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. 4346**
Filing	**)**	

DIRECT TESTIMONY OF WITNESS
BRUCE R. OLIVER

On Behalf of

The Division of Public Utilities and Carriers

October 22, 2012

TESTIMONY OF BRUCE R. OLIVER
Docket No. 4283
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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 National Grid (or hereinafter “the Company”) Annual Gas Cost Recovery (GCR) filing. This testimony provides the findings of the Division’s review of National Grid’s September 4, 2012 Testimony and Exhibits in support of its proposed GCR charges for the twelve-month period from November 1, 2012 through October 31, 2013, as well as the Company’s August 1, 2012, GCR reconciliations for the twelve months ended June 30, 2012.

This testimony addresses portions of the Direct Testimony and exhibits filed on behalf of National Grid by witnesses Arangio, Smith, and McCauley

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 Reallocation of LNG-Related Costs to DAC
Exhibit BRO-4 Comparison of Forecasted Sales and Throughput Volumes
Exhibit BRO-5 Division Recommended GCR Charges

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S 2012 GCR FILING?

A. The primary conclusions and recommendations presented in this testimony may be summarized as follows:

- The Commission should require National Grid to lower its forecast of FLS Call Payments to Distrigas for the 2012-2013 GCR year by **$467,704**.

- The Company appears to have erroneously credited $1.1 million of demand related refunds from Tennessee Gas Pipeline to its Variable Costs within its annual cost reconciliations. That amount should more appropriately be credited against its Fixed Supply costs.

- The Settlement approved by FERC in the Tennessee Gas Pipeline case provides for a sharing of excess revenue margins by its customers. However, National Grid offers no discussion of such sharing or the manner in which it would reflect such sharing in its gas costs for Rhode Island customers. Procedures for passing such revenue sharing benefits to National Grid's customers in RI should be established to avoid uncertainty regarding the treatment of such benefits, if and when they are paid.

- Consistent with the Division's position in the pending DAC proceeding (Docket 4339), the Division recommends adjustment of the portion of LNG-related costs allocated to the DAC System Pressure Factor. This adjustment reduces LNG-related costs included in the Company's GCR by **$2,595,319** based on the Company's filed allocation of LNG-related costs to the DAC.

- The Company's calculations in support of its claimed GPIP and NGPMP incentives appear to be accurately computed and determined in a manner consistent with the provisions of those incentive programs.

- In the context of National Grid's use of third parties for portions of its management of gas supply assets, the Division recommends that discussions be reopened between the Company and the Division to assess the continued appropriateness of the current NGPMP incentive structure.

- The Division generally finds that the Company's Long-Range Gas Supply Plan, filed in March of 2012 is reasonable, although the Division sees some opportunities for further refinement of future planning reports. The Division also recommends that the Commission require National Grid to prepare a new five-year planning study at least once every three years. This requirement is necessary to avoid situations, such as that encountered last year, where the Company had progressed beyond the last year of its most recent planning study and the Commission was left with no basis for evaluating the reasonableness of the Company's overall gas supply portfolio.

- The Commission should adopt the GCR rates presented in Exhibit BRO-5 attached to this testimony which lowers the Company's LNG Demand costs and changes the allocation of LNG-related costs to the DAC.

III. 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 six sections. **Section A** discusses procedural concerns relating to constraints on the Division's ability to reasonably and appropriately review the Company's Gas Cost Reconciliations and forecasted gas costs for the coming GCR year. **Section B** reviews 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 C** details the adjustments to GCR LNG-related costs that result from the Division's recommendation regarding the allocation of LNG-related costs to the DAC in Docket 4339. **Section D** provides the findings of the Division's review of National Grid's reconciliation of its GCR costs and revenue for the twelve months ended June 30, 2012. **Section E** examines the Company's claims for incentive payments under its Gas Procurement Incentive Plan (GPIP) and its Natural Gas Portfolio Management Plan (NGPMP) and related issues. **Section F** presents the Division's recommended GCR charges for the Company's 2012-2013 GCR Year.

A. Procedural Concerns

Q. WHAT ARE THE PROCEDURAL CONCERNS THAT THE DIVISION SUBMITS FOR THE COMMISSION'S CONSIDERATION IN THIS PROCEEDING?

A. The Division is concerned that it has been provided inadequate time to present a reasonable and appropriate evaluation of the Company's filing in this proceeding, and that such constraints are unduly impeding its ability to properly assess the Company's proposed rate changes.

The Company's Direct Testimony in this proceeding was filed on September 4, 2012. Within two weeks of that filing the Division submitted two sets of GCR-related data requests to the Company based on the filed testimony and exhibits of its witnesses. However, only within the last 7-9 days before the due date of this testimony were responses received. Those responses included 200 pages of documents and multiple spreadsheet files. Although the Division attempted to limit its number of discovery requests, the need for discovery was accentuated by such factors as: (1) the lack of discussion in the Company's testimony in this proceeding of the Tennessee Pipeline settlement before FERC which was identified by the Company in its 2011 filing as an important unresolved matter; (2) National Grid's disclosure of its use of third-party asset managers; (3) inconsistencies in the manner in which volumes and costs were forecasted in the Company's estimation of its end of October 2012 Deferred Gas Cost Balance; and (4) the actual contract terms and prices under which LNG supplies were obtained during the past winter.

The Division submits that a little over one week to read, digest, analyze and write testimony relating to extensive discovery responses on technical matters of relevance to the Company's actual and forecasted costs is not adequate. To alleviate such problems in future GCR proceedings, the Division recommends that:

- The Company be required to address explicitly in its Initial Direct testimony in each GCR proceeding all matters that remained open at the time of the Commission last GCR determination (e.g., the Tennessee Pipeline settlement);

- Given that the period for the Company's Annual Gas Cost Reconciliation filing is now the twelve months ended March 31 of each year, the Company's filing date for those reconciliations should be moved from August 1 to July 1 of each year.

- The Company's initial GCR testimony filing for each year should be moved from September 1 to August 1 of each year with the opportunity for the Company to supplement that testimony on or about September 1. This would give the Division greater opportunity to pursue discovery and possibly follow-ups with National Grid on its base (initial) filing while still allowing the Company the flexibility to revise and update

information relating to that filing before the Division files its testimony.

- The Commission should require that the Company provide with its testimony and exhibits the electronic spreadsheet files used to generate those quantitative analyses contained therein.

- The Company should be encouraged to make its best efforts to respond to the Division's data requests within two week of their submission to the Company.

<u>B. Changes in National Grid's GCR Rates and Gas Costs</u>

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

A. National Grid's filing proposes reductions in its GCR charges for all rate classifications except the FT-2 Marketer Charge. As shown in **Exhibit BRO-1,** the Company proposes to lower its GCR charges for Residential Heating customers, Small C&I customers, Medium C&I customers, Low Load Factor Large C&I customers, and Low Load Factor Extra Large C&I customers from $0.7896 per therm to **$0.6675 per therm**. That represents a **reduction** of **15.5%**. The Company's September 13, 2011 filing also proposes a GCR **reduction** of **17.0%** 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 also **decline** from $0.7464 per therm to **$0.6193 per therm**.

Q. HAVE THE COMPANY'S GAS COSTS DECREASED UNIFORMLY ACROSS ALL GCR COST COMPONENTS?

A. No. **Exhibit BRO-2** compares the Company's GCR cost projections by component for the 2012-13 GCR year (prior to adjustments and reconciliation amounts) with comparable measures of costs that National Grid projected in its last GCR filing Docket No. 4283. As shown on that page, the cost changes that National Grid projects are negative for all cost components **except Storage Fixed Costs**. Although the Company's **overall costs** of gas are expected to **decline** by **18.5%**, its **Storage Fixed Costs** are projected to **increase** by **7.7%**. Total Variable Costs are forecasted to decline by **22.7%** which corresponds to a reduction of **$28,231,169.**

Q. WHAT IS THE CAUSE OF THE INCREASE IN STORAGE FIXED COSTS THAT NATIONAL GRID PROJECTS FOR ITS 2012-13 GCR YEAR?

A. The Company's projected increase in Fixed Storage Costs is the result of changes in Supplier Demand Costs associated with the Company's LNG contract with Distrigas. National Grid included no fixed costs for liquid supply from Distrigas in its forecasted gas costs in Docket 4283. Its actual payments to Distrigas for the twelve months ended March 2012, as shown in its Gas Cost Reconciliation Report for that

period, total **$1,003,726**. However, Witness Leary's Attachment AEL-1, page 4 of 12, in this proceeding forecasts Distrigas payments for the 2012-2013 GCR year of **$1,471,430**.

Q. DO YOU FIND THE COMPANY'S FORECAST OF FIXED PAYMENTS TO DISTRIGAS TO BE REASONABLE?

A. No, I do not. In Docket 4283 I raised a concern that National Grid had not entered into an LNG supply contract with either Distrigas or some other supplier prior to the start of the winter season. As a result, the Company had no sound basis for estimating its LNG demand costs (fixed) payments the winter of 2011-2012. In this proceeding, National Grid, once again, has not entered into a contract for liquid supply for the winter of 2012-2013 as of the time of the Company's submission of Direct Testimony in this proceeding. Still, its forecast assumes a **31.8%** increase in Distrigas FLS Call Payments. In the Company's prior Annual Gas Cost Reconciliation filing (i.e., for the twelve months ended June 2011), the Company reported actual fixed payments to Distrigas of only **$478,204**. Thus, it's forecasted annual Call Payments to Distrigas in this proceeding represent a **$1.0 million increase** or more than **a tripling** of those costs in more than two years.

When the monthly detail of the Company forecasted payments is compared to its actual costs over the last two annual periods for which actual data have been provided, we find that a large portion of the increase is associated with assumed payments for non-winter months. In fact, unlike its actual experience in prior years,

the Company's forecasted FLS Call Payments to Distrigas are greater for non-winter months (i.e., April – October 2013) than for the winter months of November 2012 through March 2013). For April through October 2013, National Grid forecasts Distrigas payments of $125,383 per month. During the non-winter months of the (2011), the Company paid Distrigas an average of only $58,568 per month. Without either a signed contract or more substantial supporting rationale for these presumed cost increases, I find them inappropriate for inclusion in the Company's 2012-2013 GCR.

Q. WHAT LEVEL OF DEMAND (OR CALL PAYMENTS) FOR THE 2012-2013 GCR YEAR SHOULD BE INCLUDE IN THE COMPANY'S FORECASTED GAS COSTS IN THIS PROCEEDING?

A. In the absence of a signed contract or a firm indication of actual pricing for the coming GCR period, I recommend that the Commission allow only the level of costs indicated in National Grid's most recent annual gas cost reconciliation filing. That is **$1,003,726** or a reduction of **$467,704** from the level the Company has forecasted.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE ELEMENTS OF THE COMPANY'S GCR RATE COMPUTATIONS?

A. Yes, I do. As I noted in my recently filed Direct Testimony in Case No. 4339 (National Grid's pending DAC proceeding), the portion of the Company's LNG-related costs that is allocated is understated and should be adjusted upward. As a

result, the forecasted LNG costs in the Company's GCR filing are overstated. That adjustment results in a reduction in the Company's GCR costs of approximately $2.5 million. Support for this recommendation is presented in the following section of this testimony.

C. Adjustment for Change in Allocation of LNG Costs to DAC

Q. IS THE ALLOCATION OF LNG-RELATED COSTS TO THE DAC A NEW ISSUE IN THIS PROCEEDING?

A. No, it is not. At the time of the Company's last GCR proceeding, the Division raised similar issues regarding the appropriateness of the allocation factor upon which National Grid relied to determine the portion of LNG-related costs that should be appropriately allocated to the DAC System Pressure Factor. In consideration of the Division's position, the Company agreed that it would work with the Division to address the matter further as part of the new Long-Range Gas Supply Plan ("LRGSP") it intended to file in 2012.

Q. HOW DOES NATIONAL GRID'S DETERMINE THE PORTION OF ITS LNG-RELATED COSTS THAT IT ALLOCATES TO THE DAC?

A. The Company uses an allocation factor that assigns 18.12% of its LNG-related costs to the DAC. As shown at page 45 of National Grid's March 8, 2012 Long

Range Gas Supply Plan,[1] National Grid derived its 18.12% allocation factor by dividing the amount of LNG required for Pressure Support during its peak hour (i.e., 3,410 Dth/hr) by the Company's **2010-2011** Peak Hour Sendout requirement, where its Peak Hour Sendout reflects the amount of gas flowing into its system under Design Peak Hour conditions from all sources of gas supply (i.e., 18,820 Dth/hr). Thus, as computed by National Grid the System Pressure allocation factor (AF) for LNG costs is constructed as follows:

AF = Peak Hour LNG sendout capability / Total System Peak Hour Sendout

Where,

Peak Hour LNG Sendout Capability = 3,410 Dth/hr
Total System Peak Hour Sendout = 18,820 Dth/hr

Thus,

3,410 Dth/hr / 18,820 Dth/hr = **18.12%**

Q. DOES THE COMPANY'S APPROACH TO ASSIGNING LNG-RELATED COSTS TO THE DAC PROPERLY IDENTIFY THE PORTION OF THE COMPANY'S LNG-RELATED COSTS THAT ARE ASSOCIATED WITH THE MAINTENANCE OF SYSTEM PRESSURES?

[1] The analysis presented in the Company's March 8, 2012 LRGSP simply repeats the analysis offered by the Company in Docket 4283 with which the Division took issue.

A. No, it does not. There are two problems with this formulation of the Company's allocation factor. First, the allocation factor the Company employs is not properly constructed to allocated LNG-related costs. Rather, it erroneously attempts to assess the portion of total sendout of gas from all sources (i.e., pipeline supplies, storage supplies, and LNG vaporization) under peak hour conditions that is comprised of LNG used for system pressure support. That ratio of LNG for system pressure support to total system sendout tells us nothing about the portion of total **LNG costs** that is attributable to system pressure requirements. Second, the Company's allocation factor does not consider its use of LNG for system pressure support in non-peak hours throughout the year.

Q. THE COMPANY FILED A NEW LONG RANGE GAS SUPPLY PLAN IN MARCH, 2012. DID THAT PLAN PROVIDE FURTHER ANALYSES RELATING TO THE APPROPRIATE ALLOCATION OF LNG-RELATED COSTS TO THE DAC?

A. No, it did not. Despite lengthy discussions between the Division and the Company regarding this matter in the months preceding the Company's filing of its new Long Range Gas Supply Plan, its presentation regarding this issue in that Plan simply (1) repeats its filed position in Docket 4269 and (2) suggests that the matter be discussed further with the Division.

Q. HOW SHOULD THE ALLOCATION OF LNG-RELATED COSTS TO THE SYSTEM PRESSURE FACTOR BE DETERMINED?

A. Proper allocation of LNG-related costs must be accomplished in two steps which separately allocate LNG capacity (i.e., demand) costs and LNG commodity costs. Capacity-related costs should be allocated based on ratio of LNG capacity required for system pressure support under peak hour conditions to total peak hour LNG vaporization capacity. Commodity-related LNG costs should be allocated using a ratio of total annual LNG sendout for system pressure purposes under normal winter weather conditions to total forecasted LNG sendout for all purposes under normal winter conditions.

Q. HAVE YOU COMPUTED REVISED ALLOCATIONS TO DETERMINE THE PORTION OF THE COMPANY'S LNG COSTS THAT SHOULD BE CONSIDERED SYSTEM PRESSURE RELATED?

A. Yes. As explained in my testimony in Docket 4339, I have computed new allocation factors for capacity-related LNG costs and for commodity-related LNG costs.

For capacity (demand) related LNG costs I have constructed an allocation factor which reflects the percentage of peak hour LNG Required for Pressure Support to Total Peak Hour LNG Sendout Capability. Using the information provided on page 45 of the Company's March 2012 Long Range Gas Supply Plan, an allocation factor based the ratio of LNG required for system pressure support to dedicated peak hour LNG vaporization capacity is computed as follows:

LNG Facility	Dedicated Vaporization Capacity	Required for Pressure Support	Ratio
Cumberland	1,333	0	
Allen's Ave (Prov)[2]	3,958	2,999	
Exeter	750	411	
Portsmouth	325	0	
Total	5,616	3,410	**60.72%**

The allocation factor for commodity-related LNG costs is premised on the ratio of annual non-peaking related LNG sendout to total annual LNG sendout. Based on witness Arangio's Exhibit EDA-2, annual non-peaking related LNG sendout is 228,950 Dth. Total annual LNG sendout is the sum of the sendouts of LNG from the Company's Providence, Valley, and Exeter LNG facilities which as forecasted for the November 2012 through October 2013 period equals 362,200 Dth. Thus, the resulting allocation factor for commodity-related LNG costs reflects 228,950 Dth divided by 362,200 Dth or **63.21%**.

The overall allocation of LNG-related costs to the DAC is achieved by: (1) applying the 63.21% factor to the Commodity Withdrawal and Inventory Financing Costs shown in witness Smith's Exhibit MCS-2S and (2) applying the 60.72% LNG capacity allocation factor to the total Supplier Demand from GCR costs. Based on

[2] Note 4 to the table on page 45 of the Company's March 8, 2012 Long Range Gas Supply Plan states, "While the LNG vaporization capacity at Providence is 6,000 Dth/hr, the National Grid contract amount is only 3,935 Dth/hr." The measure of dedicated LNG vaporization capacity used for Providence thus reflects only the Company's contracted capacity.

the LNG-related costs claimed by the Company in this proceeding,[3] **Exhibit BRO-3** shows that these new allocations result in the assignment of a total of **$3,672,665** of LNG-related costs to the DAC. Considering that National Grid has allocated only $1,077,346 of LNG-related costs to the DAC. This change increases the amount of LNG-related costs included in the DAC by **$2,595,319**. It also yields a corresponding reduction in GCR costs.

Q. HOW DOES THIS CHANGE IN THE ALLOCATION OF LNG-RELATED COSTS IMPACT THE COMPANY'S RECOVERY OF LNG-RELATED COSTS?

A. National Grid continues to receive full recovery of its LNG-related costs. The key difference is that a greater portion of the Company's LNG-related costs is recovered through the DAC, and that results in a larger share of LNG-related costs is recovered from Firm Transportation Service customers. The Company's development of its System Pressure Factor for the DAC distributes responsibility for LNG-related costs over all Firm Throughput for both Sales and Transportation service customers. As shown in Witness Smith's Attachment MCS-3, the Firm Throughput used to compute the System Pressure Factor totals **35,387,711 Dth**. That contrasts with the treatment of LNG costs which are retained within the GCR. Those costs are recovered only from Firm Sales customers based on forecasted Firm Sales volumes of **24,879,878 Dth**. In other words, recovery of LNG-related costs that are

[3] When the effects of this change in the allocation of LNG-related costs is combined with the reduction in forecasted demand-related LNG costs presented in this testimony the overall impact is somewhat lower. The combined effect of those recommendations is presented in the final section of this testimony.

not incurred for peaking supply purposes through the DAC results in a much broader distribution of responsibility for those costs. That is appropriate given that all customers (sales and transportation service customers) benefit from the maintenance of system pressures.

D. Deferred Gas Cost Issues

Q. HAVE YOU REVIEWED THE GAS COST RECONCILIATIONS THAT NATIONAL GRID HAS PRESENTED IN THIS PROCEEDING?

A. Yes, I have review the Company's 2012 Annual Gas Cost Recovery Reconciliation filed on August 1, 2012 for the twelve months ended March 31, 2012 (a copy of which is included in the Company's September 4, 2012 filing in this proceeding as Attachment AEL-2 to the Direct Testimony of witness Leary). I have also reviewed much of the detail of the report Ernst & Young ("E&Y") prepared for National Grid based on E&Y's review of the Company's gas cost accounting for the period September 2006 through June 2012, as well as supporting workpapers provided for that analysis which reaches back in time to September 2006 and covers the entire period from September 2006 through June 2012.

Q. DO YOU FIND ANY REASON TO QUESTION THE ACCURACY OF THE ADJUSTMENTS TO THE COMPANY'S DEFERRED GAS COST BALANCE THAT ARE SET FORTH IN THE E&Y REPORT?

A. No, I do not. Although I have an appreciation for certain elements of the work undertaken by E&Y and the general basis for the E&Y findings, I am not in a position to render an opinion regarding the outcome of that rather extensive review of the Company's gas cost accounting.

1. Tennessee Gas Pipeline Demand Charge Refund

Q. DO YOU QUESTION ANY ELEMENTS OF COMPANY'S GAS COST RECONCILIATIONS FOR THE TWELVE MONTHS ENDED MARCH 2012?

A. Yes. The Company has improperly credited demand-related refunds from the Tennessee Gas Pipeline ("TGP") settlement before FERC against its Variable Supply costs.

Q. WHAT REFUNDS DID NATIONAL GRID RECEIVE FOR ITS RHODE ISLAND GAS SERVICE AS A RESULT OF THE SETTLEMENT IN THE MOST RECENT TENNESSEE GAS PIPELINE RATE CASE BEFORE FERC?

A. National Grid has received refund of both commodity-related and demand-related costs. During the twelve months ended March 2012, the Company received refunds totaling $3,175,533. Of that amount $1,141,713 represented refunds of demand-

related costs. The remaining $2,033,820 comprised refunds of commodity (variable) cost.

Q. HOW WERE THOSE TENNESSEE GAS PIPELINE REFUNDS CREDITED IN THE COMPANY'S GAS COST RECONCILIATIONS FOR THE TWELVE MONTHS ENDED MARCH 2012?

A. The detail of the Company's Annual Gas Cost Reconciliation Report that is presented in Attachment AEL-2, page 9 of 15, shows the entire $3,175,532 of "Refunds (Tennessee)" as credits against the Company's Variable Supply Costs. However, National Grid's response to Division Data Request 1-1(d)i-2 in this proceeding suggests that $1,141,713 of those costs were actually refunds of demand costs and interest on those demand cost refunds.

Q. WHAT IS THE PROPER TREATMENT OF THOSE DEMAND COST REFUNDS?

A. They should be credited to the Company's Supply Fixed Costs, not its Supply Variable Costs.

Q. HOW WOULD CORRECTION OF THE COMPANY'S CREDITING OF DEMAND-RELATED TGP REFUNDS ALTER ITS GCR COSTS IN THIS PROCEEDING?

A. It would not impact on the Company's total costs, but it would change the allocation of the credit between High Load Factor and Low Load Factor rate classifications. In other words, customers in Low Load Factor classes who bear the vast majority of

the Company's Supply Fixed Costs would receive a greater share of the benefits of this demand cost refund. .

Q. ARE THERE OTHER MATTERS RELATING TO THE TENNESSEE GAS PIPELINE SETTLEMENT THAT THIS COMMISSION SHOULD NOTE?

A. Yes. The Tennessee Gas Pipeline settlement, as described in the Company's response to Division Data Request 1-1(a), includes a revenue sharing mechanism under which 75% of revenues achieved by TGP in excess of $885,000,000 per year will be shared with TGP customers (e.g., National Grid). There is no guarantee that any funds will flow back to National Grid as a result of this sharing provision,[4] I believe it is appropriate at his point for the Commission to establish the treatment of any revenue sharing related to National Grid's may receive as a result of its Rhode Island service requirements.

Q. HOW WOULD SUCH REVENUE SHARING BE TREATED UNDER THE TERMS OF THE COMPANY'S EXISTING TARIFF?

A. At present the Company's tariff does not explicitly address revenue sharing associated with pipeline services. Rather, than leaving his issue open for debate, the Division recommends that action be taken now to establish that such revenue sharing amounts, if and when they are received, are treated in the same manner as

[4] I have been informed informally by the Company that TGP has made its initial revenue sharing filing claiming that for the first year of that program, its total revenues were $884.8 million, or just below the sharing

pipeline supplier refunds with the entirety of such sharing amounts credited against gas costs through the GCR.

2. Changes in Forecasted Sales Volumes in Monthly Reports

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE COMPANY'S REPORTING OF DEFERRED GAS COST BALANCES?

A. Yes, I do. In the Company's recent monthly reporting of deferred gas cost balances it has changed the forecast of sales service volumes that it uses for the remaining months of the current GCR period.

Q. WHY ARE THE OBSERVED CHANGES IN THE FORECASTED SALES VOLUMES IN THE COMPANY'S MONTHLY REPORTING OF MONTHLY DEFERRED GAS BALANCES OF CONCERN?

A. Until recently it has been the Company's practice to use the forecasted sales and throughput volumes from its most recent annual GCR filing as the basis for projecting deferred gas cost balances through the end of the current GCR period. In each monthly report the Company replaces one month of forecasted data with actual costs and usage to compute and expected deferred gas cost balance as of the end of October of the present GCR year. This provides the Commission a

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threshold. However, TGP's representations regarding its revenues subject to sharing may be subject to challenge in proceedings before FERC.

measure of the degree to which the Company's actual costs and usage are tracking its forecasts as we move through the months of the annual GCR period.

Due to problems identified in the Company's gas cost accounting (that have been addressed in E&Y report), National Grid suspended its reporting of deferred gas costs balances for several months within the current GCR year. When those reports were resumed in July 2012, the Division found that the Company had altered its forecasted gas usage volumes for its Sales Service classes, although no changes were made to its forecasted throughput for FT-1 and FT-2 rate classifications. The Company's response to Division Data Request 1-10 suggests that the change in forecasted sales service volumes was based an assessment of differences between projected sales and sendout which implied a higher than expected percentage of Unaccounted For Gas ("UFG"). In its efforts to correct for that implied level of UFG, the Company decided to adjust its forecasted sales service volumes.[5]

Q. WHAT WERE THE SPECIFIC ADJUSTMENTS TO SALES SERVICE VOLUMES THAT THE COMPANY MADE?

A. My analyses indicate that the Company made essentially uniform percentage adjustments to the sales volumes for each sales service rate classification on a month-by-month basis. Those adjustment percentages by month are:

[5] The Company made its adjustment to sales service volumes without making any corresponding adjustment to its forecasted throughput volumes for FT-1 and FT-2 transportation service customers. In other words, the Company assumed that responsibility for its perceived Unaccounted For Gas problem was attributable to forecasted its sales volumes. This is surprising since UFG by its very nature not attributable to any given source.

July 2012	28.9%
August 2012	20.7%
September 2012	32.1%
October 2012	8.7%

Overall, National Grid **increased** the forecasted gas sales volumes for those four months by **21.9%.**

Q. ARE THE ADJUSTMENTS TO FORECASTED SALES SERVICE VOLUMES THAT THE COMPANY HAS MADE IN ITS MONTHLY DEFERRED BALANCE REPORTS REASONABLE AND APPROPRIATE?

A. No, they are not. I submit that they provided a distorted assessment of the accuracy of the forecasted costs and volumes that were the basis for its 2011-2012 GCR rates. I also find the direction and magnitude of those changes is not supported by actual data that is now available for the first two months of the four-month period (i.e., July and August of 2012). As shown in Exhibit BRO-4, page 2, actual sales volumes for the months of July and August 2012 are closer to the Company's original forecast, than its revised forecast. Total actual sales for those two months equal 1,213,748 Dth. That total is 97,116 Dth above the Company's initial forecast.

Yet, it is 184,689 Dth below the Company's revised forecast. At least to this point, the Company's initial forecast is closer to its actual results than its revised forecast.

Finally, I submit that the Company's introduction of those unprecedented changes without explicit communication of the fact that it made such changes and the reasons for the changes when the changes were first introduced does not enhance understanding of the Company's monthly reports for either the Division or the Commission.

E. GPIP and NGPMP Incentive Determinations

1. GPIP Incentive Calculations

Q. DOES THE COMPANY SEEK APPROVAL OF A GAS PROCUREMENT INCENTIVE FOR THE 12 MONTH PERIOD ENDED JUNE 2012?

A. Yes. The September 4, 2014 testimony of witness Stephen McCauley presents National Grid's request for approval of an incentive of **$355,884** for the twelve months ended June 30, 2012. This incentive request is roughly $130,000 above the level the Company was granted in Docket 4283. However, the $355,884 incentive equates to **only 1.5%** of the **$23.7 million reduction** in Supply Variable Costs that has been achieved when the Company's forecasted Supply Variable Costs in this proceeding are compared to the Supply Variable Costs included in the Company's GCR rates for its 2011-2012 GCR year.

Q. DO YOU FIND ANY REASON TO QUESTION THE ACCURACY OF THE COMPANY'S GPIP INCENTIVE CALCULATIONS?

A. No, I do not. I have reviewed the supporting detail for the Company's mandatory and discretionary gas purchases for the twelve months ended June 2012, and I find that the Company's incentive calculation is mathematically correct and consistent with the terms of the Gas Procurement Incentive Plan (GPIP).

Q. DO YOU SUPPORT COMMISSION APPROVAL OF THE CHANGES IN THE PROVISIONS OF THE GPIP THAT WITNESS MCCAULEY PRESENTS IN ATTACHMENTS SAM-1 AND SAM-1A?

A. Yes. I have reviewed those changes, and I find them to be reasonable and appropriate.

2. NGPMP Incentives

Q. DOES THE COMPANY REQUEST APPROVAL OF AN INCENTIVE PAYMENT UNDER THE PROVISIONS OF THE NGPMP?

A. Yes. Witness McCauley's September 4, 2012 testimony at page 7 requests approval of NGPMP incentive payment of **$899,798** for the period April 2011 through March 2012.

Q. WHAT IS YOUR ASSESSMENT OF THE ASSET MANAGEMENT PERFORMANCE OF THE COMPANY OVER THE PAST YEAR?

A. The net NGPMP Ratepayer benefit that National Grid achieve over the twelve months ended March 2012, was $680,000 above its results from the prior year. That represents more than 17% increase in asset management benefits for Rhode Island gas customers. Even in the context, of generally favorable market conditions, I find this to reflect a strong performance.

Q. IS THE NGPMP INCENTIVE THAT NATIONAL GRID REQUESTS APPROPRIATELY COMPUTED?

A. Yes. The computations the Company has provided in support of its requested incentive demonstrate that those computations have been accurately computed and conform to the procedures set forth in the NGPMP.

Q. HOW DOES THE LEVEL OF NGPMP CREDIT INCLUDED IN THE COMPANY'S GCR FILING IN THIS PROCEEDING COMPARE TO THE ACTUAL NGPMP BENEFITS THAT THE COMPANY REFLECTS FOR THE CAPACITY CREDITS THAT NATIONAL GRID REFLECTED IN LAST YEAR'S GCR FILING?

A. Witness McCauley testifies that the NGPMP produce total ratepayer savings for the period April 2011 through March 2012 of **$4,599,192**. I have reviewed the supporting detail of the Company's NGPMP transactions and savings calculations,

and I concur with National Grid's assessment of those savings. For the twelve months ended March 31, 2012, the total asset management savings achieve equaled **$5,498,991**. Under the NGPMP formula for sharing net revenue the first $1.0 million of asset management revenue is assigned 100% to ratepayers. The remaining $4, 498,991 (i.e., $5,498,991- $1,000,000) is credited 80% to ratepayers and 20% to the Company. In this instance 80% of $4, 498,991 equals $3,599,192. That amount, plus the $1,000,000 that is applied 100% to ratepayers, yields a **total ratepayer benefit** for the twelve months ended March 31, 2011 of **$4,599,192.** The remainder (i.e., 20% of $4, 498,991 or **$899,798**) becomes the Company's incentive. For the twelve months ended March 31, 2012, the Company's incentive of **$899,798** equates to **16.4%** of the total reported net asset management savings.

Q. DO YOU FIND ANY REASON THAT THE COMMISSION SHOULD WITHHOLD APPROVAL OF THE $899,798 NGPMP INCENTIVE THAT NATIONAL GRID HAS COMPUTED?

A. No, I do not.

Q. ARE THERE ANY OTHER MATTERS THAT YOU WISH TO DISCUSS WITH RESPECT TO THE COMPANY'S NGPMP INCENTIVE PROGRAM?

A. Yes. The testimony of witness Arangio in this proceeding indicates that there have been changes in the manner in which the Company manages its gas supply assets, and those changes warrant further discussion between the Company and the

Division regarding the continuing appropriateness of the current NGPMP incentive structure. The current NGPMP was negotiated in the context of the presumption discussed at page 6, of witness McCauley's testimony in this proceeding. As witness McCauley notes, the presumption going into this program was that the Company would be able to achieve asset management savings that would be "*comparable to or that would exceed those from third-party asset managers*." The testimony of witness Arangio in this proceeding indicates that National Grid has now chose to outsource elements of its gas asset management to third parties. National Grid's decisions to outsource portions of its asset management activities raise questions regarding whether a 20% incentive for National Grid is warranted for those portions of the Company's gas supply assets that are managed by third parties.

As witness McCauley notes at page 7, lines 8-10, of his testimony, the Commission approved the current NGPMP in Docket 4283 for continuation through March 2014, and I support that continuation. However, prior to the Company's next annual GCR filing, further discussion of these matters would be appropriate to assess the changes, if any, to the current NGPMP structure that should be adopted for implementation effective April 1, 2014.

Q. WHAT LEVEL OF ASSET MANAGEMENT BENEFIT IS ASSUMED BY NATIONAL GRID IN WITNESS SMITH'S DEVELOPMENT OF THE COMPANY'S PROPOSED GCR RATES IN THIS PROCEEDING?

A. Attachment NG-AEL-1, page 2 of 12, line 3, column (c), reflects an assumed "NGPMP Customer Benefit" of **$4,600,000** for the November 2012 – October 2013 GCR year.

Q. IS THE LEVEL OF ASSET MANAGEMENT BENEFIT ASSUMED IN NATIONAL GRID'S DETERMINATION OF GCR CHARGES FOR THE 2011-12 GCR YEAR REASONABLE AND APPROPRIATE?

A. Yes, it is. The **$4,600,000** credit for NGPMP Ratepayer Benefit that National Grid assumes is in-line with the actual results it achieved for the twelve months ended March 2012. Given current market conditions, it appears reasonable to assume that the Company will be able to equal or exceed that level of customer benefit for its current fiscal year (i.e., the twelve months ended March 2013).

F. Presentation of Revised GCR Rates

Q. HAVE YOU COMPUTED PROPOSED GCR CHARGES THAT REFLECT THE CHANGES TO THE COMPANY'S GCR COSTS AND RATES THAT YOU HAVE RECOMMENDED IN THIS PROCEEDING?

A. Yes, I have. A revised set of GCR charges is computed in Exhibit BRO-5. This revised set of GCR charges reflects:

- A lowering of the Company's forecasted payments to Distrigas;
- An adjusted allocation of LNG-related costs to the DAC; and
- Proper recognition of TGP demand charge refunds within the Company's gas cost reconciliations.

These changes **lower** the Fixed Cost component of National Grid's forecasted 2012-2013 gas costs to **$1.7260 per Dth** for **Low Load Factor** customer classifications and **$1.2807** for **High Load Factor** customer classes. It also **lowers** the Company's forecasted Variable Cost component to **$4.6954 per Dth** for all classes. Combining the Fixed and Variable cost components, the Division's proposed GCR charges for 2012-2013 are **$0.6583 per therm** for Low Load Factor classes and to **$0.6127 per therm** for High Load Factor classes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

National Grid - RI Gas

Docket No. 4346

Company Proposed Changes in GCR Charges by Rate Class

Based on NG's Currently Effective Rates and September 4, 2012 GCR Filing

Rate Classification	Current GCR Rate ($/Therm)	NGrid Proposed GCR Rate ($/Therm)	Increase (Decrease) $ ($/Therm)	Increase (Decrease) %
Residential				
Non-Heating	$0.7464	$0.6193	($0.1271)	-17.0%
LI - Non-Heating	$0.7464	$0.6193	($0.1271)	-17.0%
Heating	$0.7896	$0.6675	($0.1221)	-15.5%
LI - Heating	$0.7896	$0.6675	($0.1221)	-15.5%
Commercial & Industrial				
Small	$0.7896	$0.6675	($0.1221)	-15.5%
Medium	$0.7896	$0.6675	($0.1221)	-15.5%
Large Low Load Factor	$0.7896	$0.6675	($0.1221)	-15.5%
Large High Load Factor	$0.7464	$0.6193	($0.1271)	-17.0%
Extra Large Low Load Factor	$0.7896	$0.6675	($0.1221)	-15.5%
Extra Large High Load Factor	$0.7464	$0.6193	($0.1271)	-17.0%
Natural Gas Vehicles	$0.6171			
FT-2 Storage Service Charge				
$ per therm	$0.0369			
$ per Dth per Day	$ 0.9617			
$ per MDCQ Dth		$7.3770		

National Grid - RI Gas

Docket No. 4346

Changes in Costs by GCR Cost Component

Based on National Grid's September 13, 2011, September 4, 2012, and September 1, 2010 GCR Filings
Without Adjustments and Reconciliations

GCR Cost Component	Forecasted Annual Cost 2012-13 1/	Forecasted Annual Cost 2011-12 2/	Forecasted Annual Cost 2010-11 3/	Change 2011-12 to 2012-13 $	Change 2011-12 to 2012-13 %	Change 2010-11 to 2011-12 $	Change 2010-11 to 2011-12 %
Supply Fixed Costs	$ 28,645,415	$ 31,644,446	$ 27,527,751	$ (2,999,031)	-10.5%	$ 4,116,695	15.0%
Storage Fixed Costs	$ 11,398,130	$ 10,518,269	$ 11,454,439	$ 879,861	7.7%	$ (936,170)	-8.2%
Supply Variable Costs	$107,717,133	$131,388,232	$149,514,232	$(23,671,099)	-22.0%	$ (18,126,000)	-12.1%
Storage Variable Costs	$ 16,438,331	$ 20,998,401	$ 23,799,192	$ (4,560,070)	-27.7%	$ (2,800,791)	-11.8%
TOTAL	$164,199,009	$194,549,348	$212,295,614	$(30,350,339)	-18.5%	$ (17,746,266)	-8.4%
Total Fixed Costs	$ 40,043,545	$ 42,162,715	$ 38,982,190	$ (2,119,170)	-5.3%	$ 3,180,525	8.2%
Total Variable Costs	$124,155,464	$152,386,633	$173,313,424	$(28,231,169)	-22.7%	$ (20,926,791)	-12.1%

1/ Source: Docket No. 4346, Attachment AEL-1, September 4, 2012, pages 2-5.
2/ Source: Docket No. 4283, Attachment JFN-1(5), September 13, 2011, pages 2-5.
3/ Source: Docket No. 4199, Attachment JFN-1, September 1, 2010, pages 2-5.

National Grid - RI Gas

Docket 4346

Reallocation of National Grid LNG Related Costs to DAC

	LNG Related Costs			
	Withdraw Commodity[1]	Inventory Costs[1]	Demand Costs from GCR[2,3]	Total
Nov-12	$ 105,291	$ 40,243	$ 163,740	$ 309,274
Dec-12	$ 510,215	$ 36,025	$ 312,178	$ 858,418
Jan-13	$ 350,598	$ 33,127	$ 312,178	$ 695,903
Feb-13	$ 201,062	$ 31,465	$ 312,178	$ 544,705
Mar-13	$ 109,212	$ 30,562	$ 312,177	$ 451,951
Apr-13	$ 105,291	$ 29,692	$ 222,308	$ 357,291
May-13	$ 109,212	$ 37,142	$ 222,308	$ 368,662
Jun-13	$ 108,710	$ 43,345	$ 222,308	$ 374,363
Jul-13	$ 115,127	$ 42,393	$ 222,308	$ 379,828
Aug-13	$ 115,127	$ 41,442	$ 222,308	$ 378,877
Sep-13	$ 110,994	$ 43,700	$ 222,308	$ 377,002
Oct-13	$ 115,499	$ 43,840	$ 222,308	$ 381,647
Total	$ 2,056,338	$ 452,976	$ 2,968,607	$ 5,477,921
System Balancing Factor	63.21%	63.21%	60.72%	
GCR Costs Allocated to DAC	$ 1,299,811	$ 286,326	$ 1,802,538	$ 3,388,676

National Grid - RI Gas

Docket No. 4346

Comparison of Forecast Changes with Actual Volumes for July and August 2012

Sales Classification	Initial Forecast[1]		Adjusted Forecast[2]		Actual Throughput[3]	
	Jul-12	Aug-12	Jul-12	Aug-12	Jul-12	Aug-12
	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)
Sales						
Residential Non-Heat	31,804	28,744	40,988	34,708	28,724	26,899
Residential Heat	422,847	362,367	544,949	437,553	410,015	381,035
Small C&I	42,243	34,558	54,441	41,729	47,044	43,411
Medium C&I	79,316	38,735	102,219	46,772	107,306	88,038
Large LLF	6,233	6,155	8,033	7,432	6,774	9,744
Large HLF	17,472	15,766	22,517	19,037	11,632	13,917
Extra Large LLF	435	-	561	-	13,387	2,304
Extra Large HLF	16,332	13,624	21,047	16,451	11,596	11,922
Total Sales	616,681	499,951	794,755	603,682	636,478	577,270
Total FT-2 Throughput	54,078	55,222	54,078	55,223	69,475	65,209
Total Sales & FT-2 Throughput	670,759	555,173	848,833	658,905	705,953	642,479
Total FT-1 Throughput	438,440	402,261	438,439	402,261	421,661	441,581
Total System Throughput	1,109,199	957,434	1,287,272	1,061,166	1,127,614	1,084,060

1/ Source: Docket No. 4283, JFN-1 9-4-2011

2/ Source: Docket No. 4283, Monthly Filing of GCR Deferred Balances, 7-23-2012

3/ Source: Docket No. 4283, Monthly Filing of GCR Deferred Balances, 9-21-2012

National Grid - RI Gas

Docket No. 4346

Comparison of Forecasted Sales and Throughput Volumes

	Forecasts of Sales and Throughput									
	From Last Annual GCR 1/					From July 2012 Deferred Balance Report				
Sales Classification	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total**
	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)	(MMBtu)
Sales										
Residential Non-Heat	31,804	28,744	28,529	35,143	124,221	40,988	34,708	37,693	38,187	151,576
Residential Heat	422,847	362,367	345,116	409,966	1,540,296	544,949	437,553	455,959	445,472	1,883,933
Small C&I	42,243	34,558	49,280	80,503	206,585	54,441	41,729	65,108	87,476	248,754
Medium C&I	79,316	38,735	74,952	106,534	299,537	102,219	46,772	99,025	115,761	363,777
Large LLF	6,233	6,155	12,641	24,366	49,396	8,033	7,432	16,702	26,476	58,643
Large HLF	17,472	15,766	16,095	20,602	69,935	22,517	19,037	21,264	22,386	85,204
Extra Large LLF	435	-	151	77	662	561	-	199	83	843
Extra Large HLF	16,332	13,624	13,451	17,697	61,104	21,047	16,451	17,771	19,230	74,499
Total Sales	616,681	499,951	540,215	694,889	2,351,736	794,755	603,682	713,721	755,071	2,867,229
Total FT-2 Throughput	54,078	55,222	56,173	117,068	282,541	54,078	55,223	56,172	117,068	282,541
Total Sales & FT-2 Throughput	670,759	555,173	596,388	811,957	2,634,276	848,833	658,905	769,893	872,139	3,149,770
Total FT-1 Throughput	438,440	402,261	450,674	604,765	1,896,140	438,439	402,261	450,674	604,764	1,896,138
Total System Throughput	1,109,199	957,434	1,047,061	1,416,722	4,530,416	1,287,272	1,061,166	1,220,567	1,476,903	5,045,908
Change in Forecasted Total Sales from Prior Forecast						**28.9%**	**20.7%**	**32.1%**	**8.7%**	**21.9%**

1/ Source: Docket No. 4283, JFN-1 9-4-2011

2/ Source: Docket No. 4283, Monthly Filing of GCR Deferred Balances, 7-23-2012

National Grid - RI Gas

Docket No. 4346

Gas Cost Recovery (GCR) Filing

Factors Effective November 1, 2012

Line No.	Description	Source Reference	Source Line No.	High Load[1]	Low Load[2]
1	Fixed Cost Factor	**BRO-5 p2**	Ln 17	$1.2807	$1.7260
2	Variable Cost Factor	**BRO-5 p3**	Line 14	$4.6954	$4.6954
3	Total Gas Cost Recovery Charge	(1)+(2)		$5.9761	$6.4214
4	Uncollectible %	Docket 3943		2.46%	2.46%
5	Total GCR Charge adj for Uncollectibles	(3) / [(1 - (4)]		$6.1268	$6.5834
6	**Division Proposed GCR Charge ($/therm)**	(5) / 10		**$0.6127**	**$0.6583**
7	Company Proposed GCR Charge	AEL-1 p1		$0.6193	$0.6675
8	Difference			($0.0066)	($0.0092)
9	Percent Change			-1.1%	-1.4%

1/ Includes: Residential Non Heating, Large High Load and Extra Large High Load
2/ Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load

National Grid - RI Gas

Docket No. 4346

Gas Cost Recovery (GCR) Filing
Fixed Cost Calculation ($ per Dth)

Line No.	Description	Source Reference	Source Line No.	Amount	High Load Factor	Low Load Factor
1	Fixed Costs (net of Cap Rel to marketers)	**AEL-1 pg 4**	Ln 56	$40,043,545		
	Less:					
2	NGPMP Customer Benefit	**EDA-1**		($4,600,000)		
3	Interruptible Costs			$0		
4	FT-2 Storage Demand Costs	**AEL-5 pg 3**	Ln 5	($1,178,704)		
5	LNG Demand to DAC	**BRO-3**		($1,802,538)		
6	Refunds			$0		
7	Total Credits	sum[(3):(7)]		($7,581,242)		
	Plus:					
8	Supply Related LNG O&M Costs	Rate Case		$618,591		
9	Working Capital Requirement	**AEL-1 pg 8**	Ln 15	$265,525		
10	Deferred Fixed Cost Balance	**AEL-1 pg 6**	Ln 12+Ln 25-Adjmt*	$9,546,825		
11	Reconciliation Amount - Fixed Costs - Marketers	**EDA-4**		($374,462)		
12	Total Additions	sum[(8):(11)]		$10,056,479		
13	Total Fixed Costs	(1) + (7) + (12)		$42,518,782		
14	Design Winter Sales Percentage	**AEL-1 pg 12**	Ln 10 & 11		2.87%	97.13%
15	Allocated Supply Fixed Costs	(13) x (14)			$1,219,581	$41,299,201
16	Sales (Dt) Nov 2012 - Oct 2013	**AEL-1 pg 11**	Ln 12	24,879,878	952,267	23,927,611
17	**Fixed Factor**	(15) / (16)			**$1.2807**	**$1.7260**

* Adjmt = Adjustment = TGP Demand Refund plus Interest

National Grid - RI Gas

Docket No. 4346

Gas Cost Recovery (GCR) Filing

Variable Cost Calculation ($ per Dth)

Line No.	Description	Source Reference	Source Line No.	Amount
1	**Variable Costs**	**AEL-1 pg 4-5**	Ln 87 - 81	$124,155,464
	Less:			
2	Non-Firm Sales			$0
3	Balancing Related LNG Costs (to DAC)	**BRO-3**		$ (1,299,811)
4	Refunds	**AEL-1 pg 4-5**	Ln 81	$0
5	Total Credits	sum [(2):(4)]		($1,299,811)
	Plus:			
6	Working Capital	**AEL-1 pg 8-9**	Ln 31	$823,727
7	Deferred Variable Cost Balance	**AEL-1 pg 6-7**	Lns 40+ 57+70+Adjmt*	($9,059,824)
8	Supply Related LNG O&M	Docket 3943		$430,129
9	Inventory Financing - LNG (Supply)	**BRO-3**		$ 286,326
10	Inventory Financing - Storage	**AEL-1 pg 10**	Ln 12	$1,485,575
11	Total Additions	sum [(6):(10)]		($6,034,066)
12	Total Variable Supply Costs	(1)+(5)+(11)		$116,821,587
13	Sales (Dt) Nov 2012 - Oct 2013	**AEL-1 pg 11**	Ln 12	24,879,878
14	**Variable Cost Factor**	(12)/(13)		**$4.6954**

1/ Adjmt = Adjustment = TGP Demand Refund plus Interest