Exhibit Northern-1

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2008-2009
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 Rates and Regulatory Services in May 2006.

Q. What are your present duties and responsibilities as Manager of Rates and Regulatory Services?

A. Since the merger of Columbia Energy Group and NiSource in November 2000, I have been responsible for 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) proposed to be billed by Northern from November 1, 2008 to April 30, 2009. 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 2008-2009 Winter Period. In addition, I have incorporated the prior period over-collection filing in my testimony. I justify the inclusion in the overall reconciled costs of certain capacity costs resulting from the Settlements in the New Hampshire Commission docket DG 05-080, as well as in the Maine Commission dockets, Docket Nos. 2005-87 and 2005-273, by citing Commission approval of those Settlements. My testimony also presents and supports the various charges and factors effective November 1, 2008, associated with providing suppliers services pursuant to Northern's Delivery Service Terms and Conditions. These include the Supplier Balancing Charge (SBC), Capacity Allocators, Peaking Service Demand Charge, and Re-Entry Fee. Finally, I present the impact that the proposed COG will have on the bills of the Company's typical customers.

COST OF GAS

Q. Would you please explain tariff page, Proposed Revised 38 and Proposed Revised Page 39?

A. Proposed Revised Page 38 and Proposed Revised Page 39 contain the calculation of the 2008-2009 Winter Unit Cost of Gas and summarizes the Company's forecast of gas sendout and gas costs. The estimated Total Anticipated Direct Cost of Gas from November 1, 2008 to April 30, 2009 is $52,193,603.

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 Costs of $52,484,799, the following indirect gas costs and credits (totaling $291,196) have been added to the $52,193,603 Total Anticipated Direct Cost of Gas:

(1) Prior Period Over Collection - ($707,166)

(2) Interest Expense - ($14,206)

(3) Working Capital Allowance - $90,666

(4) Bad Debt Allowance - $213,262

(5) Miscellaneous Overhead - $93,036

(6) Production and Storage Capacity - $686,673

(7) Capacity reserve Charge - ($71,068)

The unit anticipated cost of gas adjustment of $1.3899 per therm is the sum of the anticipated direct cost of gas rate of $1.3822 per therm and the anticipated indirect cost of gas rate of $0.0077 per therm. The direct and indirect costs of gas rates were determined using the forecasted winter period firm sales volumes of 29,889,150 therms. This unit cost of gas of $1.3899 per therm becomes the COG rate for the residential class customers. Through the SMBA method of allocating gas costs commercial and industrial low winter rate classes (G-50, G-51, G-52) are assigned a COG rate of $1.2344 per therm and the commercial and industrial high winter rate classes (G-40, G-41, G-42) are assigned a COG rate of $1.5040 per therm.

PROPORTIONAL RESPONSIBILITY (PR) ALLOCATION OF DEMAND COSTS

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

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 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. The work papers supporting the MPR factors reflect the settlement reached in the New Hampshire docket, DG 05-080 and Maine 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 New Hampshire and Maine divisions?

A. The variable gas costs have been allocated between the New Hampshire and Maine divisions of Northern Utilities, Inc. 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 Winter Period over-collection of ($707,166) shown on Proposed

Revised Page 39?

A. The reconciliation analysis that was filed with the Commission on July 29, 2008, of an over-collection of ($688,600) is being further adjusted by the application of the credit of associated carrying costs of ($18,566) on the balance through October 2008. A revised reconciliation of the 2007-2008 Winter Period has been included with this filing. While the over-collection is unchanged from the original filing, the Capacity Reserve Charge credit and the Adjusted Bill Adjustment have been revised in an offsetting manner. Additionally, the reconciliation of Environmental Response Costs has been revised.

FORECASTED SUPPLIER RATES AND COMMODITY COSTS

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 August 29, 2008 NYMEX prices plus a differential. Domestic supplies are forecasted based on NYMEX prices from August 29, 2008, plus the cost to transport the gas to the city gate.

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 Winter Period. The commodity forecast for domestic supplies rely on monthly gas indices for which the NYMEX Natural Gas Futures prices of August 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. Mr. Gibbons, how has the Company reflected the results of its hedging activity for the upcoming winter period months in the COG calculation?

A. The schedule in the Hedging Section shows the gains and losses resulting from the entry price position versus the forecasted NYMEX prices for each month of November 2008 through October 2009. The negative net position of $651,063 results in all hedged gas volumes during the upcoming winter period to be at the cost of the entry prices of the hedged positions. The net position is then allocated based on the same estimated commodity costs allocation between New Hampshire and Maine as the other commodity gas costs are allocated. This positive or negative position amount as it relates to commodity costs is also shown on the tariff sheet, Proposed Revised Page 38.

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 Utilities 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 and Portland Natural Gas Transmission System. The Suppliers 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 Granite State reservation charges. Granite State reservation charges are in accordance with a negotiated contract between Granite State and Northern, for the five-year term of November 1, 2003 through October 31, 2008, for an MDTQ of 100,000 Dth at the discounted monthly rate of $1.2639 per Dth. This contract was approved by the Commission in Docket No. 2003-762. A new contract with Granite State is currently being negotiated. It is very likely that this rate will change. The new rate will be included in any revisions to this cost of gas filing. The Suppliers Price Section contains the currently effective pipelines' tariff sheets, while the Gas Cost Section provides the summary of the pipeline reservation and product demand charges allocated to the New Hampshire division.

OTHER SUPPLY COSTS

Q. Please explain how you estimated the LNG rate for the Peak Period.

A. The LNG rate of approximately $7.53 per MMBtu shown in the Inventories Section is the estimated average cost of LNG withdrawn from inventory between November 1, 2008 and October 31, 2009. This average rate is also a function of the current actual inventory balance (volumes and costs) and the projected receipts of LNG throughout the forecasted period.

Q. Please explain how you estimated the propane rate for the 2008-2009 Winter Period.

A. Northern does not plan on using propane supplies in the 2008-2009 Winter Period.

Q. Please explain how you estimated the storage rates for the 2008-2009 Winter Period.

A. The estimated storage rates are derived based on a couple of factors. The first factor would be the average cost of gas in inventory at the time of this filing. The second factor is the estimated cost of the remaining storage refill. For the purpose of estimating a gas cost rate for the upcoming winter period, it is assumed that each storage field will be refilled to 100% of its contracted capacity by October 31, 2008. The amount of inventory that is needed to accomplish this is then assumed to be acquired evenly in each of the remaining months of the refill season. The NYMEX futures price (in this case dated August 1, 2008) is then applied to the monthly scheduled refill. Withdrawal fees and estimated money pool interest is included in the cost of the inventory. This results in an average price of inventory in each storage location which is then applied to the forecasted storage withdrawals and included in the cost of gas estimate.

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 information on Northern's forecasted supplier/transportation rates, it will notify all parties to this proceeding and will propose to revise the COG if the change is material and there is sufficient time to present a revised COG at 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 0.3% 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 ended June 30. The unaccounted-for factor reflects the same data that the Company has filed with DOT for each of those four years.

LOCAL DELIVERY ADJUSTMENT CLAUSE

ENVIRONMENTAL RESPONSE COSTS

Q Would you please explain the Environmental Response Costs rate reflected on Proposed Page 56?

A. During the period July 1, 2007 through June 30, 2008, ERC expenses totaled $232,180. The Company is allowed to recover one-seventh of the actual response costs incurred by the Company in a calendar year until fully amortized plus any insurance and third-party expenses for the calendar year. Any insurance and third-party recoveries for the calendar year are then used to reduce the out years of the amortization schedule. The $501,713 presented on Schedule 1 of the LDAC Section is one-seventh of the ERC costs incurred through June 2008 of $33,169 plus the 2006-2007 amount of $26,686, plus the 2005-2006 amount of $90,352, plus the 2004-2005 amount of $129,871, plus the 2003-2004 amount of 41,661, plus the 2002-2003 amount of $31,946 and the 2001-2002 amount of $147,916. The prior period reconciliation of ERC costs, an under-collection of $136,407, is applied to the annual ERC costs resulting in total ERC costs to be recovered from customers in the period of November 2008 through October 2009 of $638,008. Dividing these recoverable

ERC costs by estimated total annual throughput volumes of 69,234,390 therms yields an ERC rate of $0.0092 per therm. This ERC rate is included in the LDAC rate on Proposed Revised Page 56.

DEMAND SIDE MANAGEMENT CONSERVATION CHARGE

Q. Please explain the source of the Demand Side Management Conservation Charges set out on Proposed Revised Page No. 56.

A. On August 29, 2008, Northern filed its annual Energy Efficiency (DSM) filing. The DSM charge included in the LDAC rate is supported in that filing

COG RATE AND BILL COMPARISON ANALYSES

Q. How does the proposed 2008-2009 Winter COG rate compare with the actual 2007-2008 Winter COG rate?

A. The schedule in the Variance Analysis Section shows that the difference between the proposed 2008-2009 Winter rate and the average actual cost of gas in the 2007-2008 Winter period to be an increase of $0.3091 per therm. Of this increase, $0.1696 per therm can be attributed to an increase in commodity costs and an increase of $0.0768 in demand costs. Additionally, total increase reflects an increase related to the over/under collection of $0.0720.

Q. How does the proposed COG rate affect a typical Residential Heating customer's annual and Winter Period bills for the twelve-month and six-month periods ended April 2009 compared with the twelve-month and six-month periods ended April 2008?

A. The Typical Bill analysis Section shows that a typical Residential Heating customer's bill for the six months ended April 2009, compared to the six months ended April 2008, will increase by $281 or 20.0 percent based on typical winter consumption of 932 therms. For the twelve-month period ended April 2009, typical Residential Heating customers can expect to see an increase of $371 or 20.0%. These calculations used the forecasted winter 2008-2009 COG rate of $1.3899 per therm and the summer 2008 actual COG rates for the "current" period and the actual winter 2007-2008 and summer 2006 COG rates for the "previous" period. The Typical Bill Analysis Section shows that a residential heating customer using 30 therms per month will experience an increase of $7.72 in the monthly bill or a 14% increase and a customer who uses 200 therms will experience a $51.44 increase, which translates to a 17% increase.

SUPPLIER BALANCING CHARGE, PEAKING SERVICE DEMAND CHARGE, FORECAST of UPCOMING WINTER PERIOD DESIGN DAY REPORT AND CAPACITY ALLOCATORS

Q. Mr. Gibbons, how is the Company filing with the Commission its Supplier Balancing Charge, Peaking Service Demand Charge and Capacity Allocators for the upcoming winter period?

A. As part of this filing, the Company is filing its updated Supplier Balancing Charge, Peaking Service Demand Charge and Capacity Allocators effective November 1, 2008 for the upcoming winter and annual period. In this filing, through the enclosed schedules, the Company explains the derivation of the charges and allocators and presents its revised Appendix A, Eighth Revised Page 154, and Appendix C, Seventh Revised Page 169, to Northern's Delivery Service Terms and Conditions, bearing an effective date of November 1, 2008. The Company is filing these revised charges and allocators in accordance with Commission directive to update them once a year, effective for the billing (calendar) month of November. The Company has incorporated this filing into this Winter 2008-2009 COG proceeding by including it in a Supplier Charges section.

Q. Is the Company submitting any other supplier service related information with this cost of gas filing?

A. Yes, we are. The Company is taking this opportunity to file its annual Re-Enry Fee report and calculation. The filed information shows that the updated annual Unit Capacity Cost for which the Re-Entry Fee to be effective from November 1, 2008 through October 31, 2009 is based, $256.11 per MMBtu. Twenty-five percent (25%) of this annual unit capacity cost or $64.03, divided by 12 (months), yields a monthly unit capacity cost associated with the Re-Entry Fee of $5.336 per MMBtu. This monthly unit capacity cost is applied to any unassigned peak day use of a transportation customer electing to switch to firm sales service. The annual report also shows that there were no capacity-exempt ("grandfathered") firm transportation customers who switched to firm sales service over the past 12 months. Also, pursuant to PUC 509.20, the Company is filing its Forecast of Upcoming Winter Period Design Day Report in the Miscellaneous Supplier Charges section of this filing.

Q. Did any customers return to sales service from transportation service in the past 12 months?

A. As shown on this annual report, no capacity exempt ("grandfathered") firm transportation customers returned or switched to firm sales service from transportation service in the past year.

Q. Does this conclude your testimony?

A. Yes it does.