**NORTHERN UTILITIES, INC.**
**NEW HAMPSHIRE DIVISION**
**NOVEMBER 2022 / OCTOBER 2023 ANNUAL PERIOD**
**COST OF GAS ADJUSTMENT FILING**
**PREFILED TESTIMONY OF**
**CHRISTOPHER A. KAHL**

## I. INTRODUCTION

**Q. Please state your name and business address.**

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

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

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

**Q. Please summarize your professional and educational background.**

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

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

A. Yes, I have testified before the Commission in the 2021 / 2020 Annual Cost of Gas ("COG") proceeding, Docket No. DG 21-131 and the 2020 / 2021 Annual COG proceeding, Docket No. DG 20-154. I have testified in numerous other Cost of Gas proceedings as well.

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

A. This proceeding reflects the annual COG filing and will present both the 2022 / 2023 Winter Season and 2023 Summer Season COG rates as well as various ancillary rates. I, Francis Wells, Manager of Gas Supply for Unitil Service, Elena Demeris, Senior Regulatory Analyst for Unitil Service, and Daniel Nawazelski, Manager of Revenue Requirements for Unitil Service are sharing the responsibility of supporting Northern's proposed New Hampshire Division 2022 / 2023 Annual COG and other proposed rate adjustments in this proceeding.

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

Ms. Demeris is sponsoring the calculation of the 2022 / 2023 Local Distribution Adjustment Clause ("LDAC"), and the typical customer bill impacts resulting from the proposed 2022 / 2023 Winter Season and 2023 Summer Season COG rates.

Mr. Nawazelski is sponsoring the recovery of the expenses associated with the property tax adjustment mechanism component of the LDAC.

My testimony presents and explains the New Hampshire Division's 2021 / 2022 Annual COG reconciliation, the calculation of the 2022 / 2023 annual COG and the rates Northern proposes to charge customers for the November 1, 2022 to April 30, 2023 Winter Season, and for the May 1, 2023 to October 31, 2023 Summer Season. In addition, I will also discuss some of the proposed ancillary rates that are to be effective November 1, 2022 and May 1, 2023.

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

The Attachments that I have prepared in support of my testimony are listed below.

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|---|---|
| Attachment NUI-CAK-1 | Allocation of Northern Fixed Capacity Costs<br>To New Hampshire and Maine Divisions |
| Attachment NUI-CAK-2 | Allocation of New Hampshire Fixed Capacity Costs<br>To Months and Seasons |
| Attachment NUI-CAK-3 | Division Sales and Sendout Forecast |
| Attachment NUI-CAK-4 | Allocation of New Hampshire Demand Costs<br>To New Hampshire Firm Sales Rate Classes |
| Attachment NUI-CAK-5 | Allocation of Northern Commodity Costs<br>To New Hampshire and Maine Divisions |

| | |
|---|---|
| Attachment NUI-CAK-6 | New Hampshire Division Commodity Cost Analysis |
| Attachment NUI-CAK-7 | Northern Utilities Inventory Activity |
| Attachment NUI-CAK-8 | Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes |
| Attachment NUI-CAK-9 | Calculation of High and Low Load Factor Commercial & Industrial Customer Rate Adjustments |
| Attachment NUI-CAK-10 | 2021 - 2022 Annual Reconciliation |
| Attachment NUI-CAK-11 | Bad Debt Calculation |
| Attachment NUI-CAK-12 | New Hampshire Division (Over) / Under-collection Balances and Interest Calculations |
| Attachment NUI-CAK-13 | Summary of Cost of Gas Rate Calculations |
| Attachment NUI-CAK-14 | Comparison of Proposed Rates to Current Rates |
| Attachment NUI-CAK-15 | Supplier Balancing Charge |
| Attachment NUI-CAK-16 | Prior Year Re-entry Rate and Conversion Rate Revenues |
| Attachment NUI-CAK-17 | Short Term Debt Limit Calculation |

## II Summary

**Q. Please Summarize Northern's proposed 2022 / 2023 Summer Period and Winter Period COG rates and describe how they compare to last year's rates.**

A. Table 1 below provides Northern's proposed 2022 / 2023 Winter Period COG rates and compares them to the average COG rates for the 2021 / 2022 Winter Period. As this table shows, Winter Period COG rates are higher than those in 2021 / 2022 by $0.1638 for residential customers and higher by $0.1824 and $0.1618 per therm for High and Low Load Factor Commercial / Industrial ("C / I") customers, respectively.

**Table 1**

**Winter Period Cost of Gas Rates**

| Class | 2022 / 2023 Proposed Rate per therm | 2021 / 2022 Average Rate per therm | Percent Change From 2021/2022 Winter Period |
|---|---|---|---|
| Residential Non-Heat (R-5, R-6 & R-10) | $1.1357 | $0.9719 | 16.85% |
| C & I - High Load Factor (G-50, G-51 & G-52) | $1.0604 | $0.8780 | 20.77% |
| C & I - Low Load Factor (G-40, G-41 & G-42) | $1.1496 | $0.9878 | 16.38% |

Table 2 below provides Northern's proposed 2022 / 2023 Summer Period COG rates and compares them to the average COG rates for the 2021 / 2022 Summer Period. As this table shows, the proposed COG rates are $0.2431 lower for Residential customers, $0.2580 lower for High Load Factor C / I customers and $0.2233 lower for Low Load Factor C / I customers.

**Table 2**

**Summer Period Cost of Gas Rates**

| Class | 2022 / 2023 Proposed Rate per therm | 2021 / 2022 Average Rate per therm | Percent Change From 2021 / 2022 Summer Period |
|---|---|---|---|
| Residential Non-Heat (R-5, R-6 & R-10) | $0.6927 | $0. 9358 | (25.98)% |
| C & I - High Load Factor (G-50, G-51 & G-52) | $0.6342 | $0. 8922 | (28.92)% |
| C & I - Low Load Factor (G-40, G-41 & G-42) | $0.7394 | $0. 9627 | (23.20)% |

A summary of the calculation of these rates, and the components that make up these rates is provided in Attachment NUI-CAK-13. A more detailed comparison of 2022 / 2023 residential COG rates to 2022 / 2023 residential rates is provided in Attachment NUI-CAK-14. I will describe the reasons for the change in COG rates later in my testimony. Customer bill impacts resulting from the change in COG rates are discussed in the testimony of Ms. Demeris and are presented in Attachment NUI-SED-3.

## II. COST OF GAS FACTOR

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

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

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

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

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

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

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

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

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

[1] Pipeline, storage and peaking.

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

As I will explain in more detail below, I used the MPR methodology to allocate Northern's projected total annual demand costs to the Maine and New Hampshire Divisions for the 2022 / 2023 Winter Season (November 2022 through April 2023) and for the 2023 Summer Season (May 2023 through October 2023).

**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 2022 through October 2023 to the Maine and New Hampshire Divisions.**

A. I have prepared Attachment NUI-CAK-1 to explain how I calculated the MPR factors and how I used these factors to allocate Northern's total demand costs for November 2022 through October 2023 ("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 2021 through April 2022, adjusted to reflect design weather conditions from November through April and normal weather conditions from May through October.

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

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

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

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

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

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

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

6) Total Demand costs for each division are then calculated by applying the ratio of each division's Capacity-related demand costs and Off-system Peaking demand costs to Northern's total costs as shown in Lines 124 through 137. From these calculations, the PR allocators are determined. As shown, for November 2022 through October 2023, the PR allocators are 59.14% for the Company's Maine Division and 40.86% for the New Hampshire Division.

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

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

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

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

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

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

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

The development of the MPR factors and the application of these factors to allocate Pipeline, Storage and On-system Peaking demand costs to each month are shown on Attachment NUI-CAK-1, Lines 20 through 25, Lines 36 through 43 and Lines 47 through 52, respectively. In addition, Lines 29 through 32 show the calculation of the Storage Injection Fees, by month. Storage Injection Fees represent capacity costs that comprise the portion of Northern's pipeline capacity that is used to transport gas to and from the underground storage fields. If the Company expects to incur such fees, they are added to the Storage demand costs, as shown on Line 42, and subtracted from the Pipeline demand costs, as shown on Line 57. However, as indicated, for the 2022 / 2023 Winter Season, storage injection fees are zero. This is because Northern is purchasing storage gas

4 The forecast of demand costs is provided in Attachment NUI-FXW-5.

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

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

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

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

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[5] As indicated, for the 2022 / 2023 Winter Season, the credit is zero due to purchases being made directly at the storage facility.
[6] Costs reflect pipeline, storage and on-system peaking resources.

settlements[7], the design-year firm sendout quantities for the COG Period as shown on Lines 65 and 66 are the sendout quantities required to serve the Maine and New Hampshire Divisions' firm sales and transportation customers that are subject to the assigned-capacity requirements under design winter conditions from May 2021 to April 2022.

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

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

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

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

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

132 show the combined PR Allocators, 59.14% for Maine and 40.86% 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 2022 / 2023 Winter Season and the 2023 Summer Season.**

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

Lines 2 through 4 of Attachment NUI-CAK-2 summarize the Pipeline and Storage and On-system Peaking demand costs that are allocated to the New Hampshire Division, as determined in Attachment NUI-CAK-1. Lines 12 through 22 of Attachment NUI-CAK-2 show the calculation of Net Demand Costs for firm sales customers, which is Total Demand Costs allocated to the New Hampshire Division less the capacity assignment revenues from New Hampshire Division transportation customers. The Winter and Summer Season rates that will be charged to New Hampshire Division firm sales customers from November 2022 through October 2023 will recover: (1) the Net Pipeline

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

Lines 26 through 40 of Attachment NUI-CAK-2 show the calculation of pipeline demand costs for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use demand costs.[9] The Base Use that is shown on Line 31 of Attachment NUI-CAK-2 is the average projected daily use in July and August 2023[10] for all firm sales classes. The Base Pipeline Use Demand cost that is shown on Line 39 of Attachment NUI-CAK-2 is calculated by multiplying Firm Sales Base Use, shown on Line 31, times the weighted average annual cost of pipeline capacity, as shown on Line 35 of Attachment NUI-CAK-2. Line 40 shows the Remaining Pipeline Use Net Pipeline Demand costs for sales customers, which is the difference between total net Pipeline and Product Demand costs and Base Pipeline Use demand costs.

Lines 44 through 49 of Attachment NUI-CAK-2 show the calculation of the Proportional Responsibility ("PR") allocator that is used to allocate (a) Remaining Use Net Pipeline Demand costs and (b) Storage and On-system Peaking costs related to Firm Sales customers for twelve months, November 2022 through October 2023. Lines 51 through 56 show the calculation of the PR factor that is used to allocate (c) Capacity Release and Asset Management revenues, (d) Interruptible margins and Re-entry Rate and Conversion

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

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

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

Rate revenues and (e) Off-system Peaking Supplies to the Winter Season months, November 2022 through April 2023. These PR factors are summarized by type of capacity cost at lines 60 through 65. Line 60 of Attachment NUI-CAK-2 shows that 1/12th of the net annual Base Use pipeline demand costs is allocated to each month, and Lines 69 through 79 show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the "All Months" and "Peak Months Only" allocation factors.

As shown on Line 80 of Attachment NUI-CAK-2, $10,341,068 of total direct demand costs are allocated to the 2022 / 2023 Winter Season, and $1,4520,867 is allocated to the 2023 Summer Season.

### C. <u>Allocation of New Hampshire Winter and Summer Season Demand Costs to Customer Classes</u>

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

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

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

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

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

| Demand Cost Component | Attachment NUI-CAK-4 |
|---|---|
| Base Capacity | Lines 24 through 37 |
| Remaining Pipeline Capacity | Lines 50 through 66 |

| | |
|---|---|
| Peaking and Storage Demand | Lines 68 through 84 |
| Off-system Peaking Demand & Outage Expense | Lines 86 through 102 |
| Capacity Release & Asset Mgmt. Revenues | Lines 105 through 121 |
| Interruptible, Re-entry & Conversion Revenues | Lines 123 through 139 |
| Total Non-Base Capacity Costs | Lines 141 through 155 |
| Total Capacity Costs | Lines 157 through 175 |

### D. Allocation of Variable Costs

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

A. Variable costs include commodity costs and variable pipeline and storage costs[11] for firm sales. Mr. Wells prepared a forecast of Northern's variable gas costs by month, which is provided in Attachment NUI-FXW-8. These variable gas costs have been allocated between the Maine and New Hampshire Divisions based on each Division's percentage of monthly firm normal sendout. I have prepared Attachment NUI-CAK-5 to show the allocation of the 2022 / 2023 Winter and Summer Season variable gas costs between the Maine and New Hampshire Divisions.

**Q. Please explain Attachment NUI-CAK-5.**

A. Lines 1 through 10 of Attachment NUI-CAK-5 show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 19, 20 and 21 of Attachment NUI-CAK-5. This Attachment also shows

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

projected Off-system Sales revenues on Line 22. The pipeline commodity costs shown on Lines 12 and 19 are based on projected NYMEX prices as of September 7, 2022. The total variable gas costs for firm Sales Service, on Lines 24 and 36, are allocated to the Maine and New Hampshire Divisions based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 40, 41, 45 and 46. Attachment NUI-CAK-5 also shows the allocation of Commodity costs to the two Divisions, (Maine Division: Lines 51 through 57; New Hampshire Division: Lines 59 through 65). Finally, Attachment NUI-CAK-5 shows the inventory finance costs for underground storage and LNG resources (Lines 82 to 84), the allocation of these costs to the Maine and New Hampshire Divisions (Lines 87 to 89), and the allocation of New Hampshire Division's allocated share of annual inventory finance costs to the Winter Season, using the firm sales remaining sendout allocators (Lines 98 to 100).

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

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

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

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

A. I have prepared Attachment NUI-CAK-8 to show the allocation of New Hampshire Division variable gas costs to each firm sales class. Lines 1 to 21 show the calculation of the Base Sendout allocators by rate class. Lines 22 to 35 show the allocation of the monthly New Hampshire Division Base Commodity costs[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. Attachment NUI-CAK-9 adjusts C&I COG rates in order to account for differences

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

between the average cost and SMBA methodologies. This adjustment is based on the difference in total projected costs that would be assigned to Residential customers under the two methodologies, and applies the difference to the C&I customer classes based on their percentage of total allocated C&I demand and commodity costs.

### F. Refunds

**Q. Are there any refunds included in this filing?**

A. There are no refunds included in this filing.

### G. Indirect Costs and Miscellaneous Charges / Credits

**Q. Please explain the 2021 / 2022 Annual COG Reconciliation.**

A. The 2021 / 2022 Annual COG Reconciliation is provided as Attachment NUI-CAK-10. As Page 1 of this Attachment indicates, the projected October 31, 2022 annual ending balance is an over-collection of ($2,419,538). This balance is comprised of a Winter Season over-collection of ($2,519,772) and a Summer Season under-collection of $100,234.

**Q. How are the respective Summer and Winter reconciliation balances calculated?**

A. The end of season balances for the Summer and Winter periods are calculated in Appendix F of the reconciliation. For the Winter Season, the ending balance is determined by first calculating the difference between the estimated and actual April 30, 2022 balance as shown on Lines 1 through 4. This amount reflects the total cost of gas of which the working capital and bad debt balances (lines 4 & 5) must then be subtracted in order to determine the balance for demand and commodity, an over-collection of ($265,275) (Line 8). From this amount, an adjustment must be made for changes in asset management agreement ("AMA") revenues. These AMA revenues of ($2,247,007) are shown on Line 10 of Attachment F. Combining the commodity and demand balance (Line 8) with AMA revenue and interest (Lines 10 & 12) equals the Winter Season balance of ($2,419,538). The Summer Season balance, $100,234 (Line 18), is determined by subtracting the Winter Season balance (Line 14) from the annual reconciliation balance (Line 16).

**Q. Please explain why AMA revenues are factored in to the Winter Season ending balance?**

A. AMA revenue is updated annually beginning in April of each year and all revenues are received in twelve equal monthly installments. For the period April 2022 through March 2023, AMA revenues are substantially higher than in the prior year. In addition, all AMA revenues are allocated to the winter period as shown in Attachment NUI-CAK-2, Line 77. Therefore, the credits from the increase in AMA revenue must also be flowed back to the winter period. Due to the timing of the change in AMA revenues, winter period rates cannot be adjusted during the winter months and the impact of changes in AMA revenue, from May through October, must be recovered in the reconciliation. If there had been no change in AMA revenues, the winter balance would have been an over-collection of (‘$265,275) as listed on Line 8.

**Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2022 / 2023 Winter Season and 2023 Summer Season COGs?**

A. To develop its bad debt projections, Northern forecasts 12 months of customer write-offs for both supply and distribution service. This forecast is based on actual experience and any recent unexpected increases or decreases in the number of customer write-offs. As shown on Line 14 of Attachment NUI-CAK-11, for the twelve months ended December 31, 2023, Northern projects annual Bad Debt expense to be $400,000. The projected annual Bad Debt expense was then allocated to supply (35%) and distribution (65%) services based on the actual Bad Debt experience of these components over the 12-months ended July 30, 2022. This is shown on Lines 7 and 5, respectively, of Attachment NUI-CAK-11. The annual Bad Debt expense forecast allocated to supply was then allocated further to the 2022 / 2023 Winter Season (88%) and 2023 Summer Season (12%) based on the allocation of direct demand costs between the Winter and Summer seasons. This breakout establishes the Winter Season Bad Debt of $121,564 (Line 16) and a Summer Season Bad Debt expense of $17,079, (Line 17). I have also included these expenses at lines 36 and 144 in Attachment NUI-CAK-13.

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

The Working Capital Costs were based on a formula approved in Northern's 2021 base rate proceeding, Docket No. DG 21-104. This formula derives the working capital percentage by dividing the supply related net lag of 9.30 days by 366 days and then multiplying the result by the prime interest rate. Based on the current prime rate of 5.5%, the Working Capital Percentage is 0.1398%. This percentage, when multiplied by each season's forecasted Direct Cost of Gas, yields a 2022 / 2023 Winter Season Working

Capital Cost of $58,708 and a 2023 Summer Season Working Capital Cost of $8,045. These amounts are included in Attachment NUI-CAK-13 at lines 29 and 138.

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

A. Northern's local production and storage costs were set at $214,538 in the Company's most recent base rate case proceeding, Docket No. DG 21-104, and are recovered solely in the Winter Season. Also in the last base rate case proceeding, A&G expenses were set at $611,875. Of this amount, $492,287 is recovered from sales customers in the Winter Season and $119,588 is recovered in the Summer Season. These amounts are included in Attachment NUI-CAK-13 on lines 40, 42 and 150 respectively.

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

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

### H. Cost of Gas Factor

**Q. Please explain the calculation of the proposed New Hampshire Division COG Factors or Rates for the 2022 / 2023 Winter Season and the 2023 Summer Season.**

A. Attachment NUI-CAK-13, which is similar to the Company's COG tariff Pages 40 through 43, has been prepared to explain the calculation of the proposed 2022 / 2023 Winter and 2023 Summer COG Factors. Attachment NUI-CAK-13 shows the calculation of the Winter and Summer Season COGs for each of Northern's three COG Rate Groups: (1) Residential classes R-5, R-6 and R-10; (2) C&I Low Winter use classes G-50, G-51 and G-52; and (3) C&I High Winter use classes G-40, G-41 and G-42.

As shown on Page 3 of the Attachment, the 2022 / 2023 Winter Season projected Average COG is $1.1357 per therm (Line 66), which is the sum of the average Total Direct COG, $1.1830 per therm (Line 59) and the average Indirect COG, ($0.0473) per therm (Line 63). As shown of Page 7 of the Attachment, the 2023 Summer Season, the projected Average COG is $0.6927 per therm (Line 175), which is the sum of the average Total Direct COG, $0.6673 per therm (Line 168) and the average Indirect COG, $0.0254 per therm (Line 172).

Also shown on the Attachment are the proposed Residential COG Factors for the 2022 / 2023 Winter Period (Line 68) and the 2023 Summer Period (Line 177), the proposed C&I Low Winter Use COG Factors for the 2022 / 2023 Winter Period (Line 72) and 2023 Summer Period (Line 181), and the proposed C&I High Winter Use COG Factors the Winter 2022 / 2023 Winter Period (Line 92) and 2023 Summer Period (Line 201).

**Q. Please explain the calculation of the Working Capital allowances for the 2022 / 2023 Winter Season.**

The total Working Capital allowance, $66,291 as shown on Line 33 of Attachment NUI-CAK-13 is the sum of the current period working capital allowance (Line 29) plus the prior seasonal allocation of Working Capital reconciliation balance (Line 31).

**Q. Please explain the calculation of the Bad Debt allowance for 2022 / 2023 Winter Season.**

A. The Bad Debt allowance, $110,983 (Line 38), is the sum of the current period bad debt allowance (Line 36) plus the seasonal allocation of the Bad Debt reconciliation balance (Line 37).

**Q. Please explain the calculation of the 2023 Summer Season Working Capital allowances.**

The total Working Capital allowance, $9,887 as shown on Line 141 of Attachment NUI-CAK-13 is the sum of the current period working capital allowance (Line 138) plus the prior seasonal allocations of Working Capital reconciliation balance (Line 139).

**Q. Please explain the calculation of the Bad Debt allowance for 2023 Summer Season.**

A. The Bad Debt allowance, $16,522 (Line 146), is the sum of the current period bad debt allowances (Line 144), plus the seasonal allocations of the Bad Debt reconciliation balance (Line 145).

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

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

## I. <u>Summary Analyses</u>

**Q. How does the proposed average 2022 / 2023 Winter Season Residential COG rate compare to the average 2021 / 2022 Winter Season Residential COG rate?**

A. Attachment NUI-CAK-14 compares the proposed 2022 / 2023 Winter Season Residential COG rate to the average 2021 / 2022 Winter Season Residential COG rate. As Attachment shows, the proposed 2022 / 2023 Winter Season COG rate, $1.357 per therm, is $0.1638 per therm higher than the average 2021 / 2022 Winter Season COG rate, $0.9719 per therm. The increase is due to a significant increase in gas supply costs. The impact of higher commodity costs is partially offset by an increase AMA revenue, and a reconciliation over-collection compared to an under-collection compared the prior year. Commodity costs are higher due to material increases in NYMEX prices. The change in costs and AMA revenues for Residential customers is also applicable to C&I customers.

**Q. How does the proposed 2023 Summer Season Residential COG rate compare to the filed 2022 Summer Season COG rate?**

A. Attachment NUI-CAK-14 also compares the proposed 2023 Summer Season Residential COG rate to the average 2022 Summer Season Residential COG rate. As this Attachment indicates, the proposed 2023 Summer Season average COG rate, $0.6927 per therm, is $0.2431 per therm lower than the 2022 Summer Season Average COG, $0.9358 per therm. The rate decrease is due to the amended CGF rates in September and October 2022 that were required to cover the expected costs associated with very high NYMEX prices during the second half of the 2022 Summer Season. At this time, 2023 NYMEX prices are significantly lower than those in 2022 which reduce projected CGF rates below 2022 levels. This decrease in commodity costs is partially offset by higher demand costs, a larger reconciliation under-collection and small increases in bad debt, working capital and miscellaneous overhead. This change in COG rates for Residential customers is also applicable to C&I customers.

## III. ANCILLARY CHARGES & SUPPORTING INFORMATION

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

A. I have provided updates to four ancillary charges / schedules and supporting information to four separate schedules. First, I have updated the Supplier Balancing Charge to be effective November 1, 2022. The proposed charge remains unchanged at $1.00 per MMBtu. I have prepared Attachment NUI-CAK-15 to support the updated Supplier Balancing Charge calculation. Second, I have updated the On-system Peaking Demand charge to be effective November 1, 2022 through April 30, 2023. The proposed charge is $72.72 per Dth. Support for this charge is provided by Mr. Wells in Attachment NUI-FXW-5. Both the Supplier Balancing Charge and On-system Peaking Demand Charge are included in Tariff Page No. 141, Appendix A.

Third, I have updated Tariff Page 156 which updates the capacity allocation percentages for all non-exempt Delivery Service customers for the period November 1, 2022 through

October 31, 2023. The calculations supporting the capacity allocators are provided by Mr. Wells in Attachment NUI-FXW-7.

Lastly, I have updated the Re-entry Rates and Conversion Rates to be effective November 1, 2022 through April 30, 2023, and May 1, 2023 through October 31, 2023. For the Winter Season, the Re-entry Rate is $.0709 per therm for both high and low load factor customers. For the Summer Season the Re-entry Rate is $0.0000 in the Summer Seasons for the both the high and low load factor C&I rate classes. In the Winter Season, the proposed Conversion Rate is $1.6421 per therm for High Load Factor customers and $1.5529 per therm for Low Load Factor C&I customers. In the Summer Season, the Conversion Rate is $0.0000 per therm for both High and Low Load Factor customers. These rates appear on Tariff Page No. 158, Appendix D. Support for these rates is provided by Mr. Wells in Attachment NUI-FXW-11.

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

A. Yes, Attachments NUI-CAK-16 and NUI-CAK-17 have not been discussed in my testimony. Attachment NUI-CAK-16 provides the historical revenues from the Re-entry Rate and Conversion Rate Surcharges that are applied to transportation customers returning to the Company's Sales Service. Attachment NUI-CAK-17 determines Northern's short-term debt limit calculation for the period November 2022 through October 2023.

## IV. FINAL MATTERS

**Q. Will the Company propose to revise the 2022 / 2023 Winter Season COG rates if it receives any new or updated information on gas supplier or transportation rates?**

A. If requested by the Commission or Department of Energy Staff, the Company will file a revised calculation of its 2022 / 2023 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, 2022. In addition, the Company will file proposed changes to the approved 2022 / 2023 Winter Season COG rates when the projected end-of-season variance exceeds 2% of the target projected cost of gas. As mentioned above, Attachment NUI-CAK-12 projects Northern's monthly COG over/under collections, balances and interest. Northern will update this schedule each month with actual costs and updated NYMEX prices in order to determine the variance between the latest projected end-of-season balances and the target end-of-season balances established in this COG filing. As indicated on Line 92 on that Attachment, Northern projects a target balance over collection of $2,067,835[14] on April 30, 2023. This target balance will be updated in November to adjust for the actual balance effective October 31, 2022. If, during the upcoming Winter Season, the Company's monthly projected April 30, 2023 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 2022 / 2023 Winter Season COG for the subsequent month. These rates will

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[14] This over-collection is projected to be near $0 by October 31, 2023

take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2022 / 2023 Winter Season COG rates.

Lastly, the Company will also file proposed changes to the approved 2023 Summer Season COG when the projected annual variance exceeds 4% of the target projected gas costs. If, during the upcoming Summer Season, the Company's updated projected October 31, 2023 ending balance varies from the target Annual COG period balance by 4% or more of total Summer Period projected gas costs, the Company will file to change the 2023 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 2023 Summer Period COG.

**Q. Does this conclude your testimony?**

A. Yes it does.