NORTHERN UTILITIES, INC.

REPORT CONCERNING THE ALLOCATION OF GAS SUPPLY RESOURCES BETWEEN NORTHERN'S MAINE AND NEW HAMPSHIRE DIVISIONS AND THE CALCULATION OF THE MONTHLY GAS SUPPLY COMMODITY COST ALLOCATOR

I. EXECUTIVE SUMMARY

During the course of preparing its 2011-2012 Winter Season Cost of Gas ("COG") filing for New Hampshire and its 2011-2012 Peak Period Cost of Gas Factor ("CGF") filing for Maine in 2011, Northern Utilities, Inc. ("Northern" or "the Company") discovered an inconsistency in the allocation of its gas supply resource costs ("Resource Costs") between its Maine and New Hampshire Divisions. Shortly thereafter, the Company determined the allocation of Resource Costs to its Maine and New Hampshire Divisions required revision with regards to the inclusion of the Maine Division's company-managed sales volumes in its monthly gas supply commodity cost allocator ("the Allocator"). As a result, in November 2011, Northern updated the Allocator, and, in its 2012 Summer Season COG/Off-Peak Season CGF filings, included monthly Allocation Adjustments to its 2011 Summer/Off-Peak COG/CGF Reconciliations. At this point, the Company continued its research to determine the impact on the inter-state allocation of Resource Costs between New Hampshire and Maine resulting from the exclusion of the Maine Division's company-managed sales volumes from the Allocator from December 2008 to October 2011.

This report is the result of that research effort. It provides a background to the calculation and allocation of Resource Costs, an explanation as to why Northern excluded Maine Division company-managed sales volumes in the determination of the allocation of Resource Costs between New Hampshire and Maine in its COG/CGF filings during the period December 2008 through October 2011, and, lastly, provides a recalculation of Resource Costs and other associated cost elements to be allocated between Northern's New Hampshire and Maine Divisions.

The report concludes that the exclusion of the Maine Division's company-managed sales volumes from the allocation in the COG/CGF filings occurred during this period, even though a correction to the allocation formula to include these volumes had been introduced by Northern's predecessor owner's regulatory reporting group in its Maine Division CGF proceeding, Docket No. 2008-343, during the summer of 2008. The correction to the allocation formula, however, was never memorialized in either an internal Company procedures manual or in the regulatory order issued in Docket No. 2008-343 in October of 2008, and therefore the updated allocation formula was not communicated to the regulatory reporting group at Northern during the 2008-2009 transition from the predecessor owner to Unitil. Accordingly, when Northern was acquired by Unitil in December 2008, the Company carried forward the predecessor owner's uncorrected regulatory reporting formulas until Northern's recent determination that the Allocator had not been updated to conform with what had been presented in Docket No. 2008-343.

A recalculation of resource and other associated costs, based on allocation factors that include Northern's Maine Division's company-managed volumes, for the period December 2008 to October 2011 would result in a net decrease/credit to the New Hampshire division's COG of ($4,130,679) and a net increase/charge to the Maine division's CGF of $4,136,640. Detail providing support for the derivation of this recalculation is provided in Section IV, below.

Unlike a typical LDC, Northern has two divisions, located in separate states, but which are served by an integrated resource portfolio. Any reallocation of the costs of the portfolio between the divisions results in offsetting adjustments between the divisions: Northern does not profit or realize any financial benefit from the allocation or, when appropriate, reallocation of costs. An incorrect allocation of costs results in each division's COG/CGF improperly reflecting the cost of serving its respective customers. In order to correctly reflect the cost of service, any reallocation, therefore, must be made to the costs, and ultimately, the rates of both divisions. Accordingly, Northern recommends that the New Hampshire and Maine Public Utilities Commissions ("Commissions") address and resolve this matter jointly as they have in the prior proceedings such as those for the Modified Proportional Responsibility ("PR") Allocator ("Modified PR Allocator") and Northern's recent Integrated Resource Plan ("IRP") filing

II. BACKGROUND

A. NORTHERN'S RESOURCE COSTS

What are the Resource Costs of a typical natural gas local distribution company (LDC)?

Resource Costs for a typical LDC result from purchases of upstream interstate pipeline transportation and storage services, purchases of gas supplies to be consumed by customers and use of the LDC's on-system peaking facilities, like LNG.

Resource Costs are separated into two functional categories; demand and commodity. Demand-related costs are based on the maximum daily volume to be used or contracted for. Commodity-related costs are based on the daily volume used. Resource Costs are further separated into two seasons

How are the LDC's Resource Costs collected?

For the most part, LDCs recover their Resource Costs through COG Adjustment Clauses. LDCs aggregate their estimated Resource Costs and derive a per unit COG rate to be charged to bundled sales customers consuming the LDC's gas supplies in the upcoming seasonal period. COG rates may differ by customer class. An LDC's actual Resource Costs are reconciled in seasonal COG Reconciliations.

In recent years, Northern has incurred approximately $30 million annually in actual Resource Costs for each division, New Hampshire and Maine. The Company's annual Resource Costs can vary widely depending on the market price for gas supplies.

Are Resource Costs mitigated?

Yes. LDCs mitigate demand-related Resource Costs by assigning and/or releasing specific capacity contract shares and their respective costs to customers migrating from bundled sales service to distribution-only service, their third-party suppliers or their marketers ("Marketers").

For Northern, capacity contract shares and costs are assigned and/or released on voluntary and mandatory bases as discussed below. Collection of these mitigated costs is discussed below also.

B. ALLOCATING NORTHERN'S RESOURCE COSTS TO THE DIVISIONS

How does Northern allocate its Resource Costs to the Maine and New Hampshire Divisions?

As previously noted, Northern has an integrated resource (capacity and gas supply) portfolio that serves the two divisions located in separate states. Therefore, the Company must allocate its Resource Costs to each division in an appropriate manner.[1] The Company uses separate methods to allocate its demand- and commodity-related Resource Costs to the Maine and New Hampshire Divisions.

Northern uses the Modified Proportional Responsibility ("PR") Allocator to allocate expected and actual demand-related upstream interstate pipeline transportation and storage services costs and gas supply costs. The use of the PR Allocator was agreed to pursuant to settlement agreements approved in Maine Docket Nos. 2005-087 and 2005-273 and New Hampshire Docket No. DG05-080. The PR Allocator splits demand costs over the entire gas year, November through October, and is based on each division's expected design-year sendout and projected costs. For the gas year beginning November 2011, the PR Allocator assigned 52.62% of Northern's demand-related costs to the Maine Division and 47.38% to the New Hampshire Division.

For allocating expected and actual demand- and commodity-related on-system LNG peaking facility costs, Northern uses the fixed amounts approved by the respective state

[1] As noted above, cost allocation for Northern is a Zero-Sum Game. This means, if +$1 is reallocated to the Maine Division, then -$1 is reallocated to the New Hampshire Division.

Commissions in the Company's latest rate case proceedings. For the Maine Division these annual costs are $780,867; for the New Hampshire Division the costs are $719,362.

Northern uses each division's relative share of total expected (normal year) or actual sendout to allocate expected and actual <u>commodity-related</u> upstream interstate pipeline transportation and storage services costs and gas supply costs. The derivation of these allocators is explained below.

Please define "sendout."

Sendout is the volume (and makeup) of gas supply dispatched to meet the needs of Northern's firm bundled and company-managed sales customers, company use, and lost and unaccounted for ("LAUF") gas.

How is sendout used to allocate Northern's commodity-related costs to the Maine and New Hampshire Divisions?

Northern's expected and actual commodity-related interstate pipeline transportation and storage services costs and gas supply costs are allocated to the divisions based on each division's relative share of total sendout. Expected sendout is used to allocate expected commodity-related costs for COG/CGF ratemaking purposes, while actual sendout is used to allocate actual commodity-related costs for COG/CGF Reconciliation purposes.

C. CAPACITY ASSIGNMENT AND CAPACITY RELEASE

Please provide an overview of Northern's capacity assignment and capacity release transactions?

As mentioned above, Northern mitigates its Resource Costs by assigning and/or releasing capacity to migrating customers or their Marketers. Capacity assignment and releases refer to the transfer and use of an LDC's actual resources held within a gas supply and capacity portfolio. There are significant differences between these two cost mitigation transactions.

Capacity *release* transactions were mandated by the Federal Energy Regulatory Commission ("FERC") in the early 1990s. Capacity releases allow the holder of interstate pipeline and storage contracts ("the Shipper") to voluntarily release any portion of their capacity contracts to another party ("the Replacement Shipper"). Typically, unless prearranged at the maximum recourse rate, released capacity has been subject to competitive bids and awarded to the highest bidder. Upon release of a capacity contract or a portion thereof, the Replacement Shipper is held responsible for conducting business (nominations, balancing, etc.) with the pipeline or storage company that directly bills the Replacement Shipper for the released capacity and credits the Shipper. After such credits, the Shipper pays any balance due the pipeline.[2] In the Northeast, LDCs, like Northern, voluntarily release capacity in non-peak periods when bundled sales customer daily demands are below maximum daily contract quantity capacity levels. Capacity releases mitigate the Company's total demand-related Resource Costs.

---

[2] This balance reflects any difference between what the Shipper and Replacement Shipper pay for the contract service. During some months of the year Replacement Shippers may pay a discounted price for the contract service.

Capacity *assignment* transactions differ from capacity release transactions in that the Marketer is required or mandated by state PUC retail-choice programs to accept assignment of and pay for a portion of the LDC's gas capacity and supply portfolio. Capacity assignment programs were established by PUCs to address customer migration from bundled sales.

In the mid-to-late 1990s, commercial and industrial ("C&I") customers began switching or migrating from the LDC's bundled sales service to distribution-only service. This migration resulted in the LDC's remaining bundled sales customers, who were mostly residential customers, being allocated upstream pipeline and storage capacity originally acquired to serve the C&I customers who had migrated to distribution only service. In order to protect remaining bundled sales customers from higher costs, PUCs mandated that migrating C&I customers (or their Marketers) be assigned a portion of the LDC's capacity (by release, if possible) and pay for this portion of the LDC's capacity and gas supply resources.

Capacity assignment transactions allow an LDC to include its on-system LNG and propane facilities in the assignment, as well as Canadian pipeline transportation and storage capacity contracts that are not releasable within the regulatory jurisdiction of Canada's National Energy Board. As with capacity release, capacity assignment mitigates Northern's total demand-related Resource Costs.

D. THE NEW HAMPSHIRE AND MAINE DIVISION CAPACITY ASSIGNMENT PROGRAMS

Please compare the capacity assignment programs of the New Hampshire and Maine Divisions

In November 2000, in Docket Nos. DG 00-046 and DG 00-063, the New Hampshire PUC instituted a mandatory capacity assignment program for all bundled sales customers who migrate to distribution-only service after January 1, 2001. Under this program, the volume of capacity assigned is equal to the amount required to meet the migrating customer's Total Contract Quantity ("TCQ"), which is their expected design day load. This program utilizes a "slice of the system" approach where the migrating customer or Marketer is assigned capacity in slices. Each slice is comprised of one or more resources that comprise a capacity path.[3] In this assignment, upstream pipeline transportation and storage contracts that can be released are released; assignments of contracts and on-system capacity that are not released are company-managed assignments.

The Maine Division's mandatory capacity assignment program was approved in Docket Nos. 2005-087 and 2005-273. It went into effect on January 1, 2006. This program has several key differences from the New Hampshire Division's program. The first difference is that customers who migrate from bundled sales are assigned a TCQ equal to

---

[3] A capacity path provides a route by which a gas supply travels from its source to Northern's service territory. For example, Northern's "Tennessee's Long Haul Capacity Path" is comprised of two segments (Segment 1: Tennessee's supply region through Tennessee Pipeline up to Granite State Pipeline; and Segment 2: Granite State Pipeline to Northern delivery points) whereas, Northern's "Washington-10 Capacity Path" is comprised of comprised of six segments (Segment 1: Washington-10 Storage; Segment 2: Vector Pipeline from Washington-10 Storage; Segment 3: Union Gas Pipeline from Vector; Segment 4: TransCanada Pipeline from Union; Segment 5: PNGTS Pipeline from TransCanada; and Segment 6: Granite State Pipeline to Northern delivery points).

only 50 percent of their design day demand (the remaining capacity needed on the design day is the responsibility of the customer or their Marketer). The second difference is that the entire TCQ is made up of capacity assigned from three specific capacity paths, all of which are managed by the Company.[4] A third difference is that the program is in effect only during five of the six Peak Period months, November through March.

How does the Company manage capacity that is assigned buy not released?

As noted above, some of Northern's capacity and supply resource portfolio and Resource Costs are not under FERC jurisdiction, such as the Canadian transportation contracts and the Company's on-system LNG resources. Thus, these resources cannot be released. Pursuant to the two states' retail choice programs, these resources are assigned to Marketers, but they are managed by the Company and, accordingly, are referred to as "company-managed" resources.[5]

On any day, a Marketer can submit to Northern a nomination up to the assigned volume, seeking delivery of a gas supply from any one of the Company's company-managed resources. Northern will deliver a gas supply to the Marketer at the Company's city gate. Final delivery to the customer is made via the Company's distribution system. To complete this capacity assignment transaction, Northern directly bills the Marketer for this supply purchase.

---

[4] These paths are comprised of the Washington 10 Capacity Path and two Peaking Capacity Paths which are typically Winter Season delivered supplies.

[5] The Company notes that if any particular resource in a capacity path cannot be released, Northern will make the entire path company-managed. For instance, the Washington-10 Capacity Path includes non-releasable TransCanada contracts. Thus, this capacity path is company-managed.

How is the sales price of company-managed supply derived by Northern?

The sales price consists of a demand charge and a commodity charge. These charges are derived differently for the New Hampshire and Maine Divisions.

In the New Hampshire Division, the demand charges for company-managed supply are based on the demand costs of each pipeline, storage and peaking contract resource assigned to the Marketer. In the Maine Division, there is a single demand charge determined by taking Maine's share of total annual demand costs and dividing it by its share of total capacity. This annual cost is then converted to a five-month demand charge (November through March). The Company provides detailed calculations for both the Maine and New Hampshire Division demand charges in the Winter/Peak COG/GAF filings.

The derivation of the New Hampshire Division's commodity charge for company-managed supply is based on the commodity costs for each capacity path's cost of gas, variable transportation charges and the costs of fuel loss. In the Maine Division, the commodity charge for company-managed supply is based on the actual costs for the available path. These costs are then blended with the commodity costs from the capacity paths that are not assigned, such as Tennessee production area capacity. This blending is designed to have Maine Division Marketers pay the same price for supply as if they used all resources on Northern's system (i.e. a slice of the system approach).

How is the revenue received by Northern from company-managed supply sales accounted for in the COG Reconciliation?

The revenue received from the sale of company-managed supply for both the Maine and New Hampshire Divisions is listed as line items in Northern's seasonal COG Reconciliations. Specifically, this monthly revenue appears in FORM III, Schedule 4 of the Reconciliation filing as a credit to monthly gas supply demand and commodity costs.

How are the costs incurred by Northern for company-managed supply accounted for in the COG Reconciliation?

Each day, Northern purchases enough gas supply to meet the needs of all bundled sales customers, including company-managed sales volume. Thus, the Company's monthly invoices from its gas suppliers include purchases used to make company-managed sales. These invoices make up the gas supply commodity costs included in Northern's seasonal COG Reconciliations. Specifically, these monthly costs appear in FORM III, Schedule 4 of the Reconciliation filing as charges to gas supply commodity costs. However, because company-managed costs are included in the Company's aggregated commodity purchases, they are not listed as a separate line item. Therefore, in order to properly assign the company-managed costs to each division, they are allocated pursuant to a formula, termed the "Allocator."

III. DERIVATION OF THE ALLOCATOR

How has the Allocator been derived since December 2008?

In August 2008, prior to the anticipated transition of ownership, NiSource provided to Unitil personnel written instructions listing the components to be used in deriving the Allocator, including a list of components.

These instructions provided that the Allocator of actual total Company monthly gas supply commodity costs between the two divisions is to be derived using the current month COG volumes plus Company Use volumes, Company-managed volumes (for New Hampshire only) and Unaccounted For volumes (New Hampshire 1%; Maine 2%) less Interruptible Volumes, with a BTU adjustment for Maine Division Mcf volume.

Northern used this derivation of the Allocator until November 2011.

What caused Northern to question the derivation of the Allocator?

As described above, company-managed sales volumes are made to Marketers in both divisions from Northern's overall gas supply purchases. However, the Allocator used for the period December 2008 through October 2011 included company-managed volumes for the New Hampshire Division only, and not the Maine Division. In preparing its 2011-2012 Winter Season COG filing, the regulatory reporting group at Northern questioned why there appeared to be an inconsistency as to why the Maine Division company-managed volume was not included in the Allocator. The inclusion of only New Hampshire Division company-managed volume in the derivation of the Allocator omits the supply purchased by the Company for the Maine's Division's company-managed sales. In other words, excluding Maine Division company-managed sales volumes from the Allocator results in the New Hampshire Division being allocated a higher percentage of actual monthly gas supply commodity costs, unless the Maine Division company-managed sales volume is accounted for elsewhere.

Has Northern been able to determine whether Maine Division company-managed sales volumes are accounted for elsewhere in other Maine Division sales volumes, so as to justify its exclusion as a line item in the derivation of the Allocator?

No. The Company reviewed numerous COG/CGF filings as well as accounting documents transferred from NiSource to Unitil in order to determine if there was any information that would explain why New Hampshire Division company-managed volume only is included in the derivation of the Allocator. The Company was unable to find an explanation. Based on this review, the Company has concluded that the Maine Division company-managed sales volumes are not accounted for in any of the other monthly sales components, and therefore should not be excluded as a line item in the Allocator.

In the course of its investigation, the Company discovered that this issue had been raised previously by Northern prior to its acquisition by Unitil. The cover letters to Northern's 2007-2008 Winter/Peak Period COG Reconciliations, dated September 15, 2008 for the New Hampshire Division and August 15, 2008 for the Maine Division, mention the inadvertent omission of the Maine Division's company-managed volumes from the Allocators. These letters (and the accompanying COG/CGF Reconciliations) are included in Appendix A.

The transcripts from the 2008 Off-Peak Period Maine Division CGF proceeding, Docket No. 2008-343, includes a discussion of the Maine Division company-managed volumes being inadvertently omitted in the initial calculation of the Allocator (page 45-64).[6] A copy of the transcript pages is included as Appendix B. Although this issue was raised just prior to Unitil's acquisition of Northern, the correction for the omission of the Maine Division company-managed volumes from the calculation of the Allocator was not memorialized in any Northern procedures manual, or in the regulatory order issued in Docket No. 2008-343 in October of 2008, and therefore the updated allocation formula was not communicated to the regulatory reporting group at Northern during the 2008-2009 transition from the predecessor owner to Unitil.

IV. RECALCULATION OF THE HISTORIC COG/CGF RECONCILIATIONS

Has the Company revised the historic monthly Allocators for the period from December 2008 through October 2011 to account for Northern's Maine Divisions company-managed volumes?

Yes. The monthly Allocators have been revised and used to rerun the COG/CGF Reconciliations for the six seasonal periods for each division since December 2008.

Have there been any other changes or revisions made to the derivation of the Allocator since 2008, that are included in these recalculations?

---

[6] The Maine PUC's order approving Northern's CGF filing in Docket No. 2008-343, issued on October 28, 2008, does not include any discussion of or reference to this issue, although the corrected allocation resulted in an increase to Northern's Maine Division CGF of approximately $3.2 million. Similarly, the regulatory order for the Northern's New Hampshire COG proceeding for the same period, Order No. 24,912 in Docket DG 08-115, in which a credit to the COG of the same amount was applied as a result of the inclusion of the Maine Division's company-managed supply volumes, does not contain any discussion of or reference to this issue.

Beginning in November 2010, Northern made a revision to each division's monthly LAUF[7] gas supply percentage and volume to reflect the actual 4-year historical rolling-average LAUF percentage, as calculated for the Winter/Peak Period COG/CGF and used throughout the gas year. Before then, Northern used fixed estimated LAUF percentages (for the New Hampshire Division 1%; for the Maine Division 2%) to determine each month's LAUF volume includable in the Allocator. The current LAUF rates are 1.17% for the Maine Division and 0.87% for the New Hampshire Division.

The Company also revised its New Hampshire Division's company-managed volumes from December 2008 through March 2009 to include additional volumes that had been inadvertently omitted.

Please provide a summary of the impact of the recalculations on the COG/CGF Reconciliations for both divisions.

Please see Schedule 1, which provides a summary of the recalculation of seasonal COG/CGF Reconciliations. As shown on Schedule 1, page 2, line 88, the total impact would be a credit to Northern's New Hampshire Division of $4,130,679 and a charge to the Maine Division of $4,136,640.

Attached as Schedules 2 through 13 are the original COG/CGF reconciliations[8] for each period and each division, as well as the recalculated COG/CGF reconciliations which are based on allocation factors that include the Maine Division's company-managed

---

[7] An adjustment was also made to remove company-managed volumes from the LAUF calculation, as those volumes are net of LAUF.
[8] As originally filed, with only minor corrections.

volumes. Attached as Schedule 14 are the recast monthly Allocators. Attached as Schedules 15 and 16 are the derivations of the Allocation Adjustments to each division's monthly gas supply commodity costs included in the recalculated COG/CGF Reconciliations. Lastly, attached as Schedule 17 is a summary of each division's total impact by period and by type of revision (company managed, LAUF, etc.)

Why do the resulting recalculations for each division not precisely offset each other?

The recalculated amounts are not precisely offsetting due to division specific COG/CGF Reconciliation carrying charge, working capital, and bad debt allowance rates.

V. RECOMMENDATION FOR RESOLUTION OF THIS MATTER

How does the Company propose to solve this matter?

As Northern's two divisions, located in separate states, are served by an integrated resource portfolio, any reallocation of COG/CGF costs of the portfolio between the divisions is a zero sum game. Northern did not profit from nor realize any financial benefit from the original allocation of Resource Costs, and will not gain any benefit from a reallocation of these costs. An incorrect allocation of costs results in each division's COG/CGF improperly reflecting the cost of serving its respective customers. In order to correctly reflect these COG/CGF costs, any reallocation, therefore, must be made to the costs, and ultimately, the rates of both divisions. Accordingly, Northern recommends that the New Hampshire and Maine Commissions address and resolve this matter jointly as they have in past proceedings such as those for the Modified PR Allocator and Northern's Recent Integrated Resource Plan ("IRP") filing.

Does this conclude the Company's Report?

Yes.