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Corporate Services

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April 20, 2007

VIA OVERNIGHT DELIVERY AND ELECTRONIC FILING

F. Anne Ross, Esq.
New Hampshire Public Utilities Commission
21 S. Fruit St., Suite 10
Concord, New Hampshire 03301

Re: Northern Utilities, Inc., New Hampshire Division – DG 07-033

Dear Ms. Ross:

On behalf of Northern Utilities, Inc. ("Northern"), enclosed please find an original and seven (7) copies of Northern's responses to the following data requests:

Staff 1-8 Staff 1-11

These responses have been provided as requested by Staff in the transmittal letter of April 6, 2007. The remaining responses will be filed as soon as they are available.

Please do not hesitate to call me if you have any questions regarding this filing.

Very truly yours,

Patricia M. French /SBK

Patricia M. French

Enclosures

cc: Service List

ORIGINAL
N.H.P.U.C. Case No. DG 07-033
Exhibit No. 2
Witness Gibbons; Ferro
DO NOT REMOVE FROM FILE

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 8
Responsible: Ronald D. Gibbons
Manager, Regulatory Accounting

Request: On the demand detail page of the filing (Page 90) MCN, PNGTS Westbrook and PNGTS Newington capacity costs are designated as peaking demand cost. Although there appears to be no impact on the allocation of costs, in prior years these capacity costs were designated as storage costs. Please explain the change and whether or not cost allocations and/or the cost of gas rates have been impacted by the change.

Response: These costs should have been designated as storage costs. This has no impact on the cost of gas.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 11
Responsible: Ronald D. Gibbons
Manager, Regulatory Accounting

Request: Ref. page 90 of the filing, the TransCanada Pipeline capacity of 34,000 MMBtu/d is all designated as peaking. In previous filings 1,000 MMBtu/d was designated as (baseload) pipeline capacity and 33,000 as storage transportation capacity. Please explain these changes. In particular, what is the rate impact of shifting 1,000 MMBtu from a designation of pipeline to peaking?

Response: In this filing, the 1,000 MMBtu of TransCanada Pipeline capacity mentioned above is still designated as pipeline. The 34,000 of TransCanada pipeline was designated as storage in prior filings and should have continued to be designated as storage. This has no impact on rates.

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April 13, 2007

VIA OVERNIGHT DELIVERY AND ELECTRONIC FILING

F. Anne Ross, Esq.
New Hampshire Public Utilities Commission
21 S. Fruit St., Suite 10
Concord, New Hampshire 03301

Re: Northern Utilities, Inc., New Hampshire Division – DG 07-033

Dear Ms. Ross:

On behalf of Northern Utilities, Inc. ("Northern"), enclosed please find an original and seven (7) copies of Northern's responses to the following data requests:

Staff 1-1	Staff 1-2	Staff 1-3	Staff 1-4	Staff 1-5
Staff 1-6	Staff 1-7	Staff 1-9	Staff 1-10	

These responses have been provided as requested by Staff in the transmittal letter of April 6, 2007. The remaining responses will be filed as soon as they are available.

Please do not hesitate to call me if you have any questions regarding this filing.

Very truly yours,

Patricia M. French/SBK

Patricia M. French

Enclosures

cc: Service List

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 1
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: Ref. page 5, line 4-11 of Gibbons testimony he describes a small error in how the MPR was calculated in last winter's COG filing. a) When was the error in the MPR Allocation discovered? b) If the correction was in effect for November 2006 demand costs was the correction identified during the COG proceedings? c) If not, was Staff notified of the error? d) What was the impact on the proposed winter 2006/07 COG rate?

Response:

(a) Northern's Regulatory Accounting staff discovered the error in the MPR Allocation sometime in November 2006.

(b) Since the error was discovered in November 2006, after the Commission issued Order No. 24,684 on October 27, 2006 in DG 06-129, Northern Utilities, Inc. 2006/07 Winter Cost of Gas, the correction was not identified in that COG proceeding.

(c) Northern notified Staff of the error and support of the correction via the next formal COG proceeding, which is this instant 2007 Summer COG. Northern also notified the Maine Public Utilities Commission via the next formal Cost of Gas filing, which was the 2007 Off-peak Cost of Gas filing, a copy of which was provided to Staff.

(d) The impact on the proposed six-month Winter 2006/07 COG rate was $0.0050 per therm. Note, that for each Winter 2006/07 monthly filing of COG activity, in which Northern assessed whether a COG rate adjustment was warranted, Northern reflected the correct actual demand cost allocation and corrected projected allocated demand costs.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 2
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: On page 5, lines 2 through 7 of Ferro testimony he explains how higher cost long lines supplies in today's market causes the unit commodity cost to serve low and high load factor customers to be similar , or even higher (unit cost) for high load factor customers. On page 8, beginning on lines 15-16 of his testimony, he seems to contradict the earlier statement by referring to high load factor customer being served with relatively low cost long line supply. Please explain.

Response: The difference in the two explanations is that, on page 5, Mr. Ferro refers to just the unit commodity costs, while on Page 8, he refers to the total or combined cost, which includes both commodity and capacity (or demand) costs.

On page 5 of the Ferro testimony, Mr. Ferro is referring to delivered unit commodity cost, i.e., natural gas prices plus the variable cost of pipeline transportation, which has increased significantly over the recent years such that the unit commodity cost of long-haul pipeline natural gas has reached or even exceeded the unit commodity cost of certain peaking supplies, depending on the contractual pricing arrangement of such resources. This development has led Northern in its Maine Division, and Bay State Gas, Northern's parent company in Massachusetts, experience a higher or similar MBA-based unit cost of commodity for the high load factor rate classes as compared to the unit commodity cost for the low load factor rate classes. However, the overall unit cost of gas has always been lower for the high load factor classes because of the lower unit demand cost for the high load factor classes. The lower unit demand cost, which has more than offset any higher unit commodity cost, reflects both the higher load factor utilization of resources for the high load factor classes and the lower demand costs for pipeline capacity as compared to storage-related demand costs and some peaking service demand costs.

On page 8 of the Ferro testimony, Mr. Ferro explains that the combined capacity and commodity costs typically result in the overall unit cost of long-haul pipeline resources, which are first used to meet base load demand, to be the least cost resources. The MBA method ranked resources by cost, based on fully loaded costs, factoring in both demand and commodity. This ranking methodology has resulted in long-haul year-round pipeline natural gas supplies being chosen as the least cost base load resource.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 3
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: In the SMBA, if peaking supplies become less costly than typical base load supplies, are the peaking supplies assigned to high load factor customers prior to base load supplies or does it become more costly to serve high load factor customers?

Response: The SMBA recognizes that for a resource to be assigned (or acquired) to satisfy base load demand it needs to be available year-round. This is similar to the need of a third party supplier acquiring a resource to satisfy the flat load of a customer or group of customers. Since peaking supplies are typically available for the months of November through March, even if the overall cost of these resources were less than long-haul year-round pipeline natural gas supplies, such supplies would not be assigned to the base load block of the load curve.

In addition, peaking resource arrangements are typically structured to meet peak day requirements on a limited number of days. Thus, these resources typically have certain restrictions on the number of days the resource is available. Such arrangements are certainly not designed to meet base load requirements. Notwithstanding all of the above reasons why peaking resources would not be assigned to meet base load requirements, since peaking resources make up approximately 8% of total resources (11% of winter resources), while pipeline volumes are approximately 52% of total resources (37% of winter), it is unlikely that the assignment of lower cost peaking resources would materially impact the unit costs between the high load and low load factor classes.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 4
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: Please explain the difference between the NH forecast sendout on page 86, line 23 of the filing vs. total firm sales on page 42, line 19.

Response: The NH forecast sendout on page 86, line 23,of annual volumes of 5,034,826 therms is different than the total firm sales on page 42, line 19, totaling 4,850,560 for the following reasons:

(1) Sendout volumes in general are higher than sales by Company-use gas and unaccounted-for gas.

(2) Sendout on page 86 was run for the purpose of deriving the Modified Proportional Responsibility (MPR) based allocation factors to allocate demand costs between the New Hampshire and Maine divisions. Sendout is run for this purpose based on satisfying actual firm sales and non-grandfathered demand for the previous May through April period (2005 – 2006), adjusted for design year conditions. Sales volumes presented on page 42, line 19, are the forecasted firm sales and non-grandfathered demand under normal weather conditions for the period of May 2007 through April 2008.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 5
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: On page 11, lines 16 through 18 of Mr. Ferro's testimony he explains the base use portion of the load curve as the average of the July-August normal year sendout. In Schedule JAF-7, page 44 of the filing, why are base load volumes for each 31 day month of the forecast, and for each rate class (lines 36-51), not equal to the July-August average?

Response: Base load volumes for each 31 day month of the forecast do not precisely equal the July-August average demand because in most months there is at least one rate class whose monthly demand is less than the base load level. In particular, the monthly forecast demand of the G-42, High Annual / High Winter, and T-52 High Annual / Low Winter rate classes is less than the base load demand most frequently. Northern plans to be factoring in this forecast result, particularly for these 2 classes, in developing its next forecast.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 6
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: In the Tariff Pages section of the filing the Company included a page which summarizes the calculation of the cost of gas factors. Does the Company plan to file page 61 of the filing as a tariff page?

Response: Northern was not planning on filing page 61 of the filing as a tariff page, but rather provide it with each COG filing as summary support for the COG rates presented on the tariff page. Northern did not include page 61 as part of the tariff because the tariff presentation of the COG calculation continues to be provided on page 60 of the filing, which is Thirty-first Revised Page 39 of Northern's tariff. This presentation is quite similar to how the previous tariff sheet, Page 39, presented the COG calculation.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 7
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: Page 74 of the filing references total remaining commodity costs including interruptible. Are interruptible sales volumes and associated gas costs included in this filing?

Response: Interruptible sales volumes and associated costs are included in this filing, and are shown on page 75 of the filing. The net or firm costs are presented on page 77 of the filing. Although the SMBA model is designed to include (and later deduct) interruptible sales volumes and costs, Northern inadvertently did not prepare and use an interruptible sales forecast for the summer period of May – October 2007. Although this was an unintended omission, these volumes and associated costs are minor and would have been included and then deducted out. In addition, all interruptible margins are credited to the winter period.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 9
Responsible: Ronald D. Gibbons
Manager, Regulatory Accounting

Request: Ref. page 90 of the filing, the unit demand rate for the two Iroquois capacity line items does not match the tariff page on page 93 of the filing. The impact is negligible on the COG rate. Please corr ect on revised filing.

Response: Northern acknowledges that the Iroquois rate listed on Page 90 of the filing is $6.5970 per MMBtu, while the rate listed on the tariff page is $6.5971 per MMBtu. Northern will correct for this minor discrepancy in the next COG filing.

Northern Utilities, Inc.
New Hampshire Division
DG 07-033
Staff Request Set No. 1
Response: 10
Responsible: Ronald D. Gibbons
Manager, Regulatory Accounting

Request: Ref. page 90 of the filing, line items for TCPL – Empress to East Hereford, TransCanada Pipeline, Union and any other Canadian resource where the support tariff pages identify C$/GJ. Please provide the Canadian exchange rate used in the conversion to US$/MMBtu. In all future COG filings please include documentation of the exchange rate used in these conversions. Also, please indicate the GJ to MMBtu conversion factor used if it was something other than 1.0551. Please show this conversion clearly in all future COG filings.

Response: The exchange rate is 0.85 U.S. dollars per Canadian dollar. The conversion factor from GJ to MMBtu is 1.05506.