NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 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. 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. 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 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 Summer COG rate adjustments for Northern's New Hampshire Division. My prefiled testimony also describes the impact of the Comcany's Hedging Program for the 2012 Summer period.

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 Summer Period to be 2,125,572 Dth, which is 3.2% higher than the 2011 Summer Period weather-normalized distribution deliveries and 8.7% higher than the 2010 Summer Period weather-normalized distribution deliveries. Of the 2,125,572 Dth of projected distribution system deliveries, Northern projects that 746,657 Dth will be supplied by the Company through Sales Service. In order to supply 746,657 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 754,069 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 35,615 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 project Northern's total company (including the Maine Division) demand cost for the November 2011 through October 2012 gas year to be $37,586,427. (*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 the portion of that allocation to be recovered in the Summer COG rate. I also project the demand revenue from the New Hampshire Division's capacity assignment program to be $3,420,191. (*See* Schedule 5B).

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2012 Summer Period will be $4,657,839 at an average rate of $3.235 per Dth. (*See* Schedules 2 and 6A). I also calculate that the impact of the hedging program on total company commodity costs is a loss of $328,400 based on NYMEX prices as of February 27, 2012. (*See* Schedule 7). Mr. Kahl calculates the portion of these costs that are allocated to the New Hampshire Division.

Next, I present Northern's proposed hedging plan for the period beginning May 2013 through April 2014. The proposed hedging plan is consistent with the hedging program, approved by the Commission on March 30, 2010 in Docket No. DG 09-141. Supporting information concerning the proposed hedging plan can be found in Schedule 20.

Finally, I provide updates to the various pipeline rate cases affecting Northern. Northern is currently involved in the major pipeline rate cases regarding Portland Natural Gas Transmission System and TransCanada Pipelines Limited. 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. 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.[1] The analyses supporting the IRP forecast were provided by Northern in its most recent IRP filing (Docket No. DG 11-290), which was made on December 30, 2011.

[1] Northern's New Hampshire Division service classifications can be found beginning on Original Page 3 of NHPUC No. 10 – Gas (Northern's General Terms and Conditions).

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 Summer Period.

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

Month	2012 Forecast[1]	2011 Actual[2]	2012 minus 2011	Percent Change	2010 Actual[3]	2012 minus 2010	Percent Change
May	493,457	455,056	38,402	8.4%	424,623	68,834	16.2%
Jun	376,206	340,672	35,534	10.4%	305,140	71,067	23.3%
Jul	305,376	277,859	27,517	9.9%	271,701	33,675	12.4%
Aug	283,044	277,161	5,883	2.1%	283,312	-268	-0.1%
Sep	301,907	305,657	-3,750	-1.2%	294,853	7,054	2.4%
Oct	365,582	403,626	-38,044	-9.4%	375,541	-9,959	-2.7%
Summer	2,125,572	2,060,030	65,542	3.2%	1,955,169	170,403	8.7%

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 Summer Period 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 the non-heating residential rate classes, the heating residential rate classes, and the commercial and industrial rate classes, respectively. The top section of each page provides the 2012 Summer Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2011 and 2010 Summer Periods. 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 forecast 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 Rate G-52 (High Load Factor customers using greater than 80,000 therms per year) 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 forecasted 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 recent 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[2] for the upcoming Summer 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)
May-12	384,058	134,649	135,986
Jun-12	333,477	108,336	109,421
Jul-12	320,536	105,728	106,786
Aug-12	318,773	107,572	108,645
Sep-12	335,813	116,580	117,739
Oct-12	432,915	173,792	175,492
Summer	2,125,572	746,657	754,069

[2] 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, and Maritimes and Northeast, L.L.C and the Company's LNG facility.

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.

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

Supply Source	2011-2012 Winter	2012 Summer
Washington 10 Path	32,885	0
Tennessee Long-Haul	13,109	13,109
Chicago Path	6,434	6,434
Tennessee Niagara	3,282	2,332
Tennessee FS-MA & 5265	2,644	2,644
PNGTS Year-Round	1,096	1,096
Peaking Supply 1	9,965	0
Peaking Supply 2	9,965	0
Peaking Supply 3	11,958	0
Lewiston On-System LNG Production	10,000	10,000
Lewiston Baseload	5,500	0
Total Deliverable Resources	**106,838**	**35,615**

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 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 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. Peaking Supply contracts 1 through 3 will not be available during the 2012 Summer 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 o-r 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.[3] 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 13 and 14 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.

Table 4. Released Capacity

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

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. Has the Company made any other changes to its capacity portfolio since its last COG filing?

A. Yes. Northern has extended its Tennessee storage contract, contract number 5195 and the associated transportation capacity, contract number 5265 through March 31, 2015. These contracts make up the Tennessee FS-MA & 5265 capacity path, which are shown in detail on page 6 of Schedule 12. These extensions were made in compliance with the Tennessee rate case settlement in FERC Docket No. RP11-1566.

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 issued an RFP for its summer re-fill of underground storage and projected baseload supplies through March 2013. This RFP seeks asset management proposals for Northern's Chicago, Niagara, Tennessee Production and Washington 10 capacity paths. Northern also seeks 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. This summer, Northern plans to issue an RFP for replacement peaking supplies.

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 Summer 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 March 2012
- Northern's commodity costs for the period May 2012 through October 2012
- Gains and losses due to Northern's financial hedging program for the period May 2012 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 Maine and New Hampshire 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	$ 8,686,038	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 28,451,423	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	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	$ 37,586,427	Sum Lines 1 through 6.
8.	Total Demand Costs - Previous Forecast	$ 39,468,889	Winter COG Filing (Schedule 5A)
9.	Net Change in Forecast	$ (1,882,461)	Line 8 minus Line 7.

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 the Attachment, 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 Schedule 5A are found in the Attachment to Schedule 5A, Supplier Prices.

Q. Table 5 indicates a decrease in the gas supply demand cost estimate used for calculating the proposed 2012 Summer COG from that which was provided to the Commission in the 2011-2012 Winter COG filing. Please provide an explanation of the decrease.

A. The decrease in the gas supply demand cost estimate in this 2012 Summer COG filing from that which was filed in the 2011-2012 Winter COG filing reflects the NEB's approval, dated December 8, 2011, of TransCanada Interim Tolls at rates equal to the 2011 Final Tolls. Because the approved 2012 Interim Tolls were substantially lower than the tolls estimated in Northern's 2011-2012 Winter COG filing, it was appropriate to update the gas supply demand cost forecast.

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 $3,420,191. As highlighted on page 1 of Schedule 5B, the projected 2011/2012 Capacity Assignment Demand Revenue is $154,323 lower than the amount projected in the Winter COG proceeding, due to the adjustment of the demand cost forecast attributable to the change in projected TransCanada rates, as discussed in my answer to the previous question, above.

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 Summer Period.

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

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes May 2012 through October 2012			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tenn Zone 4 Spot	$1,413,197	446,542	$3.165
PNGTS	$593,424	183,356	$3.236
Lewiston Baseload	$1,491,108	460,000	$3.242
Tennessee Production	$1,118,192	341,568	$3.274
LNG	$41,917	8,280	$5.062
Total System	$4,657,839	1,439,746	$3.235

In summary, projected delivered commodity costs equal approximately $4.7 million at an average delivered rate of $3.235 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 the Attachment 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 of 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 Summer Period.

A. Please refer to Schedule 11 for this information. Schedule 11A provides Normal Year Sendout Volumes for the upcoming 2012 Summer Period. Schedule 11C presents the capacity utilization factors by resource, which is calculated by dividing total period sendout by the maximum available volume for the period. Schedules 11B and 11D refer to design cold winter conditions, and will be provided again in the 2012-2013 Winter COG filing.

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

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

Q. Please provide the impact of the hedging program on 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 February 27, 2012 NYMEX natural gas settlement price data, Northern projects a hedging loss of approximately $328,400 for hedges for the coming summer season. Please refer to Schedule 7 for the monthly hedging calculations.

V. NORTHERN HEDGING PLAN FOR MAY 2013 THROUGH APRIL 2014

Q. Has Northern developed a plan for hedging the period of May 2013 through April 2014?

A. Yes. The initial schedule for the hedging plan for the twelve-month period beginning May 2013 is attached as Schedule 20, page 1 of 3. The initial schedule plan lists the planned purchases of futures contracts for the contract months being hedged as well as placeholders for the price ceiling for each of those months. In accordance with Northern's hedging program, approved by the Commission on March 30, 2010 in Docket No. DG 09-141, so long as prices are below the respective price ceiling for each contract month, purchases will be made as scheduled each month on the expiration date of the prompt month contract. The price ceiling values shown are those utilized for the twelve-month period beginning May 2012, and will be updated in mid-April to reflect more recent prices that will determine the price ceiling values for the twelve-month period beginning May 2013.

Q. Has Northern provided a three-year schedule of projected hedging activity in accordance with the revised hedging program?

A. Yes. Schedule 20, page 2 of 3 provides a three-year projection of sendout requirements, the peak season resources expected to provide fixed pricing and the financial hedging volumes required to meet the fixed price targets under the hedging program, which are 40 percent of requirements for May and October and 70 percent of requirements for the peak season. As shown on page 2, the plan calls for 171 contracts for the twelve month period beginning May 2013, 179 contracts for the period beginning May 2014, and 188 contracts for the period beginning May 2015.

Q. Is Northern recommending any adjustments to the hedging plan for the period of May 2012 through April 2013?

A. No. Schedule 20, page 3 of 3 presents the current status of the hedge plans for the summer 2012 and winter 2012-13 periods with regard to the percentage of sendout requirements expected to be available under fixed prices given physical hedges and the purchases of futures contracts already completed. As shown on Schedule 20, page 3, the projected percentage of May and October hedged is 43%, compared to the target of 40% and the projected percentage of the peak season is 66%, compared to the target of 70%.[4] These variances are within an acceptable range of the target hedged positions, so Northern does not recommend any changes to the hedge plans for the summer 2012 and winter 2012-13 periods.

VI. 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”).

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4 Northern has decided to cancel the planned purchase of 1 May 2012 natural gas futures contract and 1 Oct 2012 natural gas futures contract, which were scheduled to take place on 3/28/2012, in order to stay within the +/- 5% tolerance of targeted hedged volumes for the 2012 Summer Period.

Q. Please provide an update on 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, 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. 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.

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, and believes its arguments will result in overturning the findings in the Initial Decision. On February 1, 2012, the parties filed Briefs on Exceptions to the Initial Decision. Reply Briefs are due in early March. Northern continues to await 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 based upon the 2010 PNGTS filed rates. The proposed COG also reflects litigation costs associated with the 2008 and 2010 PNGTS Rate Cases incurred from 8/1/2010 through 7/31/2011. Recovery of these litigation costs in the COG was approved by the Commission as part of its review of Northern's 2011-2012 Winter COG filing. *See* DG 11-207, Order No. 25,282 (Oct. 28, 2011). A summary of these costs is provided in Schedule 5C.

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.[5]

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

[5] 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. 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 contract costs for deliveries 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.

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

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

Q. Does this conclude your testimony?

A. Yes it does.