NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2005-2006
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
<u>JOSEPH A. FERRO</u>

Q. Please state your name and business address.

A. Joseph A. Ferro, 300 Friberg Parkway, Westborough, Massachusetts 01581.

Q. What is your position with Northern Utilities, Inc. ("Northern" or the "Company")?

A. My position is Manager, Regulatory Policy.

Q. Please describe your educational background and utility experience.

A. I graduated from the University of Massachusetts/Boston in 1974 with a Bachelor of Arts degree in Mathematics. I later took accounting courses at Massasoit Community College. I have been employed at Bay State Gas Company since 1977, holding various positions in the Customer Relations area before joining the Rate Department in September 1980 as an Associate Rate Analyst. In February 1983 I was promoted to Rate Analyst. In August 1987 I was promoted to Senior Rate Analyst. On February 1, 1990 I was promoted to Manager, Gas Costing and Rate Analysis; in 1994 I was promoted to Manager, Rate Services and on August 1, 1998 I was promoted to Director of Pricing Services. On August 16, 1999 I became Director, Revenue Development. Around the completion of the merger between NiSource, Inc. and Columbia Energy Group (around November 1, 2000) I was assigned the position of Manager, Regulatory Policy.

Q. What have been your primary responsibilities in the various positions that you have held in the Regulatory Affairs and Rate areas?

A. My primary responsibilities for Bay State and Northern throughout my years of service have included the preparation and support of Cost of Gas Adjustment ("CGA") filings, analyses and forecasting of rates and revenues, supporting adjustments to test year costs as well as determining and sponsoring revenues and billing determinants in Company rate case filings and other rate-related functions. As Director of Pricing Services and Director, Revenue Development, my responsibilities expanded to include directing the analysis and filing of rate design proposals including unbundling initiatives, analyzing the feasibility and filing of special rate contracts, administering all rate tariffs, as well as providing the Company with competitive pricing assessments and implementing effective pricing to enhance the Company's ability to retain and profitably grow distribution load. In my current position of Manager, Regulatory Policy, my responsibilities include setting regulatory and pricing policy and carrying out associated Company initiatives.

Q. Are you a member of any industry organizations?

A. Yes. I am a member of the Northeast Gas Association (formerly, New England Gas Association) Rates and Planning Group and a member of the American Gas Association Rates and Strategic Issues Committee.

Q. Have you previously testified before any regulatory bodies?

A. Yes. I have testified before the New Hampshire Public Utilities Commission, the Massachusetts Department of Telecommunications and Energy (formerly the Department of Public Utilities), and the Maine Public Utilities Commission.

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 Unit Cost of Gas to be billed from November 1, 2005 to April 30, 2006. I will explain the derivations of the rates and capacity quantities used in the forecast by the

Company's gas suppliers and upstream transporters, as well as the commodity volumes purchased during the winter period. I will further explain the sales forecast and resulting sendout forecast. I will also explain the derivations of interruptible credits, capacity release revenues and the proposed Local Delivery Adjustment Clause charge. Finally, I will describe the rate and typical bill impact resulting from the proposed COG rate change.

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 2005-2006 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, 2005 to April 30, 2006 is $44,781,671.

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 $45,705,038 the following indirect gas costs and credits (totaling $923,367) have been added to the $44,781,671 Total Anticipated Direct Cost of Gas:

1.) Prior Period Over Collection- ($503,755).
2.) Interest Expense- $32,535.
3.) Working Capital Allowance- $90,383.
4.) Bad Debt Allowance- $214,419.
5.) Miscellaneous Overhead- $95,870.

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

7.) Deferral of Jurisdictional Demand Costs (Winter 2004-05)- $692,273 - pending final resolution by the New Hampshire and Maine Public Utlilities Commissions.

The unit anticipated cost of gas adjustment of $1.2420 per therm is the sum of the anticipated direct cost of gas rate of $1.2161 per therm and the anticipated indirect cost of gas rate of $0.0259 per therm. The direct and indirect costs of gas rates were determined using the forecasted firm sales volumes of 36,823,440 therms. This unit cost of gas of $1.2420 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 $0.9076 per therm, which is based on the unit cost of gas times the low winter classes' gas cost ratio of 0.72633 and then adjusted by a correction factor of 1.0061 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 $1.3445 per therm by applying the gas cost ratio of 1.07588 and then adjusted for the same correction factor of 1.0061. The gas cost ratios used to derive load factor based COGs for the commercial and industrial classes resulted from a settlement approved by the Commission in the Company's rate redesign case, Docket No. 00-046.

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. The fixed, capacity-related demand costs are allocated between the Company's two divisions on the basis of Proportional Responsibility ("PR") factors. The PR allocation method looks to a design year for the 12-month period ending April 30, and assigns Northern's projected annual demand costs to the individual months on the basis of the peak demand of each month during the design year, and then allocates the resulting assigned monthly demand costs to each division on the basis of the design year's monthly firm sendout factors. This method for allocating fixed demand costs was approved by the Commission in the 1995-96 Winter COG proceeding, Docket No. 95-257. The PR allocation is established for the year beginning with the Company's upcoming winter period COG. The workpapers used to develop the PR factors in the winter 2005-2006 COG are included in the Allocation Section.

Q. In Docket No. DG 04-162, the Commission Staff noted some concerns regarding the allocation of fixed gas costs. What were these concerns?

A. In last winter's COG proceeding (Docket No. DG 04-162), the Staff noted that some fixed gas costs allocated between the two states maybe the result of unallocated capacity associated with customers that have selected Northern's Maine division's transportation service. This situation regarding the failure to allocate capacity associated with Maine transportation customers is the result of the Maine Public Utilities Commission ("MPUC") not yet having established policies relative to mandatory capacity assignment for customers who seek transportation service from Northern-Maine, while Northern-Maine retains the obligation to serve those customers should their current supplier fail.

Because of its interest in understanding more about this issue the Commission Staff reserved its rights related to the issue of the fixed cost allocation between New Hampshire and Maine for the Winter 2003-2004 COG and Summer 2004 periods pending the outcome of discussions between the MPUC Staff, the NHPUC Staff, the New Hampshire Office of the Consumer Advocate, the Maine Office of the Public Advocate and Northern.

Q. What actions has Northern taken in connection with Staff's interest relative to the allocation of fixed gas costs between the customers in New Hampshire and Maine?

A. Northern has acted on this issue by making a comprehensive tariff filing with the MPUC on February 22, 2005 proposing complete Delivery Service Terms and Conditions, which tariffs include mandatory capacity assignment. The investigation is referenced Docket No. 2005-87. The Company provided the Commission Staff and the New Hampshire Consumer Advocate with a copy of this filing and was pleased that both entities intervened in this docket. Further, at the request of Northern, both the New Hampshire Commission and MPUC opened up a joint investigation into the operation of the PR Allocation formula. See Order of Notice of May 31, 2005, docketed as DG 05-080, and Notice of Investigation of May 4, 2005 in Docket No. 2005-273. In compliance with the Commission's Order of Notice the Company filed pre-filed testimony.

Q. How do both commissions plan on proceeding with their investigations?

A. The parties to this proceeding, including the Maine and New Hampshire Commission Staffs, the New Hampshire Office of the Consumer Advocate, the Maine Office of the Public Advocate, have scheduled a joint technical session at the Company's offices in Portsmouth, New Hampshire on September 19th.

Q. Why is the Company deferring for recovery an amount of $692,273?

A. The parties to Docket No. DG 05-047, Northern Utilities, Inc. – New Hampshire Division Summer Cost of Gas, entered into a Settlement Agreement, dated April 12, 2005, to defer the calculated summer portion of capacity costs allocated to the New Hampshire Division of $100,623 that is assessed to be associated with the capacity requirements of Maine customers who have switched from firm sales to transportation service after March 14, 2000. This date represents the date after which any switching from firm sales to transportation service by NH customers invoked the mandatory assignment of capacity to such customers. The Company needs to, and is requesting through this filing, for the parties to this Winter 2005-06 COG proceeding to also enter into a similar settlement agreement to defer the Winter 2004-05 capacity costs of $692,273. Absent such an agreement the Company would seek to remove this credit from the indirect gas costs and recover this amount in the upcoming Winter 2005-06 period. Included in this filing, in the "Reconciliation" tab, is a copy of the April 12, 2005 Settlement Agreement and the schedule that presents the calculation of the capacity costs in question for both the Summer 2004 and Winter 2004-05 periods.

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 $503,755 shown on Proposed Revised Page 39?

A. The reconciliation analysis that was filed with the Commission on July 28, 2005, and included in the Reconciliation Section of this filing, provides the explanation and support of a $501,688 under-collection through May 2005. The $503,755 under-collection balance reflects the additional carrying costs on the balance through October 2005.

FORECASTED SUPPLIER RATES AND COMMODITY COSTS

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

A. Northern Utilities has firm entitlements of up to approximately 3,500 Dth/day of yearround Canadian supplies from Granite State under Granite State's Rate Schedule CS-F and directly from Northeast Gas Marketing (NEGM). The pricing provisions of the agreement that Northern has entered into with Granite State for the purchase of Canadian supplies from Direct Energy Marketing, mirror the underlying provisions contained in the contract that Granite State has with this supplier. Commodity prices for Direct Energy Marketing supplies are forecasted based on NYMEX prices from August 31, 2005, plus or minus a differential based on the U.S. border price, plus the upstream transportation costs to get the gas to Granite State's pipeline. The forecasted price of NEGM was based on the August 31, 2005 NYMEX prices plus a differential. Domestic supplies are forecasted based on NYMEX prices from August 31, 2005, plus the cost to transport the gas to the city gate.

The forecast of product demand costs from NEGM is based on the most recent month's invoice price. Product demand costs for Direct Energy Marketing mirror the demand costs in Granite's contract and are based on the fixed transportation and pressure costs for TransCanada Pipelines for service from the Alberta border to East Hereford.

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 August 31, 2005 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 2005 through October 2006. The net gain of ($2,169,613) 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 ten (10) 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, Texas Gas Transmission Corporation, Granite State Gas Transmission, Inc, TransCanada Pipeline 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 $8.8554 per MMBtu, is the estimated average cost of LNG withdrawn from inventory between November 1, 2005 and April 30, 2006.

Q. Please explain how you estimated the propane rate for the Winter 2005-2006 period.

A. The propane rate of $8.6978 per MMBtu shown in the Supplier Prices Section, is the average cost of forecasted propane sendout between November 1, 2005 and April 30,

2006. 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 2005-2006 period.

A. The rate for FS-MA storage withdrawals, (storage component of former SS-NE) of $6.3079 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, 2005 and April 30, 2006. 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 the period November 1, 2005 through April 30, 2006.

Q. Please explain how you estimated the Texas Eastern SS-1 Storage rate for Winter 2005-2006 period.

A. The rate for Texas Eastern (TETCO) SS-1 storage withdrawals of $7.0783 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, 2005 and April 30, 2006. 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, 2005 through April 30, 2006.

Q. Please explain how you estimated the Texas Eastern FSS-1 Storage rate for Winter 2005-2006 period.

A. The rate for Texas Eastern FSS-1 storage withdrawals of $6.3593 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, 2005 and April 30, 2006. 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, 2005 through April 30, 2006.

Q. Please explain how you estimated the MCN Storage rate for Winter 2005-2006 period.

A. The rate for MCN storage withdrawals of $7.1681 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, 2005 and April 30, 2006. 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, 2005 through April 30, 2006.

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, 2005.

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 1.8% for the residential class and 0.7% for C&I. 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. As indicated on the schedule in the "Lost and Unaccounted For" section, the unaccounted-for factor is 1.0%.

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, 2004 through June 30, 2005, ERC expenses totaled $909,099. 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 $539,875 presented on Schedule 1 of the ERC Section is one-seventh of the ERC costs incurred through June 2005 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 over-collection of $43,928 is applied to the annual ERC costs resulting in total ERC costs to be recovered from customers in the period of November 2005 through October 2006 of $539,875. Dividing these recoverable ERC costs by estimated total annual throughput volumes of 53,673,770 therms, yields an ERC rate of $0.0101 per therm. This ERC rate is included in the LDAC rate on Proposed Revised Page 56.

WELLS SURCHARGE

Q. Please explain the derivation of the Wells Surcharge.

A. Pursuant to a joint stipulation and agreement dated September 3, 1999 in Docket No. CP99-238-000 and CP96-610-000, between Granite State Gas Transmission, Inc., Northern Utilities, the Maine Public Utilities Commission, the New Hampshire Public Utilities Commission, the Staff of the NHPUC, the Maine Public Advocate, the New Hampshire Consumer Advocate and No Tanks, Inc., Granite State is to charge Northern Utilities $6.95 million plus carrying costs for a total of $8,342,241 over a seven year period. The Wells Surcharge schedule reflects the annual recovery of $325,076, or $27,090 a month, plus interest, plus the prior year's over-recovery amount of $51,924 by Granite State (as compared to its scheduled recoveries) over the twelve-month period of November 2005 through October 2006, which is the last recovery year of the seven-year recovery period. The Wells Surcharge of $0.0053 per therm 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 2005 through October 2006. The Year Three Residential class CC rate will be $0.0070 per therm while the CC rate for all commercial and industrial (C&I) classes will be $0.0099 per therm.

RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RATE

Q. Please explain the basis for, and the calculation of the Residential Low Income Assistance Program (RLIAP) Rate.

A. In Commission Order No. 24,508 dated September 1, 2005, in docket DG 05-076, the Commission approved a Low Income Assistance Pilot Program for eligible residential natural gas heating customers of Northern and KeySpan Energy Delivery New England. In compliance with that order the Company has calculated the RLIAP Rate of $0.0050 per therm effective November 1, 2005, which has been incorporated into the LDAC rate set out on Proposed Revised Page 56. Pursuant to the September 1, 2005 order, the Company has included $267,656 of Pilot Program costs, which include $40,000 of administrative costs. A supporting RLIAP Recovery Rate calculation schedule is included in the LDAC section of this filing.

COG RATE AND BILL COMPARISON ANALYSES

Q. How does the proposed 2005-2006 Winter COG rate compare with the actual 2004-2005 Winter COG rate?

A. The schedule in the Variance Analysis Section shows that the difference between the proposed 2005-2006 Winter rate and the average actual cost of gas in the 2004-2005 Winter period to be an increase of $0.2390 per therm. Of this increase, $0.2044 per therm can be attributed to an increase in commodity costs and $0.0474 in increased demand costs. Partially offsetting these increases is a decrease of $0.0205 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 2006 compared with the twelve-month and six-month period ended April 2005?

A. The Typical Bill analysis Section shows that a typical Residential Heating customer's bill for the six months ended April 2006, compared to the six months ended April 2005, will increase by $35 or 15.54 percent based on typical winter consumption of 932 therms. For the twelve-month period ended April 2006, typical Residential Heating customers can expect to see an increase of $20 or 13.27%. These calculations used the forecasted winter 2005-2006 COG rate of $1.2420 per therm and the summer 2005 actual COG rates for the "current" period and the actual winter 2004-2005 and summer 2004 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 $6.92 in the monthly bill or a 13% decrease and a customer who uses 200 therms will experience a $46.15 increase, which translates to a 16% increase.

SUPPLIER BALANCING CHARGE, PEAKING SERVICE DEMAND CHARGE AND CAPACITY ALLOCATORS

Q. Mr. Ferro, 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. Under separate letter dated September 13, 2005, the Company is filing its revised Supplier Balancing Charge, Peaking Service Demand Charge and Capacity Allocators for the upcoming winter period. In this filing the Company explains the derivation of the charges and allocators and presents its revised Appendix A, Fifth Revised Page 154, and Appendix

C, Fourth Revised Page 169, to Northern's Delivery Service Terms and Conditions, bearing an effective date of November 1, 2005. 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 2005-2006 COG proceeding by including it in a Supplier Charges section.

Q. Does this conclude your testimony?

A. Yes it does.