upon the Grantee’s separation from service in respect of the Restricted Stock Units (including any related Dividend Equivalents that constitute deferred compensation for purposes of Section 409A) shall instead be paid on the earlier of (i) the first business day of the sixth month following the date of the Participant’s separation from service (as that term is used in Code Section 409A) or (ii) the Grantee’s death.

(b) If it is determined that all or a portion of a Restricted Stock Unit Award constitutes deferred compensation for purposes of Code Section 409A, upon a Change in Control that does not constitute a “change in the ownership” or a “change in the effective control” of the Company or a “change in the ownership of a substantial portion of a corporation’s assets” (as those terms are used in Code Section 409A), the Restricted Stock Units shall vest at the time of the Change in Control to the extent so provided Article 13, but settlement of any Restricted Stock Units (and payment of any related Dividend Equivalents Payments) that constitute deferred compensation for purposes of Code Section 409A shall not be accelerated (*i.e.*, payment shall occur when it would have occurred absent the Change in Control).

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(16) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;

b. Owned by the spouse or minor child of an officer or director; or

c. Controlled by the officer or director directly or indirectly.

Response:

For Northern Utilities, Inc. ("Northern"), the voting stock consists solely of common stock. All shares of common stock of Northern are owned by Unitil Corporation. Further, no director or officer, or spouse or minor child owns or controls any of the outstanding shares of common stock individually, directly or indirectly.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(17) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $10,000,000 in annual gross revenues, a list of all payments in excess of $10,000;
b. For utilities with $10,000,001 to $100,000,000 in annual gross revenues, a list of all payments in excess of $50,000;
c. For utilities with annual gross revenues in excess of $100,000,000, a list of all payments in excess of $100,000;
d. The reporting thresholds for a particular entity shall be on a cumulative basis, indicating the number of items comprising the total amount of expenditure. Quarterly income statements for the previous 2 years if not previously filed with the commission.

Response:

a. N/A
b. Please see PUC 1604.01(a) - 17 Attachment 1 for a list of all payment for contractual services over $50,000.00.
c. N/A
d. Please see PUC 1604.01(a) - 17 Attachment 1 for the total number of items compromising the expenditure.

Company	Total Expenditure	Total Items for Expenditure	Description
AECOM	230,010.18	24	Professional Services
ANDERSON WELDING LLC	313,178.94	11	Construction
APPLUS RTD	66,147.50	38	Professional Services
ATLANTIC HEATING COMPANY INC	87,481.00	119	Professional Services
CENTRAL MAINE POWER	77,212.82	416	Utility
CHASCO INC	425,013.00	35	Professional Services
COASTAL ROAD REPAIR	108,936.75	44	Paving
COLLINS PIPE	641,023.10	231	Materials
CONCENTRIC ENERGY ADVISORS	59,331.75	2	Professional Services
CONSOLIDATED COMMUNICATIONS	98,612.97	71	Utility
CONSOLIDATED COMMUNICATIONS	45,587.03	35	Utility
CONSOLIDATED PIPE & SUPPLY CO INC	216,631.30	5	Materials
CONTINENTAL INDUSTRIES	96,394.06	12	Materials
ELSTER AMERICAN METER	811,587.73	26	Materials
ELSTER PERFECTION CORPORATION	193,326.71	14	Materials
ENERGY FEDERATION INC	316,145.91	64	Incentives
ENERGY SOLUTIONS	134,287.76	21	Professional Services
F W WEBB COMPANY	66,870.09	105	Materials
GDS ASSOCIATES INC	61,609.66	19	Incentives
GORHAM SAND & GRAVEL INC	95,086.50	4	Materials
GRANITE GROUP	119,982.50	137	Rental Program
HART PLUMBING & HEATING INC	70,649.89	107	Plumbing
HEWITT & HEWITT LLC	86,550.00	10	Professional Services
INDEPENDENT PIPE & SUPPLY CO	70,134.47	57	Materials
ISCO INDUSTRIES	56,792.58	5	Materials
ITRON INC	151,450.11	6	Materials
JDH ENERGY SOLUTIONS LLC	325,289.90	108	Construction
K C AUTO REPAIR	214,252.22	173	Vehicle maintenance
KNOWLES INDUSTRIAL SERVICES	62,735.79	4	Professional Services
KUBRA DATA TRANSFER LTD	316,541.29	28	Communications
LIBERTY CONSULTING GROUP	111,228.75	4	Professional Services
MATTER COMUNICATIONS	56,000.00	12	Professional Services
MCDONALD MFG CO	58,115.04	6	Materials
MERCHANTS AUTOMOTIVE GROUP	1,204,580.63	133	Vehicle maintenance
MRC GLOBAL	401,111.02	48	Materials
MUELLER CO.	132,190.92	31	Materials
NEUCO	24,062,706.35	1916	Construction
NEW ENGLAND CONTROLS	66,866.30	16	Materials
NEW ENGLAND TRAFFIC CONTROL	109,670.02	51	Construction
NEWELL & CRATHERN LLC	59,317.84	11	Incentives
NG ADVANTAGE LLC	120,467.32	1	Construction
OMARK CONSULTANTS INC	146,293.88	68	Construction
PATRIOT MECHANCIAL LLC	1,001,537.13	341	Construction
PAVEMENT TREATMENTS, INC.	132,375.61	16	Paving
PIERCE ATWOOD LLP	142,360.39	47	Professional Services
PIONEER INSPECTION LLC	239,041.22	12	Professional Services
PORTSMOUTH CAR CLINIC	91,450.19	252	Vehicle maintenance
POWELL CONTROLS	717,264.97	79	Materials
PPI GAS DISTRIBUTION INC	263,273.70	72	Materials
PROCESS PIPELINE SERVICES	600,894.99	86	Construction
QUANTITATIVE BUSINESS ANALYTICS LLC	90,000.00	2	Professional Services
QUARTER TURN RESOURCES	169,788.07	5	Materials
R W LYALL & COMPANY	530,092.37	33	Materials
SANFORD POLICE DEPT	56,022.75	21	Construction
SCADA NETWORK SERVICES INC	81,340.60	13	Professional Services
SCOTTMADDEN INC	99,115.00	7	Professional Services
SHAW BROTHERS CONSTRUCTION	385,873.00	1	Construction
SOUTHERN NH SERVICES	75,882.01	7	Rebate
STRAFFORD COUNTRY COMMUNITY ACTION	251,221.85	13	Rebate
TITAN MECHANICAL INC	13,332.72	10	Construction
TMD SERVICE	14,915.00	9	Construction
TRI MONT ENGINEERING CO	1,225,889.71	35	Professional Services
UPSCO INC	163,703.24	23	Materials
UTILITIES & INDUSTRIES	147,207.39	11	Materials
WILLIAM WELLS	128,669.15	12	Professional Services
WOOD ENVIRONMENTAL	66,935.49	15	Professional Services

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(18) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations.

Response:

Per past rate-making treatment in New Hampshire, water heaters and conversion burners are included in the cost of service.

	Amount – 12/31/20
Utility Plant in Service	$ 1,893,900
Completed Construction Not Classified	84,995
Utility Plant in Service	1,978,895
Reserve for Depreciation	959,565
Net Utility Plant in Service	$ 1,019,330

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(19) Balance sheets and income statements for the previous 2 years if not previously filed with the commission.

Response:

This information is provided in the response to PUC 1604.01(a) - 1.

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(20) Quarterly income statements for the previous 2 years if not previously filed with the commission.

Response:

Please see PUC 1604.01(a) - 20 Attachment 1 for the quarterly income statements.

Northern Utilities, Inc. — Schedule 4 NH
Inc Stmt - NH - Rate Case — 5/5/2021
G_NU_NH_ISQ_Rate Case — For Periods Ending December 31, 2020

	QTD March 2019	QTD June 2019	QTD September 2019	QTD December 2019	QTD March 2020	QTD June 2020	QTD September 2020	QTD December 2020
OPERATING REVENUES								
Sales:								
Residential (480)	$17,297,900.33	$6,893,753.73	$2,763,678.97	$7,561,894.10	$13,498,306.05	$6,274,846.81	$2,757,279.77	$7,510,902.07
General Service (481)	14,339,998.13	5,583,142.74	2,469,239.92	5,914,453.24	9,908,747.36	4,304,388.35	2,227,408.36	5,881,355.87
Firm Transport Revenues (484, 489)	3,385,106.39	2,203,157.39	1,636,242.38	2,605,361.12	3,385,617.77	2,082,894.55	1,616,713.87	2,654,587.41
Sales for Resale (483)	2,480,636.94	192,625.69	36,327.05	161,389.30	725,085.32	130,520.47	74,843.45	177,010.21
Other Sales (495)	(5,720,375.24)	(3,555,748.19)	1,390,872.75	4,369,811.68	(2,948,222.62)	(1,294,125.26)	2,719,598.64	3,767,366.60
Total Sales	31,783,266.55	11,316,931.36	8,296,361.07	20,612,909.44	24,569,533.88	11,498,524.92	9,395,844.09	19,991,222.16
Other Operating Revenues:								
Late Charge (487)	16,690.38	35,805.55	14,405.35	9,871.87	36,802.72	(41.37)	(0.79)	0.00
Misc. Service Revenues (488)	189,543.15	203,559.87	230,178.89	252,473.05	195,522.26	184,147.70	227,097.71	245,535.90
Rent from Property (493 & 457)	50,238.00	50,238.00	50,238.00	50,238.00	54,657.00	54,657.00	54,657.00	54,657.00
Other Revenues	(295,304.18)	(46,606.52)	6,655.70	23,667.61	(43,223.23)	(1,192.72)	130,297.58	34,774.44
Total Other Operating Revenues	(38,832.65)	242,996.90	301,477.94	336,250.53	243,758.75	237,570.61	412,051.50	334,967.34
TOTAL OPERATING REVENUES	31,744,433.90	11,559,928.26	8,597,839.01	20,949,159.97	24,813,292.63	11,736,095.53	9,807,895.59	20,326,189.50
OPERATING EXPENSES								
Operation & Maint. Expenses:								
Production (710-813)	15,897,984.69	2,992,646.32	1,803,296.09	7,532,804.26	9,679,399.66	3,734,187.69	3,281,204.15	6,850,068.35
Transmission (850-857)	14,925.74	18,508.91	20,591.29	18,687.07	16,482.16	15,657.39	12,962.87	18,726.49
Distribution (870-894) (586)	825,902.76	829,704.98	973,980.45	879,860.20	914,785.18	837,253.58	974,637.13	1,006,701.18
Cust. Accounting (901-905)	796,921.15	614,299.84	740,995.02	616,541.95	717,133.94	502,507.61	597,049.97	791,497.42
Cust. Service & Info (906-910)	475,075.64	493,122.36	458,269.04	892,907.98	584,640.54	384,754.36	425,587.90	946,722.73
Sales Expenses (911-916)	18,673.75	17,084.36	12,737.55	15,971.54	17,779.26	15,158.77	16,924.44	19,315.28
Admin. & General (920-935)	2,001,034.98	1,953,404.11	2,060,366.26	1,664,485.80	1,934,001.93	1,504,409.67	1,518,700.11	1,783,664.79
Total O & M Expenses	20,030,518.71	6,918,770.88	6,070,235.70	11,621,258.80	13,864,222.67	6,993,929.07	6,827,066.57	11,416,696.24
Other Operating Expenses:								
Deprtn. & Amort. (403-407)	2,441,576.01	2,082,009.70	2,212,111.30	2,269,246.37	2,402,289.30	2,406,501.08	2,408,757.41	2,476,010.97
Taxes-Other Than Inc. (408)	1,218,120.73	925,510.62	996,155.03	1,166,511.12	1,251,898.27	1,273,193.69	1,245,615.57	1,097,066.41
Federal Income Tax (409)	(339.69)	(1,030,359.41)	50,284.72	1,032,794.57	(9,122.89)	4,342.47	(14,832.03)	(10,598.62)
State Franchise Tax (409)	(138.75)	(420,859.28)	(310,425.43)	421,876.01	(3,624.12)	1,725.07	(397,389.42)	14,644.69
Def. Income Taxes (410,411)	1,841,423.87	1,564,761.43	(237,311.03)	(193,191.18)	1,641,046.53	(41,173.10)	(87,341.26)	1,087,646.79
Total Other Operating Expenses	5,500,642.17	3,121,063.06	2,710,814.59	4,697,236.89	5,282,487.09	3,644,589.21	3,154,810.27	4,664,770.24
TOTAL OPERATING EXPENSES	25,531,160.88	10,039,833.94	8,781,050.29	16,318,495.69	19,146,709.76	10,638,518.28	9,981,876.84	16,081,466.48
NET UTILITY OPERATING INCOME	6,213,273.02	1,520,094.32	(183,211.28)	4,630,664.28	5,666,582.87	1,097,577.25	(173,981.25)	4,244,723.02
OTHER INCOME & DEDUCTIONS								
Other Income:								
Other (415- 421)	53,130.56	59,976.42	87,780.59	41,899.27	81,066.45	30,889.15	100,617.63	(6,234.44)
Other Income Deduc. (425, 426)	51,374.24	57,835.74	66,764.18	56,661.55	34,000.01	53,292.65	24,096.80	40,354.73
Taxes Other than Income Taxes:								
Income Tax, Other Inc & Ded	478.44	583.14	5,725.08	(4,035.03)	12,747.01	(6,067.54)	20,724.13	(12,617.75)
Net Other Income (Deductions)	1,277.88	1,557.54	15,291.33	(10,727.25)	34,319.43	(16,335.96)	55,796.70	(33,971.42)
GROSS INCOME	6,214,550.90	1,521,651.86	(167,919.95)	4,619,937.03	5,700,902.30	1,081,241.29	(118,184.55)	4,210,751.60
Interest Charges (427 - 432)	1,237,862.07	1,157,776.47	1,124,118.49	1,154,224.71	1,256,222.14	1,164,752.88	1,115,083.71	1,242,381.81
NET INCOME	4,976,688.83	363,875.39	(1,292,038.44)	3,465,712.32	4,444,680.16	(83,511.59)	(1,233,268.26)	2,968,369.79

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(21) Quarterly sales volumes for the previous 2 years, itemized for residential and other classifications of service, if not previously filed with the commission.

Response:

Please see PUC 1604.01(a) - 21 Attachment 1 for the quarterly itemized sales volume.

Northern Utilities, Inc.
Quarterly Sales Volumes (Therms)
New Hampshire

	Therms Qtr 1 2020	Therms Qtr 2 2020	Therms Qtr 3 2020	Therms Qtr 4 2020	Therms YTD 2020
Residential:					
R-6	83,528	54,674	37,913	55,501	231,616
R-5	8,588,415	3,617,817	1,035,892	4,046,430	17,288,554
R-10	236,594	113,221	23,181	92,303	465,299
Total Residential	8,908,537	3,785,712	1,096,986	4,194,234	17,985,469
Commercial:					
G-40	5,033,279	1,747,006	371,936	2,292,641	9,444,862
G-50	483,244	291,376	342,735	356,407	1,473,762
G-41	6,953,852	2,664,815	728,090	3,402,189	13,748,946
G-51	1,674,092	845,097	839,538	1,110,773	4,469,500
Total Commercial	14,144,467	5,548,294	2,282,299	7,162,010	29,137,070
Industrial					
G-42	2,435,807	1,089,754	620,034	1,677,926	5,823,521
G-52	4,078,851	3,896,872	3,876,176	4,332,317	16,184,216
Special Contract	3,124,848	2,366,008	2,773,498	2,944,269	11,208,623
Total Industrial	9,639,506	7,352,634	7,269,708	8,954,512	33,216,360
Grand Total	32,692,510	16,686,640	10,648,993	20,310,756	80,338,899

	Therms Qtr 1 2019	Therms Qtr 2 2019	Therms Qtr 3 2019	Therms Qtr 4 2019	Therms YTD 2019
Residential:					
R-6	90,111	52,221	36,815	57,534	236,681
R-5	9,528,223	3,651,169	1,004,461	4,573,834	18,757,687
R-10	292,547	119,970	21,470	107,924	541,911
Total Residential	9,910,881	3,823,360	1,062,746	4,739,292	19,536,279
Commercial:					
G-40	6,090,014	2,087,331	463,355	2,536,199	11,176,899
G-50	748,603	426,450	349,002	390,468	1,914,523
G-41	7,135,433	2,712,160	780,334	3,735,745	14,363,672
G-51	1,723,072	1,253,455	1,010,527	1,356,065	5,343,119
Total Commercial	15,697,122	6,479,396	2,603,218	8,018,477	32,798,213
Industrial					
G-42	2,376,724	1,064,178	601,528	1,973,973	6,016,403
G-52	4,569,441	4,447,329	4,079,452	4,158,318	17,254,540
Special Contract	3,225,478	3,245,717	3,122,855	3,110,317	12,704,367
Total Industrial	10,171,643	8,757,224	7,803,835	9,242,608	35,975,310
Grand Total	35,779,646	19,059,980	11,469,799	22,000,377	88,309,802

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(22) A description of the utility's projected need for external capital for the 2 year period immediately following the test year.

Response:

Northern Utilities, Inc. ("Northern") regularly reviews and analyzes its financing requirements. Over the next two years, Northern does not have definitive permanent financing plans. Northern will continue to monitor its need to raise long-term capital and request approval from the Commission if necessary.

For short-term debt financing, Northern participates in Unitil Corporation's Cash Pool to fund any cash shortfalls between long-term financings. The short-term borrowing limit is authorized by the Commission and subject to annual adjustment.

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(23) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately following the test year.

Response:

Please refer to the testimony of Mr. Kevin Sprague for the Company's capital budget and PUC 1604.01(a) 23 – Attachment 1 for the projected sources and uses of funds for calendar years 2021 and 2022.

Northern Utilities, Inc.
New Hampshire & Maine Divisions
Sources and Uses of Funds for Years 2021 and 2022
Including the Projected Construction Budgets
($000's)

	2021 Forecast	2022 Forecast
Sources:		
Net Income	$ 17,742	$ 20,296
D&A	24,179	26,190
Change in DIT	7,777	4,672
Net Borrowings and Other	28,574	24,729
Total Uses	$ 78,272	$ 75,886
Uses:		
Capex	$ 64,388	$ 63,107
Dividends	13,884	12,779
Debt Retirements	-	-
Total Uses	$ 78,272	$ 75,886

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(24) The amount of outstanding short-term debt, on a monthly basis during the test year, for each short-term indebtedness.

Response:

Please refer to PUC 1604.01(a) - 24 Attachment 1 for the month-end and average daily balance of short-term debt outstanding on a monthly basis during the test year.

Northern Utilities, Inc.
Short-Term Debt Outstanding
12 Months Ended December 31, 2020

Line No.	Month	Month-End Amount Outstanding	Average Daily Borrowings
1	January 2020	$ 28,666,840	$ 25,109,148
2	February 2020	24,794,114	23,351,619
3	March 2020	28,316,841	27,127,612
4	April 2020	27,939,753	25,053,060
5	May 2020	26,822,898	25,283,108
6	June 2020	25,298,270	24,327,028
7	July 2020	33,152,219	29,181,116
8	August 2020	37,754,315	34,429,766
9	September 2020	4,906,721	20,504,100
10	October 2020	18,132,923	9,559,681
11	November 2020	22,751,664	19,566,665
12	December 2020	26,747,022	24,606,907

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(25) If a utility is a subsidiary, a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service.

Response:

Please see PUC 1604.01(a) - 25 Attachment 1 for the Certificate.

Unitil
NH GAS OPERATIONS

Northern Utilities, Inc.

Pursuant to the New Hampshire Code of Administrative Rules, Part 1604.01(a)(25), Northern Utilities, Inc., hereby certifies the following:

No expense for the parent company (Unitil Corporation) is included in the cost of service for Northern Utilities, Inc., as filed in this rate case.

Daniel J. Hurstak
Controller
Northern Utilities, Inc.

State of New Hampshire
County of Rockingham, ss.

Signed and sworn this

18th day of May, 2021

Notary Public

Sandra L. Whitney
NOTARY PUBLIC
State of New Hampshire
My Commission Expires January 22, 2025

T 603.772.0775 | unitil.com

6 Liberty Lane West
Hampton, NH 03842

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(26) Support for figures appearing on written testimony and in accompanying exhibits.

Response:

Please refer to other volumes presented in this filing for support for figures appearing on written testimony and in accompanying exhibits.