Prefiled Testimony of Francis X. Wells

Northern Utilities, Inc.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2011/2012
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
FRANCIS X. WELLS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton, NH.

Q. By whom are you employed and in what capacity?

A. I am employed by Unitil Service Corp. (the "Service Company") as Manager of Gas Supply. The Service Company provides professional services to Northern Utilities, Inc. ("Northern" or "the Company").

Q. Please briefly describe your educational and business experience.

A. I earned my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined the Service Company in September 1996 and have worked primarily in the Energy Contracts department. My primary responsibilities involve gas supply acquisition.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I have testified as Northern's gas supply witness before the Commission in Northern's Cost of Gas Factor ("COG") filings since Unitil Corporation acquired Northern in December 2008. I have also testified numerous times before the Commission on behalf of Northern's affiliate, Unitil Energy Systems, Inc., on electric supply related matters.

Q. What is the purpose of your prefiled testimony?

A. The purpose of my prefiled testimony is to explain the customer demand forecast and resulting forecasted gas sendout and gas costs that I developed for Northern. I also describe the impact of the Company's Hedging Program for the 2011/2012 Winter Season. In addition, I provide an update of the pipeline rate cases that impact Northern.

Q. Please summarize your prefiled testimony.

A. Northern projects combined sales service and transportation-only distribution deliveries for the New Hampshire Division for the 2011/2012 Winter Period to be 5,086,150 Dth, which is 0.8% higher than 2010/2011 Winter Period weather-normalized distribution deliveries and 3.8% higher than 2009/2010 Winter Period weather-normalized distribution deliveries. Of the 5,086,150 Dth of projected distribution system deliveries, Northern projects that 2,861,446 Dth will be supplied by the Company through Sales Service. In order to supply 2,861,446 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 2,888,612 Dth. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Northern has the ability to deliver a maximum of 106,838 Dth of supply per day during the peak winter months, November through March, and 39,065 Dth of supply per day during the months of April through October. Northern's supply sources include Lewiston, ME baseload supply, Chicago, PNGTS, Niagara, Tennessee Production Area, Washington 10 Storage, Tennessee Firm Storage, Peaking Supplies and an LNG Facility in Lewiston, Maine. The details behind Northern's portfolio are contained in Schedule 12.

I projected Northern's total company (including the Maine Division) demand cost for the November 2011 through October 2012 gas year to be $41,634,403. (See Schedule 5A). Mr. Chris Kahl, who is employed by Unitil Service Corp. as a Senior Regulatory Analyst II, calculated the portion of this annual total that is allocated to Northern's New Hampshire Division and of that allocation what portion is to be recovered in the Winter COG rate. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $3,924,022. (See Schedule 5B).

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2011/2012 Peak period will be $26,633,877 at an average rate of $4.850 per Dth. (See Schedules 2 and 6A). I also calculated the impact of the hedging program on total company commodity costs to be a loss of $962,890 based on NYMEX prices as of September 6, 2011. (See Schedule 7). Mr. Kahl has calculated the allocation of these costs to the New Hampshire Division.

Finally, I provide updates to the various pipeline rate cases affecting Northern. Northern is currently involved in major pipeline rate cases at the Federal Energy Regulatory Commission ("FERC") concerning Portland Natural Gas Transmission System ("PNGTS") and Tennessee Gas Pipeline Company. Northern is seeking recovery of $414,873 in litigation costs it has incurred to oppose the PNGTS rate cases. (See Schedule 5C). In addition, TransCanada Pipelines Limited has proposed toll increases and also seeks to restructure its rate design. Lastly, GSGT has filed a settlement agreement with the FERC, the impact of which is an increase in the demand rate from $2.80 per Dth to $3.10 per Dth effective August 1, 2011. Due to the magnitude of the increases in rates sought by the various pipelines (other than GSGT) on which Northern holds long-term capacity contracts, Northern anticipates ongoing activity at both the FERC and the Canadian National Energy Board ("NEB") through various shippers' groups to which Northern belongs in order to pursue the best interests of Northern's customers.

I. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. The Company's forecast of firm distribution deliveries was developed as part of its Integrated Resource Planning ("IRP") process. As required by the stipulation and settlement in Docket No. DG 06-098, the Company's prior IRP proceeding, the forecast was based upon regression analysis of both customer counts and usage per customer by customer segments. Adjustments were made to account for incremental expected demand-side management ("DSM") savings and expected customer growth due to marketing activities. The four customer segments analyzed were residential heating, residential non-heating, high load factor commercial and industrial, and low load factor commercial and industrial. In addition, forecasts for special contract customers were made individually. The forecasts by customer segment were subsequently attributed to specific rate classes, including both sales service and transportation service as well as usage based classes (such as rate classes 40, 41 and 42). The analyses supporting the IRP forecast will be provided when the Company makes its next IRP filing. However, the forecast is not expected to change in the IRP filing.

Q. Please provide the forecast distribution deliveries, meter counts and use-per-meter figures utilized in this COG filing and a comparison of this forecast to weather normalized data for prior periods.

A. I have prepared Table 1, below, which provides a summary of the Company's forecast of total billed distribution deliveries for the upcoming 2011/2012 Winter Period.

Table 1. 2011 / 2012 Winter New Hampshire Division Billed Distribution Service Deliveries Forecast Compared to Prior Years

Month	2011 / 2012 Forecast[1]	2010 / 2011 Actual[2]	2011 / 2012 minus 2010 / 2011	Percent Change	2009 / 2010 Actual[3]	2011 / 2012 minus 2009 / 2010	Percent Change
Nov	536,250	519,737	16,512	3.2%	526,229	10,020	1.9%
Dec	801,725	771,466	30,260	3.9%	784,485	17,240	2.2%
Jan	1,024,900	1,069,954	-45,053	-4.2%	1,054,461	-29,560	-2.8%
Feb	1,023,016	1,051,995	-28,979	-2.8%	972,557	50,458	5.2%
Mar	916,768	936,327	-19,559	-2.1%	866,984	49,784	5.7%
Apr	783,491	694,990	88,501	12.7%	693,563	89,928	13.0%
Winter	5,086,150	5,044,468	41,682	0.8%	4,898,280	187,870	3.8%

Note 1: Company Forecast.
Notes 2 and 3: Actual Weather-Normalized Data.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2011/2012 Gas Year in Attachment 1 to Schedule 10B. Page 1 of Attachment 1 to Schedule 10B provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2011/2012 Gas Year distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2010/2011 and 2009/2010 Gas Years. The changes in the distribution deliveries from the prior period are presented in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Attachment 1 to Schedule 10B provides a calculation of the use-per-meter, which has been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. Please provide an overview of the process for converting the distribution deliveries forecast to a sales service deliveries forecast.

A. In order to prepare this COG filing, Northern reduced its total distribution deliveries forecast to reflect only the distribution deliveries to those customers taking sales service. My commodity cost forecast, which I present later, reflects only the projected costs to serve Northern's sales service obligations. Customers electing transportation-only service reflect a substantial portion of Northern's total distribution deliveries, and the cost of gas for these customers is determined by the private contractual arrangements between the customers and their retail marketer.

I estimated the percentage of total distribution deliveries to be supplied through Sales Service ("Sales Service Percentage") for each rate class based upon the most recent 12 months of historical distribution and sales service deliveries data available at the time of the analysis.

I converted the billed distribution deliveries forecast to a calendar-month distribution deliveries forecast by calculating a five-year average ratio of monthly sendout to seasonal sendout and applying these monthly ratios to the forecast billed deliveries. In the case of G52 and Special Contracts customers, the bill month is the calendar month, so I made no adjustments to these rate classes. Then, I calculated the city-gate supply required to serve the Sales Service deliveries.

Attachment 2 to Schedule 10B provides my back-up calculations for this analysis. On Pages 1 and 2 of Attachment 2 to Schedule 10B, I present my calculation of the calendar month and billed sales service deliveries by rate class, using the methodology I discuss above. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the New Hampshire Division.

On Page 3 of Attachment 2 to Schedule 10B, I present my calculations of the city-gate receipts. First, I estimated Company Use by multiplying the forecast Total Deliveries and the estimated ratio of Company-Use to Total Deliveries. Then, I added Company Use to the total Calendar Sales Service Deliveries, calculated on Page 1 ("Sales Service plus Company Use"). Finally, I added an estimate for Lost and Unaccounted for Gas. Each of the estimates used in these calculations was based on the recent history of actual data.

Q. Please summarize the Company's forecast of sales service deliveries and city-gate receipts required to meet the projected sales service deliveries.

A. I have prepared Table 2, below, which provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries and City-Gate Receipts to meet the Sales Service Deliveries[1] for the upcoming Winter Period. The detailed calculations can be found in Attachment 2 to Schedule 10B.

Table 2. Required City-Gate Receipts Summary

Month	Total Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-11	671,576	366,085	369,569
Dec-11	927,446	540,243	545,359
Jan-12	1,043,951	617,378	623,217
Feb-12	937,765	541,485	546,616
Mar-12	861,790	480,275	484,838
Apr-12	643,621	315,980	319,013
Winter	5,086,150	2,861,446	2,888,612

[1] When I use the term "City-Gate Receipts to meet the Sales Service Requirements", I refer to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, Maritimes and Northeast, L.L.C and Tennessee Gas Pipeline and the Company's LNG facility.

II. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its sales customers.

A. I have prepared Table 3, below, which provides an overview of the sources of supply available to Northern through its portfolio of long-term contracts, including transportation contracts, storage contracts, peaking supply contracts and an exchange agreement with Bay State Gas Company.

Table 3. Northern Capacity by Source of Supply (Dth per Day)

Supply Source:	Northern Deliverable Winter Capacity (Nov - Mar)	Northern Deliverable Summer Capacity (Apr-Oct)
Lewiston Baseload Supply	5,500	2,500
Chicago (Interconnection of Alliance and Vector Pipelines)	6,434	6,434
Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)	1,096	1,096
Niagara (Interconnection of TransCanada and Tennessee Pipelines)	3,282	3,282
Tennessee Production Area	13,109	13,109
Washington 10 Storage	32,885	0
Tennessee Firm Storage - Market Area	2,644	2,644
Peaking Supply 1	9,965	0
Peaking Supply 2	9,965	0
Peaking Supply 3	11,958	0
Lewiston LNG Facility	10,000	10,000
Total Deliverable Capacity	106,838	39,065

I have also prepared a capacity path diagram and capacity path detail for each of the supply sources listed above, showing the transportation, storage and long-term supply contracts required to provide the Northern Deliverable Capacity listed each source of supply. This information is found in Schedule 12.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited ("TransCanada"), Vector Pipeline L.P. ("Vector"), Union Pipelines Ltd. ("Union"), Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P. ("Iroquois") and Texas Eastern Transmission System, L.P. ("Texas Eastern" or "TETCO"). The gas supply portfolio also includes long-term storage contracts with Washington 10 Storage Corporation ("Washington 10" or "W10"), Tennessee and Texas Eastern. Northern has recently contracted for three separate peaking supply agreements, each providing Northern the option to purchase supply delivered to Northern's receipt points on its Granite transportation capacity. These peaking supply arrangements were procured through a Request-For-Proposals and are for one winter in duration. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which is capable of producing approximately 10,000 Dth per day and storing approximately 12,000 Dth of LNG. Northern has also recently entered into an LNG Contract for a one-year term in order to supply this facility. Peaking Supply contracts 1 through 3 and the LNG Contract replace the long-term peaking supply contracts Northern had in place with Distrigas and FPL Energy. Finally, as I mentioned previously, the gas supply portfolio consists of an exchange agreement with Bay State Gas Company ("BSG Exchange" or "Bay State Exchange Agreement").

The capacity path diagrams and capacity path details in Attachment NUI-FXW-3 show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, in order to move natural gas supplies from the sources of supply listed in Table 3 to Northern's distribution system. Each of these contractual arrangements represents a segment in one or more capacity paths. The capacity path diagrams show how each segment in the path is interconnected within the path. The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

Q. Has the Company entered into any long-term releases of capacity?

A. Yes. The Company has found that some of its Algonquin and Texas Eastern transportation contracts were not highly utilized by Northern, but were highly valued in the market-place. Effective May 1, 2009, Northern released the Algonquin and Texas Eastern contracts for the remaining terms of these agreements, contributing to the majority of costs for the capacity paths, listed in Table 4, below.[2] These releases are at the maximum allowable rates, benefiting customers by fully recovering the costs of the released contracts. As a result, capacity from these supply sources is no longer deliverable. Pages 12 and 13 of Schedule 12 also contain capacity path diagrams and capacity path details of these released capacity paths in order to provide a complete picture of the portfolio.

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[2] Northern has the right to a single recall of its permanent releases of Algonquin contract number 93201A1C and Texas Eastern contract number 800384.

Table 4. Released Capacity	
Supply Source:	Northern Deliverable Capacity (Dth per Day)
Texas Eastern Production and Storage & Algonquin (Centerville, NJ)	286
Texas Eastern Zone M3	965
Total Released Capacity	1,251

Q. What changes have been made to Northern's gas supply portfolio since the last COG filing?

A. As I discussed in the overview of Northern's gas supply portfolio, Northern has entered into contracts for three peaking supply arrangements for the upcoming 2011/2012 winter season. Additionally, Northern has entered into an LNG Contract for the upcoming 2011/2012 gas year. These contracts replace the peaking supply contract with FPL Energy and the combination LNG and peaking supply contract with Distrigas, which both expire in accordance with their terms by November 1, 2011. The peaking supply contract with FPL Energy ended on March 31, 2011, while the Distrigas contract will end on October 31, 2011. Additionally, Northern has secured 5,500 Dth of baseload supply for the November 2011 through March 2012 period, which is delivered to Northern's Lewiston, Maine city-gate.

Q. Please describe the Company's process for procuring its gas supply commodity supplies.

A. Northern's practice is to secure its gas supply commodity supplies through annual requests-for-proposal ("RFP") for terms beginning April 1 and running through March 31 each year. In February, Northern completed an RFP for its summer re-fill of underground storage and projected baseload supplies through March 2012. This procurement included the completion of new asset management agreements for Northern's Chicago, Niagara, Tennessee Production and Washington 10 capacity paths. Northern also purchased the Lewiston baseload supply through this RFP. The Company typically enters into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers. In July, Northern completed an RFP for the procurement of the Peaking Supplies 1 through 3.

III. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Kahl to calculate the 2011/2012 Winter COG.

A. I have provided Mr. Kahl the following cost estimates, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities for the period November 2011 through October 2012
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2011 through October 2012
- Northern's commodity costs for the period November 2011 through October 2012

- Gains and losses due to Northern's financial hedging program for the period November 2011 through October 2012

The allocation of Northern's fixed demand, commodity and hedging costs to the New Hampshire Division was performed by Mr. Kahl. The figures I present in my testimony relate to total company costs, inclusive of both the New Hampshire and Maine Divisions.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 5, below, titled, "Summary of Estimated Fixed Demand Costs."

Table 5. Estimated Gas Supply Demand Costs
November 1, 2011 through October 31, 2012

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 10,419,440	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 30,740,112	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,062,730	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,303,860	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 508,750	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (4,400,490)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 41,634,403	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Schedule 5A. Page 1 of Schedule 5A provides the summary data presented here in Table 5. On page 2 of Schedule 5A, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 3 of Schedule 5A, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 4 and 5 of Schedule 5A provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of Schedule 5A, I forecast the capacity release and asset management revenue the Company expects to receive for the 2011/2012 Gas Year. Support for the transportation, storage and supply demand rates used in the Schedule 5A are found in the Attachment to Schedule 5A, Supplier Prices.

Q. Please provide Northern's forecast of Capacity Assignment Demand Revenues for the New Hampshire Division.

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed calculations of the demand revenues from capacity assignment in Schedule 5B. On page 1 of Schedule 5B, I present a summary of the Company's forecast of New Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Schedule 5B, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Schedule 5B. The 2011/2012 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $3,924,022.

Q. Please describe Northern's process for forecasting commodity costs.

A. I base the Company's commodity cost forecast on Northern's projected city-gate receipts for sales service customers, which I calculated in Attachment 2 to Schedule 10B, and the supply sources available to Northern, which I presented in Schedule 12. I forecast supply prices at each supply source, utilizing NYMEX natural gas contract price data and a forecast of the adder to NYMEX for the price of supply at each supply source available to Northern through its portfolio. I also forecast variable fuel retention factors and rates for Northern's transportation and storage contracts. Then, I utilized the Sendout® natural gas supply cost model to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.

Q. Please present the Company's commodity cost forecast for the 2011/2012 Winter Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Peak Period in Table 6, below.

Estimated Delivered City-Gate Commodity Costs and Volumes November 2011 through April 2012			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Production	$6,764,622	1,495,554	$4.523
Tenn Zone 4 Spot	$762,777	168,345	$4.531
Washington 10 Storage	$10,539,039	2,324,515	$4.534
Tennessee Storage	$910,102	198,563	$4.583
Chicago	$878,328	188,922	$4.649
Niagara	$55,157	11,194	$4.927
PNGTS	$1,082,241	181,363	$5.967
Lewiston Baseload	$5,560,110	911,000	$6.103
LNG	$81,501	12,018	$6.782
Total System	$26,633,877	5,491,472	$4.850

In summary, projected delivered commodity costs equal approximately $26.6 million at an average delivered rate of approximately $4.85 per Dth. In support of this forecast, I prepared Schedule 6A to show the monthly forecasted commodity cost by supply option. Page 1 of Schedule 6A provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Schedule 6A provides monthly delivered volumes (Dth) by supply source. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

The detailed calculations of the delivered commodity cost are found in Schedule 6B. For each supply source, I have provided the detailed monthly calculations for supply cost, fuel losses and variable transportation charges, which will be incurred by Northern in order to deliver its supplies to Northern's city-gates for ultimate consumption by our customers. Support for the supply prices and variable transportation charges found in Schedule 6B is contained in the Attachment to Schedule 5A, Supplier Prices.

Q. Please provide a summary of capacity utilization by supply source projected for the upcoming Winter Period.

A. Please refer to Schedules 11A, 11B and 11C. Schedule 11A provides monthly supply volumes for Northern's normal weather scenario. The data in Schedule 11A is also found in Schedule 6A. Schedule 11B provides monthly supply volumes for Northern's design cold weather scenario. The volumes in Schedule 11B were those used by Mr. Kahl in order to calculate the capacity cost allocators between New Hampshire and Maine. Schedule 11C calculates the capacity utilization of all supply resources in both normal and design cold weather scenarios.

Q. Please provide Northern's Design Day Report for the upcoming Winter Period.

A. Northern's Design Day Report is found in Schedule 11D.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2011 through October 2012.

A. Please refer to Schedule 14. These results are based upon the Company's Sendout® analysis.

Q. Please provide the projected results of the Company's hedging program for the upcoming 2011/2012 Winter Period.

A. I have calculated the unrealized gains or losses of the NYMEX natural gas contracts purchased by the Company in accordance with its hedging program. Based upon the September 6, 2011 NYMEX natural gas settlement price data, Northern projects a hedging loss of approximately $962,890 for hedges for the 2011/2012 Winter Period. Please refer to Schedule 7 for the monthly hedging calculations.

IV. PIPELINE RATE CASE UPDATES

Q. Please list the pipeline rate cases currently affecting Northern Utilities, Inc.

A. Northern is currently involved in the following pipeline rate cases:

- Portland Natural Gas Transmission System has filed rate cases under FERC Docket Nos. RP08-306 ("2008 PNGTS Rate Case") and RP10-729 ("2010 PNGTS Rate Case").
- Tennessee Gas Pipeline Company has filed a rate case under FERC Docket No. RP11-1566 ("Tennessee Rate Case").
- TransCanada Pipelines Limited has filed an application to the Canadian National Energy Board ("NEB") for new tolls ("TransCanada Tolls Application").
- Granite State Gas Transmission, Inc. has filed a rate settlement under FERC Docket No. RP10-896, which provides for the increase of the Granite demand rate from its current level of $2.80 per Dth to $3.10 per Dth and allows a cost-

tracker for the major planned investments on the Granite system ("Granite Settlement").

Q. Please provide an update regarding the status of the 2008 PNGTS Rate Case.

A. The Initial Decision of the Administrative Law Judge in the 2008 Rate Case was issued on December 24, 2009 and on February 17, 2011 the FERC issued its Opinion and Order on the Initial Decision ("Opinion 510"). The Initial Decision ruled on significant rate-making issues including treatment of bankruptcy revenues, capacity for purposes of the at-risk condition, return on equity, the treatment of interruptible transportation revenues, negative salvage rate, depreciation rates, and type of cost levelization model. Opinion 510 affirmed the Initial Decision with modifications and ordered PNGTS to file revised tariff sheets in compliance with Opinion 510. Numerous parties to the 2008 PNGTS Rate Case have filed requests for rehearing, including both the Portland Shippers Group ("PSG") and PNGTS. Northern is participating in both the 2008 and 2010 PNGTS Rate Cases as a member of the PSG.

Q. What is the impact of FERC's Order in 2008 PNGTS Rate Case, should it ultimately be upheld?

A. PNGTS rates from September 2008 through November 2010 were billed subject to refund at the rate proposed in the 2008 PNGTS Rate Case. Should Opinion 510 ultimately be upheld by the FERC, Northern estimates a refund of approximately $1.2M dollars plus applicable interest.

Q. Please provide an update regarding the status of the 2010 PNGTS Rate Case.

A. On May 12, 2010, PNGTS filed a new rate case which has been docketed as RP10-729. The proposed new rates represent a 47 percent increase over current rates. Northern intervened in opposition as a member of PSG. The proposed rates went into effect on December 1, 2010, subject to refund. Settlement discussions were unsuccessful and a hearing was held from April 27, 2011 through May 25, 2011. Initial briefs were filed June 6, 2011 and reply briefs were filed August 8, 2011. An initial decision is expected on December 15, 2011.

Q. Does Northern's proposed Winter Period 2011/2012 COG reflect the rate increases proposed in the 2010 PNGTS Rate Case?

A. Yes.

Q. Is Northern seeking recovery of litigation expenses related to the PNGTS rate cases in the proposed COG?

A. Yes. Northern proposes to recover costs of $414,873, which is the New Hampshire Division's share of the $878,225 in external legal and consulting costs that Northern has incurred opposing the 2008 and 2010 PNGTS rate cases from August 13, 2010 through July 2011. Schedule 5C presents the legal and consulting expenses Northern has incurred over this period by vendor. Northern has compiled the invoices, supporting these amounts and will provide these materials to the Commission Staff. In this Cost of Gas filing, Northern has reflected these costs as a deduction from Asset Management revenues.

Q: By including these legal and consulting costs in the cost of gas rates for the coming winter season, does Northern intend to request that the Commission establish any precedent for how these expenses are treated in the future?

A: No. With this request, Northern intends to recover the costs to oppose the 2008 and 2010 PNGTS rate cases that have been incurred since August 13, 2010 and does not seek to establish any precedent with regard to the manner of recovery of similar costs in the future. Northern would address the recovery of similar future costs at such future time.

Q. Please provide an update regarding the Tennessee Rate Case.

A. On November 30, 2010, Tennessee filed a rate case, which has been docketed as RP11-1566. The proposed demand rates represent a 100% increase over the prior Tennessee demand rates. The proposed demand rate increase is partially offset by a decrease in Tennessee's proposed variable transport and fuel retention rates. The Company estimates that total Tennessee costs would increase approximately 56%, taking into account the lower variable transport and fuel retention costs. On June 1, 2011, the proposed rates went into effect, subject to refund. Due to the complexity of the issues involved in the Tennessee Rate Case (including the fact that current rates have been in place since 1995), the procedural schedule in the Tennessee Rate Case sets June 12, 2012 as the date for the Initial Decision from the Administrative Law Judge. Confidential settlement discussions of the Tennessee Rate Case are currently ongoing.

Q. Does the proposed 2011/2012 Winter Period COG reflect the rate increases proposed in the Tennessee Rate Case?

A. Yes.

Q. Please provide an update regarding the TransCanada Tolls Application.

A. On January 25, 2011, TransCanada filed an application for 2011 Interim Tolls, which reflected a 45% increase over the 2010 demand tolls. This revised interim toll filing was prepared in accordance with the 2007-2011 Mainline Settlement Agreement, which had previously been approved by the NEB and set forth the rate design and revenue requirement calculations for the five-year period. The NEP approved the new application for interim tolls, which went into effect March 1, 2011. On April 29, 2011, TransCanada filed for 2011 Final Tolls. The proposed 2011 Final Tolls are 69% higher than the 2010 Final Tolls. The increase in the proposed 2011 Final Tolls and the approved 2011 Interim Tolls were due to the roll-in of 2010 deferred balances and an update of 2011 forecast volumes. In its filing, TransCanada proposed to continue billing the lower approved 2011 Interim Tolls and defer recovery of the incremental costs until 2012.

On May 13, 2011, Northern and Bay State jointly filed a letter in opposition to the 2011 Final Tolls Application on two grounds. Firstly, the calculation of the East Hereford Delivery Pressure Demand Toll assumed absolutely no short-term, “discretionary” revenue, as the rate design assumed that Northern and Bay State would be the only TransCanada customers, utilizing the East Hereford interconnection with PNGTS for most of the year. Secondly, TransCanada’s proposal to continue to bill at the 2011 Interim Toll rate would ultimately increase interest costs needed to finance higher deferred balances and could potentially allow TransCanada to force short-haul shippers with long-term contracts to shoulder a larger portion of the deferred balances than would have been required under the 2007-2011 Mainline Settlement.

On September 9, 2011, the NEB issued a decision on the 2011 Final Tolls, setting the 2011 Final Tolls equal to the 2011 Interim Tolls, which had been in effect since March 1, 2011, including the East Hereford Delivery Pressure Demand Toll. The NEB decided that the treatment of deferred balances and East Hereford Delivery Pressure Charge Demand Tolls calculations would be handled in TransCanada's application for 2012 and 2013 Tolls.

On September 1, 2011, TransCanada filed an Application for 2012-2013 Tolls. This 2012-2013 Tolls Application includes a new proposal for the calculation of TransCanada's revenue requirement and tolls. TransCanada plans to file 2012 revenue requirement and tolls calculations no later than October 31, 2011. Northern is in the process of reviewing this new TransCanada Tolls Application.

Q. Are the impacts of the TransCanada Tolls Application reflected in the proposed COG?

A. Yes. The forecasted TransCanada tolls reflect TransCanada's proposed 2011 Final Tolls. Although TransCanada's proposal is to continue billing the lower 2011 Interim Toll rate, I believe that this is the best available estimate of the cost that Northern will ultimately pay for its TransCanada capacity contracts. As better information becomes available through the 2012 TransCanada Tolls Application process, I plan to update the forecasted TransCanada tolls.

Q. Please provide an overview of the Granite Settlement.

A. On July 26, 2011, the Granite Settlement was filed with the FERC. The parties to the Granite Settlement include Granite, the New Hampshire Public Utilities Commission, the Maine Public Utilities Commission, and the Maine Public Advocate. The Granite Settlement provides for an initial increase in Granite's demand rate from $2.80 per Dth to $3.10 per Dth and provides for the annual adjustment in Granite's rates to recover investments in Granite's Integrity Management Program, the replacement of disbanded pipe between Exeter and Greenland, New Hampshire, and the Little Bay Bridge Crossing.

Q. Are the impacts of the Granite Settlement reflected in the proposed COG?

A. The increase in Granite's demand rate from $2.80 to $3.10 per Dth is reflected in proposed COG.

Q. Does this conclude your testimony?

A. Yes it does.