NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2013-2014
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 Energy Planning. 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 planning and 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 Adjustment (“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 summarize your prepared direct testimony in this proceeding.

A. Northern projects combined sales service and transportation-only distribution deliveries for the New Hampshire Division for the 2013-2014 Winter Period to be 5,405,250 Dth, which is 5.8% higher than the 2012-2013 Winter Period weather-normalized distribution deliveries and 9.0% higher than the 2011-2012 Winter Period weather-normalized distribution deliveries. Of the 5,405,250 Dth of projected distribution system deliveries, Northern projects that 2,789,116 Dth will be supplied by the Company through Sales Service. In order to supply 2,789,116 Dth of supply to customer's retail meters, Northern projects a city-gate sendout requirement of 2,806,475 Dth to supply its New Hampshire Sales Service deliveries. In addition, Northern expects its Company-Managed Sales obligation to equal 994,900 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 3,801,375 Dth for the upcoming Winter Period. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Northern has the ability to deliver up to 122,004 Dth of contract supply and on-system peaking capacity per day during the peak winter months, November through March and 36,861 Dth per day during the months of April through October. Northern's contract supply sources include Tennessee Production, Chicago City-Gates, Algonquin Receipts, Niagara, PNGTS, PNGTS Delivered, Lewiston City-Gate Baseload Supply, Tennessee Firm Storage, Washington 10 Storage and Peaking Supplies. Northern has system peaking LNG capacity 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 2013 through October 2014 gas year to be $27,510,064. (*See* Schedule 5A). Mr. Chris Kahl, who is employed by Unitil Service Corp. as a Senior Regulatory Analyst, 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 Period COG rate. I also project the demand revenue from the New Hampshire Division's capacity assignment program to be $3,335,606. (*See* Schedule 5B).

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2013-2014 Winter Period will be $32,563,281 at an average rate of $5.640 per Dth. (*See* Schedule 6A). I also calculated the impact of the hedging program on total company commodity costs of a loss of $297,730 based on NYMEX prices as of September 5, 2013. (*See* Schedule 7). Mr. Kahl presents the allocation of the total company commodity cost to the Northern's New Hampshire Division.

Finally, I provide updates to the PNGTS and TransCanada pipeline rate cases affecting Northern. PNGTS has issued a refund to Northern in the 2008 PNGTS Rate Case in the amount of $1,253,010.85 of which $609,807.51 is allocated to the New Hampshire Division. (*See* Schedule 5C). Northern proposes to recover PNGTS litigation costs in this proceeding in the amount equal to $22,987.94. (*See* Schedule 5D).

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm 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 for each customer class: use-per-meter and the number of meters. 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. Separate sets of forecast models were developed for both the total distribution system deliveries (based on historic total distribution system sales data) and for sales service deliveries (based on historic sales service data).

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 2013-2014 Winter Period.

Table 1. 2013-14 Winter New Hampshire Division Billed Distribution Service Deliveries Forecast Compared to Prior Years

Month	2013-14 Forecast[1]	2012-13 Actual[2]	2013-14 minus 2012-13	Percent Change	2011-12 Actual[2]	2013-14 minus 2011-12	Percent Change
Nov	540,836	512,746	28,090	5.5%	549,801	-8,965	-1.6%
Dec	847,002	801,576	45,427	5.7%	791,110	55,892	7.1%
Jan	1,110,192	1,045,501	64,692	6.2%	1,015,931	94,261	9.3%
Feb	1,143,366	1,076,884	66,482	6.2%	1,004,485	138,881	13.8%
Mar	1,017,419	955,266	62,153	6.5%	905,458	111,961	12.4%
Apr	746,435	719,023	27,412	3.8%	691,661	54,773	7.9%
Winter	5,405,250	5,110,994	294,256	5.8%	4,958,446	446,804	9.0%

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 2013-2014 Winter 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 non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2013-2014 Winter Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2012-2013 and 2011-2012 Winter 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 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 and City-Gate Sendout[1] for the upcoming Winter Period.

[1] When I use the term "City-Gate Sendout", 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.

Table 2. Required City-Gate Sendout Summary					
Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	Sales Service City-Gate Sendout (Dth)	Estimated Company-Managed Sales	Total Estimated City-Gate Sendout Requirement
Nov-13	743,511	358,059	360,148	49,745	409,893
Dec-13	979,136	527,474	530,552	218,878	749,430
Jan-14	1,183,125	665,906	669,791	298,470	968,261
Feb-14	1,023,258	556,685	559,933	268,623	828,556
Mar-14	869,971	429,151	431,655	159,184	590,839
Apr-14	606,248	252,921	254,396	0	254,396
Peak	5,405,250	2,790,197	2,806,475	994,900	3,801,375
Off-Peak	2,115,778	657,102	660,936	0	660,936
Annual	7,521,028	3,447,299	3,467,411	994,900	4,462,311

The detailed calculations can be found in Attachment 2 to Schedule 10B. On Pages 1 and 2 of Attachment 2 to Schedule 10B, I present calendar month and billed sales service deliveries by rate class. 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"). I then added an estimate for Lost and Unaccounted for Gas. Finally, I added Northern's projection of Company-Managed Sales pursuant to New Hampshire Division's capacity assignment program. Each of the estimates used in these calculations was based on the recent history of actual data, which are present in Attachment 3 to Schedule 10B.

Q. What are Company Managed Sales?

A. Company Managed Sales are a form of Capacity Assignment. Capacity Assignment is a means of transferring the responsibility for capacity contracts from Northern to the retail marketers on its system. Whenever a retail marketer enrolls a customer, who is "capacity assigned," the retail marketer assumes responsibility for a pro-rated portion of the capacity contracts entered into by Northern, subject to the capacity assignment provisions of each division. These capacity contracts can include interstate pipeline contracts, underground storage contracts, peaking supply contracts and on-site peaking facilities. When possible, such transfer is achieved by releasing a portion of capacity directly to the retail marketer, who may then purchase their own supplies and utilize the released contracts to deliver supplies to their customers. Certain capacity contracts do not lend themselves to capacity release, including Canadian transportation contracts, peaking supply contracts and on-site peaking facilities. In these circumstances, Northern bills the retail marketer for a pro-rated portion of the associated demand costs and offers a city-gate delivered supply. Such city-gate supplies are priced in accordance with the capacity assignment provisions of each division. Such arrangements are known as “Company Managed Sales.”

Q. Please explain the process used to project Company Managed Sales for the New Hampshire Division.

A. Company Managed resources for the New Hampshire Division include pipeline, storage and peaking resources. The maximum daily volume of each company managed resource was estimated, based on current capacity assigned transportation customer data. Northern requires its retail marketers to purchase pipeline Company Managed resources as baseload supplies. Northern allows marketers to nominate their storage and peaking company managed resources on a daily basis. The Company Managed Sales forecast reflects the following assumptions: First, that retail marketers will nominate all underground storage all LNG based peaking supplies volumes assigned on a company managed basis. Second, the forecast assumes that peaking company managed resources, whose price is based on daily New England spot market prices, will not be utilized by retail marketers under normal weather conditions.

Q. Prior COG filings have not included Company Managed Sales in Northern's projection of required city-gate sendout. Please explain why Northern has chosen to include this item in its city-gate sendout projections and its gas supply dispatch analysis.

A. Company Managed sales are a significant portion of Northern's gas supply obligation, due to its reliance on resources that require Canadian pipeline transportation for delivery to the Company's system and due to its reliance on delivered peaking supply contracts. Northern believes that inclusion of the Company Managed supply obligations for both New Hampshire and Maine Divisions in its gas supply dispatch analysis is necessary to better demonstrate the expected utilization of resources.

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	2013-2014 Winter	2014 Summer
Tennessee Production	13,109	13,109
Chicago City-Gates Supply	6,434	6,434
Algonquin Receipt Points Supply	1,251	1,251
Niagara	2,327	2,327
PNGTS	1,096	1,096
PNGTS Delivered	897	0
Lewiston City-Gate Baseload Supply	6,500	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Supply 1	14,948	0
Peaking Supply 2	5,000	0
Peaking Supply 3	24,913	0
Lewiston On-System LNG Production	10,000	10,000
Total Deliverable Resources	**122,004**	**36,861**

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 Tennessee Zone 6, PNGTS or Maritimes meters. These peaking supply arrangements were procured through a Request-For-Proposals ("RFP") 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 replace its current LNG Contract (which ends 10/31/2013) in order to supply this facility. 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 Texas Eastern Contract 800384 for the remaining term of the agreement, which is through October 31, 2017. This release is at the maximum allowable rates, benefiting customers by fully recovering the costs of the released contract.

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 RFP for terms beginning April 1 and running through March 31 each year. Northern has recently completed its annual RFP for the delivery period beginning April 1, 2013 through March 31, 2014. Northern has entered into asset management agreements for its Chicago capacity path, Algonquin Receipts capacity path, Niagara capacity path, a portion of its Tennessee Production capacity path and its Washington 10 capacity path. Northern also entered into baseload supply agreements through this RFP. Northern has completed its RFP process for replacement peaking supplies. Northern has issued an RFP for replacement LNG Contract and is in the process of negotiating an LNG Contract for the upcoming Winter Period.

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 2013-2014 Winter Period 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 2013 through October 2014
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2013 through October 2014
- Northern's commodity costs for the period November 2013 through October 2014, net of Company Managed Sales revenues.
- Gains and losses due to Northern's financial hedging program for the period November 2013 through April 2014

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, 2013 through October 31, 2014			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,421,877	Att NUI-FXW-4, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 24,622,894	Att NUI-FXW-4, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	Att NUI-FXW-4, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,725,894	Att NUI-FXW-4, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 1,658,750	Att NUI-FXW-4, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,956,197)	Att NUI-FXW-4, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 27,510,064	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 2013-2014 Gas Year. Support for the transportation and storage demand rates used in Schedule 5A are found in the Attachment to Schedule 5A, Supplier Prices.

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

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed calculations of the demand revenues from capacity assignment in Schedule 5B. On page 1 of Schedule 5B, I present a summary of the Company's forecast of New

Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Schedule 5B, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Schedule 5B. The 2013-2014 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $3,335,606.

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

A. I base the Company's commodity cost forecast on Northern's projected Sales Service and Company Managed Sales city-gate sendout requirement, 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 2013-2014 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 2013 through April 2014			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Tennessee Storage	$759,520	193,442	$3.926
Tenn Zone 4 Spot	$887,485	224,755	$3.949
Washington 10 Storage	$10,126,992	2,548,803	$3.973
Tennessee Production	$4,679,966	1,147,820	$4.077
Chicago	$3,791,653	871,493	$4.351
TGP Zone 6	$252,686	56,894	$4.441
Algonquin Receipts	$844,050	188,901	$4.468
Niagara	$1,599,104	347,191	$4.606
Iroquois Receipts	$512,833	86,760	$5.911
PNGTS	$929,923	135,424	$6.867
LNG	$69,852	9,860	$7.084
PNGTS Delivered	$1,099,553	135,424	$8.119
Lewiston Baseload	$8,776,512	1,026,500	$8.550
Peaking Supply 3	$4,037,149	249,125	$16.205
Total Delivered Commodity Cost	$38,367,279	7,222,392	$5.312

In summary, projected delivered commodity costs equal approximately $38.4 million at an average delivered rate of $5.312 per Dth. This represents the projected system commodity cost for both Northern's Sales Service and Company Managed Sales city-gate sendout requirements. 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. Schedule 6A differs from Table 5 in that Schedule 6A includes estimated of Company Managed revenue in order to present a net amount of commodity cost for the Sales Service city-gate sendout requirement for the New Hampshire and Maine Divisions.

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, Supplier Prices.

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

A. Please refer to Schedules 11A, 11B and 11C. Schedule 11A provides monthly supply volumes for Northern's normal weather scenario. The data in Schedule 11A is also found in Schedule 6A. Schedule 11B provides monthly supply volumes for Northern's design cold weather scenario. 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 2013 through October 2014.

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

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 September 5, 2013 NYMEX natural gas settlement price data, Northern projects a hedging loss of approximately $297,730 for hedges for the upcoming winter 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"). The 2008 PNGTS Rate Case pertains to PNGTS rates for the period effective from September 1, 2008 through November 30, 2010. The 2010 PNGTS Rate Case pertains to PNGTS rates effective from December 1, 2010.
- TransCanada Pipelines Limited 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. On March 21, 2013, FERC issued the Order on Requests for Rehearing and Clarification of the Initial Decision in the 2008 PNGTS Rate Case ("Opinion 510-A"). Opinion 510 had been issued by FERC on February 17, 2011 and had addressed briefs on and opposing exceptions to the 2008 PNGTS Rate Case Initial Decision, which had been issued on December 24, 2009. Opinion 510-A generally denies rehearing of Opinion

510, with one notable exception. Opinion 510-A establishes PNGTS' at-risk capacity to be 217,405 Dth per day, instead of the 210,840 Dth per day established as PNGTS' at-risk condition in Opinion 510. Opinion 510-A also affirms Opinion 510's requirement that PNGTS reduce its rate base by the amount of bankruptcy proceeds it received and partially grants PNGTS' request for rehearing concerning the level of its pipeline integrity costs. Opinion 510-A denies various requests for rehearing concerning Portland's return on equity. The order required PNGTS to file revised tariff pages for effect September 1, 2008 through November 30, 2010, in compliance with the order, and to issue refunds for this period. On April 19, 2013, PNGTS filed a request for rehearing of Opinion 510-A. On May 21, 2013, PNGTS, refunded Northern $1,253,010.85, including reservation rate refunds and interest. Northern awaits FERC action on the PNGTS' request for rehearing of Opinion 510-A.

Q. Please provide the allocation of the PNGTS Refund to the New Hampshire Division.

A. $609,807.51 of the PNGTS Refund is allocated to the New Hampshire Division. Schedule 5C provides the detailed calculations of the allocation of the PNGTS Refund between New Hampshire and Maine Divisions.

Q. Does the proposed COG reflect the 2008 PNGTS Rate Case Refund?

A. Yes, it does. The proposed COG reflects the 2008 PNGTS Rate Case Refund. Northern proposes that a pro-rated portion of this refund be credited to the New Hampshire Capacity Assigned customers, so that the credit is allocated as equitably as possible to all Northern's customers who support PNGTS litigation costs. Page 6 of Schedule 5B provides an estimate equal to $547,629 as the net amount of the PNGTS refund that would be credited to the COG.

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

A. On March 21, 2013, FERC issued its Order on the 2010 PNGTS Rate Case Initial Decision ("Opinion 524"). Opinion 524 addresses exceptions to the 2010 PNGTS Rate Case Initial Decision, which had been issued on December 8, 2011 by the administrative law judge. Opinion 524 established PNGTS' at-risk condition at 210,840 Dth per day, and required PNGTS to design its rates based on this at-risk level, and that PNGTS reduce its rate base by the amount of bankruptcy proceeds. The order set PNGTS' return on equity at 11.59 percent and affirmed the administrative law judge's findings with respect to several cost-of-service items, PNGTS' levelized rate structure, depreciation and negative salvage, capital structure, and cost of debt. In April 2013, Requests for Rehearing on Opinion 524 were filed by the Portland Shippers Group ("PSG") and PNGTS. Northern awaits FERC action on these Requests for Rehearing.

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 $22,988. Schedule 5D presents the legal and consulting expenses Northern has incurred since August 1, 2012 by vendor. Consistent with the proposed treatment of the 2008 PNGTS Rate Case Refund, Northern proposes to continue to allocate a portion of its PNGTS litigation costs to the New Hampshire Capacity Assigned customers, the details of which can be found on page 6 of Schedule 5B.

Q. Please provide an update of the 2012 and 2013 TransCanada Tolls Application.

A. On March 27, 2013, the NEB issued its decision on the TransCanada Tolls Application, which had been filed on September 1, 2011. Through this decision, the NEB set multi-year fixed tolls through December 31, 2017, which were significantly lower than the tolls in effect prior to the 2012 and 2013 TransCanada Tolls Application. Demand tolls for TransCanada Contract No. 33322 (part of Northern's Washington 10 Capacity Path) were reduced 29% from their prior levels and TransCanada Contract No. 29594 (part of Northern's Chicago Capacity Path) were reduced 14%. Commodity tolls for all paths were eliminated. The NEB rejected TransCanada's proposal to carve out Trans Québec & Maritimes ("TQM") costs and assign these costs only to customers taking delivery at TQM points. The NEB approved TransCanada's proposal to charge an average delivery pressure tolls to all export points. Both of these issues were of critical importance to Northern, since acceptance of the TQM carve-out or rejection of the average delivery pressure tolls would have increased costs of transportation service to East Hereford, the interconnection between TransCanada and PNGTS. Overall, Northern is pleased with the results of the TransCanada Tolls Application process and with the Company's participation in the process through Alberta Northeast Gas, Limited ("ANE").

There continue to be business and regulatory challenges related to TransCanada. TransCanada has recently proposed tariff changes, which would alter Northern's renewal rights to its current capacity. TransCanada is also proposing to convert a portion of its pipeline to oil transportation, including pipeline capacity that is currently under contract for natural gas transportation. TransCanada has also proposed a pipeline abandonment surcharge. Northern monitors and participates in these proceedings through ANE.

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

A. Yes. The forecasted TransCanada rates reflect TransCanada's approved 2013 Final Tolls.

Q. Does this conclude your testimony?

A. Yes it does.