NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2006-2007
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 Regulatory Accounting, in May 2006.

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

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 pre-filed 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, 2006 to April 30, 2007. 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 2006-2007 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 Settlement in DG O5-080 and Commission Order in DG 05-147, Northern's 2005-06 Winter COG, by citing Commission approval of the Settlement. 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 2006-2007 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, 2006 to April 30, 2007 is $42,395,150.

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 $45,741,340 the following indirect gas costs and credits (totaling $3,346,190) have been added to the $42,395,150 Total Anticipated Direct Cost of Gas:

1.) Prior Period Under-Collection- $2,262,217.
2.) Interest Expense- $35,119.
3.) Working Capital Allowance- $76,318.
4.) Bad Debt Allowance- $190,403.
5.) Miscellaneous Overhead- $95,460.

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

The unit anticipated cost of gas adjustment of $1.3701 per therm is the sum of the anticipated direct cost of gas rate of $1.23258 per therm (Comm - $0.95145 and Dem - $0.28113) and the anticipated indirect cost of gas rate of $0.13751 per therm. The direct and indirect costs of gas rates were determined using the forecasted firm sales volumes of 33,385,510 therms. This unit cost of gas of $1.3701 per therm becomes the COG rate for the residential class customers. The commercial and industrial low winter rate classes (G-50, G-51, G-52) are assigned a COG rate of $1.3682 per therm, which is based on the unit cost of gas times the low winter classes' gas cost ratio of 0.9911 and then adjusted by a correction factor of 1.0021 to balance to the upcoming period gas costs intended to be recovered. Similarly, the commercial and industrial high winter rate classes (G-40, G-41, G-42) are assigned a COG rate of $1.3839 per therm by applying the gas cost ratio of 1.0471 and then adjusted for the same correction factor of 1.0021. The derivation of the gas cost ratios used to derive load factor based COGs for the commercial and industrial classes were established in the Summer Period Cost of Gas Adjustment Filing, DG 06-038. The applicable ratios represent the ratio of the unit demand charge associated with serving the High Load Factor (or Low Winter) classes to the total system unit demand cost, and the ratio of the unit demand charge associated with serving the Low Load Factor (High Winter) classes to the total system unit demand cost. The unit demand charge ratios are calculated in the schedules deriving the Capacity Allocators for effect each November 1. These resulting ratios are applied to the total system unit demand cost component of the COG to derive the respective C&I classes unit demand cost component, which is then added to the total system unit commodity cost to determine the COG rate for each group of C&I classes. The ratios are contained in the Appendix A and C section, where the Capacity Alloactor schedules are provided.

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 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. The workpapers supporting the MPR factors reflect the settlement reached in Docket Nos. 2005-087 and 2005-273 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 UNDERCOLLECTION

Q. Please explain the prior Winter Period under-collection of $2,262,217 shown on Proposed Revised Page 39?

A. The reconciliation analysis that was filed with the Commission on July 25, 2006 is being revised by $8,801 due to a discrepancy discovered subsequent to the July 25, 2006 filing of the reconciliation. A complete revised filing is included in this Cost of Gas filing and provides the explanation and support of a $2,135,942 under-collection through May 2006. The $2,262,217 under-collection balance reflects the additional carrying costs on the balance through October 2006.

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 September 13, 2006 NYMEX prices plus a differential. Domestic supplies are forecasted based on NYMEX prices from September 13, 2006, 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 Peak Period. The commodity forecast for domestic supplies rely on monthly gas indices for which the NYMEX Natural Gas Futures prices of September 13, 2006 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 the basis for the projected costs of the Company's domestic gas supply purchases.

A. The Company will be purchasing all of its domestic requirements on a short-term (monthly, daily) basis for the upcoming Winter Period. The commodity forecast for domestic supplies relies on monthly gas indices for which the NYMEX Natural Gas Futures prices of September 13, 2006 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 commodity costs and added to the monthly gas indices.

Q. Mr. Ferro, 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 2006 through October 2007. The net loss of $980,544 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 gain 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 gain or credit 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 eleven (11) interstate pipeline companies: Tennessee Gas Pipeline Company, Iroquois Gas Transmission System, Algonquin Gas Transmission Company, Texas Eastern Transmission Corporation, Transcontinental Gas Pipe Line Company, Dominion Transmission Corporation, Granite State Gas Transmission, Inc, TransCanada Pipeline, Union Gas, 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. 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 Winter Period.

A. The LNG rate shown in the Gas Cost Section, of $8.6799 per MMBtu, is the estimated average cost of LNG withdrawn from inventory between November 1, 2006 and April 30, 2007.

Q. Please explain how you estimated the propane rate for the Winter 2006-2007 period.

A. The propane rate of $5.8287 per MMBtu shown in the Supplier Prices Section, is the average cost of forecasted propane sendout between November 1, 2006 and April 30, 2007. The cost of propane put into inventory, including transportation is forecasted at $9.265 per MMBtu, based on an $0.85 per gallon price of propane. The derivation of the average cost of propane and the corresponding forecasted inventory activity is presented in the Inventories Section.

Q. Please explain how you estimated the FS-MA Storage rate for the Winter 2006-2007 period.

A. The rate for FS-MA storage withdrawals, (storage component of former SS-NE) of $6.8571 per MMBtu, as shown in the Supplier Prices Section, is the average cost of FS-MA storage gas withdrawn from inventory and used for processing between November 1, 2006 and April 30, 2007. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the $0.0102 per MMBtu Tennessee injection charge. The derivation of the average cost of FS-MA Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for

9

the period November 1, 2006 through April 30, 2007.

Q. Please explain how you estimated the Texas Eastern SS-1 Storage rate for Winter 2006-2007 period.

A. The rate for Texas Eastern (TETCO) SS-1 storage withdrawals of $7.3968 per MMBtu, as shown in the Supplier Prices Section, is the average cost of TGP SS-1 storage gas withdrawn from inventory and used for processing between November 1, 2006 and April 30, 2007. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the $0.04 per MMBtu TGP injection charge. The derivation of the average cost of TETCO SS-1 Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for the period November 1, 2006 through April 30, 2007.

Q. Please explain how you estimated the Texas Eastern FSS-1 Storage rate for Winter 2006-2007 period.

A. The rate for Texas Eastern FSS-1 storage withdrawals of $7.8275 per MMBtu, as shown in the Supplier Prices Section, is the average cost of Texas Eastern FSS-1 storage gas withdrawn from inventory and used for processing between November 1, 2006 and April 30, 2007. The cost of injections into inventory is at the estimated weighted average costs of incremental domestic supplies plus the $0.04 per MMBtu Texas Eastern FSS-1 injection charge. The derivation of the average cost of Texas Eastern FSS-1 Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for the period November 1, 2006 through April 30, 2007.

Q. Please explain how you estimated the MCN Storage rate for Winter 2006-2007 period.

A. The rate for MCN storage withdrawals of $7.4664 per MMBtu, as shown in the Supplier Prices Section, is the average cost of MCN storage gas withdrawn from inventory and used for processing between November 1, 2006 and April 30, 2007. The derivation of the average cost of MCN Storage is shown in the Inventories Section. Withdrawal and processing volumes are forecasted for the period November 1, 2006 through April 30, 2007.

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 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, the Company will then notify all parties to this proceeding and file a revised proposed COG bearing an effective date of November 1, 2006.

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 2.2% for the residential classes and 1.8% for C&I classes. The increases are driven mainly by customer growth.

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.

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, 2005 through June 30, 2006, ERC expenses totaled $441,746. 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 $441,746 presented on Schedule 1 of the ERC Section is one-seventh of the ERC costs incurred through June 2006 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 $56,395 is applied to the annual ERC costs resulting in total ERC costs to be recovered from customers in the period of November 2006 through October 2007 of $498,141. Dividing these recoverable ERC costs by estimated total annual throughput volumes of 60,307,240 therms, yields an ERC rate of $0.0083 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. The Company implemented the Demand Side Management Conservation Charges ("DSM CC") with its Summer 2003 COG in connection with the Energy Efficiency Programs for Gas Utilities, DG 02-106, and pursuant to Order No. 24,109 issued on December 31, 2002. The DSM CCs are designed to recover Year Three Energy Efficiency costs over the 12-month period of November 2006 through October 2007. The Year Three Residential class CC rate will be $0.0128 per therm while the CC rate for all commercial and industrial (C&I) classes will be $0.0101 per therm.

COG RATE AND BILL COMPARISON ANALYSES

Q. How does the proposed 2006-2007 Winter COG rate compare with the actual 2005-2006 Winter COG rate?

A. The schedule in the Variance Analysis Section shows that the difference between the proposed 2006-2007 Winter COG rate and the average actual cost of gas in the 2005-2006 Winter period to be an increase of $0.1583 per therm. Of this increase, $0.0286 per therm can be attributed to an increase in commodity costs and $0.0461 in increased demand costs. Contributing to the over all increase is an increase of $0.0518 in the over/under collection balance.

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 period ended April 2007 compared with the twelve-month and six-month period ended April 2006?

A. The Typical Bill analysis Section shows that a typical Residential Heating customer's bill for the six months ended April 2007, compared to the six months ended April 2006, will increase by $152 or 10.04 percent based on typical winter consumption of 932 therms. For the twelve-month period ended April 2007, typical Residential Heating customers can expect to see an increase of $144 or 7.16%. These calculations used the forecasted Winter 2006-2007 COG rate of $1.3701 per therm and the Summer 2006 actual COG rates for the "current" period and the actual Winter 2005-2006 and Summer 2005 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 $4.69 in the monthly bill or an 8% increase, and a customer who uses 200 therms will experience a $31.24 increase, which translates to a 10% increase.

SUPPLIER BALANCING CHARGE, PEAKING SERVICE DEMAND CHARGE AND CAPACITY ALLOCATORS

Q. Mr. Gibbons, please explain the Company's submittal of its Supplier Balancing Charge, Peaking Service Demand Charge and Capacity Allocators for the upcoming winter period?

A. On March 15, 2001, the New Hampshire Public Utilities Commission ("Commission") issued Order No. 23,652 in the Gas Restructuring Docket, D.E. 98-124, essentially approving Northern Utilities, Inc.'s ("Northern" or "Company") Model Delivery Tariff, which currently is NHPUC No. 10 – Gas, Part VII. Delivery Service Terms and Conditions ("T&Cs"). Among the Supplier Charges set out in Appendix A of the T&Cs, Schedule of Administrative Fees and Charges, are the Supplier Balancing Charge and the Peaking Service Demand Charge. The Company is required to update these charges once a year, effective for the billing (calendar) month of November. Therefore, in the "Misc. Supplier Charges" section of this filing the Company has included its proposed Supplier Balancing Charge of $0.78 per MMBtu of Daily Imbalance Volumes, effective November 1, 2006, and a monthly Peaking Service Demand Charge of $18.97 per MMBtu, per Maximum Daily Peaking Quantity ("MDPQ"), for the six months of November 2006 through April 2007. The Company's proposed tariff, Sixth Revised Page 154 – Appendix A, bearing an effective date of November 1, 2006 contains the Supplier Balancing Charge and Peaking Service Demand Charge.

SUPPLIER BALANCING CHARGE

The calculation of the Supplier Balancing Charge is based on Northern's daily dispatch activity for the twelve-month period May 1, 2000 through April 30, 2001. This calculation is updated each year with the current costs of the Company's balancing resources, which have been reflected in this Winter COG filing. A slight increase in the annual costs of these resources as compared to last year's costs resulted in a slightly higher Supplier Balancing Charge, $0.78 per MMBtu, as compared to the rate that was applicable during last winter ($0.77 per MMBtu).

15

Attachment I, pages 1 through 5, contains the Supplier Balancing Charge calculation. Page 1 is the description of the calculation by sequential step, while pages 2 through 4 present the current capacity and associated costs of the balancing resources. Page 5 is a summary of the analysis of monthly swings on Northern's system that the Company managed with its balancing resources for the "test year" period of May 2000 through April 2001. This identical schedule was also submitted last year in support of the November 2005 – April 2006 Supplier Balancing Charge.

PEAKING SERVICE DEMAND CHARGE

The derivation of the Peaking Service Demand Charge of $18.97 per MMBtu is presented in Attachment II in the "Misc. Supplier Charges" section and is based on the same peaking resources and associated costs included in this Winter 2006-07 Cost of Gas. As shown on Attachment II, the first step is to identify the monthly demand costs of the peaking resources (and upstream Granite State capacity) by applying the contractual Maximum Daily Quantities ("MDQ") of each resource to the monthly demand rate. The annual costs are then calculated by multiplying these monthly costs by the number of months that Northern is assessed such monthly charge. The annual demand costs are then divided by six months to derive the monthly costs to be recovered over the six month winter period of November 2006 through April 2007. Finally, these monthly costs are divided by the quantity of each resource used to satisfy peak day requirements. The Company has filed, under separate letter, a Motion for Protective Order and confidential Treatment for the resource and cost information contained in the Peaking Service Demand Charge calculation.

CAPACITY ALLOCATORS

The Company is also required to update once a year, effective every November, its Capacity Allocators contained in Appendix C of the T&Cs. Attachment III, page 1, in the "Misc. Supplier Charges" section provides a detailed description of the calculation determining the updated percentages of pipeline, underground storage and peaking capacity resources that make up the Total Capacity Quantity ("TCQ") assigned to suppliers. Pages 2 and 3 present the data inputs and calculation, which reflects the Company's current Design Day demands by rate class and capacity quantities and costs by resource as forecast in the current Winter 2006-07 COG filing. The Company's proposed tariff, Fifth Revised Page 169 – Appendix C, bearing an effective date of November 1, 2006 contains the Capacity Allocators.

Q. Does this conclude your testimony?
A. Yes it does.