Prefiled Testimony of Francis X. Wells

Unitil
Northern Utilities, Inc.

**NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
2010-2011 WINTER PERIOD
COST OF GAS FILING
PREFILED TESTIMONY OF
FRANCIS X. WELLS**

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Francis X. Wells. I am Senior Energy Trader for Unitil Service Corp. (“Unitil”). My business address is 6 Liberty Lane West, Hampton, NH.

Q. Please describe your relevant educational and work experience.

A. I received my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined Unitil in September 1996, assisting in the planning and operation of both electric power and natural gas supply portfolios. Since January 2001, I have worked as a Senior Energy Trader in the Energy Contracts Department. I have responsibilities in the areas of (1) energy supply acquisition, including natural gas supply procurement, electric default service purchasing; (2) regulatory testimony and reporting; (3) budgeting for both natural gas and electric supply, and (4) long-term supply planning.

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. Please explain the purpose of your prepared direct testimony in this proceeding.

A. First, I will provide an overview of Northern's sales and sendout projections for the 2010-2011 Winter Period.

Second, I will provide a summary of Northern's natural gas supply portfolio, which will be used to meet these supply requirements.

Third, I will provide a detailed forecast of the gas supply cost forecast, based on the sendout forecast and the natural gas supply portfolio. The gas supply cost forecast includes the following items:

- Fixed Demand Costs, including reservation and demand charges for supply contracts, transportation contracts and storage contracts that are part of Northern's wholesale portfolio of contracts and any projected offsets due to Northern's capacity assignment program or the optimization of Northern's portfolio through capacity release contracts or asset management contracts. The Fixed Demand Cost forecast is updated once annually, for COG rates effective November 1 each year.

- Variable Commodity Costs, including any variable supply and transportation or storage charges to be incurred to deliver natural gas commodity to meet Northern's projected sendout requirements.

- Gains or Losses of Northern's Hedging Program

- Projected Storage Inventory costs and balances

Finally, I will also provide support to the Company's proposal to recover approximately $184,000 in external legal and consulting costs rising from Northern's opposition to proposed rate increases by Portland Natural Gas Transmission System under FERC Docket No. RP08-306 ("2008 PNGTS Rate Case") and FERC Docket No. RP10-729 ("2010 PNGTS Rate Case").

I have provided these materials to James Simpson, Vice President of Concentric Energy Advisors, who used them as inputs to calculate the proposed COG. He also discusses the impact that the proposed COG will have on the bills of the Company's typical customers.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast metered distribution deliveries[1] 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 forecast customers times forecast use-per-customer. Forecast deliveries for the large commercial customers with special contracts were developed separately for each of these customers.[2]

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 2010-2011 Peak Period.

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[1] In my testimony I use the term "deliveries" to refer to the volumes or quantities of gas that are distributed to the premises of sales customers and transportation customers. I use the term "sales customer" to refer to a gas customer that receives bundled distribution and gas supply service from Northern. Finally, I use the term "transportation customer" to refer to a gas customer that receives distribution service from Northern and gas supply service from a competitive retail supplier.

[2] When forecasting the Large General rate classes (G42 & T42, G52 & T52 and Special Contracts), the Company utilizes individual customer forecasts through the first full calendar year of the forecast. Thereafter, the Company relies on its forecast of use-per-meter and the number of meters for each rate class. Since this COG filing relies solely on forecast data within the first calendar year, the Large General forecast is based on the individual forecasts.

Table 3. 2010-2011 Winter New Hampshire Division Metered Usage Forecast Compared to Prior Years (All Units in Dth)							
Month	2010-11 Forecast[1]	2009-10 Actual[2]	2010-11 minus 2009-10	Percent Change	2008-09 Actual[3]	2010-11 minus 2008-09	Percent Change
Nov	542,536	525,777	16,759	3.19%	549,450	-6,913	-1.26%
Dec	770,259	785,751	-15,492	-1.97%	792,007	-21,748	-2.75%
Jan	1,015,419	1,050,941	-35,522	-3.38%	990,236	25,183	2.54%
Feb	1,015,501	974,983	40,518	4.16%	991,088	24,413	2.46%
Mar	878,056	868,777	9,279	1.07%	894,108	-16,052	-1.80%
Apr	677,756	697,010	-19,254	-2.76%	678,954	-1,198	-0.18%
Season	4,899,527	4,903,238	-3,712	-0.08%	4,895,842	3,685	0.08%

Note 1: Company Forecast.
Note 2: Actual Weather-Normalized Data.
Note 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 2010-2011 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 classes, heating residential rate classes and commercial and industrial rate classes, respectively. The top section of each page provides the 2010-2011 Gas Year distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2009-2010 and 2008-2009 Gas Years. The changes in the distribution deliveries from the prior period are explained 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 have 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.

I estimated the percentage of total distribution deliveries 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 utilizing the same model used by the Company to develop the billed distribution deliveries forecast. Using this model, I replaced the projected bill cycle data for monthly days and effective degree days with calendar month days and effective degree days. For each rate class, I multiplied by projected Sales Service Percentage times the projected calendar-month distribution deliveries forecast to calculate the sales service deliveries forecast. Having converted the billed distribution service deliveries to calendar month Sales Service deliveries, I then 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. I have also prepared Schedule 13, which provides annual summary data for sales service and transportation service deliveries by rate class.

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.

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[3] for the upcoming Peak Period. The detailed calculations can be found in Attachment 2 to Schedule 10B.

Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary

Month	Total Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-10	586,642	304,710	312,051
Dec-10	851,652	472,252	483,928
Jan-11	1,045,034	638,023	652,778
Feb-11	912,462	542,998	555,527
Mar-11	892,658	525,753	537,934
Apr-11	599,363	319,160	326,540
Winter	4,887,810	2,802,895	2,868,758

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.

[3] 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.

Table 3. Northern Capacity by Source of Supply	
Supply Source:	Northern Deliverable Capacity (Dth per Day)
Chicago (Interconnection of Alliance and Vector Pipelines)	6,433
Pittsburgh, NH (Interconnection of TransCanada and PNGTS Pipelines)	1,095
Niagara (Interconnection of TransCanada and Tennessee Pipelines)	3,280
Tennessee Production Area	13,089
Washington 10 Storage*	32,835
Tennessee Firm Storage - Market Area	2,640
Peaking Supply 1	4,975
Peaking Supply 2*	52,735
Lewiston LNG	10,000
Total Deliverable Capacity	127,082

* indicates that the capacity is deliverable only during the months of November through March on a firm basis.

I have prepared a capacity path diagram and capacity path detail for each of the supply sources listed above (except the Lewiston LNG, which feeds directly into Northern's distribution system), 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, Transportation ("TransCanada"), Vector Pipeline L.P. ("Vector"), 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, as well as long-term peaking supply contracts, Distrigas of Massachusetts Corporation ("Peaking Supplier 1") and FPL Energy Power Marketing, Inc. ("Peaking Supplier 2"). 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"). 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.

I have prepared the capacity path diagrams and capacity path details in Schedule 12 in order to 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. Northern has permanently released the Algonquin and Texas Eastern contracts contributing to the majority of costs for the capacity paths, listed in Table 4, below.[4] 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. For completeness, Pages 9 and 10 of Schedule 12 also contains 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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[4] 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 updates have been made to Northern's capacity portfolio since the last Winter COG filing?

A. Northern has elected not to renew 1,196 GJ of TransCanada capacity from Empress, Alberta to the interconnection of TransCanada and PNGTS at East Hereford. At current TransCanada demand rates, the annual projected demand cost for this capacity is approximately $750,000 per year.

Northern has recently entered into a new contract with Granite. Contract 10-010-FT-NN contains a renewal clause, allowing the contract to continue on a year-to-year basis. Each party shall have the right to terminate the agreement effective November 1 of each year with a one-year notice provision.

Northern has also entered into an amendment of the Bay State Exchange, which will become effective for the upcoming peak season. The effect of this amendment is to define the volume of natural gas to be exchanged as the lower of the volumes desired by each party to the Bay State Exchange (Northern and

Bay State). The purpose of this amendment is to provide more flexibility and control of monthly and daily gas supply purchasing.

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 concluded an RFP during the month of March 2010 for the supplies necessary to meet its projected requirements for the period beginning April 2010 through March 2011. These supplies include summer re-fill of underground storage and projected baseload supplies through March 2011. The Company entered into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers.

Q. What steps has Northern taken since the 2010 Summer COG proceeding to better match the Adjusted Target Volumes ("ATV") for the non-daily metered transportation customers with the actual consumption for these customers?

A. Effective August 1, 2010 Northern has implemented revised consumption factors used to estimate the ATV for most of its non-daily metered transportation customers.[5] This project was completed by compiling a two-year history of bill cycle consumption and weather data for all customers eligible for non-daily metered transportation service. The raw bill cycle consumption data was reviewed to clean the data of errors, duplications and inconsistencies. The total Effective Degree Days ("EDD") were calculated for each bill cycle for each customer. Finally, weather-sensitive and non-weather sensitive coefficients were calculated for each customer based upon the bill cycle consumption and weather data. Following the calculation of the new factors, Northern communicated to the retail marketers with non-daily metered pools in order to ensure a smooth transition to the new ATV consumption factors. Since August 1, Northern has observed a significant reduction in the amount of gas it requires retail marketers serving non-daily metered to deliver. Northern also now monitors the monthly variance between the ATV deliveries and the aggregate consumption of non-daily metered transportation customers in order to ensure the accuracy of the ATV and to estimate the costs or revenues associated with the seasonal ATV reconciliation so that this item be accounted for in the determination of monthly COG recovery balances.

IV. GAS SUPPLY COST FORECAST

[5] This includes T40, G41, T41, G50, T50, G51 and T51 customers for both the New Hampshire and Maine Divisions. This includes approximately 5,000 total customers, of which approximately 1,700 are New Hampshire Division customers.

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Simpson to calculate the 2010-2011 Winter COG.

A. I have provided Mr. Simpson the following cost estimates for the period beginning November 2010 through October 2011, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities
- Northern's commodity costs
- Impact of Northern's financial hedging program

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

In addition, I also prepared the estimates of New Hampshire Division Capacity Assignment program demand revenues.

Q. Please provide Northern's demand cost forecast.

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

Table 5. Summary of Estimated Fixed Demand Costs November 1, 2010 through October 31, 2011			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 6,979,327	Schedule 5A, Page 2 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 23,000,956	Schedule 5A, Page 2 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,008,911	Schedule 5A, Page 3 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,578,485	Schedule 5A, Page 2 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 4,582,488	Schedule 5A, Page 4, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (2,931,530)	Schedule 5A, Page 5 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 36,218,638	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Schedule 5A. On page 1 of the Attachment, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 2 of Schedule 5A, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 3 and 4 of Schedule 5A provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 5 of Schedule 5A, I forecast the capacity release and asset management revenue the Company expects to receive for the

2010-2011 Gas Year. Support for the pipeline, storage and supply contract rates used in Schedule 5A can be found in the Attachment to Schedule 5A.

Q. Please compare the Demand Cost estimates for the upcoming gas year (2010-2011) to the Demand Cost estimates provided for the current gas year in Docket No. DG 09-167.

A. The Demand Cost estimates for the upcoming gas year are $36.2 million compared to estimated Demand Cost estimates of $27.1 million provided in Docket No. DG 09-167. These projected increase of $9.1 million is explained by the following.

1. $3.4 million of the increase in estimated demand costs are due to the PNGTS increase in tariff rates, proposed in the rate case, filed in FERC Docket RP10-729.

2. $2.1 million of the increase are due to increases in TransCanada demand costs. Rates increased substantially on January 1, 2010. This increase in TransCanada demand costs is net of the savings to the Company by turning back the Empress, Alberta to East Hereford capacity, discussed previously.

3. $1.9 million of the increase in estimated demand costs are due to the Granite increase in tariff rates, proposed in the rate case, filed in FERC Docket RP10-896.

4. $1.4 million of the increase in the estimated demand costs are due to the decrease in projected asset management and capacity

release demand revenue due to the lower values offered by bidders in the March 2010 RFP.

5. $0.3 million of the increase is due to peaking supply contract demand cost increases, stipulated by these long-term agreements.

Q. Please provide the 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 this figure 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 2010-2011 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $2,600,137.

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 2010-2011 Winter Period.

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

Table 6. Contracts Ranked on a Per-Unit Cost Basis November 1, 2010 through April 30, 2011			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes (Dth)	Delivered Cost per Dth
Peaking Supply 1	$2,404,468	602,041	$3.9939
Washington 10 Storage	$11,577,747	2,559,895	$4.5227
Tennessee Storage	$707,503	147,681	$4.7908
Chicago	$1,667,801	301,862	$5.5251
Niagara	$1,035,386	184,693	$5.6060
Tennessee Production	$7,768,412	1,375,093	$5.6494
LNG	$111,223	18,872	$5.8934
Pittsburgh, NH	$1,240,066	199,100	$6.2284
Peaking Supply 2	$21,557	2,670	$8.0723
Total System	$26,534,162	5,391,907	$4.9211

In summary, projected delivered commodity costs equal approximately $26.5 million at an average delivered rate of approximately $4.92 per Dth. This table can also be found in Schedule 2. In support of Table 6 and Schedule 2, 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 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 of the supply prices and variable transportation charges found in the Schedule 6B are found in the Attachment to Schedule 6B.

I based my commodity cost forecast on NYMEX prices as of July 22, 2010. Mr. Simpson has updated the commodity costs in the proposed COG rates to reflect updated NYMEX prices as of September 2, 2010.

Q. Please provide projected monthly supply volumes and capacity utilization calculations for both Northern's normal weather and design weather scenarios for the upcoming 2010-11 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 is Schedule 11B were those used by Mr. Simpson to calculated 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 an overview of the changes in Northern's hedging program since the last Peak COG filing.

A. Northern has made four substantive changes to its hedging program: 1) the adoption of a portfolio approach to hedging whereby Northern would combine its physically hedged supplies with its financial hedges to begin each peak season with approximately 70 percent of the supply requirements available under a fixed-price. The remaining supply (approximately 30%) would be purchased at market prices throughout the peak period; 2) the introduction of a price ceiling calculated pursuant to a formula, above which purchases of futures contracts would be postponed; 3) elimination of the price-based component of the existing hedging program; and 4) the introduction of a process under which futures contracts that appreciate in value above a specified percentage would be sold. Northern has also made an administrative change to the hedging program in that seasonal hedging plans are established and filed with the Commission as part of the Summer COG filings, rather than semi-annually.

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

A. I have also calculated the gains or losses of the NYMEX natural gas contracts purchased by the Company in accordance with its hedging program. Based upon the July 22, 2010 NYMEX natural gas settlement price data, Northern projects a hedging loss of approximately $546,240 for time-based hedges for the coming peak season. Time-based hedges are allocated between the New Hampshire and Maine Divisions on the basis of the projected commodity allocators. I have also provided the Commission a projection of the hedging loss due to price-based hedges of approximately $396,920. Since the Maine Public Utilities Commission suspended the price-triggered hedging strategy in its Order in Docket No. 2008-93 dated September 23, 2009, Northern procured price-triggered hedging using only New Hampshire supply requirements. Thus, price-based hedges are 100% allocated to the New Hampshire Division. Please refer to Schedule 7 for the monthly hedging calculations.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2010 through October 2011.

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

VI. PNGTS Rate Case Litigation Update & Proposed Cost Recovery

Q. What is the current status of the litigation opposing proposed rate increases by Portland Natural Gas Transmission System ("PNGTS")?

A. The Initial Decision of the Administrative Law Judge in FERC Docket No. RP08-306-000 ("2008 Rate Case") was issued on December 24, 2009. Briefs on Exceptions to the Initial Decision and Briefs Opposing Exceptions have been filed with the FERC. Although no specific timeframe for an order from FERC is established, an order is expected approximately six months after the briefs were submitted, which would be in the October 2010 timeframe. PNGTS rates since September 2008 have been billed subject to refund at the rate proposed in April 2008. The FERC order would establish the rates applicable to the refund period as well as the prospective rates, at least until December 1, 2010 when rates from RP10-729 go into effect.

Q. What is the impact of the Initial Decision in FERC Docket No. RP08-306-000, should it be upheld by the FERC?

A. The Initial Decision was very favorable to Northern and the PNGTS Shipper Group ("PSG"), with PNGTS losing on most significant issues including treatment of bankruptcy revenues, capacity for purposes of the at-risk condition (affirmed at 210,840 Dth), return on equity, treatment of interruptible transportation revenues, negative salvage rate, depreciation rates, and type of cost levelization model. Should the final order from FERC uphold the Initial Decision in RP08-306, Northern estimates a refund of approximately $1.2M dollars, $628,298 of which would be credited to the New Hampshire Division, would be due. Please refer to Schedule 5C for the back-up calculations for this amount.

Q: Please identify the costs incurred to oppose PNGTS proposed rate increases that Northern proposes to recover.

A: Northern proposes to recover costs of $183,943, which is the New Hampshire Division's share of the $376,840 in external legal and consulting costs that Northern has incurred opposing the 2008 and 2010 PNGTS rate cases and since September 1, 2009. The proposed 2010-2011 fixed proportional responsibility allocators were used to assign these costs by state for costs incurred from September 2009 through August 2010, which are presented to the Commission with this filing. Please see Schedule 5D, which lists the legal and consulting fees Northern seeks to recover. Northern has compiled the invoices, supporting these amounts and will provide these materials to the Commission Staff. Northern is not proposing to recover costs for expenses that were paid before December 1, 2008 or the costs of internal resources. In this Cost of Gas filing, Northern has reflected these costs as a deduction from Asset Management revenues.

Q: In making this request for inclusion of these extraordinary legal and consulting costs in the cost of gas rates for the coming winter season, does Northern intend to establish any precedent for such future treatment?

A: No. With this request, Northern intends to recover the costs to oppose the 2008 PNGTS rate case that have been incurred since September 1, 2009 and does not intend 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. Does Northern anticipate future litigation with PNGTS regarding firm transportation rates?

A. Yes. On May 12, 2010, PNGTS filed a new rate case which has been docketed RP10-729 ("2010 Rate Case"). The proposed new rates represent a 47 percent increase over current rates. Northern has intervened as a member of PSG and has begun incurring additional legal and consulting costs. On June 11, 2010, FERC ordered suspending the proposed new rates until December 1, 2010, when they go into effect subject to refund.

Q. Does this conclude your testimony?

A. Yes it does.