NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2008
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
RONALD D. GIBBONS

Q. Please state your name and business address.

A. Ronald D. Gibbons, 200 Civic Center Drive, Columbus, Ohio 43215.

Q. By whom are you employed?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource") and affiliate of Northern Utilities, Inc. ("Northern").

Q. What positions have you held during your employment with NiSource and its predecessors?

A. Since my employment in January 1981 by the Columbia Gas System Service Corporation, the predecessor of NCSC, I have held positions of increasing responsibility in the accounting department (1981-1984), as an auditor (1984-1989), and in the regulatory accounting department (1989-present). I was promoted to my present position, Manager of Rate and Regulatory Services, in May 2006.

Q. What are your present duties and responsibilities as Manager of Rate and Regulatory Services as well as your past Rate and Regulatory Services duties?

A. Since the merger of Columbia Energy Group and NiSource in November 2000, I have been responsible for managing, and/or coordinating and preparing data and reports required to support the recovery of gas costs as well as assisting in the preparation of rate case data and exhibits for Northern. In my current position as Manager, my responsibilities have increased to include all regulatory accounting activities for Northern, Bay State Gas Company ("Bay State") and Columbia Gas of Maryland. In the past, my work has included gas cost recovery activities and filings for Northern's affiliates Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Pennsylvania and Columbia Gas of Virginia. I also assist the Director of Regulatory Services on various types of regulatory activities.

Q. What is your educational background?

A. I graduated from The Ohio State University in 1980 with a Bachelor of Science degree in Administrative Science. My major was accounting. I have also attended several ratemaking seminars sponsored by universities and trade associations.

Q. Have you previously testified before any regulatory bodies?

A. Yes. I have testified before the Public Service Commission of Kentucky, the Public Service Commission of Maryland, the Maine Public Utilities Commission ("MPUC" or "the Commission") and the New Hampshire Public Utilities Commission ("NHPUC").

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

A. The purpose of my testimony is to explain the calculation of the Cost of Gas ("COG") to be billed by Northern from May 1, 2008 to October 31, 2008. I will explain the derivations of the rates used in the forecast by the Company's gas suppliers and upstream transporters. I will also explain the forecast of sales and resulting sendout requirements for the Summer 2008 Period. In addition, I have incorporated a discussion supporting the prior period overcollection filing in my testimony as well as the impact that the proposed COG will have on the bills of the Company's typical customers. Finally, I will present a discussion supporting the Company's use of its hedging Program.

COST OF GAS ADJUSTMENT

Q. Would you please explain tariff page Proposed Thirty-fifth Revised Page 38 and Thirty-fifth Revised Page 39?

A. Proposed Thirty-fifth Revised Page 38 and Thirty-fifth Page 39 contain the calculation of the 2008 Summer Cost of Gas rate and summarize the Company's forecast of gas sendout and gas costs. The estimated total anticipated cost of gas from May 1, 2008 to October 31, 2008 is $15,740,734.

The Gas Cost section presents the forecast commodity and capacity volumes and costs allocated to the New Hampshire Division.

To derive the Total Anticipated Period Cost of Gas of $15,740,283, the following charges, including the indirect gas costs, have been added to the $15,740,734 Total Anticipated Direct Cost of Gas:

1.) Prior Period Over Collection- ($95,342).

2.) Interest Expense- ($6,386).

3.) Total Working Capital Allowance- $21,650.

4.) Total Bad Debt Allowance- $50,844.

5.) Miscellaneous Overhead- $28,784.

The Total Anticipated Cost of Gas Adjustment of $1.1096 per therm was determined using the forecasted firm sales volumes of 14,184,780 therms as well as the direct and indirect anticipated cost of gas as shown on tariff sheet, Page 39.

Q. How are you calculating the overall Demand and Commodity COG factors?

A. Proposed Thirty-fifth Revised Page 38 and Thirty-fifth Revised Page 39 details the commodity and demand costs as well as the calculation of the 2008 Summer Period Cost of Gas rate by rate category—Residential, and Commercial & Industrial Low Winter and High Winter. The costs were assigned to the Summer Period for each of the Company's firm sales customer classes. The assignment of costs between the Winter and Summer Periods and among the customer classes was developed using the Simplified Market Based Allocation Method ("SMBA"). The SMBA methodology was approved in DG-07-033, the Summer 2007 COG. The Summer Period Demand and Commodity costs as well as the indirect costs for each customer category were then divided by the forecasted sales volumes for each customer category to arrive at class/category specific Summer Period.

Q. Please explain the basis for allocating the fixed, capacity-related demand cost between the Maine Division and New Hampshire Division of Northern.

A. These costs are allocated between the divisions based on the Modified Proportional Responsibility ("MPR") methodology, which allocates the fixed capacity-related gas costs based on the demand each division places on the available capacity each month. The MPR methodology was approved by the Commission on December 23, 2005, effective January 1, 2006, pursuant to the New Hampshire Commission-approved Settlement in DG 05-080 and the Maine Commission-approved Settlement in Docket Nos. 2005-87 and 2005-273.

Accordingly, the MPR method was used to establish the proportional cost responsibility of Northern's Maine Division and Northern's New Hampshire Division in the 2007-2008 Winter Period Cost of Gas. The work papers supporting the MPR factors also reflect the settlement reached in DG 05-080 as well as in the Maine Division dockets, Docket Nos. 2005-077 and 2005-473, and are provided in the Allocation Exhibits section.

Q. What is the basis for allocating the variable gas costs between Northern's Maine and New Hampshire Divisions?

A. The variable gas costs have been allocated between Northern's Maine Division and New Hampshire Division on the basis of each division's percentage of monthly firm sendout. The monthly variable allocation factors are shown in the Allocation section.

PRIOR PERIOD OVERCOLLECTION

Q. Please explain the prior Summer Period over collection of $95,342 shown on Thirty-fifth Revised Page 39.

A. The reconciliation analysis that was filed with the Commission on January 29, 2008, and included in the Reconciliation section of this filing, provides the support for $92,816 of the over-collection. The remainder, $2,526, is interest estimated prior to May 1, 2008.

Q. On December 20, 2007, Northern filed a letter with the New Hampshire Public Utilities Commission and Office of Public Advocate that an investigation of unaccounted for gas in the New Hampshire Division had uncovered a supply metering problem. The letter went on to say that this metering problem most likely resulted in a higher amount of gas being recorded and billed to Northern for some period leading up to December 2007. Is any gas cost credit included in the 2007 Summer Period reconciliation or reflected in the proposed 2008 Summer Period COG rate calculated within the filing?

A. No, there is no gas cost credit reflected in this filing. At the time of the final preparation of this testimony and COG filing, Northern continues pursuing final resolution with the delivering pipelines of both the final adjustment to the metered volumes and associated commodity credit, which will then be run through Northern's gas costs for both the Maine and New Hampshire divisions. Northern is anticipating final resolution of this matter in the near future, and is hopeful that an associated Summer Period credit to gas costs can be incorporated into this COG for effect May 1, 2008.

FORECASTED PURCHASE GAS PRICES

Q. Please explain the basis for projecting costs for the purchases of Canadian gas supplies.

A. Northern has firm entitlements of up to approximately 2,400 Dth/day of year-round Canadian supplies directly from Northeast Gas Marketing (NEGM). The forecasted price of NEGM was based on the February 29, 2008 NYMEX prices plus a differential.

Q. Please explain the basis for the projected costs of the Company's domestic gas supply purchases.

A. The Company will purchase all of its domestic supply on a short-term (monthly, daily) basis for the Summer Period. Domestic supplies are forecasted based on NYMEX prices from February 29, 2008, plus the cost to transport the gas to the city gate. The commodity forecast for domestic supplies relies upon monthly gas indices for which the NYMEX

Natural Gas Futures prices of February 29, 2008 were used. The transportation costs are forecasted based on the route the SENDOUT® model chooses that the gas will travel. The SENDOUT® model provides the forecasted MMBtus transported on each of the upstream pipelines. The sendout on each pipeline is then multiplied by the appropriate upstream unit commodity costs and added to the monthly gas indices.

Q. Please explain how the Company's hedging activity for gas purchases for May and October 2008 have been reflected in the 2008 Summer period commodity costs.

A. The Company has executed hedges for approximately 39% of its projected natural gas requirements for the month of May and approximately 45% of its projected requirements for the month of October 2008 at various prices throughout the past twelve months. The aggregate current position (gains or losses) of all executed hedging transactions for May and October is reflected in Proposed Thirty-fifth Revised Page 38. The hedging transaction "Profit and Loss Statement", which is provided in the Hedging section of this filing, shows a projected positive net position of $437,047. This was calculated by applying the February 29, 2008 NYMEX Natural Gas Futures prices to all hedged positions for May and October 2008.

Q. Has the Company established new price triggers for its hedging program, which was approved in Commission Order No. 24,037 in Docket No. DG 02-137?

A. Yes. Pursuant to Order No. 24,037 dated August 16, 2002 in Docket No. DG 02-137, Northern has been directed to provide the Commission, in its semi-annual COG proceedings, its recommendation for new price targets for the price-triggered component of the hedging program, or alternatively, why the current targets are appropriate. The Company typically re-establishes its price targets every six months, prior to each COG season. These price triggers are based on trigger points set at the 65^{th}, 35^{th} and 20^{th}

percentiles of a matrix of NYMEX traded futures contracts analyzed by Risk Management Inc. (RMI), an independent consultant retained by the Company. The RMI price matrix is adjusted for inflation and weighted, with 20% of the price being attributed to the most recent year (short-term) and 80% being attributed to the last four years (long-term). This scaled distribution gives the matrix a slight bias toward recent prices, allowing for greater market sensitivity to the current environment. This market sensitivity is needed because these weighted prices are broken into deciles for the purposes of developing meaningful buy or trigger points. The Hedging section of the filing presents the RMI Matrix that sets forth the updated price triggers per MMBtu of \$8.14, \$7.41 and \$7.05 for the 65^{th}, 35^{th} and 20^{th} percentile, respectively.

FORECASTED TRANSPORTATION COSTS

Q. Please explain the basis for the Company's forecasted pipeline reservation and commodity charges for transportation services included in this COG filing.

A. Northern currently has entitlement to firm transportation capacity on eight (8) interstate pipeline companies: Tennessee Gas Pipeline Company, Iroquois Gas Transmission System, Algonquin Gas Transmission Company, Texas Eastern Transmission Corporation, Granite State Gas Transmission, Inc, TransCanada Pipeline, Vector Pipeline and Portland Natural Gas Transmission System. The Supplier Prices Section reflects the maximum daily transportation quantity (MDTQ) of firm capacity that Northern has with each of the above pipelines. As an interstate pipeline, each company is regulated by the Federal Energy Regulatory Commission (FERC) and is required to file tariffs reflecting its rates for transportation services. For purposes of forecasting pipeline reservation and commodity charges, the rates reflected on each pipeline's currently effective tariff sheets have been applied to the applicable contracted MDTQ and to the forecasted transportation quantities, with the exception of the contracts listed in Tables 1 and 2 which list all rates that cannot be determined from existing rate sheets. Table 1 lists all negotiated and discounted demand rates while Table 2 converts Canadian rates from Canadian dollars per GJ to U.S. dollars per MMBtu The Supplier Prices Section contains the currently effective pipelines' tariff sheets and summaries of the pipeline reservation and product demand charges allocated to the New Hampshire Division.

OTHER SUPPLY COSTS

Q. Please explain how you estimated the rate for the LNG boil-off during the Summer Period.

A. The estimated LNG rate used in this Off-peak Period CGF Filing is $8.4915 per MMBtu. This is the average cost of the LNG inventory at the time of this filing.

Q. Will the Company propose to revise the COG if it receives any new or updated information on supplier or transportation rates?

A. Yes. If the Company receives more accurate or updated information on Northern's forecasted supplier/transportation rates, it will assess whether a revised COG proposal is warranted. If the different rate information materially changes the proposed COG and if time permits before the hearing date, it will then notify all parties to this proceeding and make a revised filing. Such updated rate information will include the latest NYMEX natural gas prices, which the Company will review within reasonable lead-time prior to the hearing.

SALES AND SENDOUT FORECAST

Q. Please compare forecasted sales for the COG period with normalized sales for the same period last year.

A. Sales for the COG period are projected to increase by 0.4% for the residential class and 0.8% for C&I. The increases are driven mainly by customer growth, with the residential growth rate reduced by projected conservation.

Q. How does the Company forecast firm sales and transportation?

A. For the residential and small commercial forecasts, the Company relies upon econometric and time-series techniques for two components: use per meter and the number of meters. Individual forecasts are made for large commercial customers with special contracts. The growth rates for customers and volume from these models are applied to the most recent data normalized for weather.

Q. How does the Company forecast firm sendout?

A. The firm sales and transportation forecast serves as the basis of the sendout forecast. Calendar month firm sales and transportation is converted to a forecast of sendout by applying an unaccounted-for conversion factor that is the average of the most recent four years ending June 30. The unaccounted-for factor reflects the same data that the Company has filed with DOT for each of those four years.

COG RATE COMPARISON AND BILL IMPACT ANALYSES

Q. How does the proposed 2008 Summer COG rate compare with the actual 2007 Summer COG rate?

A. The Variance Analysis Section shows that the difference between the proposed 2008 Summer rate and the average actual cost of gas in the 2007 Summer period to be an increase of $0.2924 per therm. Of this increase, $0.2393 per therm can be attributed to an increase in the forecast of commodity prices and a $0.0701 per therm increase in the amount of the over/under collection, which are partially offset by a $0.0204 per therm decrease in demand costs.

Q. How does the proposed COG rate affect a typical Residential Heating customer's annual and

Summer Period bills for the twelve-month and six-month period ended October 2008 compared with the twelve-month and six-month period ended October 2007?

A. The Typical Bill Analysis Section shows that a typical Residential Heating customer's bill for the six months ended October 2008, compared to the six months ended October 2007, will increase by $87 or 19.3 percent based on typical Summer consumption of 318 therms. This comparison is based on the proposed Summer 2008 residential rate and the actual billed residential rate for each month of the Summer 2007 period. However, the Company is forecasting that the typical Residential Heating customer will experience a total decrease for the twelve months ended October 2008 of $194 or 9.2%. The Typical Bill Analysis section also details monthly bill comparisons at various consumption levels for a Residential Heating customer and compares those to the average actual gas cost rate calculations for the Summer 2007 period. This analysis shows that, a residential customer using 30 therms per month will experience an increase of $8.57 or a 18% increase and a customer who uses 200 therms will experience an increase of $57.14 or 23%.

Q. Does this conclude your testimony?

A. Yes, it does.