BEFORE THE

PUBLIC UTILITIES COMMISSION
OF THE
STATE OF RHODE ISLAND
AND PROVIDENCE PLANTATIONS

IN THE MATTER OF

The National Grid Annual	**)**	
Gas Cost Recovery Charge	**)**	**Docket No. 4097**
Filing	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities and Carriers

October 16, 2009

TABLE OF CONTENTS

TESTIMONY OF BRUCE R. OLIVER
Docket No. 4097
October 16, 2009

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Bruce R. Oliver. My business address is 7103 Laketree Drive, Fairfax Station, Virginia, 22039.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Revilo Hill Associates, Inc., and serve as President of the firm. I manage the firm's business and consulting activities, and I direct its preparation and presentation of economic, utility planning, and policy analyses for our clients.

Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?

A. My testimony in this proceeding is presented on behalf of the Division of Public Utilities and Carriers (hereinafter "the Division").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. This testimony addresses issues relating to the National Grid (or hereinafter “the Company”) Annual Gas Cost Recovery (GCR) filing. This testimony reviews and comments on the content of the September 1, 2008 direct testimony of witnesses

Arangio and Beland, as well as the attachments submitted in support of those testimonies and the Company's responses to data requests.

Q. WHAT EXHIBITS ARE YOU SPONSORING AS PART OF THIS TESTIMONY?

A. Attached to this testimony are five exhibits. They include:

Exhibit BRO-1	Proposed Changes in GCR Charges by Rate Class
Exhibit BRO-2	Changes in Costs by GCR Cost Component
Exhibit BRO-3	U.S Natural Gas Imports (January 2000 – July 2009)
Exhibit BRO-4	Changes in Natural Gas Drilling Activity
Exhibit BRO-5	U.S. Natural Gas Storage Inventories as of October 8, 2009
Exhibit BRO-6	U.S. Natural Gas Use by Sector
Exhibit BRO-7	NYMEX Natural Gas Strip Prices for 2009-10 and 2010-11
Exhibit BRO-8	Changes in Forecasted Normal Weather Sales and Throughput
Exhibit BRO-9	Changes in Forecasted Design Winter Throughput
Exhibit BRO-10	Division Recommended GCR Charges

II. DISCUSSION OF ISSUES

Q. HOW IS YOUR DISCUSSION OF ISSUES RELATING TO NATIONAL GRID'S GCR FILING IN THIS PROCEEDING ORGANIZED?

A. This discussion is presented in seven sections. **Section A** discusses the changes in GCR charges by rate class that National Grid proposes and analyzes the changes in costs by gas cost component that underlie the Company's proposed GCR charges. **Section B** provides insight regarding current natural gas market conditions and forward looking natural gas pricing considerations. **Section C** evaluates reasonableness of the forecasts of normalized sales and design winter sales that have been relied upon in the development of National Grid's proposed GCR charges. **Section D** presents an assessment of the Company's GPIP performance, the incentive calculations that National Grid offers for FY 2008, and the reasonableness of the amount of the GPIP incentive that National Grid seeks. **Section E** examines the impacts of Natural Gas Portfolio Management Plan (NGPMP) on the costs subject to recovery through the Company's proposed GCR rates. **Section F** reviews National Grid's reconciliation of its GCR costs and revenue for FY 2008. **Section G** addresses the Company's proposed tariff edits and amendments.

A. Changes in National Grid's GCR Rates and Gas Costs

Q. HOW DO THE COMPANY'S PROPOSED CHANGES IN GCR CHARGES VARY BY RATE CLASSIFICATION?

A. National Grid's filing proposes small percentage reductions in its GCR charges for all rate classifications except Natural Gas Vehicles and the FT-2 Storage Service Charge. As shown in **Exhibit BRO-1,** the Company's proposes to lower its GCR charges for Residential Heating customers, Small and Medium C&I customers, Low Load Factor Large C&I customers, and Low Load Factor Extra Large C&I customers from $1.0975 per therm to **$1.0892 per therm**. That represents a reduction of 0.8% or less than one-cent per therm. The Company's September 1, 2009 filing also proposes a GCR reduction of 2.2% for Residential Non-Heating customers and High Load Factor Large and Extra Large C&I customers. As a result, GCR charges for those customers would be lowered from $1.0636 per therm to **$1.0402 per therm**. The GCR rate for Natural Gas Vehicles would increase 8.4% from $0.8388 to $0.9091, and the FT-2 Storage Charge would be lowered by 18.8% from $0.0415 per therm to $0.0337 per therm.

Q. WHY ARE THE PERCENTAGE DECREASES IN GCR CHARGES SHOWN IN EXHIBIT BRO-1 NOT UNIFORM ACROSS RATE CLASSES?

A. Three basic factors contribute to the differences in percentage decreases in GCR charges by rate class that National Grid proposes. Those are:

1. Differences in the rates of change in the size of the GCR cost components; and

2. Differences in the magnitude of over- or under-collections of costs by GCR component; and

3. Differences in the manner in which the five components of GCR costs are allocated among classes.

Q. HOW SIGNIFICANT ARE THE DIFFERENCES IN MAGNITUDE AND DIRECTION OF CHANGES IN COSTS BY GCR COST COMPONENT THAT NATIONAL GRID PROJECTS FOR THE 2008-09 GCR YEAR?

A. **Exhibit BRO-2, page 1,** compares the Company's updated GCR cost projections by component for the 2009-10 GCR year with the costs that National Grid projected for the 2008-09 GCR year in its October 31, 2008 Update filing in Docket No. 3982. As shown on that page, the changes in individual cost components vary widely. Although overall the Company's gas costs have declined by 4.6%, percentage changes in individual cost components range from -40.4% for Storage Variable Non-Product Costs to +24.5% for Supply Fixed Costs.

Q. DOES THE COMPANY EXPLAIN THE LARGE VARIATIONS IN THE CHANGES IN COMPONENTS OF ITS GAS COSTS?

A. Not directly. My review and analysis of the Company's filed testimony and exhibits finds that the increases in National Grid's Supply Fixed Costs are explained primarily by the change in the manner in which the Company's gas assets are managed.

However, the major factors underlying the Company's projected changes in variable components of its gas supply costs are less easily identified.

Exhibit BRO-2, page 1, depicts an increase in the Company's forecasted Supply Fixed Costs for the 2009-10 GCR year of $5,777,733. That increase is driven primarily by the combined effects of the termination of the Company's asset management contract with Merrill Lynch and the implementation of National Grid's self-management of Rhode Island's gas assets under the terms of the Natural Gas Portfolio Management Plan (NGPMP). Last year in Docket No. 3982, the Company's October 31, 2008 Updated Attachment GLB-1 reflected capacity release credits of $11,412,686. The comparable attachment to the Company's September 1, 2009 filing in this proceeding projects capacity release credits of $5,242,797.[1] Thus, the change in the Company's approach to asset management has resulted in a significant lowering of capacity release credits. That reduction in capacity release credits yields an increase of $6,169,889 in National Grid's projected Company's 2009-10 Supply Fixed Costs. The difference between the $6,169,889 reduction in capacity release credits and the $5,777,733 increase in overall Supply Fixed Costs (i.e., $392,156) is attributable to changes in other elements of the demand charges that the Company expects to pay during the November 2009 through October 2010 period.

[1] Attachment EAD-1, page 1, in this proceeding also includes $1,000,000 of NGPMP Credit, but that credit is accounted for separately in the Company's GCR determinations (Attachment GLB-1, page 2,

Q. DO THE COMPANY'S GAS COSTS BY COST COMPONENT SHOWN IN ATTACHMENT EDA-1, PAGE 1, TIE DIRECTLY TO THE STARTING COSTS BY GAS COST COMPONENT THAT ARE USED IN THE COMPUTATION OF THE COMPANY'S PROPOSED GCR CHARGES ON PAGES 2-5 OF ATTACHMENT GLB-1?

A. Yes, they do.

Q. WHY ARE THE PERCENTAGE REDUCTIONS IN THE COMPANY'S PROPOSED GCR CHARGES LESS THAN THE 4.6% OVERALL REDUCTION IN GAS COSTS THAT SHOWN IN EXHIBIT BRO-2, PAGE 1?

A. The difference is explained by changes in the cost adjustments that are incorporated in the GCR rate calculations in Attachment GLB-1 of the Company's filing. For example, **Exhibit BRO-2, page 2**, illustrates the large swings in reconciliation adjustment amounts applicable to the 2008-09 and 2009-10 GCR periods. The net of the reconciliation adjustments is a $4.39 million increase in GCR costs for the November 2009 to October 2010 period.

Q. ARE THE GCR CHARGES THAT NATIONAL GRID PROPOSES IN ITS SEPTEMBER 1, 2009 FILING PROPERLY COMPUTED?

---

line 4 in this proceeding) and thus that $1,000,000 dollars in not included in the Supply Fixed Costs that are compared in **Exhibit BRO-2, page 1**.

A. The methods that National Grid uses in its September 1, 2009 filing to compute the GCR charges that it proposes are consistent with those the Company has used, and the Commission has accepted in past GCR filings. Furthermore, the computations the Company has used to derive the specific charges set forth in witness Beland's testimony and attachments appear to be mathematically accurate. Thus, any issues associated with the GCR charges that National Grid proposes are related to the development of the data inputs and assumptions used to compute the levels of those charges.

<u>B. Natural Gas Market Considerations</u>

Q. DO YOU AGREE WITH WITNESS ARANGIO'S OBSERVATIONS REGARDING NATURAL GAS MARKETS AT PAGES 4 THROUGH 6 OF HER SEPTEMBER 1, 2009 TESTIMONY IN THIS PROCEEDING?

A. Only in part. In general, I find her portrayal of the benefits of anticipated new gas supply options to be somewhat overly optimistic. Given current market conditions, I do not expect significant expansion of gas supply into the Northeastern United States over then next few years. Although substantial LNG import capability has been added, LNG imports over the last year are down dramatically. (See **Exhibit BRO-3**.) For the 12-month period ended July 2009 (i.e., the most recent annual period for which data is available), LNG imports are at just **52.6%** of the peak LNG import levels achieved in 2007 even thought LNG terminal capacity in the U.S. has nearly doubled since 2007.

Likewise, construction of the Rockies Express Pipeline may bring additional gas supplies into the Central and Eastern parts of the U.S., but that increase in Rocky Mountain supplies appears to be offset in part by declines in Canadian imports. **Exhibit BRO-3** also depicts the decline in pipeline imports of natural gas to the U.S. from Canada in recent months. Imports of natural gas to the U.S. from Canada have fallen 13% since they peaked in March of 2008, and are now at their lowest level since late 1999.

Q. WILL INCREMENTAL NATURAL GAS PRODUCTION FROM THE MARCELLUS SHALE FORMATION OR OTHER SHALE FORMATIONS IN THE U.S. LIKELY HAVE A SIGNIFICANT IMPACT ON AVAILABLE GAS SUPPLY OVER THE NEXT FEW YEARS?

A. No. The Marcellus Shale formation that witness Arangio references certainly has some potential, but the costs of developing that formation tend to be higher than current market pricing will support. When gas prices were much higher in the first half of 2008, near term prospects for Marcellus Shale production were much greater. However, at today's market prices for natural gas, the costs of developing such formations often exceed market price expectations.

In addition, the Barnett Shale Formation in Northern Texas, has been prolific over the past several years, but in the face of the downturn in the U.S. economy, decisions have been made that will substantially limit expected peak production from that formation. Prior to the economic downturn in the U.S. and the dramatic fall of natural gas prices, the industry anticipated that output from the Barnett Shale formation would peak at 9.0-10.0 Bcf per day. However, plans for pipeline expansion into that region have been trimmed back such that the maximum daily supply from North Texas Barnett Shale production will be limited to roughly 4.5-5.0 Bcf per day. That reduction of approximately 4-5 Bcf per day is more than double the amount of incremental gas supply that the Rockies Express is expected to provide.

Furthermore, it will be difficult, if not impossible, for the U.S. to sustain current levels of natural gas production without returning to the levels of drilling activity achieved over the last few years. Yet, current Natural Gas drilling activity is now at less than 50% of the peak level achieved in the late summer of 2008. (See **Exhibit BRO-4**).

Q. SHOULD FURTHER DECREASES IN NATURAL GAS COMMODITY COSTS BE ANTICIPATED IN THE COMING MONTHS?

A. Although some continuing volatility in natural gas prices can be expected, I do not anticipate further dramatic declines in natural gas prices. Future price uncertainties tend to be more associated with when prices will move upward again and how fast and how far they will rise. Since the preparation of the Company's September 1, 2009 filing in this proceeding natural gas commodity prices have risen by more than

10% for most months in the November 2009 to October 2010 period. Still, in the absence of extremely cold early winter weather, I find little likelihood of a continuing resurgence of natural gas prices over the next six to eight months. As shown in **Exhibit BRO-5**, the U.S. is entering this winter with record high storage inventories.

In general, futures prices for natural gas continue to exhibit "contango" relationship with near-term prices generally lower than those for comparable months in future years, and prices for periods further out in time become progressively higher. That is a very different pricing structure than has typically been observed over most of this decade. For most of the period since the year 2000, natural gas commodity prices have reflected a "backwardized" relationship in which prices for comparable months became progressively less expensive as one looked further into the future. The current "contango" relationship in natural gas futures prices suggests that the market believes higher natural gas prices will prevail in the future. Such higher prices will most likely be the result of a rebound in natural gas demand (particularly within the industrial and electric generation sectors) and/or a contraction of U.S. domestic natural gas production. If reduced natural gas drilling activity leads to a contraction of domestic natural gas production (which seems almost inevitable given the pronounced decline in drill activity that has been experienced over the last year), prices for natural gas may rise even if natural gas demand remains comparatively flat.

Considerable uncertainty remains, however, with respect to future growth in U.S. natural gas demand, and actual natural gas demand growth can be expected to have substantial impact on future natural gas prices for periods beyond the next six to eight months. Exhibit BRO-6 depicts changes in annual natural gas utilization by end-use sector over the past decade. As illustrated in Exhibit BRO-6, Residential and Commercial uses of natural gas have remained comparatively flat over the last several years despite large market price fluctuations and despite the current economic recession. The major drivers of changes in natural gas demand have been primarily industrial natural gas use and the use of natural gas for electricity generation and both of those sectors display considerable weakness.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING THE NYMEX PRICE DATA THAT WITNESS ARANGIO PRESENTS IN ATTACHMENT EDA-3?

A. Yes. I believe that it is important to note that the August 24, 2009 NYMEX strip prices reflect essentially a pattern of continually increasing pricing over the November 2009 through October 2010 period. Such a pattern (without clearly discernible seasonal price variations and with summer month prices that are higher than those for the preceding winter months) is very atypical for the natural gas industry, and it suggests an industry that is clearly in transition. **Exhibit BRO-7** compares the August 24, 2009 NYMEX strip data with more recent NYMEX data for the 2009-10 GCR period. It also provides recent NYMEX pricing for the 2010-11 GCR period in which seasonal price differences begin to reappear.

C. Evaluation of Sales and Throughput Projections

Q. WHAT IS THE BASIS FOR THE FORECASTED SALES AND THROUGHPUT VOLUMES THAT NATIONAL GRID HAS USED IN THIS PROCEEDING?

A. The September 1, 2009 testimony of witness Beland at pages 12-13 describes the development of National Grid's sales and throughput forecast for this proceeding. As noted by witness Beland, the Company's base forecast of throughput requirements was premised on regression analyses of daily sendout and degree days over the May 2008 through April 2009 time period. Incremental load growth was then estimated using statistical forecast models for the company's major customer classifications with adjustments added to reflect projected load reductions from energy efficiency programs. The results of that forecasting effort are presented in Attachment GLB-1, page 14. National Grid also provides a forecast of Design Winter Period Throughput on page 15 of Attachment GLB-1.

The Company's forecasts of Sales and Throughput forecasts are used to allocate among rate classes Variable Supply Costs, Storage Variable Product Costs, and Storage Variable Non-Product Costs. Forecasted Design Winter Throughput is used to allocate Supply Fixed Costs and Storage Fixed Costs.

Q. DOES THE COMPANY EXPLAIN THE MANNER IN WHICH IT DETERMINES FORECASTED DESIGN WINTER THROUGHPUT REQUIREMENTS?

A. No, it does not.

Q. HOW DO NATIONAL GRID'S FORECASTS OF NORMAL WEATHER THROUGHPUT AND DESIGN WINTER THROUGHPUT COMPARE WITH THE FORECASTS IT PRESENTED IN ITS LAST GCR PROCEEDING?

A. **Exhibit BRO-8, pages 1 and 2,** provide comparisons of the Company's forecasts of Normal Weather Sales and Throughput as filed in this proceeding with its comparable forecast data from Docket No. 3982. Those comparisons show an overall increase in throughput volume of **2.5%** which is the product of a **0.1%** increase in Firm Sales service volumes and a **70.7%** increase FT-2 annual throughput requirements. In addition, **Exhibit BRO-8, page 1,** displays some rather large variations in projected sales and throughput growth by rate class. Residential Heating sales are forecasted to decline by 5.0% on an annual weather-normalized basis while sales for most other classes show double digit increases. Likewise, **Exhibit BRO-8, page 2,** reflects an irregular pattern of increases and decreases in forecasted weather-normalized sales volumes across the months of the year, including an unexplained 11.3% increase in forecasted requirements for the month of October.

Design Winter throughput forecasts are compared in **Exhibit BRO-9.** Once again, aggregate changes in forecasted requirements are comparatively small (i.e., an overall increase of 1.2%). However, the comparisons on **Exhibit BRO-9** also depict substantial shifts in the monthly distribution Design Winter Sales and Throughput requirements. More than **2,000,000 dekatherms** or roughly **10%** of forecasted Design Winter Sales requirements are shifted from the months of

January, February and March to the months of November and December. Although I would anticipate that such a shift would have a noticeable impact on the Company's planning and operations for the coming winter, if not longer-term as well, the implications of this pronounced change in the pattern of forecasted Design Winter requirements is not discussed anywhere in the Company's filing. It seems inconceivable that such a large shift in the monthly distribution of Design Winter requirements would have no impact on either the Company's Design Day Peak and/or Cold Snap requirements which in the past have been portrayed as key considerations in the Company's gas supply planning. Yet, the impacts of these changes are not addressed in National Grid's filed testimony and attachments.

Q. SHOULD THE COMMISSION QUESTION THE REASONABLENESS OF THE COMPANY'S FORECASTED DESIGN WINTER REQUIREMENTS?

A. Yes. The forecasted changes in Design Winter requirements that National Grid presents are not adequately explained or justified. Moreover, they appear inconsistent with the Company's forecasted changes in Normal Weather Throughput. As shown in below, the changes in monthly throughput requirements that National Grid projects under normal and design conditions are often move in opposite directions and are of significant magnitude for the Company's winter months.

Table 1
Forecasted Percentage Changes in Throughput Requirements

Month	Normal Weather Throughput	Design Winter Throughput
November	-1.0%	+54.1%
December	-2.5%	+31.0%
January	+7.5%	-7.7%
February	+4.6%	-9.8%
March	-1.2%	-25.4%

These results are counter-intuitive and raise concerns regarding the consistency of the forecast models from which they were derived. As a result, the Commission must question the confidence it can place in the reasonableness and appropriateness of the Company's allocations of GCR costs among rate classes unless the Company can provide further explanation and justification for the changes observed within its forecasted data.

D. GPIP Incentive Calculations

Q. DOES THE COMPANY SEEK APPROVAL OF A GAS PROCUREMENT INCENTIVE FOR THE 12 MONTH PERIOD ENDED JUNE 2009?

A. Yes. The September 1, 2009 testimony of witness Gary Beland presents National Grid's request for approval of an incentive of at least **$1,000,000.** The Company actually computes an incentive of **$1,097,727** for FY 2009, but it suggests that some uncertainty exists regarding whether the total amount of incentives for the Company for any fiscal year remains capped at $1,000,000. Support for the Company's requested incentive amount is presented in Attachment GLB-9.

Q. DO YOU FIND ANY REASON TO QUESTION THE ACCURACY OR APPROPRIATENESS OF THE COMPANY'S INCENTIVE COMPUTATIONS?

A. No, I do not. I have reviewed the supporting detail for the Company's mandatory and discretionary gas purchases for FY 2009, and I find that the Company's calculation of the requested incentive appears to be consistent with the terms of the Gas Procurement Incentive Plan (GPIP). However, my review of the gas purchase data upon which the Company's GPIP incentive is determined indicates that further revisions to the current incentive structure should be considered at this time.

Q. SHOULD THE COMPANY BE GRANTED THE FULL AMOUNT OF THE INCENTIVE THAT IT COMPUTES IN ATTACHMENT GLB-9?

A. No. If the Company felt that there was ambiguity regarding the continued application of the $1,000,000 cap on incentive payments that is specified in the GPIP, it should have raised those well in advance of its request for approval of an incentive in excess of that amount. Furthermore, I do not support the Commission's a waiver of the incentive cap specified in the GPIP either for this one-time event or on a more permanent basis. When the $1,000,000 cap was adopted, it was intended to address both gas purchasing and asset management incentives. With the implementation of the new Natural Gas Portfolio Management Plan in the spring of 2009, asset management incentives are now addressed through a separate mechanism that is not subject to an upper bound or cap on achievable incentives for the Company. As a result, application of the $1,000,000 cap to only GPIP incentives already represents a somewhat generous interpretation of the present incentive structure.

In addition, it is my assessment that most if not all of the Company's computed incentive in this proceeding represents derives from the dramatic downturn in market prices over the last year. Given the prolonged period of comparatively sharp declines in natural gas prices that has been experienced over the last 12-15 months, National Grid was able to achieve incentives without significant risk and without the requirements for the demonstration of particular expertise or acumen in gas procurement.

Q. GIVEN ACTUAL EXPERIENCE WITH THE GPIP OVER THE LAST COUPLE OF YEARS, ARE ANY FURTHER MODIFICATIONS OF THE GPIP NECESSARY OR APPROPRIATE AT THIS TIME?

A. Yes, I believe they are. The intent of the GPIP was to incent the Company to make gas purchases that it would not otherwise make to reduce the costs of gas billed to its firm sales service customers. The last two years have shown, however, that the discretionary purchases for which the Company seeks incentives are primarily purchases that it would have undertaken in a declining price market regardless of whether the current gas procurement incentives were in place. As a result, firm sales service customers have been unnecessarily denied a portion of the benefits that they otherwise could have reasonably expected in the absence of the current incentive structure.

Actual experience under the GPIP to date has shown that National Grid has generally only made significant discretionary purchases late in the purchasing cycle for each supply month when the Company could be certain that it would receive incentives for making such purchases even though the Company most likely would have had to make similar purchases to fulfill its firm sales service requirements in the absence of incentives.

Although the GPIP was modified last year to provide increased incentives for the Company to make discretionary purchases early in the procurement cycle for each gas supply month, National Grid has not taken advantage of such opportunities. Rather, as I observed in Docket No. 3982, the focus of National Grid's **discretionary** gas purchases has once again been on capturing the **"*low hanging fruit*"** (i.e., easily obtained savings that reveal themselves after the average cost of discretionary purchases is sufficiently known to substantially eliminate any risk the Company might otherwise face related to discretionary purchase decisions). Such purchasing adds little of value for ratepayers and does not justify the payment of significant incentives to the Company. I do not fault National Grid for its highly risk-adverse approach to discretionary purchases under the current gas purchasing incentive program, but it has become apparent that the

Company approach to discretionary gas purchases substantially dilutes the value that firm gas sales service customers derive from the offered incentives.

For these reasons, I recommend that the gas purchasing incentives presently provided the GPIP should either be eliminated or substantially reduced.

Q. SHOULD THE ENTIRE GPIP BE ELIMINATED?

A. No. Although I encourage reduction or elimination of the current GPIP purchasing incentives, I support continuation of the "dollar cost averaging" elements of the current gas purchasing program. The elements of the current plan which identify monthly mandatory purchasing requirements starting two-years in advance of each gas supply month have generally served Rhode Island ratepayers well by providing comparative rate stability in the face of highly volatile markets. Those elements of the current GPIP should be continued.

Q. HOW WOULD YOU RESPOND TO THOSE WHO MIGHT ARGUE THAT ELIMINATION OF THE INCENTIVES CURRENTLY PROVIDED UNDER THE GPIP WILL BE DISADVANTAGEOUS FOR RATEPAYERS IF AND WHEN GAS PRICES TURN UPWARD ONCE AGAIN?

A. The current incentives did not work as intended when we had a rising price market in the past, and I find no reason to believe that they would produce any better results in the future.

Q. DOES THE COMPANY PROPOSE ANY CHANGES IN THE GPIP?

A. Yes. The September 1, 2009 testimony of witness Beland indicates that "the Company is requesting that it be allowed to recover its short term borrowing cost, less any interest earnings it may receive on collateral from the party requiring the posting of collateral, currently the New York Mercantile Exchange (NYMEX).

Q. IS THE COMPANY'S REQUEST FOR RECOVERY OF SHORT-TERM BORROWING COSTS ASSOCIATED WITH COLLATERAL REQUIREMENTS ON FINANCIAL HEDGES REASONABLE?

A. In concept, I believe the Company's request is reasonable as long as the terms of such cost recovery are balanced with provisions that provide ratepayers the benefit of interest earned on collateral received from other parties. However, before rendering a final opinion I would like to review the specific tariff language that the Company intends to use to implement that request. In addition, the Commission should consider requiring that recovery of short term borrowing costs only be allowed where collateral is provided in the form of cash. In some commercial transactions letters of credit or other instruments can be substituted for the provision of cash. If and when a letter of credit is used in place of the posting of cash as collateral for a gas purchase transaction, then the costs subject to recovery should be the lesser of (1) the costs of securing and maintaining the letter of credit or (2) the costs of an equivalent amount of short-term borrowing.

E. Natural Gas Portfolio Management Plan (NGPMP)

Q. IS THE COMPANY'S NGPMP WORKING AS ANTICIPATED?

A. To date there is not sufficient experience under that plan to fully evaluate its operations and effectiveness. However, I find no reason at this time to question the reasonableness of the structure of that plan.

Q. DOES THE NATURAL GAS PORTFOLIO MANAGEMENT PLAN (NGPMP) HAVE ANY IMPACT ON THE DETERMINATION OF GCR CHARGES IN THIS PROCEEDING?

A. Yes. The NGPMP is reflected in the Company's GCR rate determinations in two places. First, a prorated portion of the annual $1.0 million minimum credit is reflected for each month of FY 2009 in which the NGPMP was in effect (i.e., the months of April through June of 2009). Second, NGPMP credits are reflected in an adjustment to National Grid's projected Supply Fixed Costs for the 2009-2010 GCR period. (See Attachment GLB-1, page 2, line 3.)

Q. WHAT IS THE DOLLAR MAGNITUDE OF NGPMP IMPACT ON THE COMPANY'S GAS COST RECONCILIATION RESULTS?

A. The Company's recognition of a prorated portion of the minimum annual NGPMP credit for FY 2009 results in a $250,000 credit against FY 2009 Supply Fixed Costs as shown in Attachment GLB-2, Schedule 2, page 1 of 2, on the line labeled "Less

Credits from Insourcing" in National Grid's "Annual Gas Cost Recovery Reconciliation Report."

Q. HOW DOES THE NGPMP IMPACT NATIONAL GRID'S ESTIMATED GAS COSTS FOR THE 2009-2010 GCR PERIOD?

A. Due to uncertainties regarding value of future asset management transactions, National Grid has conservatively included only the $1.0 million of guaranteed NGPMP benefit in its development of proposed GCR charges for this proceeding.

Q. HOW DOES THE LEVEL OF NGPMP CREDIT INCLUDED IN THE COMPANY'S GCR FILING IN THIS PROCEEDING COMPARE TO THE CAPACITY CREDITS THAT NATIONAL GRID REFLECTED IN ITS OCTOBER 31, 2008 FILING IN DOCKET NO. 3982?

A. It is significantly smaller.

Last year in Docket No. 3982, the Company's Supply Fixed Costs reflected the benefit of capacity release credits totaling $11,412,686. The majority of those credits were attributable to the Company's former asset management arrangement with Merrill Lynch which provided ratepayers with an assured level of annual asset management benefit.

In this proceeding, the Company's cost estimates for the 2009-10 GCR period reflect credits for capacity released to marketers of $5,242,797 as well as $1,000,000 million credit for its in-sourced asset management activities under the

NGPMP. Thus, total capacity release credits for the 2009-10 GCR year equal $6,242,797. However, that amount is $5,169,889 or 45% less than the level of credits forecasted for the 2008-09 GCR year.

Q. IS IT LIKELY THAT THE COMPANY'S ACTUAL NET ASSET MANAGEMENT REVENUE FROM THE NGPMP FOR 2009-10 GCR YEAR WILL EXCEED $1.0 MILLION?

A. Although I do not presume to be able to accurately predict the Company's actual net asset management revenue from the NGPMP program for the coming GCR period, I assess that it is reasonable to anticipate that National Grid will achieve net asset management revenue in excess of the minimum annual guarantee.

Q. IF NET ASSET MANAGEMENT REVENUE IN EXCESS OF THE MINIMUM ANNUAL GUARANTEE IS ACHIEVED, WHAT PORTION OF ANY EXCESS IS CREDITED TO RATEPAYERS?

A. Under the new NGPMP the level of annual guaranteed benefit is set at $1.0 million, but ratepayers will receive 80% of all asset management revenue that the Company derives in excess of $1.0 million. .

Q. WHAT LEVEL OF NGPMP CREDITS SHOULD BE ASSUMED IN THE DEVELOPMENT OF PROPOSED GCR CHARGES FOR THE 2009-10 GCR PERIOD?

A. I encourage the Commission to assume annual NGPMP credits to ratepayers of not less $3.4 million annually. A $3.4 million annual credit is consistent with the achievement of $4.0 million of annual net asset management revenue. Furthermore, $4.0 million of annual NGPMP credits represents a reasonable compromise between (1) the NGPMP guaranteed minimum credit and (2) the level of credit obtained previously through the Company's third party asset manager.

The Company's estimate of NGPMP credits in the filing is essentially the most conservative estimate possible. Even in the current market I assess that it is reasonable to expect that annual NGPMP credits will exceed the established $1.0 million minimum guarantee. Although I recognize that the level of credit formerly obtained through the Merrill Lynch contract may not be achievable given current market conditions, I find the assumption of only $1.0 million of NGPMP credit for the 2009-10 GCR period unnecessarily and inappropriately limits the level of benefit that will be conveyed to the Company's firm service customers over the coming GCR year. I assess that the assumption of $4.0 million of net asset management revenue and $3.4 million of NGPMP credits for the Company's ratepayers is more reasonable.

Q. WOULD THE ASSUMPTION OF $3.4 MILLION OF NGPMP CREDITS EFFECTIVELY RAISE THE GUARANTEED MINIMUM ANNUAL CREDIT FOR RATEPAYERS SET FORTH IN THE PROVISIONS OF THE NGPMP?

A. No. If the $3.4 million of credits is not achieved, the Company can recover any deficiency plus interest through the GCR reconciliation process. The effective minimum annual credit guarantee remains $1.0 million, and nothing in my proposal is intended to increase the dollar amount of credits for which the Company is at risk.

F. Gas Cost Reconciliations

Q. HAVE YOU REVIEWED THE COMPANY'S RECONCILIATION OF GAS COSTS FOR THE TWELVE MONTHS ENDED JUNE 30, 2009?

A. Yes, I have. Attachment GLB-2 submitted with witness Beland's September 1, 2009 testimony in this proceeding provides the Company's "Annual Gas Cost Recovery Reconciliation." In that reconciliation report, the Company presents its costs and revenue collections by month for each of the major components of its Gas Supply Costs for the twelve months ended June 30, 2009. I have reviewed that document in detail. I have also reviewed additional detail upon which the Company has relied to support those reconciliations that was obtained through discovery. Although my review must not be considered a comprehensive audit of National Grid's gas cost and revenue reconciliations, my review has, for the most part, provided me with reasonable comfort regarding the accuracy and reliability of those reconciliations.

Q. SHOULD THE COMMISSION ACCEPT THE COMPANY'S ANNUAL GAS COST RECOVERY RECONCILIATION AS FILED?

A. Yes.

G. Tariff Edits and Amendments

Q. HAVE YOU REVIEWED THE TARIFF EDITS AND AMENDMENTS THAT WITNESS BELAND PRESENTS ON BEHALF OF THE COMPANY?

A. Yes, I have.

Q. WHAT IS THE NATURE OF THE TARIFF CHANGES THAT THE COMPANY ASKS THIS COMMISSION TO APPROVE IN THIS PROCEEDING?

A. At page 17 of witness Beland's September 1, 2009 testimony, he lists five proposed changes to National Grid's gas tariff. The first two changes provide recognition of already approved changes in the Company's asset management activities and incentives. The next three address aspects of the Company's provision of gas transportation services.

Q. SHOULD THE COMMISSION APPROVE THE COMPANY'S PROPOSED TARIFF EDITS AND AMENDMENTS AS PRESENTED?

A. Yes. I find the proposed tariff changes to be reasonable and appropriate.

III. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS THAT YOU HAVE PRESENTED IN THIS TESTIMONY.

A. My recommendations to the Commission in this proceeding include the following:

1. The Commission should reduce or eliminate the current GPIP purchasing incentives, while maintaining the "dollar cost averaging" elements of the current gas-purchasing program.

2. The Commission should assume annual NGPMP credits to ratepayers of not less than $3.4 million for the 2009-10 GCR period and reduce the Company's GCR charges accordingly.

3. The Commission should require the Company to more fully document and explain year to year changes in its forecasted Normal Weather and Design Winter Sales and Throughput requirements in all future GCR proceedings. It should also require the Company to address the implications of changes in its annual throughput and design winter forecasts on both its near-term and long-term gas supply planning with particular focus on the expected availability of capacity resources for release or use in the production of asset management credits.

4. The Commission should accept as reasonable the Company's annual gas cost recovery reconciliations.

5. The Commission should approve the Company's proposed tariff edits and amendments.

Q. HAVE YOU COMPUTED PROPOSED GCR CHARGES BASED ON YOUR RECOMMENDED INCREASE IN THE ASSUMED LEVEL OF NGPMP CREDITS?

A. Yes, I have. The development of the GCR charges that result from my recommendation regarding NGPMP credits is presented in **Exhibit BRO-10**. With the change that I recommend, the GCR charges for all major classes of customers would be further reduced. The GCR charge for Residential Heating, Small C&I, Medium C&I, Large Low Load Factor, and Extra Large Low Load Factor customers would fall to **$1.0801** per therm, while GCR charges for Residential Non-Heating, Large High Load Factor, and Extra Large High Load Factor customers would be set at **$1.0338** per therm.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

National Grid - RI Gas
Docket No. 4097

Company Proposed Changes in GCR Charges by Rate Class
Based on NG's Currently Effective Rates and September 1, 2009 GCR Filing

Rate Classification	Current GCR Rate ($/Therm)	NGrid Proposed GCR Rate ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$1.0636	$1.0402	($0.0234)	-2.2%
LI - Non-Heating	$1.0636	$1.0402	($0.0234)	-2.2%
Heating	$1.0975	$1.0892	($0.0083)	-0.8%
LI - Heating	$1.0975	$1.0892	($0.0083)	-0.8%
Commercial & Industrial				
Small	$1.0975	$1.0892	($0.0083)	-0.8%
Medium	$1.0975	$1.0892	($0.0083)	-0.8%
Large Low Load Factor	$1.0975	$1.0892	($0.0083)	-0.8%
Large High Load Factor	$1.0636	$1.0402	($0.0234)	-2.2%
Extra Large Low Load Factor	$1.0975	$1.0892	($0.0083)	-0.8%
Extra Large High Load Factor	$1.0636	$1.0402	($0.0234)	-2.2%
Natual Gas Vehicles	$0.8388	$0.9091	$0.0703	8.4%
FT-2 Storage Service Charge	$0.0415	$0.0337	($0.0078)	-18.8%

National Grid - RI Gas

Docket No. 4097

Changes in Costs by GCR Cost Component

Based on National Grid's October 31, 2008 GCR Update Filing and September 1, 2009 GCR Filing

GCR Cost Component	Forecasted Annual Cost 2008-09 1/	Forecasted Annual Cost 2009-10 2/	Change $	Change %
Supply Fixed Costs	$ 23,566,240	$ 29,343,973	$ 5,777,733	24.5%
Storage Fixed Costs	$ 9,338,117	$ 10,450,090	$ 1,111,973	11.9%
Supply Variable Costs	$ 213,390,438	$ 196,408,852	$ (16,981,586)	-8.0%
Storage Variable Product Costs	$ 38,902,803	$ 36,624,047	$ (2,278,756)	-5.9%
Storage Variable Non-Product Costs	$ 1,893,321	$ 1,128,324	$ (764,997)	-40.4%
TOTAL	$ 287,090,919	$ 273,955,286	$ (13,135,633)	-4.6%
Total Fixed Costs	$ 32,904,357	$ 39,794,063	$ 6,889,706	20.9%
Total Variable Costs	$ 254,186,562	$ 234,161,223	$ (20,025,339)	-7.9%

1/ Source: Docket No. 3982, Updated Attachment GLB-1, October 31, 2008, page 1.
2/ Source: Docket No. 4097, Attachment EDA-1, September 1, 2009, page 1.

National Grid - RI Gas

Docket No. 4097

Changes in Reconciliation Amounts by Gas Cost Component

Based on National Grid's October 31, 2008 GCR Update Filing and September 1, 2009 GCR Filing

GCR Cost Component	Forecasted Annual Cost 2008-09 1/	Forecasted Annual Cost 2009-10 2/	Change $	Change %
Supply Fixed Costs	$ (2,232,818)	$ 1,584,026	$ 3,816,844	170.9%
Storage Fixed Costs	$ (865,243)	$ 1,211,860	$ 2,077,103	240.1%
Supply Variable Costs	$ 19,257,064	$ 45,481,451	$ 26,224,387	136.2%
Storage Variable Product Costs	$ (7,421,641)	$ (31,689,296)	$ (24,267,655)	-327.0%
Storage Variable Non-Product Costs	$ (1,423,487)	$ (4,883,861)	$ (3,460,374)	243.1%
TOTAL	$ 7,313,875	$ 11,704,180	$ 4,390,305	60.0%
Total Fixed Costs	$ (3,098,061)	$ 2,795,886	$ 5,893,947	190.2%
Total Variable Costs	$ 10,411,936	$ 8,908,294	$ (1,503,642)	-14.4%

1/ Source: Docket No. 3982, Updated Attachment PCC-1, October 31, 2008, pages 2-5.

2/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, pages 2-5.

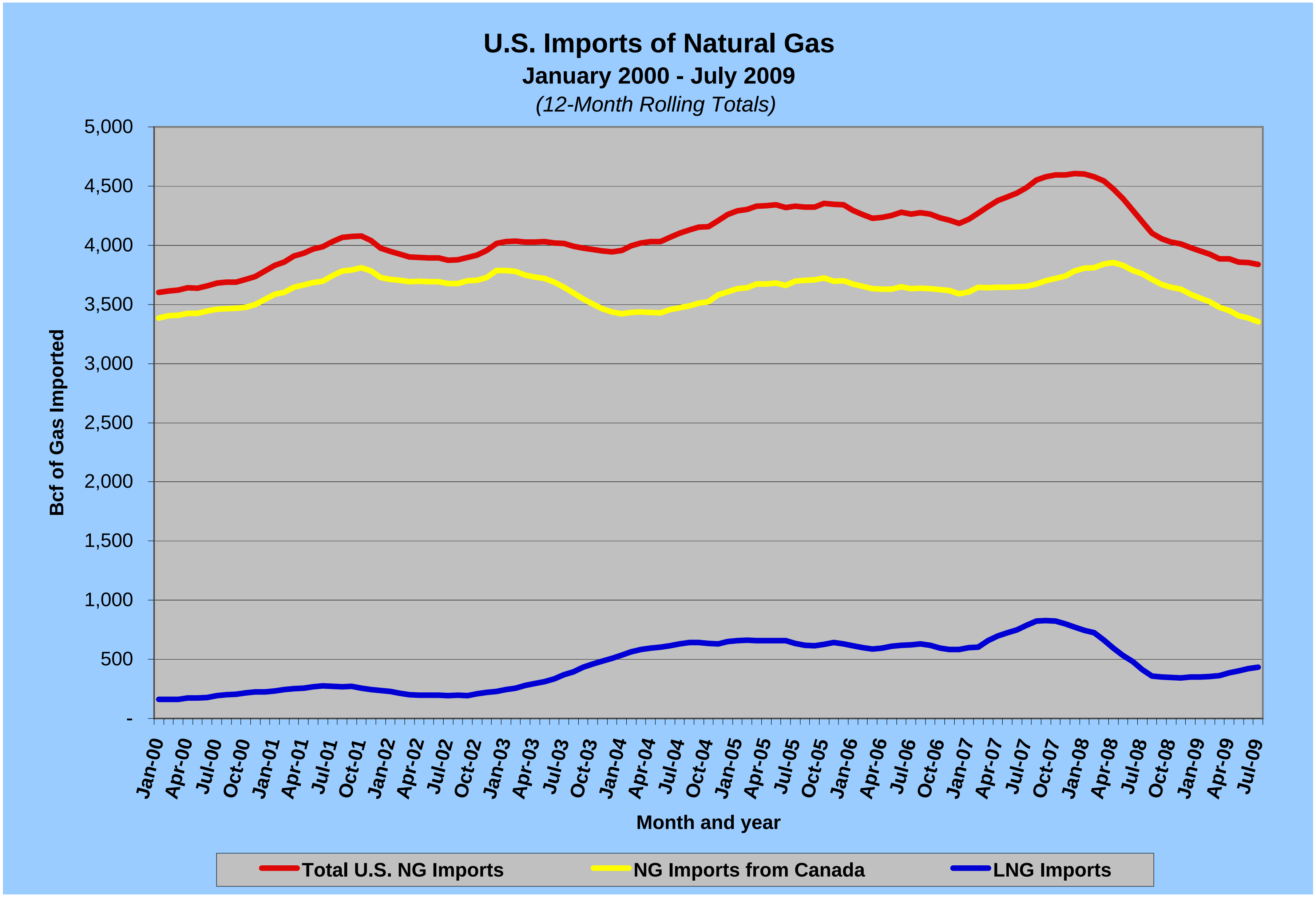
National Grid - RI Gas
Docket No. 4097

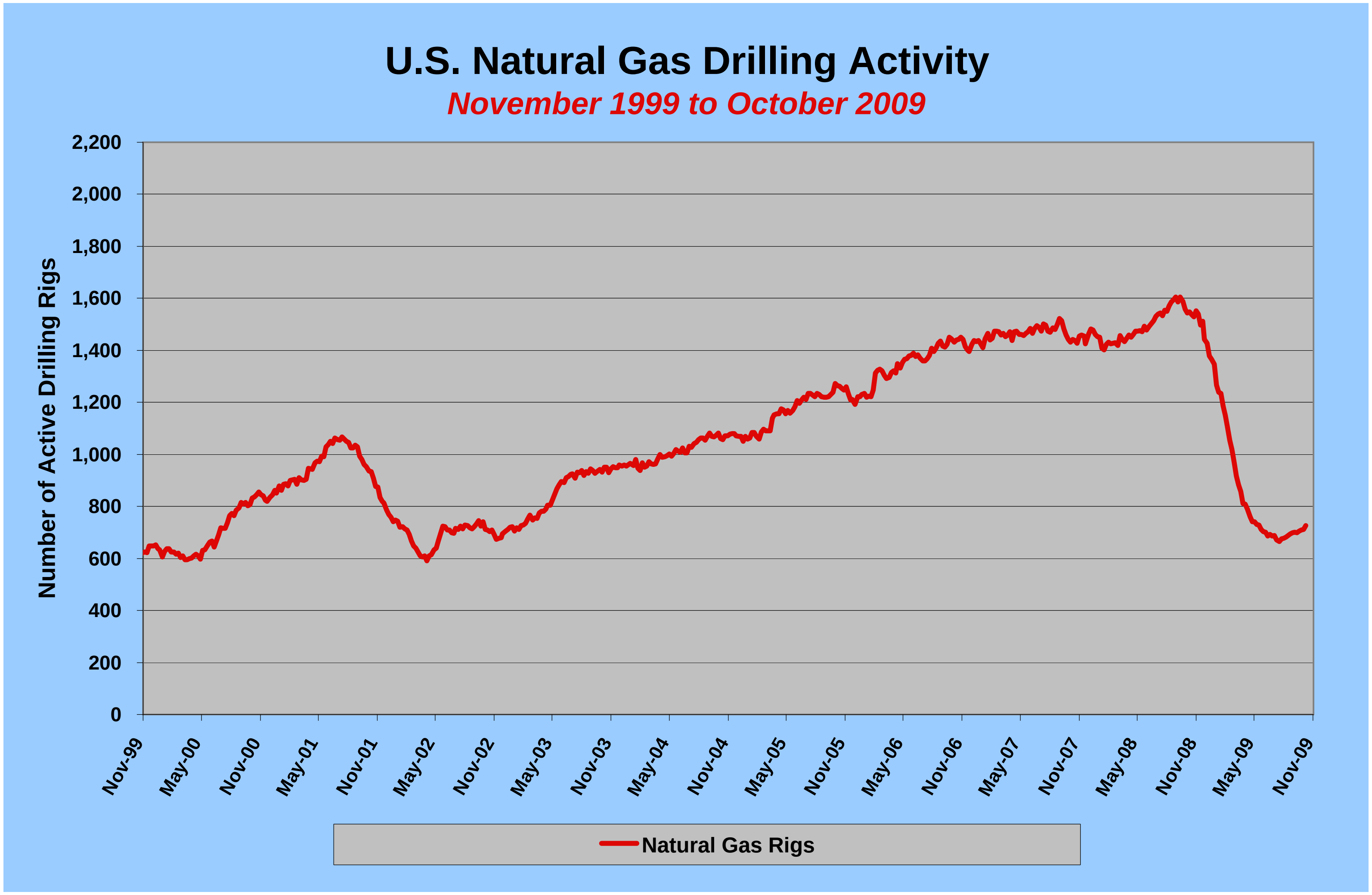
Changes in Other Adjustment Amounts by Gas Cost Component
Based on National Grid's October 31, 2008 GCR Update Filing and September 1, 2009 GCR Filing

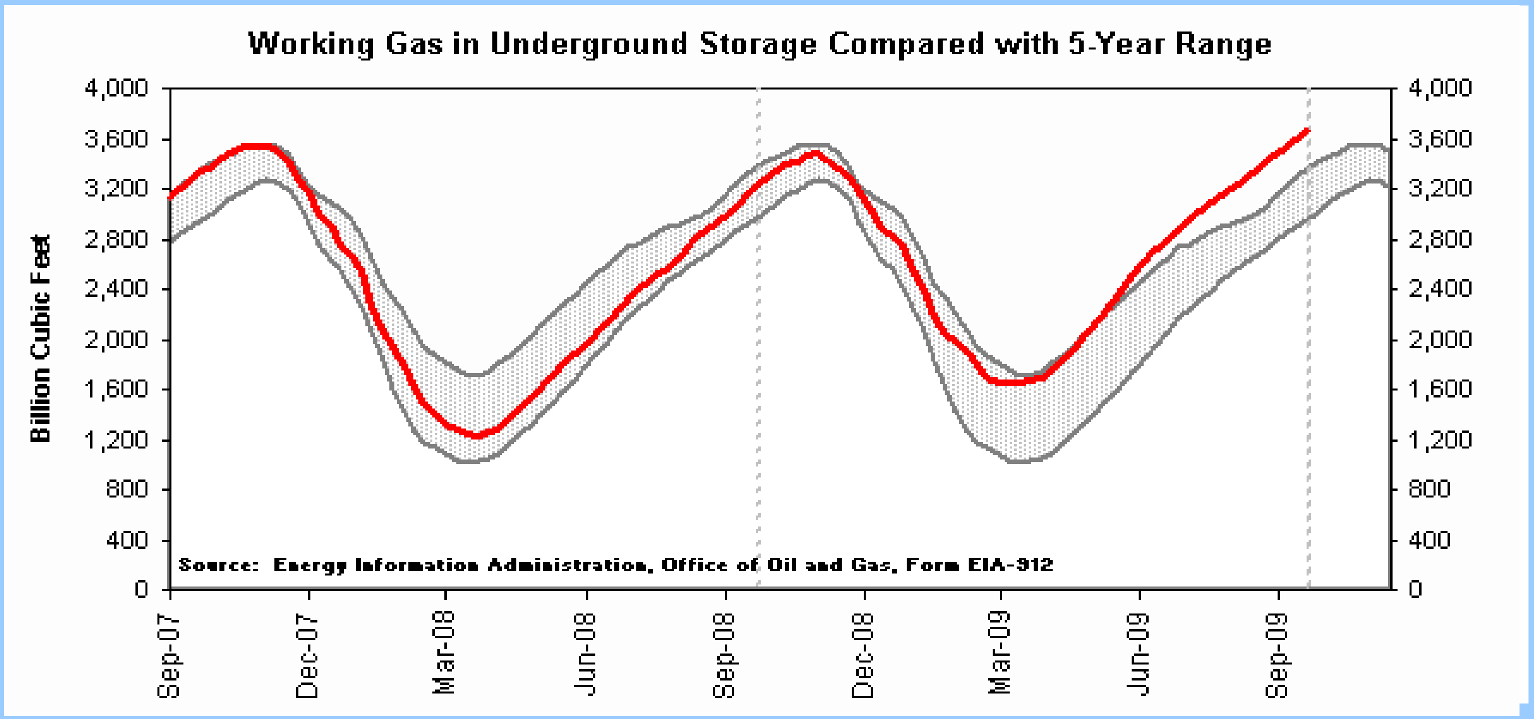
GCR Cost Component	Forecasted Annual Cost 2008-09 1/	Forecasted Annual Cost 2009-10 2/	Change $	Change %
Supply Fixed Costs	$ 93,193	$ (781,773)	$ (874,966)	-938.9%
Storage Fixed Costs	$ 101,707	$ 203,923	$ 102,216	100.5%
Supply Variable Costs	$ (1,689,863)	$ (203,832)	$ 1,486,031	87.9%
Storage Variable Product Costs	$ 2,212,821	$ 2,875,223	$ 662,402	29.9%
Storage Variable Non-Product Costs	$ 2,507,713	$ 1,660,598	$ (847,115)	33.8%
TOTAL	$ 3,225,571	$ 3,754,139	$ 528,568	-16.4%
Total Fixed Costs	$ 194,900	$ (577,850)	$ (772,750)	-396.5%
Total Variable Costs	$ 3,030,671	$ 4,331,989	$ 1,301,318	42.9%

1/ Source: Docket No. 3982, Updated Attachment PCC-1, October 31, 2008, pages 2-5.
2/ Source: Docket No. 4097, Attachment GLB-1, September 1, 2009, pages 2-5.

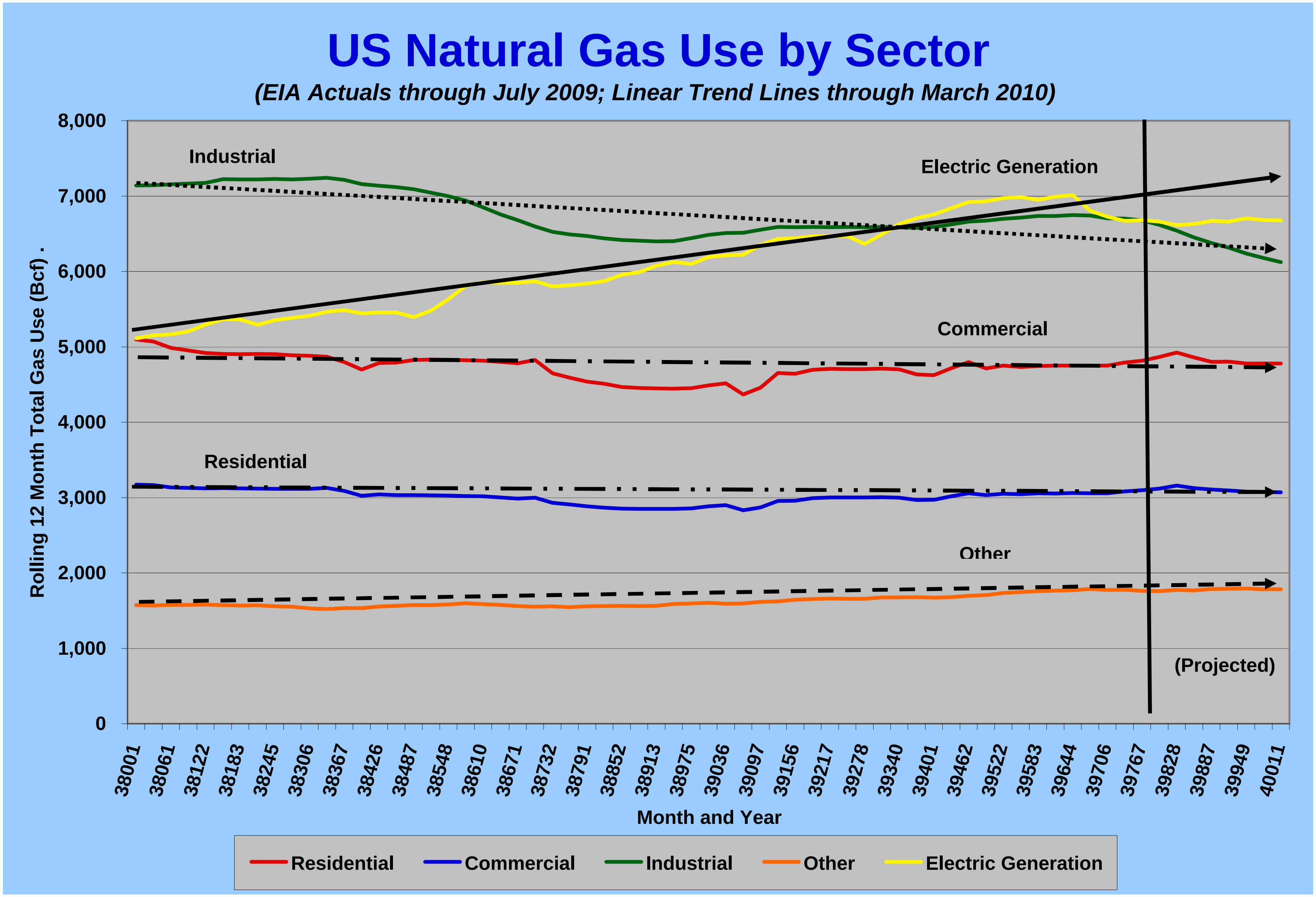
Exhibit BRO - 3
Page 1 of 1
October 16, 2009

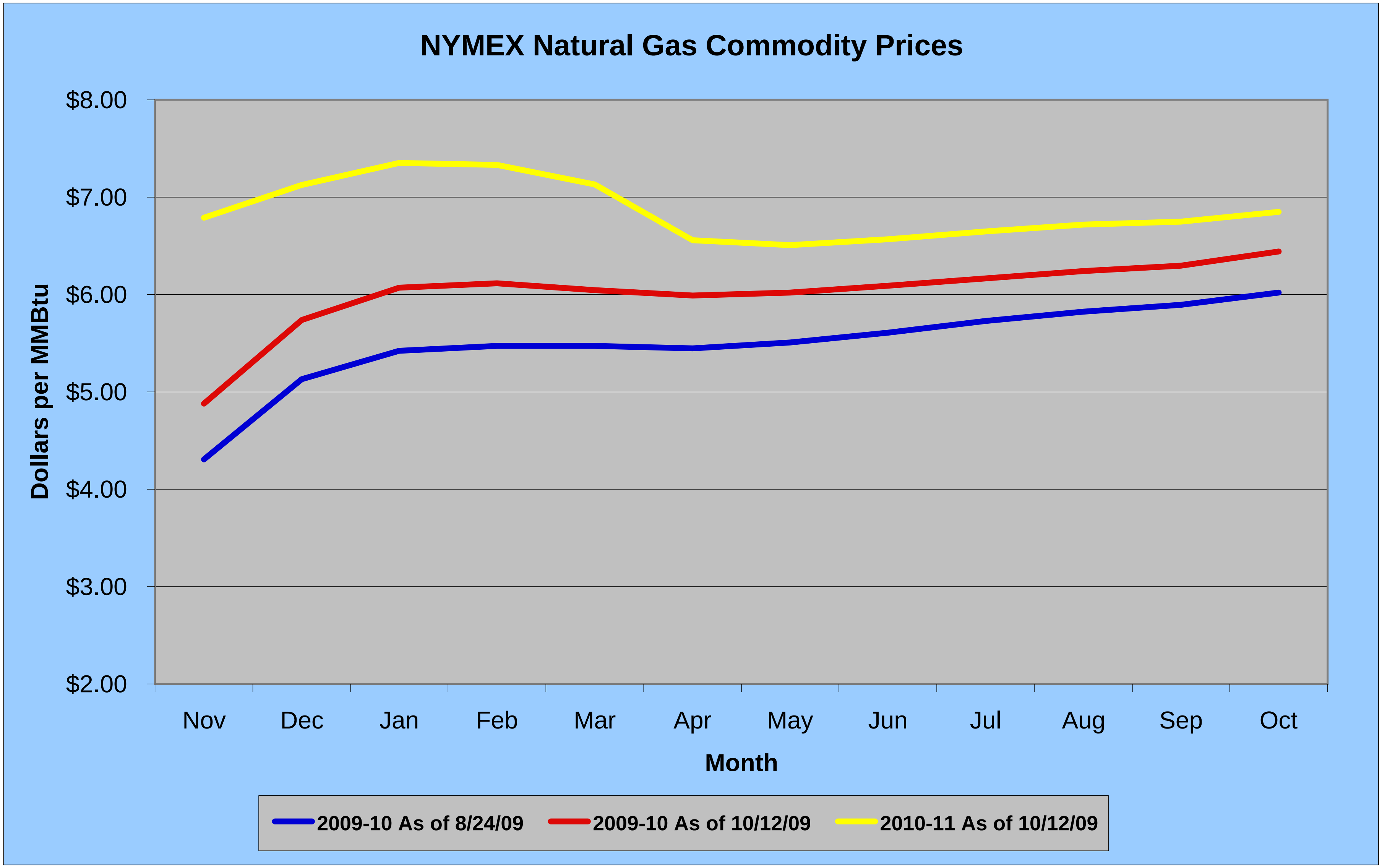



U.S. Natural Gas Drilling Activity
November 1999 to October 2009
Number of Active Drilling Rigs
2,200
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
Nov-99
May-00
Nov-00
May-01
Nov-01
May-02
Nov-02
May-03
Nov-03
May-04
Nov-04
May-05
Nov-05
May-06
Nov-06
May-07
Nov-07
May-08
Nov-08
May-09
Nov-09
Natural Gas Rigs



Region	Stocks in Billion cubic feet (Bcf)			Historical Comparison			
				Year Ago (10/02/08)		5-Year (2004-2008) Average	
	10/02/09	09/25/09	Change	Stocks (Bcf)	Change	Stocks (Bcf)	Change
East	1,992	1,955	37	1,893	5.2%	1,854	5.2%
West	497	489	8	431	15.3%	427	15.3%
Producing	1,169	1,145	24	862	35.6%	897	35.6%
Total	3,658	3,589	69	3,185	14.9%	3,178	14.9%


US Natural Gas Use by Sector
(EIA Actuals through July 2009; Linear Trend Lines through March 2010)
Industrial
Electric Generation
Commercial
Residential
Other
(Projected)
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Rolling 12 Month Total Gas Use (Bcf)
38001 38061 38122 38183 38245 38306 38367 38426 38487 38548 38610 38671 38732 38791 38852 38913 38975 39036 39097 39156 39217 39278 39340 39401 39462 39522 39583 39644 39706 39767 39828 39887 39949 40011
Month and Year
Residential
Commercial
Industrial
Other
Electric Generation


NYMEX Natural Gas Commodity Prices
Dollars per MMBtu
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Month
2009-10 As of 8/24/09
2009-10 As of 10/12/09
2010-11 As of 10/12/09

National Grid - RI Gas

Docket No. 4097

Changes in Forecasted Sales and Throughput Volumes by Rate Class

For November through October (12 Months)

	Forecasted 2008-09 Sales 1/ (MMBtu)	Forecasted 2009-10 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
Residential Non-Heat	569,704	650,517	80,813	14.2%
Residential Heat	18,015,743	17,121,459	(894,284)	-5.0%
Small C&I	2,366,018	2,672,144	306,126	12.9%
Medium C&I	4,087,667	4,405,703	318,036	7.8%
Large LLF	1,290,082	1,419,227	129,145	10.0%
Large HLF	483,166	437,759	(45,407)	-9.4%
Extra Large LLF	133,086	234,991	101,905	76.6%
Extra Large HLF	272,903	312,750	39,847	14.6%
Total Sales	27,218,369	27,254,552	36,183	0.1%
FT-2 Throughput				
Medium C&I	530,261	738,021	207,760	39.2%
Large LLF	287,703	621,927	334,224	116.2%
Large HLF	87,013	126,864	39,851	45.8%
Extra Large LLF	14,031	16,538	2,507	17.9%
Extra Large HLF	17,040	94,578	77,538	455.0%
Total FT-2 Throughput	936,048	1,597,928	661,880	70.7%
Total Throughput	28,154,417	28,852,480	698,063	2.5%

1/ Source: November 2008 from Schedule PCC-7, page 12, filed Sepember 2, 2008, in Docket No. 3982;
Dec 2009 - Nov 2009 from Updated Schedule PCC-7, page 12, filed October 31, 2008, Docket No. 3982.

2/ Source: Schedule GLB-1, page 14, filed September 1, 2009 in Docket No. 4097.

National Grid - RI Gas
Docket No. 4097

Forecasted Weather Normal Sales & Throughput by Month

	Forecasted 2008-09 Sales 1/ (MMBtu)	Forecasted 2009-10 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
November	1,749,934	1,696,390	(53,544)	-3.1%
December	3,237,563	3,092,425	(145,138)	-4.5%
January	4,307,201	4,535,743	228,542	5.3%
February	4,579,592	4,690,914	111,322	2.4%
March	4,201,508	4,061,612	(139,896)	-3.3%
April	3,173,214	2,970,754	(202,460)	-6.4%
May	1,830,600	1,889,993	59,393	3.2%
June	1,142,202	1,147,972	5,770	0.5%
July	753,365	788,472	35,107	4.7%
August	633,220	672,664	39,444	6.2%
September	734,503	733,349	(1,154)	-0.2%
October	875,466	974,264	98,798	11.3%
Total Sales	27,218,368	27,254,552	36,184	0.1%
FT-2 Throughput				
November	60,053	95,791	35,738	59.5%
December	103,814	167,042	63,228	60.9%
January	147,377	252,279	104,902	71.2%
February	141,316	244,941	103,625	73.3%
March	132,799	220,406	87,607	66.0%
April	101,904	185,264	83,360	81.8%
May	69,299	126,591	57,292	82.7%
June	49,972	86,855	36,883	73.8%
July	31,443	49,149	17,706	56.3%
August	27,024	50,766	23,742	87.9%
September	32,903	48,629	15,726	47.8%
October	38,143	70,215	32,072	84.1%
Total FT-2 Throughput	936,047	1,597,928	661,881	70.7%
Total Sales & Throughput				
November	1,809,987	1,792,181	(17,806)	-1.0%
December	3,341,377	3,259,467	(81,910)	-2.5%
January	4,454,578	4,788,022	333,444	7.5%
February	4,720,908	4,935,855	214,947	4.6%
March	4,334,307	4,282,018	(52,289)	-1.2%
April	3,275,118	3,156,018	(119,100)	-3.6%
May	1,899,899	2,016,584	116,685	6.1%
June	1,192,174	1,234,827	42,653	3.6%
July	784,808	837,621	52,813	6.7%
August	660,244	723,430	63,186	9.6%
September	767,406	781,978	14,572	1.9%
October	913,609	1,044,479	130,870	14.3%
Total Throughput	28,154,415	28,852,480	698,065	2.5%

1/ Source: November 2008 from Schedule PCC-7, page 12, filed Sepember 2, 2008, in Docket No. 3982;
Dec 2009 - Nov 2009 from Updated Schedule PCC-7, page 12, filed October 31, 2008, Docket No. 3982.
2/ Source: Schedule GLB-1, page 14, filed September 1, 2009 in Docket No. 4097.

National Grid - RI Gas

Docket No. 4097

Forecasted Design Winter Sales & Throughput by Month

	Forecasted 2008-09 Sales 1/ (MMBtu)	Forecasted 2009-10 Sales 2/ (MMBtu)	Forecasted Sales Increase (MMBtu)	% Increase
Sales				
November	1,749,934	2,696,056	946,122	54.1%
December	3,422,185	4,482,493	1,060,308	31.0%
January	5,283,194	4,876,345	(406,849)	-7.7%
February	5,136,327	4,630,437	(505,890)	-9.8%
March	4,997,229	3,728,166	(1,269,063)	-25.4%
Total Sales	20,588,869	20,413,497	(175,372)	-0.9%
FT-2 Throughput				
November	60,053	149,266	89,213	148.6%
December	108,848	240,503	131,655	121.0%
January	178,075	260,528	82,453	46.3%
February	156,942	246,806	89,864	57.3%
March	155,868	202,149	46,281	29.7%
Total FT-2 Throughput	659,786	1,099,252	439,466	66.6%
Total Throughput	21,248,655	21,512,749	264,094	1.2%

1/ Source: Schedule PCC-1, page 13, filed October 31, 2008.
2/ Source: Schedule GLB-1, page 13, filed September 1, 2006.

National Grid - RI Gas
Docket No. 4097

Division Recommended Gas Cost Recovery (GCR) Charges
Factors Effective November 1, 2009
($ per Dth)

Line No.	Description	Reference	Residential Non-Heat	Residential Heating	Small C&I	Medium C&I	Large LLF	Large HLF	Extra Large LLF	Extra Large HLF	FT-2 Marketer	NGV
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Supply Fixed Cost Factor	pg. 2	$ 0.7137	$ 1.0345	$ 1.0345	$ 1.0345	$ 1.0345	$ 0.7137	$ 1.0345	$ 0.7137	n/a	
2	Storage Fixed Cost Factor	pg. 3	$ 0.2886	$ 0.4186	$ 0.4186	$ 0.4186	$ 0.4186	$ 0.2886	$ 0.4186	$ 0.2886	$ 0.4015	
3	Supply Variable Cost Factor	pg. 4	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	$8.8677	n/a	$8.8677
4a	Storage Variable Product Cost Factor	pg. 5	$ 0.2866	$ 0.2866	$ 0.2866	$ 0.2866	$ 0.2866	$ 0.2866	$ 0.2866	$ 0.2866	n/a	
4b	Storage Variable Non-product Cost Factor	pg. 5	$ (0.0726)	$ (0.0726)	$ (0.0726)	$ (0.0726)	$ (0.0726)	$ (0.0726)	$ (0.0726)	$ (0.0726)	$ (0.0726)	
5	Total Gas Cost Recovery Charge	(1)+(2)+(3)+(4)	$ 10.0840	$ 10.5348	$ 10.5348	$ 10.5348	$ 10.5348	$ 10.0840	$ 10.5348	$ 10.0840	$ 0.3289	$ 8.8677
6	Uncollectible %	Docket 3943	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%	2.46%
7	Total GCR Charge Adjusted for Uncollectibles	(5)/[(1)-(6)]	$ 10.3383	$ 10.8005	$ 10.8005	$ 10.8005	$ 10.8005	$ 10.3383	$ 10.8005	$ 10.3383	$ 0.3372	$ 9.0913
8	**GCR Charge on a per therm basis**	(7)/10	**$ 1.0338**	**$ 1.0801**	**$ 1.0801**	**$ 1.0801**	**$ 1.0801**	**$ 1.0338**	**$ 1.0801**	**$ 1.0338**	**$ 0.0337**	**$ 0.9091**
	Current Effective Rate 12/01/08		$ 1.0636	$ 1.0975	$ 1.0975	$ 1.0975	$ 1.0975	$ 1.0636	$ 1.0975	$ 1.0636	$ 0.0501	$ 0.9326
	Difference		$ (0.0298)	$ (0.0174)	$ (0.0174)	$ (0.0174)	$ (0.0174)	$ (0.0298)	$ (0.0174)	$ (0.0298)	$ (0.0164)	$ (0.0235)
	Percent Change		-2.8%	-1.6%	-1.6%	-1.6%	-1.6%	-2.8%	-1.6%	-2.8%	-32.7%	-2.5%

National Grid - RI Gas
Docket No. 4097

Gas Cost Recovery (GCR)
Division Adjusted Fixed Cost Calculation ($ per therm)

Line No.	Description (a)	Reference (b)	Amount (c)	Residential Heating (d)	Small C&I (e)	Medium C&I (f)	Large LLF (g)	Extra Large LLF (h)	Low Load Factor Total (i)	Residential Non-Heat (j)	Large HLF (k)	Extra Large HLF (l)	Low Load Factor Total (m)
1	Supply Fixed Costs (Net of Cap Release to Mktrs)	EDA-1	$ 29,343,973										
2	Less:												
3	NGPMP Guarantee	Per BRO	$ 3,400,000										
4	Interruptible Costs		$ -										
5	Non-Firm Sales Costs		$ -										
6	Off-System Sales Margin		$ -										
7	Refunds		$ -										
8	Total Credits	Sum[(3)-(7)]	$ 3,400,000										
9	Plus:												
10	Working Capital Requirement	pg. 8	$ 218,227										
11	Reconciliation Amount	pg. 6	$ 1,584,026										
12	Total Additions	(10) + (11)	$ 1,802,253										
13	Total Supply Fixed Costs	(1) -(8) + (12)	$ 27,746,226										
14	Winter Sales Percentage	pg 13		63.76%	9.96%	15.98%	5.69%	1.01%	96.40%	1.68%	1.16%	0.76%	3.60%
15	Allocated Supply Fixed Costs	(13) x (14)	$ 27,746,226	$ 17,692,108	$ 2,763,384	$ 4,432,776	$ 1,577,912	$ 280,102	$ 26,746,282	$ 466,667	$ 321,540	$ 211,736	$ 999,943
16	Sales (Dt) Nov 2009 - Oct 2010	pg. 12	27,254,552	17,121,459	2,672,144	4,405,703	1,419,227	234,991	25,853,526	650,517	437,759	312,750	1,401,026
17	Supply Fixed Factor	(15)/(16)							$ 1.0345				$ 0.7137