NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
NOVEMBER 2019 / OCTOBER 2020 ANNUAL PERIOD
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
CHRISTOPHER A. KAHL

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. Please summarize your professional and educational background.

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

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

A. Yes, I have testified before the Commission in the 2018 / 2019 Annual Cost of Gas ("COG") proceeding, Docket No. DG 18-143 and the 2017 / 2018 Annual COG proceeding, Docket No. DG 17-144. I have testified in numerous other Cost of Gas proceedings as well.

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

A. This proceeding reflects the annual COG filing and will present both the 2019 / 2020 Winter Season and 2020 Summer Season COG rates as well as various ancillary rates. I, Francis Wells, Manager of Gas Supply for Unitil Service, and Elena Demeris, Senior Regulatory Analyst for Unitil Service are sharing the responsibility of supporting the proposed New Hampshire Division 2019 / 2020 Annual COG and other proposed rate adjustments in this proceeding with testimony.

Mr. Wells' testimony is with regard to the customer demand forecast and the resulting forecasted gas sendout and gas costs he developed for the Maine and New Hampshire Divisions. Mr. Wells also describes recent changes to Northen's supply portfolio.

Ms. Demeris' testimony concerns the calculation of the 2019 / 2020 Local Distribution Adjustment Clause ("LDAC"), and the typical customer bill impacts resulting from the proposed 2019 / 2020 Winter Season and 2020 Summer Season COG rates.

My testimony presents and explains the New Hampshire Division's 2018 / 2019 Annual COG Reconciliation, the calculation of the 2019 / 2020 annual COG and the rates Northern proposes to charge customers for the November 1, 2019 to April 30, 2020 Winter Season, and for the May 1, 2020 to October 31, 2020 Summer Season. In addition, I will also discuss some of the proposed ancillary rates that are to be effective November 1, 2019.

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

A. Before providing the list of attachments, I would like to point out that the filing has been reorganized in order for the benefit of the Commissioners, Commission Staff, the Office of the Consumer Advocate, and any other interested parties to more easily tie the schedules to the testimony. The new format of the filing presents the schedules in a more sequential order, consistent with the order in which they are referenced in the testimony. All schedule numbers are followed by the initials of the witness sponsoring the schedule. In addition, the proposed ancillary rates and other supporting information are located in the rear section of the filing. In adopting this new format, the Company has not eliminated any of the schedules provided in previous filings. Consistent with prior filings, all testimony is provided first. All supporting schedules are divided into four sections:

I. Introduction and Summary;

II. Cost of Gas Factor Calculations;

III. Gas Supply Costs;

IV. Ancillary Rates and Other Information.

My testimony will reference schedules in sections I, II and IV. The schedules that I have prepared in support of my testimony are listed below.

Schedule 1- CAK	Cost Overview & Calculation of the COG Rates
Schedule 2- CAK	Comparison of Proposed Residential Rates to 2018 / 2019 Rates
Schedule 4- CAK	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Schedule 5- CAK	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons
Schedule 6- CAK	Division Sales and Sendout Forecast
Schedule 7- CAK	Allocation of New Hampshire Demand Costs To New Hampshire Firm Sales Rate Classes
Schedule 8- CAK	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Schedule 9- CAK	New Hampshire Division Commodity Cost Analysis
Schedule 10- CAK	Northern Utilities Inventory Activity
Schedule 11- CAK	Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Schedule 12-CAK	Calculation of High and Low Load Factor Rate Adjustments
Schedule 13- CAK	2018 - 2019 Annual Reconciliation
Schedule 14- CAK	Bad Debt Forecast
Schedule 15-CAK	New Hampshire Division (Over) / Under-collection Balances and Interest Calculations
Schedule 27- CAK	Supplier Balancing Charge
Schedule 28- CAK	Prior Year Re-entry Rate and Conversion Rate Revenues
Schedule 29 -CAK	Short Term Debt Limit Calculation

Note: Schedules 3 and 16 through 25 are provided by Ms. Demeris and Mr. Wells.

II Summary

Q. Please Summarize Northern's proposed 2019 / 2020 Summer Period and Winter Period COG rates and describe how they compare to last year's rates.

A. Table 1 below provides Unitil's proposed 2019 / 2020 Winter Period COG rates and compares them to the average COG rates for the 2018 / 2019 Winter Period. As this table shows, Winter Period COG rates are lower than those in 2018 / 2019 by $0.2432 for residential customers and lower by $0.2364 and $0.2326 per therm for High and Low Load Factor Commercial / Industrial customers, respectively.

Table 1

Class	**2019 / 2020 Proposed Rate per therm**	**2018 / 2029 Average Rate per therm**	**Percent Change From Winter Period 2018 / 2019**
Residential Non-Heat (R-6, R-6 & R-10)	$0.5861	$0.8293	-29.33%
C & I - High Load Factor (G-50, G-51 & G-52)	$0.6082	$0.8446	-27.99%
C & I - Low Load Factor (G-40, G-41 & G-42)	$0.4950	$0.7276	-31.97%

Table 2 below provides Unitil's proposed 2019 / 2020 Summer Period COG rates and compares them to the average COG rates for the 2018 / 2019 Summer Period. As this table shows, the proposed COG rates are $0.0219 lower for Residential customers and $0.0143 and $0.0159 lower for High and Low Load Factor Commercial / Industrial customer, respectively.

Table 2

Class	**2019 / 2020** **Proposed** **Rate per therm**	**2018 / 2029** **Average** **Rate per therm**	**Percent Change From Winter Period 2018 / 2019**
Residential Non-Heat (R-6, R-6 & R-10)	$0.2768	$0.2987	-7.34%
C & I - High Load Factor (G-50, G-51 & G-52)	$0.2443	$0.2586	-5.54%
C & I - Low Load Factor (G-40, G-41 & G-42)	$0.3116	$0.3275	-4.86%

A summary of the calculation of these rates, and the components that make up these rates is provided in Schedule 1-CAK. A more detailed comparison of 2019 / 2020 residential COG rates to 2019 / 2020 residential rates is provided in Schedule 2-CAK. I will describe the reasons for the change in COG rates later in my testimony. Customer bill impacts resulting from the change in COG rates are discussed in the testimony of Ms. Demeris and are presented in Schedule 3-SED.

II. COST OF GAS FACTOR

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

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

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

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

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

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

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

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

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

[1] Pipeline, storage and peaking.

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

As I will explain in more detail below, I used the MPR methodology to allocate Northern's projected total annual demand costs to the Maine and New Hampshire Divisions for the 2019 / 2020 Winter Season (November 2019 through April 2020) and for the 2020 Summer Season (May 2020 through October 2020).

Q. Please give an overview of the process you followed to derive the MPR allocator used to assign Northern's projected total demand costs for the 12-month period November 2019 through October 2020 to the Maine and New Hampshire Divisions.

A. I have prepared Schedule 4-CAK to explain how I calculated the MPR factors and how I used these factors to allocate Northern's total demand costs for November 2019 through October 2020 ("COG Period") to the Maine and New Hampshire Divisions. In this attachment, I distinguish between two types of demand costs; Capacity-related and Off-system Peaking demand costs. Capacity-related demand costs reflect the resource costs of Pipeline, Storage and On-system Peaking supplies, as well as credits for capacity release and asset management agreements, for both Sales Service and capacity assigned Delivery Service customers. Off-system Peaking demand costs reflect the costs

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[2] For the MPR allocation process, Design Year demand is calculated as the actual demand to Maine and New Hampshire Division's firm sales and assigned capacity / non-grandfathered transportation customers for the period May 2018 through April 2019, adjusted to reflect design weather conditions from November through April and normal weather conditions from May through October.

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

Schedule 4-CAK is arranged in the following six major sections;

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

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

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

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

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

6) Total Demand costs for each division are then calculated by taking a weighted average of Capacity- related demand costs and Off-system Peaking demand costs as shown in Lines 124 through 137. From these calculations, the PR allocators are determined. As shown, for November 2019 through October 2020, the PR allocators are 58.16% for the Company's Maine Division and 41.84% for the New Hampshire Division.

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

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

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

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

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

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

The development of the MPR factors and the application of these factors to allocate Pipeline, Storage and On-system Peaking demand costs to each month are shown on Schedule 4-CAK, Lines 20 through 25, Lines 36 through 43 and Lines 47 through 52, respectively. In addition, Lines 29 through 32 show the calculation of the Storage Injection Fees, by month. Storage Injection Fees represent capacity costs that comprise the portion of Northern's pipeline capacity that is used to transport gas to and from the underground storage fields. If the Company expects to incur such fees, they fees are added to the Storage demand costs, as shown on Line 42, and subtracted from the Pipeline demand costs, as shown on Line 57. However, as indicated, for the 2019 / 2020 Winter Season, storage injection fees are zero. This is because Northern is purchasing storage gas directly at the underground storage facility thereby eliminating the need for transportation to the facility and the associated transfer of costs.

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

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

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

A. Northern's Total Capacity-related Demand Costs[6] and Capacity Release and Asset Management revenues allocated to each month are then allocated to the Maine and New Hampshire Divisions according to the design year total firm sendout for both divisions, which is shown in Lines 65 and 66 of Schedule 4-CAK; the calculated percentages are provided in Lines 70 and 71. In accordance with Commission-approved settlements[7], the design-year firm sendout quantities for the COG Period as shown on Lines 65 and 66 are the sendout quantities required to serve the Maine and New Hampshire Divisions' firm

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[5] As indicated, for the 2019 / 2020 Winter Season, the credit is zero due to purchases being made directly at the storage facility.
[6] Costs reflect pipeline, storage and on-system peaking resources.
[7] These settlements were approved in Docket Nos. 2005-87 and 2005-273.

sales and transportation customers that are subject to the assigned-capacity requirements under design winter conditions from May 2018 to April 2019.

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

A. Yes. Lines 101 through 106 of Schedule 4-CAK use the same process for allocating resource costs to each month as that used in Lines 47 through 52. Also, Lines 109 through 123 use the same process for applying monthly costs to divisional sendout as used in Lines 62 through 77. As shown in Lines 121 and 122, Off-system Peaking demand costs are allocated to each division based on the design year dispatch of Sales Service customers only.

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

A. The combined PR allocators are based on the weighted average of the Capacity-related and Off-system Peaking PR Allocators. Lines 125 and 130 of Schedule 4-CAK show the Capacity-related PR allocators while Lines 126 and 131 show the corresponding values for Off-system peaking PR allocators. Lines 127 and 132 show the combined PR Allocators, 58.16% for Maine and 41.84% for New Hampshire, used to assign costs between divisions.

B. <u>Allocation of New Hampshire Demand-Related Costs to Seasons</u>

Q. Please explain how the projected annual demand-related costs that are allocated to the New Hampshire Division are then assigned to be recovered in the 2019 / 2020 Winter Season and the 2020 Summer Season.

A. Northern allocates costs between the seasons as well as among customer classes through the Simplified Market Based Allocation ("SMBA") method. I have prepared Schedule 5-CAK to show detailed support for the allocation of New Hampshire Division Sales Customer demand costs to months, and then to seasons utilizing the SMBA method.

Lines 2 through 4 of Schedule 5-CAK summarize the Pipeline and Storage and Peaking demand costs that are allocated to the New Hampshire Division, as determined in Schedule 4-CAK. Lines 12 through 22 of Schedule 5-CAK show the calculation of Net Demand Costs for firm sales customers, which is Total Demand Costs allocated to the New Hampshire Division less the capacity assignment revenues from New Hampshire Division transportation customers. The Winter and Summer Season rates that will be charged to New Hampshire Division firm sales customers from November 2019 through October 2020 will recover: (1) the Net Pipeline Demand costs shown on Line 19; (2) the Net Storage costs shown on Line 20; and (3) the On-system Peaking demand costs shown on Line 21 of Schedule 5-CAK.[8]

[8] These direct demand costs are adjusted by Capacity Release and Asset Management revenues (Line 76); Interruptible margins (Line 77); and Re-Entry Rate and Conversion Rate Credits (Line 78).

Lines 26 through 40 of Schedule 5-CAK show the calculation of pipeline demand costs for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use demand costs.[9] The Base Use that is shown on Line 31 of Schedule 5-CAK is the average projected daily use in July and August 2020[10] for all firm sales classes. The Base Pipeline Use Demand cost that is shown on Line 39 of Schedule 5-CAK is calculated by multiplying Firm Sales Base Use, shown on Line 31, times the weighted average annual cost of pipeline capacity, as shown on Line 35 of Schedule 5-CAK. Line 40 shows the Remaining Pipeline Use Net Pipeline Demand costs for sales customers, which is the difference between total net Pipeline and Product Demand costs and Base Pipeline Use demand costs.

Lines 44 through 49 of Schedule 5-CAK show the calculation of the Proportional Responsibility ("PR") allocator that is used to allocate (a) Remaining Use Net Pipeline Demand costs and (b) Storage and On-system Peaking costs related to Firm Sales customers for twelve months, November 2019 through October 2020. Lines 51 through 55 show the calculation of the PR factor that is used to allocate (c) Capacity Release and Asset Management revenues, (d) Interruptible margins and Re-entry Rate and Conversion Rate revenues and (e) Off-system Peaking Supplies to the Winter Season months, November 2019 through April 2020. These PR factors are summarized by type of capacity cost at lines 60 through 65. Line 60 of Schedule 5-CAK shows that 1/12th of

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

10 Average Projected Daily demand by class in July and August is shown in Schedule 6-CAK, Line 48.

the net annual Base Use pipeline demand costs is allocated to each month, and Lines 69 through 79 show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the "All Months" and "Peak Months Only" allocation factors.

As shown on Line 79 of Schedule 5-CAK, $7,344,405 of total direct demand costs are allocated to the 2019 / 2020 Winter Season, and $725,806 is allocated to the 2020 Summer Season.

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

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

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

I have prepared Schedule 6-CAK to show the calculation of the factors that are used to allocate New Hampshire Division sales service Winter and Summer Season Base Use demand-related costs for each month to each sales service rate class. The firm sales forecast, shown on Lines 1 to 16, and the firm sendout forecast by class, shown on Lines

18 to 33, are used to determine: daily Base Use, shown on Lines 35 to 48; Base Use sendout, shown on Lines 49 to 64; and Remaining Use sendout, shown on Lines 66 to 80. The Base and Remaining Use sendout values for each class are used to allocate the seasonal demand costs to the New Hampshire Division firm sales classes.

I have prepared Schedule 7-CAK to show the allocation of Winter and Summer Season New Hampshire Division Net Demand costs to each firm sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Winter Season and Summer Season month as shown in Schedule 5-CAK, Lines 69 through 79, and (b) the Rate Class allocators as shown Schedule 6-CAK, Lines 49 to 80. The Base Use Sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Schedule 7-CAK. The Remaining Use Design Day allocators, which are used to allocate all other demand-related costs and credits to firm sales rate classes, are shown on Lines 39 through 48.

The following table shows the location in Schedule 7-CAK of the Net Demand-related costs and credits by component allocated to each firm sales rate class:

Demand Cost Component	Schedule 7-CAK
Base Capacity	Lines 24 through 37
Remaining Pipeline Capacity	Lines 50 through 66
Peaking and Storage Demand	Lines 68 through 84
Off-system Peaking Demand	Lines 86 through 102
Capacity Release & Asset Mgmt. Revenues	Lines 105 through 121
Interruptible, Re-entry & Conversion Revenues	Lines 123 through 139
Total Non-Base Capacity Costs	Lines 141 through 155
Total Capacity Costs	Lines 157 through 175

D. <u>Allocation of Variable Costs</u>

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

A. Variable costs include commodity costs and variable pipeline and storage costs[11] for firm sales. Mr. Wells prepared a forecast of Northern's variable gas costs by month, which is provided in Schedule 23-FXW. These variable gas costs have been allocated between the Maine and New Hampshire Divisions based on each Division's percentage of monthly firm normal sendout. I have prepared Schedule 8-CAK to show the allocation of the 2019 / 2020 Winter and Summer Season variable gas costs between the Maine and New Hampshire Divisions.

Q. Please explain Schedule 8-CAK.

A. Lines 1 through 10 of Schedule 8-CAK show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 12, and Lines 19 through 21 of Schedule 8-CAK. This Schedule also shows projected Off-system Sales revenues on Line 22. The pipeline commodity costs shown on Lines 12 and 19 are based on projected NYMEX prices as of August 30, 2019. The variable gas costs for firm sales service summarized, on Lines 24 and 36, are allocated to the Maine and New Hampshire Divisions based on projected monthly firm sales sendout

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

in each division; the allocators are shown on Lines 40, 41, 45 and 46. Schedule 8-CAK also shows the allocation of Commodity costs to the two Divisions, (Maine Division: Lines 51 through 57; New Hampshire Division: Lines 59 through 65). Finally, Schedule 8-CAK shows the inventory finance costs for underground storage and LNG resources (Lines 82 to 84), the allocation of these costs to the Maine and New Hampshire Divisions (Lines 87 to 89), and the allocation of New Hampshire Division's allocated share of annual inventory finance costs to the Winter Season, using the firm sales remaining sendout allocators (Lines 98 to 100).

I have prepared Schedule 9-CAK to summarize the New Hampshire Division variable gas costs that were determined in Schedule 8-CAK. This attachment also shows the calculation of base and remaining commodity costs.

Q. Please explain how you calculated the inventory finance costs for underground storage and LNG resources that are included in Schedule 8-CAK.

A. The allocation of inventory finance charges to the Company's Maine and New Hampshire Divisions are shown on Lines 87 and 88 of Schedule 8-CAK. These inventory finance costs, as shown on Lines 82 and 83 were calculated based on forecasted inventory activity calculations which are shown in Schedule 10-CAK.

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

A. I have prepared Schedule 11-CAK to show the allocation of New Hampshire Division variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the Base

Sendout allocators by rate class. Lines 22 to 35 show the allocation of the monthly New Hampshire Division Base Commodity costs[12] to each rate class. Lines 37 to 56 show the calculation of the Remaining Sendout allocators by rate class. Lines 57 to 70 show the allocation of the monthly New Hampshire Division Remaining Commodity costs[13] to each rate class. A summary of all commodity costs allocated to the New Hampshire Division's firm sales classes is shown on Lines 71 to 84.

E. <u>Adjustments</u>

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

A. Yes. Since Residential COG rates are based on the average cost of gas (total seasonal cost of gas divided by total seasonal demand), and the High and Low Load Factor Commercial and Industrial ("C&I") COG rates are determined through the SMBA method, an adjustment to C&I COG rates is required in order to properly recover all costs. Schedule 12-CAK adjusts C&I COG rates in order to account for differences between the average cost and SMBA methodologies. This adjustment is based on the difference in total revenues that would be collected from Residential customers under the two methodologies, and applies the difference to the C&I customer classes bases on their percentage of total C&I revenues.

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12 New Hampshire Division Winter Season Base Commodity costs by month are shown in Schedule 9-CAK, Line 34.

13 New Hampshire Division Winter Season Remaining Commodity costs and Hedging costs by month are shown in Schedule 9-CAK, Line 35.

F. Refunds

Q. Are there any refunds included in this filing?

A. There are no refunds included in this filing.

G. 2018 / 2019 Annual Reconciliation

Q. Please explain the 2018 / 2019 Annual COG Reconciliation.

A. The 2018 / 2019 Annual COG Reconciliation is provided as Schedule 13-CAK. As Page 1 of this Schedule indicates, the projected October 31, 2018 annual ending balance is an over-collection of $1,746,721. As shown on Page 1 of this Schedule, the allocation of the ending balance between seasons will be based on the portion of projected sales that occur in each season. Similar allocations are provided for Attachment A (Working Capital) and Attachment B (Bad Debt) of this Annual Reconciliation.

H. Miscellaneous Charges and Credits

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

A. Northern is projecting a combined total of $10,000 in revenues associated with the Re-entry Rate and Conversion Rate. This amount is included in Schedule 1-CAK at Line 14.

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

The Working Capital Costs were based on a formula approved in Northern's 2017 base rate proceeding, Docket No. DG 17-070. This formula derives the working capital percentage by dividing the supply related net lag of 10.02 days by 365 days and then multiplying the result by the prime interest rate. Based on the current prime rate of 5.25%, the Working Capital Percentage is 0.288%. This percentage, when multiplied by the each season's forecasted Direct Cost of Gas, yields a 2019 / 2020 Winter Season Working Capital Cost of $61,778 and a 2020 Summer Season Working Capital Cost of $7,609. These amounts are included in Schedule 1-CAK at lines 29 and 138.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2019 / 2020 Winter Season and 2020 Summer Season COGs?

A. To develop its bad debt projections, Northern forecasts 12 months of customer write-offs for both supply and distribution service. This forecast is based on actual experience and any recent unexpected increases or decreases in the number of customer write-offs.

As shown on Line 3 of Schedule 14-CAK, for the 12-months ended July 31, 2019, actual write-offs for Northern's New Hampshire Division were approximately $476,599. For the twelve months ended December 31, 2020, Northern projects annual Bad Debt expense to be $415,000 (Line 14).

The projected annual Bad Debt expense was then allocated to supply (41%) and distribution (59%) services based on the actual Bad Debt experience of these components over the 12-months ended July 31, 2019. This is shown on Lines 7 and 5, respectively, of Schedule CAK-14. The annual Bad Debt expense forecast allocated to supply, $168,378, as shown on Line 15, was then allocated further to the 2019 / 2020 Winter Season (91%) and 2020 Summer Season (9%) based on the allocation of demand costs between the Winter and Summer Seasons. This breakout establishes the Winter Season Bad Debt of

$153,235 (Line 16) and a Summer Season Bad Debt expense of $15,153, (Line 17). I have included these expenses at lines 36 and 144 in Schedule 1-CAK.

Q. What steps does the Company take to reduce its Bad Debt Expense?

A. In addition to proactively providing customers with tools and information to manage their accounts and avoid arrearages, the Company has a multi-step program in place for maximizing the collection of receivables from customers with delinquent balances and reducing bad debt. The goal of this program is to enable customers with delinquent balances the ability to avoid disconnection and continue to receive gas service while meeting their payment obligations. In this program, the Company employs a variety of measures to maximize collections of receivables and reduce bad debt. Customer specific measures include the following:

- Invoices are mailed out monthly so the customer is aware of any past due balance;
- All accounts with a delinquent balance that meet the criteria established by New Hampshire Public Utilities Commission ("PUC") rules, and are not protected from disconnection pursuant to said rules, receive a disconnect notice requiring that the customer pay the delinquent balance before the scheduled disconnection date or call the Company to discuss a payment plan;
- If the past due location is a master meter (e.g., a single meter that serves a multi-unit property), the property is posted to advise tenants of potential disconnection of service.

The Company also communicates regularly with its customers via bill messages, bill inserts, newsletters, and its website, and shares tools and information that enable customers to manage their accounts, including a budgeting tool, payment plan options, and information regarding the discount program and financial assistance.

In addition to the steps outlined above, Northern performs a monthly review of C&I customer accounts to identify commercial customers that have received four or more disconnect notices in a twelve month period. Unitil sends a deposit warning letter to such customers notifying them that if their outstanding balance is not paid within 30 days, the Company will assess a deposit to their account.

When a customer calls the Company in response to a disconnect notice or to otherwise address a delinquency, we review several options with the customer to resolve the delinquency, including full payment and sufficient partial payment coupled with a payment plan for the balance. All payment plans are confirmed in writing and then the monthly payment plan amount due is clearly displayed along with the due date on each invoice. The Company may also refer customers to “211” for contact information regarding discounted rates, financial assistance and energy efficiency programs.

When Northern learns that a customer is protected from a service disconnection per PUC rules, the Company codes customers’ accounts accordingly to prevent disconnect notices, but continues to work with the customers to set reasonable payment arrangements. Such efforts include monthly outbound calls to customers to discuss payment and plans and bi-monthly letters to customers to discuss payment and plans.

When a customer remains delinquent two days before the scheduled disconnection date, the Company will make an outbound call to attempt to secure payment and discuss the customer’s options. If an adequate payment is not received, an acceptable payment plan is not established, or the Company does not determine that the customer is protected from disconnection, the Company issues a disconnection work order to shut off the customer's service.[1]

If, after an account is shut off for non-payment, the customer calls and makes a full or otherwise sufficient payment, the Company will reinstate service to the customer, establish a payment plan for any remaining balance and may assess a deposit to the account. If the customer does not -address the unpaid balance after the disconnection, the Company closes the account and mails a final bill to the customer. If the customer does not make payment on the final bill, the Company makes two outbound calls to the customer to request payment or establish a reasonable payment plan. It is only after the Company receives no response to its proactive steps or if a customer does not follow through with their payment plan, that the customer account is referred to a Collection Agency and the receivables are classified as bad debt.

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

A. Northern's local production and storage costs were set at $476,106 in the Company's most recent base rate case proceeding, Docket No. DG 17-070, and are recovered solely in the Winter Season. Also in the last base rate case proceeding, A&G expenses were set at $580,455. Of this amount, $467,545 is recovered from sales customers in the Winter

[1] If a disconnection work order is issued during the Winter Moratorium, the Company makes contact with an adult resident of the property prior to disconnecting service.

Season and $112,910 is recovered in the Summer Season. These amounts are included in Schedule 1-CAK on lines 40, 42 and 150.

I. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG Factors or Rates for the 2019 / 2020 Winter Season and the 2020 Summer Season.

A. Schedule 1-CAK, which is similar to the Company's COG tariff Pages 40 through 43, has been prepared to explain the calculation of the proposed 2019 / 2020 Winter and 2020 Summer COG Factors. The text descriptions in Column D, pages 2, 4, 6, 8 and 10 explain the calculations on this tariff page and provide references to other schedules for the sources of the data that appear on referenced COG tariff pages. Schedule 1-CAK shows the calculation of the Winter and Summer Season COGs for each of Northern's three COG Rate Groups: (1) Residential classes R-5, R-6 and R-10; (2) C&I Low Winter use classes G-50, G-51 and G-52; and (3) C&I High Winter use classes G-40, G-41 and G-42.

As shown on Page 3 of Schedule 1-CAK, the 2019 / 2020 Winter Season projected Average COG is $0.5861 per therm (Line 66), which is the sum of the average Total Direct COG, $0.5949 per therm (Line 59) and the average Indirect COG, ($0.0088) per therm (Line 63). As shown of Page 7 of Schedule 1-CAK, the 2020 Summer Season, the projected Average COG is $0.2768 per therm (Line 175), which is the sum of the average Total Direct COG, $0.3034 per therm (Line 168) and the average Indirect COG, ($0.0266) per therm (Line 172).

Also shown on Schedule 1-CAK are the proposed Residential COG Factors for the 2019 / 2020 Winter Period (Line 68) and the 2020 Summer Period (Line 177), the proposed C&I Low Winter Use COG Factors for the 2019 / 2020 Winter Period (Line 72) and 2020 Summer Period (Line 181), and the proposed C&I High Winter Use COG Factors the Winter 2019 / 2020 Winter Period (Line 92) and 2020 Summer Period (Line 201).

Q. Please explain the calculation of the Working Capital allowances for the 2019 / 2020 Winter Season.

The total Working Capital allowance, $26,145 shown on Line 33 of Schedule CAK-1 is the sum of the current period working capital allowance, $61,778 (Line 29), plus the prior seasonal allocations of Working Capital reconciliation balance, ($35,633) (Line 31).

Q. Please explain the calculation of the Bad Debt allowance for 2019 / 2020 Winter Season.

A. The Bad Debt allowance, $150,423 (Line 38), is the sum of the current period bad debt allowances, $153,235 (Line 36), plus the seasonal allocations of the Bad Debt reconciliation balance, ($2,812) (Line 37).

Q. Please explain the calculation of the 2020 Summer Season Working Capital allowances.

The total Working Capital allowance, ($996), as shown on Line 141 of Schedule 1-CAK is the sum of the current period working capital allowance, $7,609 (Line 138), plus the prior seasonal allocations of Working Capital reconciliation balance, ($8,605) (Line 139).

Q. Please explain the calculation of the Bad Debt allowance for 2020 Summer Season.

A. The Bad Debt allowance, $14,490 (Line 146), is the sum of the current period bad debt allowances, $15,143 (Line 144), plus the seasonal allocations of the Bad Debt reconciliation balance, ($653) (Line 145).

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

A. Interest expense is calculated in Schedule 15-CAK (Line 95) and is based on expected costs and revenues during the Winter and Summer seasons. Winter and Summer period interest expense is also shown on Schedule 1-CAK, on Lines 21 and 130 respectively.

J. Summary Analyses

Q. How does the proposed average 2019 / 2020 Winter Season Residential COG rate compare to the average 2018 / 2019 Winter Season Residential COG rate?

A. Schedule 2-CAK compares the proposed 2019 / 2020 Winter Season Residential COG rate to the average 2018 / 2019 Winter Season Residential COG rate. As this Schedule indicates, the Winter Season 2018 / 2019 COG rate was adjusted several times during the season in order to minimize variances between target and projected end of season balance. Schedule 2-CAK also shows that the proposed 2019 / 2020 Winter Season COG rate, $0.5861 per therm, is about $0.2432 per therm lower than the average 2018 / 2019 Winter Season COG rate, $0.8293 per therm. This $0.2432 per therm decrease is due to a significant reduction in demand costs, a moderate reduction in commodity costs, higher projected sales, and a reconciliation over-collection compared to a reconciliation under collection in the prior year. The reduction in demand costs is due to significantly higher asset management revenues combined with lower pipeline demand charges and higher expected revenues from capacity assignment. Commodity costs are lower due to a reduction in NYMEX prices. This change in costs and projected sales for Residential customers is also applicable to C&I customers.

Q. How does the proposed 2020 Summer Season Residential COG rate compare to the filed 2019 Summer Season COG rate?

A. Schedule 2-CAK also compares the proposed 2020 Summer Season Residential COG rate to the average 2019 Summer Season Residential COG rate. As this Schedule indicates, the proposed 2020 Summer Season average COG rate, $0.2768 per therm, is $0.0219 per therm lower than the 2019 Summer Season Average COG, $0.2987 per therm. This $0.0219 per therm decrease is primarily due to the lower demand costs, higher sales and the reconciliation over-collection compared to the prior year's reconciliation under-collection. This change in costs and projected sales for Residential customers is also applicable to C&I customers.

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

A. Seasonal variances can differ for a number of reasons. This includes mid-season rate changes to the COG in the prior season, changes in seasonal demands, allocation of costs to the Summer and Winter Seasons, and fluctuations in NYMEX prices. For the 2019 / 2020 Winter Season, an early season COG rate increase helped boost the average COG rate whereas 2020 Summer COG rates have only reflected a rate decrease. In addition, the increase in Asset Management Agreement revenues in 2019 / 2020 is allocated solely to the Winter Period.

III. ANCILLARY CHARGES & SUPPORTING INFORMATION

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

A. I have provided updates to four ancillary charges / schedules and supporting information in schedules in Section 4 of the filing. First, I have updated the Supplier Balancing Charge to be effective November 1, 2019. The proposed charge remains unchanged at $0.71 per MMBtu. I have prepared Schedule 27-CAK to support the updated Supplier Balancing Charge calculation. Second, I have updated the On-system Peaking Demand charge to be effective November 1, 2019 through April 30, 2020. The proposed charge is $65.41 per Dth. Support for this charge is provided by Mr. Wells in Schedule 21-FXW. Both the Supplier Balancing Charge and On-system Peaking Demand Charge are included in Tariff Page No. 141, Appendix A.

Third, I have updated Tariff Page 156 which updates for capacity allocation percentages for all non-exempt Delivery Service customers for the period November 1, 2019 through October 31, 2020. The calculations supporting the capacity allocators are provided by Mr. Wells in Schedule 22-FXW.

Lastly, I have updated the Re-entry Rates and Conversion Rates to be effective November 1, 2019 through April 30, 2020, and May 1, 2020 through October 31, 2020. For both High and Low Load Factor C&I customers the Re-entry Rate is $0.0409 per therm in the Winter Season and $0.0406 per therm in the Summer Season. In the Winter

Season, the proposed Conversion Rate is $0.2537 for High Load Factor customers and $0.1405 for Low Load Factor C&I customers. In the Summer Season, the Conversion Rate is $0.0406 for both High and Low Load Factor customers. These rates appear on Tariff Page No. 158, Appendix D. Support for these rates is provided by Mr. Wells in Schedule 38-FXW.

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

A. Yes, Schedules 28-CAK and 29-CAK have not been discussed in my testimony. Schedule 29-CAK provides the historical revenues from the Re-entry Rate and Conversion Rate Surcharges that are applied to transportation customers returning to the Company's Sales Service. Schedule 29-CAK determines Northern's short-term debt limit calculation for the period November 2019 through October 2020.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2019 / 2020 Winter Season COG rates if it receives any new or updated information on gas supplier or transportation rates?

A. If requested by Commission Staff, the Company will file a revised calculation of its 2019 / 2020 Winter and Summer Season COG rates to reflect updated gas and pipeline transportation cost projections as well as any other cost information a few weeks prior to the effective date of the Winter Season, November 1, 2019. In addition, the Company will file proposed changes to the approved 2019 / 2020 Winter Season COG rates when the projected end-of-season variance exceeds 2% of the target projected cost of gas. As mentioned above, Schedule 15-CAK projects Northern's monthly COG over/under collections, balances and interest. Northern will update this schedule each month with actual costs and updated NYMEX prices in order to determine the variance between the latest projected end-of-season balances and the target end-of-season balances established in this COG filing. As indicated on Line 89 on that schedule, Northern projects an over collection target balance of $1,451,490 on April 30, 2020. This target balance will be updated in December to adjust for the actual balance effective November 1, 2019. If, during the upcoming Winter Season, the Company's monthly projected April 30, 2020 ending balance varies from the target balance by 2% or more of total target projected gas costs, then the Company will file to adjust the 2019 / 2020 Winter Season COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2019 / 2020 Winter Season COG rates.

Lastly, the Company will also file proposed changes to the approved 2020 Summer Season COG when the projected annual variance exceeds 4% of the target projected gas costs. As indicated on Schedule 15-CAK, Line 89, Northern projects an under-collection of $1,768 on October 31, 2020, the end of the Annual COG period. If, during the upcoming Summer Season, the Company's updated projected October 31, 2020 ending balance varies from the target Annual COG period balance by 4% or more of total targeted projected gas costs, and a rate change will help to lower the annual reconciliation balance, it will then file to change the 2020 Summer COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2020 Summer Period COG.

Q. Does this conclude your testimony?

A. Yes it does.