NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2012 / 2013
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. What is your relationship with Northern Utilities, Inc.?

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.

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.

Q. What is the purpose of your prefiled testimony in this proceeding?

A. The purpose of my prefiled testimony is to describe and explain the forecast of gas demand and the resulting forecasted gas sendout and gas costs that were used to calculate the Winter COG rate adjustments for Northern's New Hampshire Division. My prefiled testimony also describes the impact of the Company's Hedging Program for the 2012-2013 Winter period, and provides an update on the status of the pipeline rate cases in which Northern is involved, including their impact on this COG filing.

Q. Please summarize your prefiled direct testimony in this proceeding.

A. Northern projects combined sales service and transportation-only distribution deliveries for the New Hampshire Division for the 2012/2013 Winter Period to be 5,0019,842 Dth, which is 1.9% higher than the 2011/2012 Winter Period weather-normalized distribution deliveries and 0.3% higher than the 2010/2011 Winter Period weather-normalized distribution deliveries. Of the 5,0019,842 Dth of projected distribution system deliveries, Northern projects that 2,730,592 Dth will be supplied by the Company through Sales Service. In order to supply 2,730,592 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 2,747,533 Dth. The details behind these estimates are contained in Attachment 1 to Schedule 10B and Attachment 2 to Schedule 10B.

Northern has the ability to deliver a maximum of 116,143 Dth of supply per day during the peak winter months, November through March, and 36,815 Dth of supply per day during the months of April through October. Northern's supply sources include Chicago, Lewiston, ME Baseload, Tennessee Zone 6 Baseload, PNGTS, Niagara, Tennessee Production, Algonquin Receipts, Tennessee Firm Storage, Washington 10 Storage, Peaking Supplies and an LNG Facility in Lewiston, Maine. The details behind Northern's portfolio are contained in Schedule 12.

I project Northern's total company (including the Maine Division) demand cost for the November 2012 through October 2013 gas year to be $37,195,794. (*See* Schedule 5A). Mr. Chris Kahl, who is employed by Unitil Service Corp. as a Senior Regulatory Analyst II, presents the allocation of the total annual demand cost to Northern's New Hampshire Division and the portion of that allocation of annual demand costs to be recovered in the Winter COG. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $4,513,535. (*See* Schedule 5B).

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2012/2013 Winter Period will be $22,405,337 at an average rate of $4.112 per Dth. (*See* Schedule 6A) I also calculated the impact of the hedging program on total company commodity costs of a loss of $1,630,690 based on NYMEX prices as of August 28, 2012. (*See* Schedule 7) Mr. Kahl calculates the portion of these costs, which are allocated to the New Hampshire Division.

Finally, I provide updates to the various pipeline rate cases affecting Northern. Northern is currently involved in the major pipeline rate cases on Portland Natural Gas Transmission System and TransCanada Pipelines Limited. Northern seeks recovery of $151,922 in PNGTS litigation costs, which have been incurred by Northern since August 2011. (*See* Schedule 5C). Northern anticipates ongoing activity at both the Federal Energy Regulatory Commission ("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.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast metered distribution deliveries for the Company's residential, small commercial and larger industrial/commercial classes, the Company has utilized time-series techniques to develop two forecast models: use-per-meter and the number of meters. The growth rates for customers (meters) and use-per-meter from these models are applied to the most recent data normalized for weather; the forecast monthly billed deliveries for each customer class was calculated by multiplying the number of forecast customers by the forecast use-per-customer. Forecast deliveries for the large commercial customers with special contracts were developed separately for each of these customers.

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 2012/2013 Winter Period.

Table 1. 2012 / 2013 Winter New Hampshire Division Billed Distribution Service Deliveries Forecast Compared to Prior Years							
Month	2012 / 2013 Forecast[1]	2011 / 2012 Actual[2]	2012 / 2013 minus 2011 / 2012	Percent Change	2010 / 2011 Actual[2]	2012 / 2013 minus 2010 / 2011	Percent Change
Nov	563,246	546,018	17,228	3.2%	516,450	46,796	9.1%
Dec	808,129	779,702	28,427	3.6%	759,990	48,139	6.3%
Jan	992,955	989,691	3,264	0.3%	1,065,429	-72,474	-6.8%
Feb	1,030,069	1,011,643	18,426	1.8%	1,035,123	-5,054	-0.5%
Mar	917,243	902,981	14,262	1.6%	936,166	-18,923	-2.0%
Apr	708,200	697,251	10,949	1.6%	689,189	19,011	2.8%
Winter	5,019,842	4,927,286	92,556	1.9%	5,002,348	17,494	0.3%

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 2012 / 2013 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 2012 / 2013 Gas Year distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2011 / 2012 and 2010 / 2011 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.

Northern 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, 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"). Then, 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. I present the historic Company Use and Lost and Unaccounted for Gas data used in this analysis in Attachment 3 to Schedule 10B.

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 Peak 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-12	682,429	351,075	353,261
Dec-12	931,012	516,209	519,408
Jan-13	1,045,588	593,135	596,805
Feb-13	918,262	517,170	520,372
Mar-13	837,703	451,952	454,757
Apr-13	604,848	301,052	302,930
Peak	5,019,842	2,730,592	2,747,533

III. 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.

[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 the Company's LNG facility.

Table 3. Northern Capacity by Supply Source (Dth per Day)		
Supply Source	2012-2013 Winter	2013 Summer
Chicago Path	6,434	6,434
Lewiston Baseload	5,500	0
Tennessee Zone 6 Delivered Baseload	4,983	0
PNGTS Year-Round	1,096	1,096
Tennessee Niagara	2,331	2,331
Tennessee Long-Haul	13,109	13,109
Algonquin Receipt Points	1,251	1,251
Tennessee FS-MA & 5265	2,644	2,644
Washington 10 Path	32,885	0
Peaking Supply 1	9,983	0
Peaking Supply 2	5,000	0
Peaking Supply 3	4,983	0
Peaking Supply 4	15,944	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**116,143**	**36,865**

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's gas supply portfolio includes four separate peaking supply agreements, each providing Northern the option to purchase supply delivered to Tennessee Zone 6, PNGTS or Maritimes meters. 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 plans to issue an RFP to replace its current LNG Contract (which ends 10/31/2012) for a one-year term in order to supply this facility. These Peaking Supply contracts will not be available during the 2013 Off-Peak Period. 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 Schedule 12 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. Effective May 1, 2009, Northern released Algonquin Contract 93201A1C and Texas Eastern Contract 800384 for the remaining terms of these agreements. These releases were at the maximum allowable rates, benefiting customers by fully recovering the costs of the released contracts. Effective November 1, 2012, Northern has renewed Algonquin Contract 93201A1C and plans to use this capacity to supply customers for the upcoming 2012-2013 Peak Period.

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. Northern has completed an RFP for its summer re-fill of underground storage and projected baseload supplies through March 2013. Northern has entered into asset management agreements for Northern's Chicago, Niagara, Algonquin Receipts, Tennessee Production and Washington 10 capacity paths. Northern has also entered baseload supply agreements for the upcoming winter period. The Company typically enters into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers. Northern has recently completed its RFP for replacement peaking supplies for the upcoming 2012 / 2013 Winter Period. Northern is currently preparing to issue an RFP for replacement LNG supply in order to supply the Lewiston LNG plant.

Q. Please describe the changes to Northern's supply portfolio for the upcoming 2012 / 2013 Winter Period since the 2011 / 2012 Winter Period.

A. Tennessee Contract 46314, Texas Eastern Contract 800464 and Texas Eastern Contract 400513 will not be part of the 2012 / 2013 Winter Period supply portfolio. Each of these contracts will have terminated in accordance with their terms prior to November 1, 2012.[2]

As discussed previously, Algonquin Contract 93201A1C was renewed and Northern plans to utilize this capacity to deliver supplies to Northern via the Bay State Exchange during this 2012-2013 peak period. Please refer to Page 8 of Schedule 12 for the details of this new additional capacity path.

Northern has secured replacement baseload supplies deliverable to the Lewiston city-gate and a new baseload supply deliverable to Tennessee Zone 6.

Northern has also secured replacement peaking supplies, the details of which are provided on pages 11 through 15 of Schedule 12.

IV. 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 2012 / 2013 Peak COG.

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

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[2] Tennessee Contract 46314 provided 929 Dth of capacity from Niagara to Bay State's city-gate. Northern did not have renewal rights to this capacity. Texas Eastern Contract 800464 provided 59 Dth of capacity to the Texas Eastern production area in the Gulf of Mexico. Texas Eastern Contract 400513 provided Texas Eastern storage in Texas Eastern Zone M3.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities for the period November 2012 through October 2013
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2012 through March 2013
- Northern's commodity costs for the period November 2012 through October 2013
- Gains and losses due to Northern's financial hedging program for the period November 2012 through October 2013

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 4, below, titled, "Estimated Gas Supply Demand Costs."

Table 4. Estimated Gas Supply Demand Costs
November 1, 2012 through October 31, 2013

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,397,821	Sch 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 28,394,226	Sch 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,035,662	Sch 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,728,786	Sch 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 662,750	Sch 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (5,023,450)	Sch 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 37,195,794	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 4. 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 2012 / 2013 Gas Year. Support for the transportation, storage and supply demand rates used in Schedule 5A are found in 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. The 2012 / 2013 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $4,513,535. 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.

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 2012 / 2013 Winter Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter Period in Table 5, below.

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes
November 2012 through April 2013

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage	$563,423	187,947	$2.998
Tenn Zone 4 Spot	$561,321	172,378	$3.256
Tennessee Production	$3,537,890	1,066,617	$3.317
Algonquin Receipts	$279,438	82,610	$3.383
Niagara	$13,839	3,987	$3.471
Chicago	$837,772	238,936	$3.506
Washington 10 Storage	$5,702,266	1,617,793	$3.525
TGP Zone 6 Spot	$8,711	2,432	$3.581
LNG	$38,997	8,145	$4.788
TGP Zone 6	$5,298,725	1,102,330	$4.807
PNGTS	$691,765	135,725	$5.097
Lewiston Baseload	$4,871,191	830,500	$5.865
Total Delivered Commodity Cost	$22,405,337	5,449,399	$4.112

In summary, projected delivered commodity costs equal approximately $22.4 million at an average delivered rate of $4.112 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 are found in the Attachment to Schedule 5A.

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 Northern's 7-Day Cold Snap Analysis for the upcoming Winter Period.

A. Northern's 7-Day Cold Snap Analysis is found in Schedule 11E.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2012 through October 2013.

A. Please refer to Schedule 14. These results are based upon the Company's Sendout® analysis, which I provided to Mr. Kahl.

Q. Please provide the results of the hedging program related to the Company's proposed COG rates.

A. I have calculated the unrealized gains or losses of the NYMEX natural gas futures contracts purchased by the Company in accordance with its hedging program. Based upon the August 28, 2012 NYMEX natural gas settlement price data, Northern projects a total company hedging loss of approximately $1,630,690 for hedges for the upcoming peak season. Please refer to Schedule 7 for the monthly hedging calculations.

V. 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").

- TransCanada Pipelines Limited has filed an application with the NEB on September 1, 2011, which proposes to restructure its business and services and establish final tolls for 2012 and 2013 ("2012 and 2013 TransCanada Tolls Application").

Q. Please provide an update to 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 rate-making, return on equity, 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. Northern continues to await FERC action on the 2008 PNGTS Rate Case.

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. Of that amount, approximately $600,000 would be credited to the Company's New Hampshire Division. [SSG1]

Q. Please provide an update on the 2010 PNGTS Rate Case.

A. On May 12, 2010, PNGTS filed a new rate case which was docketed RP10-729. The proposed rates represent a 47 percent increase over prior 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. The Administrative Law Judge issued an Initial Decision in the 2010 PNGTS Rate Case on December 8, 2011. Although the Initial Decision found in favor of PNGTS on several key issues, Northern believes that the Initial Decision in the 2010 PNGTS Rate Case supports a lower rate than was proposed, if it is approved by the FERC. However, Northern, through the PSG, disagrees and opposes the 2010 PNGTS Rate Case Initial Decision in several material respects, the most significant of which is the capacity for purposes of rate-making. On February 1, 2012, the parties filed Briefs on Exceptions to this Initial Decision. Briefs Opposing Exceptions were filed by both PSG and PNGTS on March 7, 2012. Northern awaits final FERC action on the 2010 PNGTS Rate Case.

Q. Does the proposed COG reflect the rate increases proposed in the 2010 PNGTS Rate Case?

A. Yes. The forecast gas supply demand costs include costs projected at the 2010 PNGTS filed rates.

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

A. Yes. Northern proposes to recover PNGTS litigation costs of $151,922, which is the New Hampshire Division’s share of the external legal and consulting costs that Northern has incurred opposing the 2008 and 2010 PNGTS rate cases since August 2011.

Schedule 5C presents the legal and consulting expenses Northern has incurred since August 1, 2011 by vendor. Northern has compiled the invoices, supporting these amounts and will provide these materials to the Commission Staff.

Q. Please provide a summary of the 2012 and 2013 TransCanada Tolls Application.

A. On September 1, 2011, TransCanada filed the 2012 and 2013 TransCanada Tolls Application. The 2012 and 2013 TransCanada Tolls Application makes the following proposals.

- TransCanada proposes to modify the calculation of depreciation expense.
- TransCanada proposes to extend the TransCanada Tolls to include portions of TransCanada's natural gas gathering system in western Canada.
- TransCanada proposes to modify TransCanada Toll design. These modifications include increasing the allocation of TransCanada costs to short-haul contracts, carving out Trans Québec & Maritimes ("TQM") costs and assigning these costs to those customers taking delivery on TQM points, and changes to the delivery pressure toll methodology.
- TransCanada proposes to raise bid floors for the sale of short-term, discretionary service.

Based on TransCanada's update of the 2012 and 2013 TransCanada Tolls Application, filed on October 31, 2011, the proposed tolls would be 6% higher than current tolls for

Northern's contract number 33322 and 4% higher than current tolls for Northern's contract number 29594.[3]

Q. Does Northern have concerns with the 2012 and 2013 TransCanada Tolls Application?

A. Yes. Northern is particularly concerned with TransCanada's toll design proposals. Northern's contracts are short-haul; therefore, TransCanada's proposal to allocate a greater portion of its costs to short-haul capacity contracts would increase costs to Northern over time. Northern is also concerned by TransCanada's proposal to carve out TQM costs from its overall rate base and assign these costs only to those contracts utilizing the TQM capacity. TransCanada utilizes TQM capacity to make deliveries to East Hereford, which is the interconnection with PNGTS. Such a change in cost allocation could permanently increase costs for contracts delivering to East Hereford, including Northern's contract number 33322. In general, Northern also believes that a thorough investigation of the proposed revenue requirement, including TransCanada's depreciation expense calculations is warranted, due to the already high rates for transportation service on this pipeline. Ultimately, TransCanada's high revenue requirement and declining throughput are the cause of consistent increases in TransCanada's tolls.

Q. Please describe TransCanada's proposal to modify the calculation of delivery pressure tolls.

[3] TransCanada Contract 33322 is for 35,872 GJ of capacity from Dawn to East Hereford and is part of the Washington 10 capacity path. TransCanada Contract 29594 is for 6,264 GJ of capacity from Parkway to Iroquois pipeline and is part of the Chicago capacity path.

A. TransCanada proposes to modify its delivery pressure tolls methodology, such that the delivery pressure toll shall be equal at all export points, requiring increased delivery pressure. Northern supports this proposal because it will mitigate the impacts of reduced flows through East Hereford on the delivery pressure toll paid by Northern on contract 33322.

Q. Please describe how Northern is pursuing its interests in the 2012 and 2013 TransCanada Tolls Application.

A. Northern is pursuing its interests in this case through its membership in Alberta Northeast Energy Limited ("ANE"). Northern's contract 29594 has long been covered under the ANE customer group. In response to the 2012 and 2013 TransCanada Tolls Application, Northern elected to add its TransCanada contract 33322 to ANE. By adding TransCanada contract 33322, ANE is able to represent issues specific to Northern's TransCanada contract 33322, including both TransCanada's TQM carve-out proposal and delivery pressure charge proposal.

Q. When is a decision in the TransCanada Tolls Application expected?

A. Hearings for the TransCanada Tolls Application are expected to continue until mid-September with an order from the NEB expected 90 days following completion.

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

A. Yes. The forecasted TransCanada rates reflect TransCanada's approved 2012 Interim Tolls.

Q. Does this conclude your testimony?

A. Yes it does.