nationalgrid

October 18, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4647 – 2016 Gas Cost Recovery Filing
Rebuttal Testimony

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's[1] rebuttal testimony in the above-referenced docket. This filing consists of the rebuttal testimonies of Elizabeth D. Arangio, Ann E. Leary, and Theodore Poe, Jr.

Thank you for your attention to this filing. If you have any questions, please contact Jennifer Brooks Hutchinson at 401 784-7288 or Robert Humm at 401-784-7415.

Very truly yours,

Jennifer Brooks Hutchinson

Robert J. Humm

Enclosures

cc: Docket 4647 Service List
Leo Wold, Esq.
Steve Scialabba, Division
Bruce Oliver, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

____
Joanne M. Scanlon

October 18, 2016
Date

Docket No. 4647 – National Grid – 2016 Annual Gas Cost Recovery Filing (GCR) - Service List as of 9/2/16

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REBUTTAL TESTIMONY

OF

ELIZABETH D. ARANGIO

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I. **<u>Introduction</u>**

Q. Please state your name and business address.

A. My name is Elizabeth D. Arangio. My business address is National Grid, 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Have you previously submitted testimony in this docket?

A. Yes. I previously submitted pre-filed direct testimony in this docket on September 1, 2016 and revised attachments to my testimony on October 3, 2016.

Q. Did you review the pre-filed direct testimony of Bruce Oliver on behalf of the Division of Public Utilities and Carriers (Division) dated October 7, 2016?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the following comments that Mr. Oliver expresses in his direct testimony regarding the Company's Gas Cost Recovery (GCR) filing: (1) Mr. Oliver's suggestion for a more rigorous review of the Company's long-term gas supply planning process; (2) the Algonquin Incremental Market Expansion (AIM) Project capacity; (3) the Texas Eastern Transmission Company (Texas Eastern) Delmont outage; and (4) the Cumberland liquefied natural gas (LNG) facility.

II. Long-Range Planning

Q. Does the Company agree with Mr. Oliver that the Company's Rhode Island long-range gas supply plans (Long-Range Plan) should be subject to a more in-depth review by the Public Utilities Commission (PUC)?

A. Yes. To date, the Company's long-range gas planning filings, specifically the long-range forecast and long-term planning processes, have not been subject to a formal review process in Rhode Island. This is, in part, because Rhode Island law requires that the gas company submit every two years to the PUC a long-range energy plan for the five-year period subsequent to the date the plan is submitted and to apprise the PUC in the interim of any changes which substantially affect the plan.[1] However, the law does not expressly require that the PUC approve or otherwise rule on the submitted plan. In compliance with Rhode Island law, the Company has filed three Long-Range Gas Supply Plans in Rhode Island to date: on March 12, 2012, on March 10, 2014 and, most recently, on March 10, 2016. In contrast, in Massachusetts, as Mr. Oliver references in his testimony, the Company is obligated to file a Long-Range Forecast and Supply Plan with the Massachusetts Department of Public Utilities (MA DPU) on a biennial basis, which the MA DPU either approves or rejects. In addition, M.G.L. c. 164 § 94A requires that the Company file with the MA DPU for pre-approval any supply contract with terms in excess of one-year.

[1] See R.I. Gen. Laws § 39-24-2. The Company has historically filed its Long-Range Plan in Rhode Island for a 10-year period. The statute also requires that the PUC, by rule, specify such information as it shall reasonably require, to include, but not be limited to, the Company's peak demand forecasts, annual sales in cubic feet, major proposed additions to plant, and an analysis of the cost and financing of any proposed additions to plant or purchases.

The purpose of the Long-Range Plan in Rhode Island is to set forth the process by which the Company documents the development of its forecasting methodology, and to some extent, its planning decisions. Although there is presently no formal pre-approval process for long-term supply contracts in Rhode Island, the Company nonetheless collaborates with the Division prior to entering into such long-term contracts.[2] Historically, the Company's long-term supply contracts have been implicitly approved through the annual GCR process; however, the condensed timeframe and reconcilable nature of the GCR do not afford sufficient opportunity in which to undertake a complete review the Company's forecasts and resulting planning decisions. Such process is more appropriate in the context of the Company's Long-Range Plan, and then at the time the Company enters into gas supply contracts in order to allow sufficient time for a comprehensive analysis and consideration of the Company's forecast methodology. Therefore, the Company supports Mr. Oliver's proposal for greater PUC oversight of the Company's Long-Range Plans and forecasts, and its decisions regarding commitments to long-term gas supply resources. The Company foresees an even greater need for such a process going forward, given the cancelation of the Tennessee Gas Pipeline Company's (Tennessee) NED Project as well as the current market dynamics surrounding the future of incremental pipeline capacity in New England.

[2] Following the Company's decision to enter into the Tennessee Gas Pipeline and the Northeast Energy Direct (NED) Project, the Division requested more timely notification of such discussions. The Company has agreed, and has done so regarding its most recent commitments to its long-term liquefaction projects.

Q. Does the Company have a proposed regulatory framework to facilitate such a process in the future?

A. Yes. The Company recommends a two-step approach. As an initial step, there is a benefit to having PUC review and acceptance of the forecasting methodology that is documented in the Long-Range Plan and used in the development of the long-term forecast for planning purposes. The Company agrees with the Division and Mr. Oliver that the current Long-Range Plan process has historically lacked relevance to the extent that once the Company files the Long-Range Plan, it then begins the process of updating its annual forecast, thereby creating a "chicken and egg" effect. However, the Company follows the methodology documented in the Long-Range Plan when developing the long-term forecast upon which it then relies to make decisions about the acquisition of long-term gas supply resources. Acceptance of the Company's long-term forecast for this purpose is predicated upon first accepting the underlying forecasting methodology.

The Company also recommends PUC approval of future gas supply precedent agreements greater than one year. Although Rhode Island has no statutory mechanism for approval of gas supply contracts similar to Massachusetts, the Company proposes that the PUC may exercise its broad regulatory powers under R.I. Gen. Laws § 39-1-1, *et seq.*, to implement by written order a pre-approval requirement on gas supply precedent agreement in excess of one-year that the Company executes going forward. A pre-approval requirement would allow for a thorough review of such contracts, including discovery, analysis of proposals and costs, development of record evidence and a decision prior to the Company's financial commitment to such contracts.[3] Such a process is consistent with the PUC's authority to review the prudency of the Company's actions and to set just and reasonable rates. Then, if such contracts are approved, there would be no need to evaluate the reasonableness of the costs of such contracts as part of the annual GCR proceeding.

Q. What is the Company's position regarding Mr. Oliver's suggestion for a bi-furcated GCR process?

A. It is not clear from Mr. Oliver's testimony how a bi-furcated GCR process would function. The Company is amendable to exploring with the Division changes to the timing of the filing of its Long-Range Plan; however, the Company believes that implementing the approach discussed above would achieve the same objectives as Mr. Oliver proposes in his testimony.

Q. Mr. Oliver's testimony also references the Company's proposal from last year to allow Capacity Exempt customers to transfer to Capacity Assigned service. What is the status of this proposal?

A. At this time, the Company has made no further proposals on the matter as the Company believes it needs to come to a resolution on the outstanding forecasting and planning issues in conjunction with a Capacity Exempt proposal. The Company continues to

[3] The Company has generally included a condition in its gas supply contracts that permits the Company to terminate the contract if regulatory approval is not obtained by a date certain.

believe a long-term solution is needed, and is committed to working with the Division to develop a future proposal that appropriately balances the overall reliability of the gas supply portfolio as well as the associated costs to all firm customers.

III. <u>AIM Project Capacity</u>

Q. Where are the AIM Project costs included in the Company's GCR filing?

A. The fixed charges of the AIM capacity are included in Attachment EDA-2 Revised submitted on October 3, 2016. On page 1 of 17, the monthly volumes of AIM capacity expected to be dispatched under a normal weather scenario are provided in the line titled "Algonquin-AIM". On page 6 of 17, the per-unit price by month is provided in the line titled "Algonquin – AIM/Total Delivered". On page 9 of 17, the monthly total delivered cost is provided in the line titled "Algonquin – AIM/Total Delivered Cost".

Q. According to Mr. Oliver, the Division's expectation is that the AIM Project capacity would serve to reduce National Grid's Variable Supply Costs, but no quantification of Variable Cost reductions resulting from the scheduled start-up of AIM Project capacity is included in the Company's 2016-17 GCR filing. Is the Division's expectation correct?

A. Yes. The AIM Project provides access to significantly less expensive gas supplies sourced at the Ramapo, New Jersey receipt point than those available at the HubLine receipt point of Beverly, Massachusetts. This actuality is precisely what prompted the

Company to contract for the AIM capacity in the first place. The difference in variable cost is evidenced by comparing the delivered cost of supply for AIM supplies (provided in Attachment EDA-2 Revised) as compared to the delivered cost of supplies available at the Algonquin citygate, the index historically used to price gas purchased at Beverly. The table below summarizes the comparison of these two prices per dekatherm (Dth):

	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17
07/29/2016 NYMEX	$3.076	$3.320	$3.436	$3.418	$3.360	$3.070	$3.036	$3.066	$3.095	$3.104	$3.084	$3.108
ALGONQUIN - AIM												
Basis	($0.830)	$0.420	$2.650	$2.600	$0.110	($0.750)	($0.865)	($0.858)	($0.780)	($0.850)	($1.015)	($0.945)
AGT Usage	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126
AGT Fuel	1.08%	0.87%	0.87%	0.87%	0.87%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%	1.08%
Total Delivered	$2.2831	$3.7854	$6.1520	$6.0834	$3.5131	$2.3579	$2.2073	$2.2447	$2.3529	$2.2912	$2.1042	$2.1992
ALGONQUIN - HUBLINE												
Basis	$0.365	$2.182	$4.578	$4.515	$1.965	$0.082	($0.530)	($0.580)	($0.350)	($0.525)	($0.652)	($0.348)
AGT Usage	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126
AGT Fuel	0.71%	0.63%	0.63%	0.63%	0.63%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%	0.71%
Total Delivered	$3.4782	$5.5495	$8.0774	$7.9959	$5.3714	$3.1871	$2.5365	$2.5164	$2.7772	$2.6100	$2.4620	$2.7923
Total Delivered Savings	**$1.1951**	**$1.7641**	**$1.9254**	**$1.9125**	**$1.8583**	**$0.8292**	**$0.3292**	**$0.2717**	**$0.4243**	**$0.3188**	**$0.3578**	**$0.5931**

The average savings for the year is $0.9816 per Dth; peak season savings (November – March) is $1.7311 per Dth and off-peak savings (April – October) is $0.4463 per Dth. These savings can be even greater on a daily basis when taking into account daily winter price volatility. The introduction of the AIM capacity into the portfolio realigns the entire dispatch of assets, given the AIM Project's access to low-cost supplies throughout the year. In the Company's 2015-16 GCR filing, under a normal weather scenario, the HubLine capacity was forecasted to meet sendout requirements for an annual total of 390,800 Dth, representing an annual load-factor of 6%. In this GCR filing, under a normal weather scenario, the AIM capacity is forecasted to meet sendout requirements for an annual total of 3,129,420 Dth, representing an annual load-factor of 48%. Under a design weather scenario, the AIM capacity is forecasted to meet sendout requirements for an annual total of 3,230,700 Dth, representing an annual load-factor of 50%.

In summary, the decision to replace the Company's HubLine capacity with capacity from the AIM Project is supported by price and non-price factors, which was the case when the Company made the decision in 2013 and remains to be the case today. The ability to access lower-cost domestic supplies is essential for both the short and long term in order to continue to maintain a least-cost portfolio. And, from a reliability and flexibility perspective, it is critical to have access to gas supplies when needed. The Ramapo receipt point on Algonquin represents a far more liquid purchasing point than the Beverly receipt point. With the ability to access lower-cost supplies, this contract is expected to be utilized throughout the year, as opposed to only during the winter when most other flowing supplies, including underground storage, have been exhausted and it is one of the last available supplies to call upon. The Company will have increased flexibility all year long to access the least-cost gas supplies to meet customer requirements.

IV. <u>Texas Eastern Delmont Outage</u>

Q. What is the status of the Texas Eastern Delmont outage?

A. Texas Eastern continues to strive for restoration of full service by November 1, 2016. However, the Delmont outage and associated restrictions are presently still in place, as described in the handout provided by Spectra at the September 1, 2016 customer meeting (and provided in the Company's response to the Division's Data Request 2-3 (a) at Attachment DIV 2-3(a)). The maximum volume designed to flow through Delmont is 2.6 BCF per day. Currently, only 1.1 BCF per day is able to flow – approximately 40% of the total capacity – which equates to a restriction of approximately 60%. A 60% restriction would have a significant impact on the availability of supplies at Lambertville, New Jersey into Algonquin. If the foregoing restriction remains in place for the winter, it would equate to a reduction of 32,073 Dth per day available to the Company through Texas Eastern and, therefore, into Algonquin for delivery to the Company's citygates.[4] To put this into perspective, the Company maintains a total of 152,705 Dth per day of Algonquin capacity. A 60% restriction through Delmont on Texas Eastern would result in a reduction of **21%** of the Company's available gas supplies on Algonquin. Assuming near design or design weather conditions, the Company would have an extremely difficult time meeting customer requirements without 21% of its supply on Algonquin. In order for Spectra to restore full service, the work plan includes, among other tasks, the inspection of 626 anomalies as well as hydrostatic testing of miles of pipe, and the need for permits from multiple state and local agencies. The immensity of the effort cannot be understated. In its September 1 handout, Spectra provided two other scenarios for planning purposes; one which resulted in a 50% restriction of the flows through Delmont, and the other which resulted in a 30% restriction of the flows through Delmont. Given the Company's need for volumes from Lambertville to meet customer requirements, the

[4] The Company's capacity on Texas Eastern provides for a total of 53,455 Dth per day through Delmont.

Company took action to secure the availability of supplies at Lambertville. As discussed in my direct testimony, the Company planned for an approximately 40% restriction of the flows through Delmont. The Company believes its contingency planning was prudent in that it secures the availability of supplies at Lambertville to meet the much needed customer requirements in both a normal winter and a design winter.

Q. What is the Company's position regardingMr. Oliver's opinion of the Company's decision to contract for contingent supplies downstream of the Delmont receipt point?

A. The Company does not agree with Mr. Oliver's assessment of the Company's contingency plan to replace supplies if the Delmont Compressor Outage continues through the winter. Although Texas Eastern expects service to be fully restored by November 1, 2016, there are events as described above that could delay the pipe from returning to full capacity. If the Delmont section of the pipe returns to full service, then the contingency plan will allow the Company to continue to purchase supplies at the lower-cost supply areas of Texas Eastern zone M2. If capacity is restricted through the Delmont section of the pipe, then the contingency plan will provide the Company the firm contractual rights to call on supplies downstream of the Delmont section.

The Company's option to call on supply is critical because if capacity is restricted through the Delmont Compressor, then supplies downstream will be more difficult to acquire because all firm shippers will be looking for replacement supplies, most likely during periods of high demand. Having the contractual right to call on supply during periods of high demand, or less liquid areas, ensures that sufficient supplies will be available to meet the Company's requirements on colder than normal days. The reservation charge associated with the Company's contingency contract is similar to the reservation charge associated with the option to call on supplies to fill the Company's Tennessee Pipeline capacity at Dracut, as described in my direct testimony at page 15, line 11 to page 16, line 2.

It is important to note that the contractual option to call on supply downstream of the Delmont Compressor guarantees the physical delivery of supply past the restriction, similar to the call of supply at Dracut, and does not fix the price of the supply. The Company will pay the fluctuating daily index price of Texas Eastern zone M3 only on days the Company exercises the option to call on supplies. The Company agrees with Mr. Oliver that if the price of the gas supplies under this contract were fixed then it would fall within the Company's Gas Procurement Incentive Plan (GPIP). Since the price of the supplies has a call option pursuant to the contract and is not fixed, it does not fall within GPIP. The Company believes the reservation charge to guarantee firm physical delivery of supplies downstream of the Delmont Compressor is similar to the reservation charge paid for supplies at Dracut or any other upstream pipeline capacity feeding the Algonquin pipeline and should be permitted in the Company's GCR rates and deferred gas cost balances.

V. <u>Cumberland LNG Facility</u>

Q. Why did the Company make the decision to remove the Cumberland LNG tank from service?

A. Safety is the Company's top priority. After discovery of a temperature anomaly within the tank, the Company's engineering report concluded that water had infiltrated through the tank foundation and into the insulation blocks, creating a "cold spot." Although the tank is not currently leaking and the Company does not believe that the tank's integrity has been compromised, it is impossible to know whether there has been damage to the tank that could result in a future failure without visually inspecting the inside of the tank. Also, the manufacturer's engineering report suggests that decommissioning the tank to inspect it would likely compromise the tank's integrity. Therefore, inspecting and refilling the tank would be considered a high-risk activity and not prudent. Based on this information, the Company made the decision to permanently remove the tank from service, with safety as its primary concern. The Company reviewed its plans for the decommissioning of the Cumberland LNG tank with the Division at a meeting held on August 26, 2016, and the Division concurred, at that time, with the Company's approach.

Q. Please describe the importance of the Cumberland LNG tank to the Company's gas portfolio?

A. As stated in my direct testimony, and as described in each of the Company's Long-Range Forecast and Supply Plans, the Company relies on the Cumberland LNG tank to provide up to 30,000 Dth per day and 80,000 Dth per season to meet customer requirements. Given these capacities, assuming full output, this tank can be fully utilized in 2.3 days. Conversely, it takes approximately 84 days to refill the tank. The Cumberland LNG tank provides supplies to an isolated portion of the Company's distribution system. This system, referred to as the "Valley" pocket, is fed by two Tennessee Pipeline citygate stations, Scott Road and Lincoln, as well as the Cumberland LNG tank.[5]

Q. What is the effect on the Company's overall gas supply to its customers without the Cumberland LNG tank?

A. Assuming no replacement for such volumes, the Company would not be able to meet customer requirements under design weather conditions. As referenced in my response to the Division Data Request 2-8, there are no practical alternatives available to the Company as a result of the location of the Cumberland LNG tank as well as the configuration of the Company's distribution system. The loss of this source of supply cannot be replaced by deliveries to any of the other Tennessee gate station nor can it be replaced by additional deliveries to any of the Company's Algonquin gate stations.

[5] There is an Algonquin gate station that can feed the Valley system (Cumberland /meter #00083); however, it only provides up to 1,000 Dth per day.

Q. Why were the Tennessee Pipeline capacity and the portable LNG resources selected to replace the Cumberland LNG tank?

A. As noted above, the Cumberland LNG tank provides gas supplies to an isolated portion of the Company's distribution system, which is fed only by the Tennessee Pipeline and the Cumberland LNG tank. Without the Cumberland LNG tank, the only options to feed this portion of the system are through the existing Tennessee citygate stations and/or portable LNG. The peak day forecast for this upcoming winter for this isolated portion of the system totals 62,916 Dth. The Company has 32,238 Dth per day of existing capacity to Scott Road and 6,800 Dth per day available of existing capacity to Lincoln, resulting in a 23,878 Dth peak day <u>deficiency</u>. When faced with this outcome, and knowing that no third party maintains primary point capacity to any of the Company's Tennessee Pipeline meter stations, the Company contacted Tennessee to determine the availability of capacity to either or both of the Company's citygates.[6] The ability to provide portable LNG to meet a design day need of 23,878 Dths is logistically infeasible, as it would require the need for a minimum of 25 truckloads of LNG on the peak day, even before taking into account the need for additional supply to meet hourly peaks throughout the day.[7] In the absence of any alternatives, when Tennessee notified the Company of the availability of capacity from Dracut to the Company's Lincoln citygate for a volume of 24,000 Dth per day, the Company made the decision to proceed with securing the capacity with primary

[6] As provided in the Company's response to the Division Data Request 5-7 in RIPUC Docket No. 4634.

[7] From a safety perspective, the Company did not consider portable LNG as a viable option to meet the entire peak day need.

point deliverability for the upcoming winter. Although the capacity of 24,000 Dth per day solved for the peak day need, it did not solve for the peak hour need. The peak hour forecast for this upcoming winter for this isolated portion of the system totals approximately 3,436 Dth. The Company has 1,343 Dth of available peak hour existing capacity to Scott Road and 1,283 Dth of available peak hour existing capacity to Lincoln, resulting in a 810 Dth peak hour <u>deficiency</u>. The Company determined to contract for a volume of up to 7,000 Dth per day (equivalent to roughly seven truckloads) and up to 22,000 Dth for the season, or approximately three days' worth of LNG to be used during the months of December through March.

Q. What is your response to Mr. Oliver's comment that "[t]he fact that the incremental capacity at Dracut that National Grid has arranged as part of its plan to replace Cumberland LNG Tank capacity equals the amount of capacity it had planned to add at Dracut as part of the now cancelled NED project may suggest that National Grid has greater plans for that capacity."

A. Under Tennessee's NED Project, the Company contracted for a total of 35,000 Dth/day of capacity from Wright, New York to the Company's citygates. 15,000 Dth per day of such capacity represented a one-for-one replacement of the Company's existing capacity from Dracut, Massachusetts to the Company's citygates. The remainder of the capacity, 20,000 Dth per day, represented incremental capacity needed to meet forecasted future customer requirements. The need for additional capacity to meet forecasted future customer requirements was determined assuming the Cumberland LNG tank was an available resource in the gas supply portfolio. That is no longer the case. The Company has made the decision to permanently take the Cumberland LNG tank out of service for the reasons discussed above, and is working to finalize its plans. Thus, assuming forecasted future customer requirements remain constant, the Company would need ***both***, the 24,000 Dth per day of capacity from Dracut as well as 20,000 Dth per day of incremental capacity.

Q. Are the Company's plans to replace the Cumberland LNG tank capacity reasonable?

A. Yes, for several reasons. First, the capacities of the Cumberland LNG tank given the actual sendout volumes provided by the tank over the last three winter seasons is a significant consideration. It is important to note the Company has not experienced a design day in the last three winter seasons, which is the day on which maximum output from the plant would be required. It is reasonable and necessary that the Company continue to plan for a design day. Second, Mr. Oliver states that "[r]ecognizing uncertainties regarding the degree day requirements that may be encountered and the demands that will need to be served, this appears to be a situation in which further use of the types of risk and reward analyses used by Witness McCauley may be productive." The Company is obligated to provide least-cost reliable service. The Company does not believe it would be prudent to engage in a risk/reward analysis in determining whether or not to meet customer requirements because doing so would serve to negate the Company's obligation to provide least-cost reliable service. Lastly, in the absence of the Cumberland LNG tank, the resources secured to replace these volumes represent the only practical solution to allow the Company to continue to meet forecasted customer requirements in a least-cost reliable manner.

Q. In your direct testimony, you discuss the Company's right of first refusal (ROFR) for the Tennessee Pipeline capacity. Please explain further the importance of this right and how the Company will go about making such a decision.

A. The Company is paying Tennessee's maximum tariff rate (zone 6 to zone 6) for such capacity and, as such, is granted ROFR on the capacity for next year. As required under Tennessee's tariff, the Company must decide by October 31, 2016 in order to secure the capacity for next year (November 2017 – October 2018). In order to make the determination on whether to renew the capacity, the Company performs the same analysis to secure the capacity as described above. At this time, given forecasted customer requirements for next year, the Tennessee Pipeline capacity continues to be needed. The Company plans to renew such capacity for next year; however, that decision is pending the PUC's approval of such replacement capacity that will be reflected in the GCR for November 1, 2016 and future reconciliations as part of the deferred gas cost balances.

VI. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

REBUTTAL TESTIMONY

OF

ANN E. LEARY

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I. Introduction

Q. Please state your name and business address.

A. My name is Ann E. Leary. My business address is National Grid, 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Have you previously submitted testimony in this docket?

A. Yes. I previously submitted pre-filed direct testimony in this docket on September 1, 2016 and pre-filed revised testimony on October 3, 2016.

Q. Did you review the pre-filed direct testimony of Bruce Oliver on behalf of the Division of Public Utilities and Carriers (Division) dated October 7, 2016?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the following comments that Mr. Oliver expresses in his direct testimony regarding the Company's Gas Cost Recovery (GCR) filing: (1) the Company's Supply-Related Liquefied Natural Gas (LNG) Operation and Maintenance (O&M) costs; and (2) the Company's 2016-17 GCR forecasting.

Q. Are you including any Attachments with your testimony?

A. Yes. I am sponsoring the following attachment:

- Attachment AEL-1 Rebuttal, RIPUC NG-GAS No. 101, Section 2 (Gas Charge), Schedule A.

II. <u>Supply-Related LNG O&M Costs</u>

Q. Mr. Oliver recommends that the Company's Supply Related LNG O&M costs contained in the proposed 2016-17 GCR factor should be adjusted to reflect the removal of the Cumberland LNG tank from service. Does the Company agree with Mr. Oliver's recommended adjustment?

A. No. Supply-related LNG O&M costs, which are recovered through the Company's GCR factors, are fixed at a level established in the Company's general rate cases. The amount stated in the Company's GCR filing represents the customers' share of the total LNG O&M supply-related production and storage costs for the Company's most recent rate case in Docket No. 4323. Pursuant to the Company's gas tariff, when such costs are determined and transferred/removed from the distribution revenue requirement to the GCR, those costs are fixed until the Company's next general rate case. *See* RIPUC NG-GAS No. 101, Section 2 (Gas Charge), Schedule A, Sheets 3-4. Therefore, the recovery of supply-related LNG O&M costs is the same as the recovery of costs through distribution rates and cannot be changed until the Company's next general rate case.

Q. Why can Supply-Related LNG O&M costs be updated only in a general rate case?

A. In Docket No. 2374, the Company began the process of unbundling its rates into those that separately recover distribution costs and supply costs so that customers could choose to purchase their gas supply from third party entities. The Company segregated its distribution costs from its gas supply costs by transferring the recovery of certain gas-related costs from its distribution rates to its gas supply rates. LNG O&M expense was one of the cost categories that was transferred from the Company's distribution rates to its GCR. Although LNG O&M costs are recovered in the GCR, the Company continues to recover such costs in the same manner as all other costs determined in the last general rate case. Therefore, the Company cannot deviate from the terms of its gas tariff regarding the amount to be recovered in the GCR.

In addition, in Docket No. 3401, the Public Utilities Commission (PUC) approved additional language in the gas tariff's GCR Clause to define the recovery of supply-related portion of location production and storage (i.e., LNG O&M costs) as the amount determined in the Company's most recent rate case proceeding. A copy of the applicable GCR Clause excerpted from the Company's gas tariff currently on file with the PUC is attached hereto as Attachment AEL-1 Rebuttal. Therefore, LNG O&M costs, like other traditional O&M costs, can be updated only in a general rate case proceeding. To adjust LNG O&M costs in the GCR by either increasing or decreasing the amount to reflect current costs incurred by the Company would violate the Company's gas tariff.

III. <u>The Company's 2016-17 GCR Forecasting</u>

Q. What is the purpose of Attachment AEL-1, pages 13-15?

A. The purpose of Attachment AEL-1, pages 13-15, is to allocate the fixed gas costs between the high load factor customer classes and low load factor customer classes found in Attachment AEL-1, page 2, line 14.

Q. Was Attachment AEL-1, pages 13-15, used to develop the Company's normal or design forecast?

A. No. In Attachment AEL-1, paged 13-15, the Company adjusts the normalized forecast to reflect winter design degrees with the intent on using this analysis to allocate the fixed demand costs between the High Load and Low Load factor rate classes. This "design" forecast, found in Attachment AEL-1, pages 13-15, is not used by the Company to determine the amount of gas to purchase or to determine the proper pipe-sizing in the field.

Q. Mr. Oliver refers to a Residential Heating factor of 2,585 Dth in January compared to 10,762 Dth in July. What do these numbers represent as it pertains to Attachment AEL-1, page 13, lines 18-34?

A. The heating factors indicated in Attachment BRO-4 are residual values calculated by subtracting the average summer base load amount from the total monthly normal use. Specifically, in Attachment AEL-1, page 13, lines 18-34, the Company first calculates the base use for each rate class based on the average use for the months of July through September. The Company then calculates the residual heat use by subtracting the base use from the total normal use.

Q. Was the 10,762 Dth in July referenced by Mr. Oliver used to derive the factors used to allocate the fixed gas costs?

A. No. In July, the normal use was greater than the average use for the period July through September, so the difference appeared as heat use found in Attachment AEL-1, page 14, line 36. However, because the month of July was **<u>not</u>** used to determine the high load and low load allocation percentages found on Attachment AEL-1, page 12, lines 10-11, the Company did not adjust this amount. Had the Company used this information for July in the calculation of the proposed GCR factors, the Company would have set the base use equal to the total use for each of the months for the period July through September, which would have resulted in a heat use of zero for the months of July through September (reflecting the assumption is that there is no heating use in these months). Therefore, the heat factor for July would be zero.

IV. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

GAS COST RECOVERY CLAUSE

1.0 GENERAL:

1.1 Purpose:

The purpose of this clause is to establish procedures that allow the Company, subject to the jurisdiction of the PUC, to annually adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity in order to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, purchased gas working capital, and to credit supplier refunds, capacity credits from off-system sales and revenues from capacity release transactions.

The Gas Cost Recovery Clause shall include all costs of firm gas, including, but not limited to, commodity costs, demand charges, hedging and hedging related costs, local production and storage costs and other gas supply expense incurred to procure and transport supplies, transportation fees, inventory finance costs, requirements for purchased gas working capital, all applicable credits, taxes, and deferred gas costs. Any costs recovered through the application of the Gas Charge shall be identified and explained fully in the annual filing.

1.2 Applicability:

The Gas Charge shall be calculated separately for the following rate groups:

(1) Residential Non-Heating, Low Income Residential Non-Heating, Large C&I High Load Factor, Extra Large C&I High Load Factor;
(2) Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large C&I Low Load Factor, and Extra Large C&I Low Load Factor; and
(3) FT-2 Firm Transportation – Marketers.

The Company will make annual Gas Charge filings based on forecasts of applicable costs and volumes and annual Reconciliation filings based on actual costs and volumes. The Gas Charge shall become effective with consumption on or after November 1 as designated by the Company. In the event of any change subsequent to the November effective date which would cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than five percent (5%) of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate that non-zero balance.

Unless otherwise notified by the PUC, the Company shall submit the Gas Charge filings no later than sixty (60) days before they are scheduled to take effect. The Annual Reconciliation filing will be made by July 1 of each year containing actual

GAS COST RECOVERY CLAUSE

data for the twelve months ending March 31 of that year.

2.0 GAS CHARGE FACTORS

2.1 Gas Charges to Sales Customers:

The Gas Charge consists of two (2) components: (1) Fixed Costs and (2) Variable Costs. These components shall be computed using a forecast of applicable costs and volumes for each firm rate schedule based on the following formula:

$$GC_S = FC_S + VC_S$$

Where:

GC_S Gas Charge applicable to High Load Factor sales rates (Residential Non-Heating, Low Income Residential Non-Heating, Large and Extra Large High Load C&I) and Low Load Factor sales rates (Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large and Extra Large Low Load C&I).

FC_S Fixed Cost Component for a rate classification. See Item 3.1 for calculation.

VC_S Variable Cost Component for a rate classification. See Item 3.2 for calculation.

This calculation will be adjusted for the uncollectible percentage approved in the most recent rate case proceeding and the Gas Charges to Sales Customers are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

2.2 Gas Charge to FT-2 Marketers:

The FT-2 Demand Rate (SDC_M) recovers fixed costs associated with storage and peaking resources including pipeline supplies designated by the Company for peaking purposes. See item 3.3 for calculation.

The FT-2 Variable Charges for underground storage components consist of the following:

SLF The Company's weighted average loss factor on storage withdrawals across all storage contracts.

GAS COST RECOVERY CLAUSE

WWCC — The Company's weighted average commodity cost of storage withdrawals under all storage contracts.

PLF — The Company's weighted average loss factor on pipeline contracts used to deliver storage withdrawals to the system.

PCC — The Company's weighted average commodity cost on pipeline contracts used to deliver storage withdrawals to the system

This calculation will be adjusted for the uncollectible percentage approved in the most recent rate case proceeding and the Gas Charges to Sales Customers are subject to the Rhode Island Gross Earnings Tax provisions in Section 1, Schedule C.

3.0 GAS CHARGE CALCULATIONS

3.1 Supply Fixed Cost Component:

The Supply Fixed Cost Component shall include all fixed costs related to the purchase, storage, or delivery of firm gas, including, but not limited to, pipeline and supplier fixed reservation costs, demand charges, operation and maintenance costs for storage facilities and other fixed gas supply expense incurred to transport or store supplies, transportation fees, and requirements for purchased gas working capital. Any costs recovered through the application of the Supply Fixed Cost Component shall be identified and explained fully in the annual filing.

The Supply Fixed Cost Component is calculated for each applicable rate schedule as follows:

$$FC_S = \frac{DWS_S * (TC_{FC} - TR_{FC} + WC_{FC} + R_{FC} - (SDC_M * MDQ_{SM} * 12))}{Dt_S}$$

Where:

FC_S — Supply Fixed Cost Component for High Load Factor rates (Residential Non-Heating, Low Income Residential Non-Heating, Large High Load C&I and Extra-Large High Load C&I) and Low Load factor rates (Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low C&I and Extra Large Low Load C&I).

DWS_S — Percent of Design Winter Sales Sendout (November - March) for High Load Factor rates (Residential Non-Heating, Low Income Residential

GAS COST RECOVERY CLAUSE

Non-Heating, Large High Load C&I and Extra-Large High Load C&I) and Low Load factor rates (Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low C&I and Extra Large Low Load C&I).

TC_{FC} — Total Fixed Costs, including, but not limited to pipeline, storage, and supplier reservation and supply related local production and storage costs. The level of supply-related local production and storage costs shall be as determined in the Company's most recent rate case proceeding.

TR_{FC} — Credits to Fixed Costs relating to supply services, including, but not limited Marketer capacity release revenues and the amount forecasted to customers under the Natural Gas Portfolio Management Plan ("NGPMP") for the November to October period.

WC_{FC} — Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.

R_{FC} — Deferred Fixed Cost Account Balance as of October 31, as derived in Item 6.0 less the amount guaranteed to customers under the NGPMP and, following approval by the PUC, the net positive revenue from optimization transactions reduced by the guaranteed amount and the Company incentive under the Plan.

SDC_M — FT-2 Storage Demand Charge rate charged to Marketers based on their Maximum Daily Quantity of storage gas. See Item 3.3 for calculation.

MDQ_{SM} — Storage Forecast of Maximum Daily Quantity to be billed to Marketers.

Dt_S — Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I.

3.2 Supply Variable Cost Component:

The Supply Variable Cost Component shall include all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expense incurred to transport supplies, transportation fees, and requirements

GAS COST RECOVERY CLAUSE

for purchased gas working capital, storage commodity costs, taxes on storage commodity and other gas storage expense incurred to transport supplies, transportation fees, inventory commodity costs, and inventory financing costs. Any costs recovered through the application of the Supply Variable Cost Component shall be identified and explained fully in the annual filing.

The Supply Variable Cost Component is calculated for each applicable rate schedule as follows:

$$VC = \frac{TC_{VC} - TR_{VC} + WC_{VC} + R_V + IF_s}{Dt_{VC}}$$

Where:

VC Supply Variable Cost Component for High Load Factor rates (Residential Non-Heating, Low Income Residential Non-Heating, Large and Extra Large High Load C&I) and Low Load Factor rates (Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large and Extra Large Low Load C&I).

TC_{VC} Total Supply Variable Costs, including, but not limited to pipeline, supplier, storage, commodity-billed pipeline transition costs, and any hedge, hedging related cost or the carrying cost on hedge collateral.

TR_{VC} Total Credits to Supply Variable Costs, including, but not limited to balancing commodity charge revenues and transportation imbalance charges.

WC_{VC} Working Capital requirements associated with Total Supply Variable Costs. See item 5.0 for calculation.

R_V Deferred Cost Account Balance as of October 31, as derived in Item 6.0 plus the net of any Gas Procurement Incentives/Penalties associated with the Gas Procurement Incentive Plan.

Dt_{VC} Forecast of annual sales to Residential Non-Heating, Low Income Residential Non-Heating, Residential Heating, Low Income Residential Heating, Small C&I, Medium C&I, Large Low and High Load C&I, and Extra Large Low and High Load C&I.

GAS COST RECOVERY CLAUSE

IF_S Inventory Finance Cost as calculated in 4.0 below.

3.3 FT-2 Storage Demand Charge:

The FT-2 Storage Demand Charge (SDC_M) shall include all fixed costs related to the operations, maintenance, and delivery of storage, including, but not limited to, the supply-related portion of local production and storage costs as determined in the most recent rate case proceeding, delivery of storage gas to the Company's Distribution System, Storage Inventory Financing Charges and requirements for purchased gas working capital. Any costs recovered through the application of the Storage Demand Charge shall be identified and explained fully in the annual filing.

The Storage Demand Charge Component is calculated for the FT-2 rate schedule as follows:

$$SDC_M = \frac{TFC_S + IF_S + WC_S}{MDQ_S \text{ X } 12}$$

Where:

SDC_M FT-2 Storage Demand Charge in $/per Maximum Daily Quantity of Storage gas to be charged to Marketers.

TFC_S Total Storage Fixed Costs, equals all fixed costs of storage, including, but not limited to, the supply related portion of local production and storage costs, taxes on storage, any demand or fixed charges associated with storage or delivery of storage gas to the Company's Distribution System, and any demand or fixed pipeline reservation charges designated by the Company as a peaking resource. The level of supply-related local production and storage costs shall be as determined in the most recent rate case proceeding.

IF_S Inventory Finance Cost as calculated in 4.0 below.

MDQ_S The total maximum daily quantity of storage gas in Dekatherms deliverable to the Company's Distribution System using the LNG facilities, storage resources, and pipeline contracts related to storage delivery.

GAS COST RECOVERY CLAUSE

WC_{FC} — Working Capital requirements associated with Supply Fixed Costs. See Item 5.0 for calculation.

4.0 INVENTORY FINANCING:

$IFs = (ASB_U + ASB_L) * COC$

Where:

IF_S — Inventory Finance Charges for storage

ASB_U — Average underground storage balance

ASB_L — Average LNG storage balance

COC — Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent rate case proceeding. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended March as presented in the Company's annual Distribution Adjustment Clause Filing.

5.0 WORKING CAPITAL REQUIREMENT:

$WC_M = WCA_M * [DL / 365] * COC$

Where:

WC_M — Working Capital requirements of Supply Fixed (WC_{FC}) and, Storage Fixed (WC_{SFC}), Supply Variable (WC_{SV}), Storage Variable Product (WC_{SVC}) or Storage Variable Non-product (WC_{SVNC}) Cost Components.

WCA_M — Working Capital Allowed in the Supply Fixed, Storage Fixed, and Supply Variable, Storage Variable Product, or Storage Variable Non-product Cost component calculations.

DL — Days Lag approved in the most recent rate case proceeding.

COC — Weighted Pre-tax Cost of Capital, consisting of three components: Short-term Debt, Long-term Debt, and Common Equity. The Common Equity components shall reflect the rates approved in the most recent rate case

GAS COST RECOVERY CLAUSE

proceeding. The Short-term debt component shall be based on the Company's actual short-term borrowing rate for the twelve months ended March as presented in the Company's annual Distribution Adjustment Clause (DAC) filing in support of the Earnings Sharing Mechanism (ESM). The long-term debt component will be based on the Company's actual long-term borrowing rate as presented in the Company's annual DAC filing.

6.0 DEFERRED GAS COST ACCOUNTS:

The Company shall maintain two (2) separate Deferred Gas Cost Accounts: (1) Fixed Costs and revenues and (2) Supply Variable Costs and revenues. Entries shall be made to each of these accounts at the end of each month as follows:

An amount equal to the allowable costs incurred less:

1. Gas Revenues collected adjusted for the RIGET and uncollectible percentage approved in the most recent rate case proceeding;

2. Credits to costs, including but not limited to GCR Deferred Responsibility surcharge/credits and Transitional Sales Service (TSS) surcharge revenues,

   and including

3. Monthly interest based on a monthly rate of the current Bank of America prime interest rate less 200 basis points (2%), multiplied by the arithmetic average of the account's beginning-of-the-month balance and the balance after entries 1. and 2. above.

7.0 REFUNDS:

Any refund associated with the Company's total gas cost for Sales customers shall be credited to the Deferred Cost Account.

8.0 WEIGHTED AVERAGE UPSTREAM PIPELINE TRANSPORTATION COST:

At the request of a marketer or the Division, the Company will provide within 21 days an estimate of the pipeline path costs for the next GCR year beginning November 1. The estimate will be based on the most recent GCR filing updated for current commodity pricing and other known changes which would significantly affect the factor. Concurrent with the annual GCR filing, the Company shall calculate the final weighted average cost of upstream pipeline transportation capacity. The cost shall be applicable to capacity release under the

GAS COST RECOVERY CLAUSE

Transportation Terms and Conditions effective November 1 of each year or at such time as the PUC approves the rates.

9.0 DEFERRED GAS COST RESPONSIBILITY:

Under the Transportation Terms and Conditions, Section 6, Schedule C, Item 1.0, if a Customer who has been receiving firm sales service and elects to transfer to transportation service to purchase gas from a Marketer, the Customer is responsible for their portion of the deferred gas cost balance. The calculation of any under-recovered or over-recovered gas cost attributable to the Customer's prior service will be charged or credited to the Customer's account at the time transportation service is initiated.

9.1 Factor Calculations:

The calculation of the Customer's deferred gas cost balance consists of: (1) the prior period deferred gas cost reconciliation amount reflected in the Company's current Gas Charge; and (2) any incremental under-recovery or over-recovery of actual costs versus projected costs that accrue while the current Gas Charge is in effect.

The first component is calculated on the basis of the Company's Gas Charge filing with the PUC in accordance with the following formula:

$$PPF = \frac{DAB_B}{Dt_S}$$

Where:

PPF Prior Period Factor as a \$/Dt.

DAB_B Deferred Gas Cost Account Beginning Balance for the first month covered under the Gas Charge filing.

Dt_S Forecast of sales volumes for the period covered by GCC filing.

The second component is calculated on a quarterly basis and represents the additional deferral balance since the balance determined in the Company's last Gas Charge filing. The factor is calculated as follows:

$$IDF = \frac{DQB_E - PDAB_B}{}$$

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Dt_a

Where:

IDF Incremental Deferred Gas Cost Balance Factor as a $/Dt.

DQB_E Actual Deferred Gas Cost Account Ending Balance for a quarter subsequent to the PPF.

$PDAB_B$ Projected Deferred Gas Cost Account Ending Balance for the quarter subsequent to the PPF.

Dt_a Actual sales volumes for the quarter(s) subsequent to the PPF.

9.2 Application of Factors:

The customer's total Deferred Gas Cost Responsibility will equal the sum of the following:

(1) The PPF times: (a) the Customer's prior GCR year's total Dt minus (b) the Customer's current year's Dt where the current GCR year's Dt reflects the period the customer has been billed the current Gas Charge; and

(2) The IDF times the Customer's Dt during the period covered by the IDF.

REBUTTAL TESTIMONY

OF

THEODORE POE, JR.

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I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Theodore Poe, Jr. My business address is National Grid, 40 Sylvan Road, Waltham, MA 02451.

Q. Have you previously submitted testimony in this docket?

A. Yes. I previously submitted pre-filed direct testimony in this docket on September 1, 2016.

Q. Did you review the pre-filed direct testimony of Bruce Oliver on behalf of the Division of Public Utilities and Carriers (Division) dated October 7, 2016?

A. Yes.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to address the following comments that Mr. Oliver expresses in his direct testimony: (1) concerns regarding the accuracy and reliability of the Company's forecasts, as presented in this proceeding; (2) the five specific areas in the Company's forecasts that Mr. Oliver refers to as errors on pages 33-37 of his direct testimony; and (3) concerns regarding the Company's gas resource planning decisions, including the Cumberland liquefied natural gas (LNG) tank, which is more fully discussed in the pre-filed direct and rebuttal testimony of Elizabeth D. Arangio.

II. <u>Forecasting Methodology</u>

Q. Please describe the Company's forecasting methodology that it utilizes to determine gas supply and capacity requirements for the upcoming Gas Cost Recovery (GCR) period, as well as for its longer-term planning process.

A. The Company's Long-Range Plan documents the annual process used by the Company to design a reliable resource portfolio to meet the combined forecasted needs of the Company's Rhode Island customers at least-cost. Annually, the Company develops its forecast of normalized retail demand on its system, translates that retail demand into normal-year and design-year wholesale citygate requirements, defines its inventory of the expected available resources in the Company's portfolio, and develops its resource portfolio to reliably meet customer requirements under design-weather conditions.

Throughout my testimony, I will refer to "retail volumes" as those gas volumes delivered at the customers' burner tips, and "wholesale volumes" as those gas volumes flowing through the Company's citygates.

Q. Does the Company agree with Mr. Oliver that there are errors and inconsistencies in the Company's forecasts?

A. No. The Company is confident in its forecasting process to deliver the best estimate of the natural gas requirements for its Rhode Island customers.

Q. Why is Company confident that its forecasting process delivers the best estimate of the natural gas requirements for its Rhode Island customers?

A. The Company employs a conservative approach to its forecasting process using the most updated data to arrive at what the Company believes is the best estimate of natural gas requirements in order to provide the least-cost reliable service to its Rhode Island customers on the coldest day of the year. In its Long-Range Plan submissions, the Company has documented the efforts that it undertakes to develop its annual retail and wholesale natural gas forecasts. The Company develops its annual forecast beginning in April of each year immediately following the heating season so that its forecast captures the most recent patterns of gas usage by its customers. The Company's retail forecast regression analysis is based on historical data beginning in 2010, and is based on historical and forecasted economic and fuel price data specific to the Company's Rhode Island territory. The Company performs this analysis for each of its internal rate codes at the monthly level. Annually, the Company also performs a regression analysis of daily wholesale sendout versus weather from the most-recent 12-month period. The Company uses this wholesale regression equation to translate its retail forecast from the monthly to the daily level in order to arrive at a design day and design year forecast for its gas resource planning for the upcoming winter season and beyond.

III. <u>Response to Specific Forecasting Issues</u>

Q. On pages 33-37 of Mr. Oliver's direct testimony, he identified five areas of concern, which he characterizes as errors or inconsistencies in the Company's forecasts presented in this proceeding. Please respond.

A. Mr. Oliver identified the following five issues that he refers to as errors or inconsistencies in the Company's forecast in this proceeding:

1. The identification and use of measures of baseload gas use for the Small Commercial and Industrial (C&I) Sales service;
2. A projection of gas use for the Residential Non-Heating class;
3. Use of "inconsistent" and "irrational" representations of gas use per degree day (i.e., "heat factors") by month for numerous service classifications;
4. Unexplained increases in forecasted design peak day requirements despite forecasted decreases in both normal weather and design winter volumes; and

5. Large unexplained shifts in the distribution of gas use across months in both the Company's forecasts of normal weather and design winter requirements.

I address each of these issues below.

Q. What is the Company's response to Mr. Oliver's comment that there is an error in the Small C&I Sales service volume forecast?

A. Mr. Oliver reached out to the Company regarding this issue before submitting his pre-filed testimony, and the Company investigated and responded. In its investigation, the Company discovered an error in the historical data for Rate Code 404 (C&I Small, Sales) during the off-peak period of 2015 that led to a minor error in its initial forecast for Small C&I Sales volumes.

The Company remodeled Rate Code 404 by increasing the 2016-17 forecast of sales and transportation volumes by 126,402 dekatherms (Dth) (0.3 percent) during the off-peak period. The allocation of incremental energy efficiency reductions in the C&I market then caused very minor changes in the C&I transportation categories. Because the 0.3 percent change in volumes was minor, the Company and the Division agreed that the Company would not refile a corrected sales forecast in this docket on the basis that the GCR is reconcilable and that it would be more administratively efficient to capture the minor changes in the forecast as part of next year's filing.

The Company's adjustment is consistent with Mr. Oliver's testimony, although not all twelve months required adjustment as Mr. Oliver suggests in his testimony, which is how he arrived at the larger adjustment of 500,000 Dth. Figure 1, below, shows the month-by-month adjustment proposed by the Company for its Planning Year (PY) 2017 forecast of Small C&I Sales in Dth.

	Small C&I Sales
Nov-2016	-32005
Dec-2016	1
Jan-2017	4
Feb-2017	5
Mar-2017	4
Apr-2017	3
May-2017	1
Jun-2017	21108
Jul-2017	42027
Aug-2017	40411
Sep-2017	41777
Oct-2017	12924
Total	126261

Figure 1

In revising the forecast, the July through September months' volumes were increased on the order of 40,000 Dth per month. The months of June and October were increased as well. The month of November has a decrease. With the adjustment, the Company's forecast for PY2017 falls right in line with historical volumes for the Rate Class (Figure 2, below), particularly the summer period. Figure 1 reflects the appropriate correction to Small C&I Sales volumes.

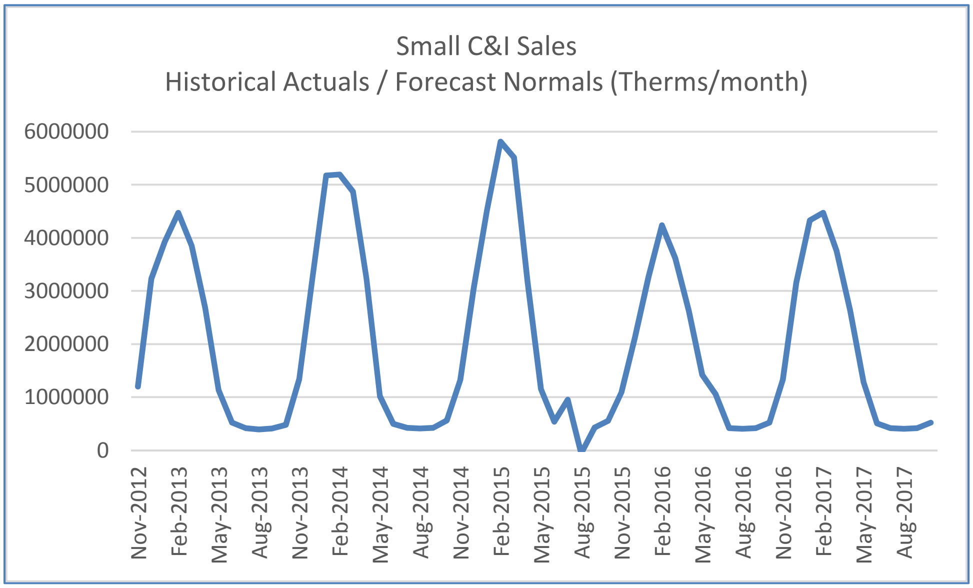

Figure 2

Q. What is the Company's response to Mr. Oliver's comment that the Company's projections of residential non-heating sales class volumes are erroneous?

A. Mr. Oliver's basis for this comment is the decline in the numbers of Residential Non-Heating customers as a result of the Company having transferred customers from the Residential Non-Heating class to the Residential Heating class over the last two years as part of the Company's Distribution Adjustment Clause filing. Mr. Oliver presents a chart (Attachment BRO-3, Figure 3, below) with the average use per customer values for the Company's Residential Non-heating classes that appears to have been developed using the data presented in Attachments TEP-1 and TEP-2 of my direct testimony.

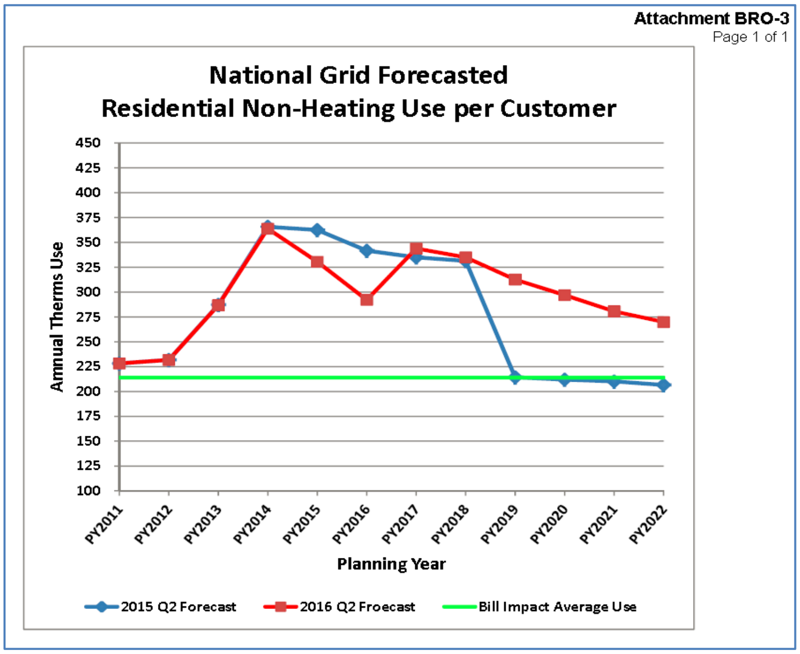

Figure 3

The Company has produced its own version of the Residential Non-Heating use per customer data from those Attachments in Figure 4, below, to confirm this.

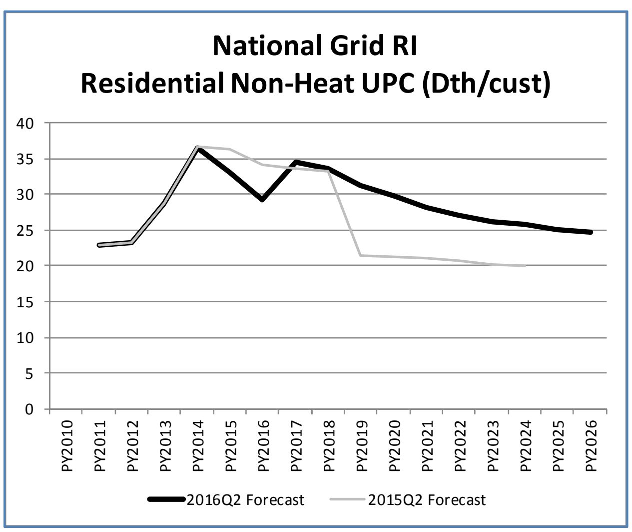

Figure 4

The Company's 2015Q2 and its 2016Q2 forecasts reflected the drop in Residential Non-Heating meter counts in PY2015, as described by Mr. Oliver (see Figure 5, below; Source: Attachment TEP-2, page 2 of 2). The Company's data shows a decrease from 25,951 Residential Non-Heating meters at the end of PY2014 to 22,274 meters at the end of PY2015 (see Attachment TEP-2, page 1 of 2).

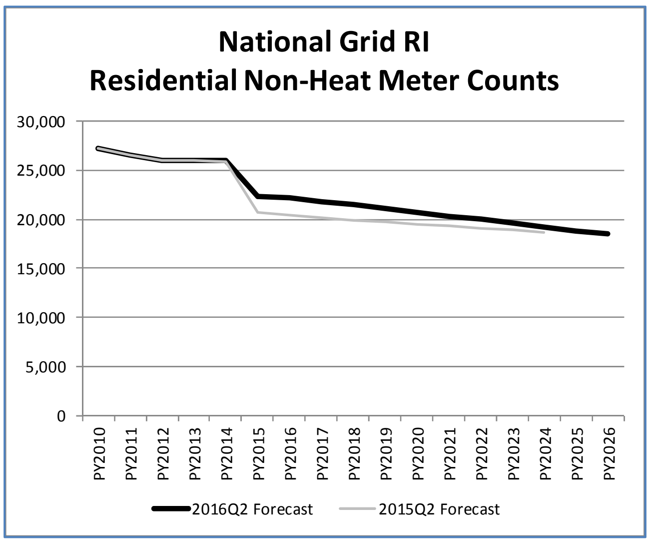

Figure 5

The Company's 2016Q2 forecast of Residential Non-Heating use per customer (Figure 5, above) reflects a return to levels that it had forecasted in its 2015Q2 forecast for PY2017 and PY2018 following the extremely warm PY2016 heating season prior to decaying in ensuing years. Both forecasts reflect a decrease in Residential Non-Heating use per customer following the decrease in meter count in PY2015.

In Figure 6, below, the Company shows the actual and forecasted data (divided by the black line) for its Rate Code 401 (Residential Non-Heating) and Rate Code 403

(Residential Non-Heating Low-Income) from its 2015Q2 forecast (right) and current forecast (left). The volumes (in therms) are for the Planning Years (Nov-Oct); the meter counts are for year-end of the Planning Years; the use-per-customer (UPC, in therms per customer) is volume divided by meter count by month and summed to annual totals. The data in Figure 6 corroborates the decrease in meter counts for Residential Non-Heating that occurred between PY2014 and PY2015, prior to the figures which Mr. Oliver is using in this testimony.

	2016Q3 Forecast						2015Q2 Forecast					
	VOLUME Actual		METER COUNT		UPC		VOLUME Actual		METER COUNT		UPC	
	401	403	401	403	401	403	401	403	401	403	401	403
	RNH	RNH-LowI	RNH	RNH-LowI	RNH	RNH-LowI	RNH	RNH-LowI	RNH	RNH-LowI	RNH	RNH-LowI
PY2011	5,842,658	220,838	26,239	331	219	678	5,842,005	220,838	26,238	331	219	678
PY2012	5,830,689	183,302	25,563	392	224	579	5,830,383	183,302	25,552	392	224	579
PY2013	7,198,600	270,234	25,545	495	279	681	7,197,620	270,234	25,507	495	279	681
PY2014	9,025,204	415,057	25,321	630	352	820	9,030,588	414,837	25,198	629	353	820
PY2015	7,068,100	292,852	21,830	444	307	652	7,212,547	291,858	20,272	431	332	669
PY2016	6,261,785	219,503	21,778	410	286	533	6,721,116	259,343	20,013	415	334	634
PY2017	7,270,084	229,339	21,404	410	336	559	6,511,249	244,862	19,773	396	327	624
PY2018	6,954,367	227,512	21,030	410	327	555	6,373,573	230,401	19,552	377	324	617
PY2019	6,357,624	227,383	20,656	410	305	555	4,004,065	217,123	19,344	356	206	614
PY2020	5,916,502	228,485	20,282	410	289	557	3,925,211	203,998	19,148	335	204	614
PY2021	5,470,950	230,341	19,908	410	272	562	3,858,783	190,916	18,962	313	203	614
PY2022	5,155,599	227,553	19,534	410	261	555	3,766,567	173,167	18,784	290	200	601
PY2023	4,874,517	228,125	19,160	410	252	556	3,656,607	158,413	18,615	266	196	597
PY2024	4,717,603	226,706	18,786	410	248	553	3,580,218	141,093	18,452	242	193	585
PY2025	4,477,750	227,456	18,412	410	240	555	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY2026	4,331,475	227,033	18,038	410	237	554	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A

Figure 6

To factor out the effect of weather, the table in Figure 7, below, reproduces the Company's current historical and forecasted volumes, meter counts, and use per customer for the two Rate Codes where the historical volumes are normalized and, thus, consistent in terms of weather with its forecasted values. The data clearly indicates that Rate Code 401 meter count decreased from 25,321 in PY2014 to 21,830 in PY2015, and that Rate Code 403 meter count decreased from 630 in PY2014 to 444 in PY2015. Concurrently, Rate Code 401 use per customer decreased from 333 in PY2014 to 290 in PY2015, and Rate Code 403 use per customer decreased from 773 in PY2014 to 599 in PY2015.

	2016Q3 Forecast					
	VOLUME normalized		METER COUNT		UPC	
	401	403	401	403	401	403
	RNH	RNH-LowI	RNH	RNH-LowI	RNH	RNH-LowI
PY2011	5,738,379	213,430	26,239	331	215	654
PY2012	6,280,913	206,025	25,563	392	241	653
PY2013	7,290,581	274,992	25,545	495	282	696
PY2014	8,536,866	393,899	25,321	630	333	773
PY2015	6,675,049	270,953	21,830	444	290	599
PY2016	7,425,140	254,799	21,778	410	339	618
PY2017	7,270,084	229,339	21,404	410	336	559
PY2018	6,954,367	227,512	21,030	410	327	555
PY2019	6,357,624	227,383	20,656	410	305	555
PY2020	5,916,502	228,485	20,282	410	289	557
PY2021	5,470,950	230,341	19,908	410	272	562
PY2022	5,155,599	227,553	19,534	410	261	555
PY2023	4,874,517	228,125	19,160	410	252	556
PY2024	4,717,603	226,706	18,786	410	248	553
PY2025	4,477,750	227,456	18,412	410	240	555
PY2026	4,331,475	227,033	18,038	410	237	554

Figure 7

Mr. Oliver's concern – which the Company has also observed – is the increase in Rate Code 401 use per customer back up to 339 in PY2016 and Rate Code 403 use per customer back up to 618 in PY2016 that the Company attributes to consumer behavior since it occurred after the PY2015 reclassification.

As the Company has established an annual process of reviewing Residential Non-Heating use per customer on an account-by-account basis, sizable changes in use per customer are not driven by improper classification. Hence, the Company's forecasted use per customer reflects its current forecast of declining use per customer for Rate Code 401 and flat use per customer for Rate Code 403.

Q. What is the Company's response to Mr. Oliver's comment that the Company's estimated gas use per degree day, or "heat factors," are irrational and inconsistent?

A. Mr. Oliver's comments are based on what he describes as large differences in the applicable heat factor for a specific class of customers across months of a given year. Mr. Oliver presents a chart (Attachment BRO-4; Figure 8, below) with the monthly use per customer per degree day values by rate class for the period November 2016 – October 2017 from the Company's filing in this docket (Docket No. 4647) and compares them to a similar table using the period November 2015 – October 2016 from the Company's 2015 GCR filing (Docket No. 4576). He then raises the following issues: (1) peak period vs. off-peak period gas use per degree day in the Residential Heating class; and (2) changes in gas use per degree day from one filing to the next in the C&I Extra Large Low Load Factor class, the Extra Large High Load Factor Transportation service, the Medium C&I Sales service class, the Medium C&I Transportation service class, and the Residential Non-Heating service class.

Attachment BRO-4
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National Grid - RI Gas
Docket 4647 - 2016 GCR Filing

Comparison of Heat Factors by Rate Class by Month - Docket 4576 vs Docket 4647

	Docket 4576	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov - Oct
1	Residential Non-Heating	43	51	63	91	112	142	101	183	547	-	21	14	76
2	Residential Heating	1,861	2,097	2,477	2,923	3,054	3,841	3,716	8,332	27,643	-	344	482	2,579
3	Small C&I Sales	176	389	412	426	435	502	564	1,064	7,330	-	-	53	383
4	Small C&I Transport	6	7	9	10	10	14	14	34	329	-	-	4	9
5	Medium C&I Sales	219	344	421	594	579	635	557	794	6,778	-	-	77	441
6	Med C&I Transport	191	234	272	351	333	388	353	578	6,781	-	-	92	282
7	Large Low Load - Sales	72	106	110	115	116	134	147	264	1,027	-	28	31	106
8	Large Low Load - Transport	259	316	323	334	332	359	385	547	-	-	128	195	316
9	Large High Load - Sales	-	4	7	8	-	-	-	-	-	3,692	-	-	4
10	Large High Load - Transport	34	48	53	64	63	71	55	175	1,252	-	42	22	54
11	XL Low Load - Sales	5	15	18	15	16	19	27	58	841	-	-	10	15
12	XL Low Load - Transport	161	167	168	159	160	170	202	318	2,572	-	31	177	167
13	XL High Load - Sales	9	13	1	-	-	-	-	-	-	-	187	14	6
14	XL High Load - Transport	207	173	179	171	119	73	-	-	-	10,544	515	144	156
15	Total	3,243	3,963	4,512	5,260	5,329	6,346	6,121	12,348	55,100	14,236	1,296	1,317	4,594
	Docket 4647	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov - Oct
16	Residential Non-Heating	63	69	77	94	92	118	123	241	144	-	19	30	82
17	Residential Heating	1,997	2,255	2,585	3,152	3,111	3,940	4,066	7,056	10,762	-	437	1,066	2,737
18	Small C&I Sales	286	339	394	478	472	582	566	677	1	-	-	116	403
19	Small C&I Transport	12	13	15	18	17	22	23	40	49	-	3	6	15
20	Medium C&I Sales	305	343	391	478	469	597	614	1,084	1,176	-	82	163	415
21	Med C&I Transport	219	243	276	339	331	425	439	807	371	-	69	114	295
22	Large Low Load - Sales	78	87	99	120	118	149	155	265	427	-	15	41	105
23	Large Low Load - Transport	230	257	292	353	348	441	457	797	1,172	-	49	123	309
24	Large High Load - Sales	7	7	8	11	10	13	13	35	-	-	6	3	9
25	Large High Load - Transport	31	32	37	49	45	60	57	138	-	-	28	15	41
26	XL Low Load - Sales	7	8	9	11	11	14	15	31	42	-	1	4	10
27	XL Low Load - Transport	124	138	156	190	186	237	244	426	521	-	30	65	165
28	XL High Load - Sales	-	-	-	-	-	-	-	4	-	-	5	-	-
29	XL High Load - Transport	75	70	85	139	98	148	69	170	-	-	229	28	96
30	Total	3,434	3,861	4,426	5,432	5,307	6,746	6,842	11,771	14,663	-	975	1,773	4,681

Figure 8

Regarding peak period vs. off-peak period gas use per degree day, in Attachment BRO-4, Mr. Oliver reproduces a table of monthly heat volumes by rate class divided by the number of monthly heating degree days within the period November 2016 – October 2017 from this year's filing (Attachment AEL-1, page 14) and compares them to the equivalent table from the Company's 2015 GCR filing. The Company has used the methodology in Attachment AEL-1 Revised, pages 13-15, as a reviewable method of deriving forecasted monthly design weather sales from its monthly forecasted normal weather sales.

As heating equipment is not used by the Company's customers in the summer, Mr. Oliver misinterprets fluctuations in the Company's monthly load by rate class as being associated with heat consumption. Mr. Oliver's interpretation must take into consideration the fact that summertime load can fluctuate, but is not necessarily due to heat usage. Figure 9, below, lists the Company's actual retail volumes by month from November 2013 through October 2014.

Actual Retail Volumes (Dth) Nov 2013 - Oct 2014	Nov-2013	Dec-2013	Jan-2014	Feb-2014	Mar-2014	Apr-2014	May-2014	Jun-2014	Jul-2014	Aug-2014	Sep-2014	Oct-2014	Total
RNH (Dth)	60,098	112,434	148,103	150,376	141,972	105,938	64,116	39,226	29,615	28,659	28,629	34,860	944,026
RH (Dth)	1,190,578	2,533,759	3,450,027	3,492,894	3,247,361	2,238,681	1,151,162	557,434	408,109	388,156	394,359	519,848	19,572,368
Small CI(Dth)	134,386	327,645	517,440	519,561	487,302	324,136	102,094	50,086	42,460	41,428	42,488	56,455	2,645,481
SmallCIT (Dth)	1,744	4,271	6,672	6,643	6,301	4,173	2,014	1,127	840	884	1,092	1,237	37,000
MedCI (Dth)	209,593	463,560	535,295	573,342	554,629	377,018	215,028	113,661	89,860	89,157	90,099	115,046	3,426,288
Med CIT (Dth)	195,294	308,080	394,532	388,249	366,310	247,345	146,389	85,149	72,802	70,788	71,666	94,909	2,441,511
Lg LLF (Dth)	45,358	98,553	138,125	141,603	138,962	91,677	48,139	17,899	10,569	10,116	11,048	16,026	768,075
Lg LLFT (Dth)	211,356	311,007	402,399	395,658	372,713	235,996	115,612	50,416	37,160	35,966	42,719	84,313	2,295,316
Lg HLF(Dth)	25,307	28,358	30,954	30,923	32,823	25,106	22,358	22,455	21,179	30,217	15,059	15,589	300,329
Lg HLFT (Dth)	75,297	92,225	108,027	101,572	97,798	79,509	66,244	56,551	55,198	55,929	56,709	62,669	907,727
XL LLF (Dth)	6,519	17,374	17,691	17,993	17,365	12,507	7,660	3,021	1,600	829	859	2,261	105,681
XL LLFT (Dth)	146,105	182,477	206,731	189,465	181,661	106,948	47,116	18,448	17,151	17,370	22,094	59,446	1,195,012
XL HLF (Dth)	7,173	21,257	37,694	23,194	27,557	30,790	28,560	32,566	25,586	28,491	52,165	37,341	352,375
XL HLFT (Dth)	442,125	503,362	553,154	505,088	504,450	410,078	365,018	351,880	353,038	411,239	412,940	448,379	5,260,751
Total (Dth)	2,750,933	5,004,364	6,546,844	6,536,561	6,177,205	4,289,902	2,381,508	1,399,919	1,165,166	1,209,230	1,241,927	1,548,381	40,251,940

Figure 9

Similarly, Figure 10, below, lists the Company's actual retail volumes by month from November 2014 through October 2015.

Actual Retail Volumes (Dth)
Nov 2014 - Oct 2015

	Nov-2014	Dec-2014	Jan-2015	Feb-2015	Mar-2015	Apr-2015	May-2015	Jun-2015	Jul-2015	Aug-2015	Sep-2015	Oct-2015	Total
RNH (Dth)	61,522	81,054	104,736	122,269	116,474	84,343	44,073	29,693	23,765	21,152	21,352	25,663	736,095
RH (Dth)	1,167,761	2,438,704	3,251,132	3,985,170	3,750,887	2,471,847	1,023,044	558,932	429,721	380,568	387,793	535,402	20,380,961
Small CI(Dth)	132,711	306,283	454,807	582,936	553,533	319,390	115,910	54,234	95,681	-5,579	42,815	55,930	2,708,651
SmallCIT (Dth	2,239	5,126	9,153	15,667	14,155	7,631	3,038	1,676	1,468	1,478	1,446	1,782	64,860
MedCI (Dth)	232,450	409,449	559,676	674,719	642,702	427,908	191,064	115,986	92,438	85,176	86,810	115,119	3,633,497
Med CIT (Dth	178,634	279,043	365,720	418,507	383,299	260,272	133,640	80,536	74,056	69,975	72,202	106,478	2,422,361
Lg LLF (Dth)	44,076	96,953	133,728	162,030	155,064	105,497	41,990	16,361	10,828	9,630	8,243	15,537	799,939
Lg LLFT (Dth)	195,292	304,054	406,817	441,582	388,035	228,904	92,356	49,598	37,367	30,345	32,664	85,413	2,292,427
Lg HLF(Dth)	18,300	23,456	31,086	31,674	27,797	21,082	13,999	11,545	11,674	13,543	15,466	16,069	235,691
Lg HLFT (Dth)	73,835	92,212	109,925	119,563	111,504	86,936	66,763	63,352	56,890	58,243	54,141	63,899	957,263
XL LLF (Dth)	4,695	10,891	15,247	16,267	17,897	11,505	6,415	3,597	1,692	1,542	1,609	2,650	94,007
XL LLFT (Dth)	142,527	175,765	226,398	200,528	194,155	117,473	42,710	24,195	21,506	20,814	23,760	82,954	1,272,786
XL HLF (Dth)	41,511	51,020	43,774	44,581	45,612	36,752	26,714	29,541	23,152	18,045	15,925	14,731	391,358
XL HLFT (Dth)	503,124	545,681	610,118	582,601	597,250	488,941	459,616	452,795	469,010	469,875	462,798	498,994	6,140,802
Total (Dth)	2,798,675	4,819,691	6,322,315	7,398,093	6,998,366	4,668,481	2,261,333	1,492,040	1,349,250	1,174,808	1,227,023	1,620,623	42,130,698

Figure 10

Through each of the July and August time periods, Residential Heating (RH) monthly retail volumes show minor fluctuations during periods when the Company would not expect spaceheating equipment to be used even though the Company's normal heating degree days show one heating degree day each in July and August.

Regarding changes in gas use per degree day in several rate classes from one filing to the next, Mr. Oliver points out in the aforementioned Attachment BRO-4 (Figure 8 above), between the Company's two GCR filings, that month-to-month values in gas use per customer per degree day change in certain of the rate classes. The Company performs its forecast of retail volumes by rate class annually so that it can reflect in its GCR filings the most recent information on its customer's gas usage. The instant GCR filing has the benefit of an additional 12 months of actual usage data since its previous GCR filing and its forecast is reflective of the trends in gas use as well as the Rhode Island economic climate since 2010. In his example, Mr. Oliver points out the change in the Heat Factor in the C&I Extra Large Low Load Factor-Transport (XL Low Load – Transport) class from 159 Dth per degree day in February in the Company's 2015 GCR filing in Docket No. 4576 to 190 Dth per degree day in this year's filing.

In order to give context to the Company's modeling of the C&I Extra Large Low Load Factor - Transport class, the Company has normalized its actual volumes by class for the time period November 2013 through October 2014 in Figure 11, below.

Normal Volumes (Dth)														
		Nov-2013	Dec-2013	Jan-2014	Feb-2014	Mar-2014	Apr-2014	May-2014	Jun-2014	Jul-2014	Aug-2014	Sep-2014	Oct-2014	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	60,098	112,434	148,103	150,376	141,972	105,938	64,116	39,226	29,615	28,659	28,629	34,860	944,026
(2)	Residential Heating	1,190,578	2,533,759	3,450,027	3,492,894	3,247,361	2,238,681	1,151,162	557,434	408,109	388,156	394,359	519,848	19,572,368
(3)	Small C&I	134,386	327,645	517,440	519,561	487,302	324,136	102,094	50,086	42,460	41,428	42,488	56,455	2,645,481
(4)	Small Transport	1,744	4,271	6,672	6,643	6,301	4,173	2,014	1,127	840	884	1,092	1,237	37,000
(5)	Medium C&I	209,593	463,560	535,295	573,342	554,629	377,018	215,028	113,661	89,860	89,157	90,099	115,046	3,426,288
(6)	Med Transport	195,294	308,080	394,532	388,249	366,310	247,345	146,389	85,149	72,802	70,788	71,666	94,909	2,441,511
(7)	Large Low Load	45,358	98,553	138,125	141,603	138,962	91,677	48,139	17,899	10,569	10,116	11,048	16,026	768,075
(8)	Large Low Load Transport	211,356	311,007	402,399	395,658	372,713	235,996	115,612	50,416	37,160	35,966	42,719	84,313	2,295,316
(9)	Large High Load	25,307	28,358	30,954	30,923	32,823	25,106	22,358	22,455	21,179	30,217	15,059	15,589	300,329
(10)	Large High Load Transport	75,297	92,225	108,027	101,572	97,798	79,509	66,244	56,551	55,198	55,929	56,709	62,669	907,727
(11)	XL Low Load	6,519	17,374	17,691	17,993	17,365	12,507	7,660	3,021	1,600	829	859	2,261	105,681
(12)	XL Low Load-Transport	146,105	182,477	206,731	189,465	181,661	106,948	47,116	18,448	17,151	17,370	22,094	59,446	1,195,012
(13)	XL High Load-Transport	7,173	21,257	37,694	23,194	27,557	30,790	28,560	32,566	25,586	28,491	52,165	37,341	352,375
(14)	XL High Load	442,125	503,362	553,154	505,088	504,450	410,078	365,018	351,880	353,038	411,239	412,940	448,379	5,260,751
(15)	Total	2,750,933	5,004,364	6,546,844	6,536,561	6,177,205	4,289,902	2,381,508	1,399,919	1,165,166	1,209,230	1,241,927	1,548,381	40,251,940

Figure 11

Similarly, the Company has normalized its actual volumes by class for the time period November 2014 through October 2015 in Figure 12, below.

Normal Volumes (Dth)														
		Nov-2014	Dec-2014	Jan-2015	Feb-2015	Mar-2015	Apr-2015	May-2015	Jun-2015	Jul-2015	Aug-2015	Sep-2015	Oct-2015	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	61,522	81,054	104,736	122,269	116,474	84,343	44,073	29,693	23,765	21,152	21,352	25,663	*736,095*
(2)	Residential Heating	1,167,761	2,438,704	3,251,132	3,985,170	3,750,887	2,471,847	1,023,044	558,932	429,721	380,568	387,793	535,402	*20,380,961*
(3)	Small C&I	132,711	306,283	454,807	582,936	553,533	319,390	115,910	54,234	*45,051*	*45,051*	42,815	55,930	*2,708,651*
(4)	Small Transport	2,239	5,126	9,153	15,667	14,155	7,631	3,038	1,676	1,468	1,478	1,446	1,782	*64,860*
(5)	Medium C&I	232,450	409,449	559,676	674,719	642,702	427,908	191,064	115,986	92,438	85,176	86,810	115,119	*3,633,497*
(6)	Med Transport	178,634	279,043	365,720	418,507	383,299	260,272	133,640	80,536	74,056	69,975	72,202	106,478	*2,422,361*
(7)	Large Low Load	44,076	96,953	133,728	162,030	155,064	105,497	41,990	16,361	10,828	9,630	8,243	15,537	*799,939*
(8)	Large Low Load Transport	195,292	304,054	406,817	441,582	388,035	228,904	92,356	49,598	37,367	30,345	32,664	85,413	*2,292,427*
(9)	Large High Load	18,300	23,456	31,086	31,674	27,797	21,082	13,999	11,545	11,674	13,543	15,466	16,069	*235,691*
(10)	Large High Load Transport	73,835	92,212	109,925	119,563	111,504	86,936	66,763	63,352	56,890	58,243	54,141	63,899	*957,263*
(11)	XL Low Load	4,695	10,891	15,247	16,267	17,897	11,505	6,415	3,597	1,692	1,542	1,609	2,650	*94,007*
(12)	XL Low Load-Transport	142,527	175,765	226,398	200,528	194,155	117,473	42,710	24,195	21,506	20,814	23,760	82,954	*1,272,786*
(13)	XL High Load-Transport	41,511	51,020	43,774	44,581	45,612	36,752	26,714	29,541	23,152	18,045	15,925	14,731	*391,358*
(14)	XL High Load	503,124	545,681	610,118	582,601	597,250	488,941	459,616	452,795	469,010	469,875	462,798	498,994	*6,140,802*
(15)	Total	*2,798,675*	*4,819,691*	*6,322,315*	*7,398,093*	*6,998,366*	*4,668,481*	*2,261,333*	*1,492,040*	*1,298,619*	*1,225,438*	*1,227,023*	*1,620,623*	*42,130,698*

Figure 12

In Docket No. 4576, Attachment AEL-1, page 14, the Company presented its normalized forecasted volumes by class for the time period November 2015 through October 2016 in Figure 13 below.

Normal Volumes (Dth)														
		Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Jul-2016	Aug-2016	Sep-2016	Oct-2016	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	48,049	71,423	92,942	107,427	113,117	87,291	46,799	31,200	24,471	22,307	24,221	28,799	*698,046*
(2)	Residential Heating	1,462,287	2,349,767	3,119,896	3,107,497	2,828,266	2,124,881	1,241,085	751,389	425,245	352,061	402,675	561,110	*18,726,159*
(3)	Small C&I	150,098	412,467	502,968	445,399	395,993	275,911	177,969	95,230	57,312	44,037	46,985	68,102	*2,672,471*
(4)	Small Transport	5,363	8,696	11,591	10,934	10,410	8,175	5,238	3,493	2,396	1,784	1,955	3,346	*73,381*
(5)	Medium C&I	226,941	423,681	566,157	652,912	564,095	387,529	229,766	134,838	110,007	97,621	98,729	129,347	*3,621,623*
(6)	Med Transport	193,275	303,653	384,203	409,058	350,625	258,521	165,741	108,354	92,475	80,448	81,394	117,046	*2,544,793*
(7)	Large Low Load	52,508	109,572	132,377	117,870	103,702	71,427	44,582	22,548	12,314	8,822	12,359	21,893	*709,974*
(8)	Large Low Load Transport	193,833	339,407	399,879	355,152	309,381	206,353	132,733	67,827	44,989	38,807	50,460	111,317	*2,250,138*
(9)	Large High Load	14,538	19,318	23,722	22,322	14,405	15,209	13,872	14,726	14,458	19,582	13,117	14,091	*199,360*
(10)	Large High Load Transport	78,709	105,298	118,838	117,330	111,436	91,120	73,563	66,700	62,218	57,547	61,167	68,286	*1,012,212*
(11)	XL Low Load	4,205	14,733	20,770	14,692	13,574	9,759	7,268	3,689	2,026	608	880	4,676	*96,880*
(12)	XL Low Load-Transport	116,250	179,379	208,355	171,056	151,292	100,183	69,941	37,280	26,627	19,847	24,917	84,065	*1,189,192*
(13)	XL High Load-Transport	28,920	35,960	25,159	16,451	15,315	18,775	20,994	22,523	20,767	18,159	33,250	29,065	*285,338*
(14)	XL High Load	533,656	588,830	624,359	560,165	522,493	446,653	405,972	390,417	390,118	438,007	440,474	476,331	*5,817,475*
(15)	Total	*3,108,632*	*4,962,184*	*6,231,216*	*6,108,265*	*5,504,104*	*4,101,787*	*2,635,523*	*1,750,214*	*1,285,423*	*1,199,637*	*1,292,583*	*1,717,474*	*39,897,042*

Figure 13

Similarly, the Company has normalized its actual volumes by class for the time period November 2015 through February 2016 in Figure 14, below.

Normal Volumes (Dth)													
		Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Jul-2016	Aug-2016	Sep-2016	Oct-2016	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	38,402	60,440	77,196	90,022	103,077	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(2)	Residential Heating	1,042,667	1,846,137	2,546,480	3,092,767	2,825,826	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(3)	Small C&I	109,593	212,463	326,189	424,330	361,592	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(4)	Small Transport	3,430	6,831	11,818	15,994	14,651	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(5)	Medium C&I	206,889	303,189	415,044	507,169	504,567	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(6)	Med Transport	161,186	227,735	316,599	347,205	361,771	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(7)	Large Low Load	38,630	67,513	95,154	120,602	104,174	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(8)	Large Low Load Transport	150,083	215,710	325,300	342,072	307,461	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(9)	Large High Load	17,574	18,486	21,062	22,578	23,663	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(10)	Large High Load Transport	70,864	77,772	94,872	93,724	96,288	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(11)	XL Low Load	3,725	7,927	9,957	9,985	9,091	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(12)	XL Low Load-Transport	119,406	133,676	201,201	186,708	178,201	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(13)	XL High Load-Transport	14,330	18,643	8,005	7,939	11,451	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(14)	XL High Load	510,441	533,924	599,005	542,360	586,446	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
(15)	Total	*2,487,220*	*3,730,447*	*5,047,881*	*5,803,457*	*5,488,259*	*#N/A*	*#N/A*	*#N/A*	*#N/A*	*#N/A*	*#N/A*	*#N/A*	*#N/A*

Figure 14

In this year's docket, Attachment AEL-1, page 14, the Company presents its normalized forecasted volumes by class for the time period November 2016 through October 2016 in Figure 15, below.

Normal Volumes (Dth)													
		Nov-2016	Dec-2016	Jan-2017	Feb-2017	Mar-2017	Apr-2017	May-2017	Jun-2017	Jul-2017	Aug-2017	Sep-2017	Oct-2017	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	61,398	89,290	110,313	112,206	98,591	78,155	53,411	35,271	25,629	24,348	25,656	35,674	749,942
(2)	Residential Heating	1,468,822	2,422,361	3,163,979	3,252,058	2,798,847	2,097,234	1,245,874	622,889	333,615	289,355	335,174	684,134	18,714,342
(3)	Small C&I	165,415	315,799	433,065	447,372	375,474	263,850	128,588	29,824	28	25	28	39,202	2,198,668
(4)	Small Transport	8,999	14,333	18,388	18,779	16,201	12,307	7,573	4,097	2,464	2,218	2,484	4,476	112,319
(5)	Medium C&I	254,663	399,478	510,752	522,834	453,810	348,373	219,911	125,684	81,767	75,158	82,250	135,881	3,210,561
(6)	Med Transport	200,552	302,473	379,821	388,069	339,766	266,096	175,632	109,040	76,371	72,042	77,135	114,700	2,501,698
(7)	Large Low Load	52,415	88,802	116,353	119,020	101,449	74,903	42,642	18,952	7,967	6,309	8,101	21,542	658,455
(8)	Large Low Load Transport	161,095	268,006	349,937	357,796	305,997	227,768	132,694	63,040	30,089	25,175	30,556	70,514	2,022,667
(9)	Large High Load	17,142	20,113	22,351	22,569	21,134	18,966	16,331	14,397	13,180	13,048	13,191	14,260	206,682
(10)	Large High Load Transport	72,899	86,798	97,270	99,035	92,265	82,038	69,609	60,897	56,230	55,592	56,282	61,882	890,796
(11)	XL Low Load	4,605	7,782	10,188	10,421	8,887	6,569	3,751	1,682	352	204	364	1,563	56,368
(12)	XL Low Load-Transport	96,935	154,436	197,958	202,172	174,405	132,458	81,479	44,044	26,644	24,028	26,857	48,070	1,209,486
(13)	XL High Load-Transport	11,250	11,153	11,069	11,062	11,109	11,179	11,264	11,327	11,399	11,404	11,398	11,354	134,968
(14)	XL High Load	549,020	587,602	616,543	619,372	600,731	572,570	538,346	513,215	517,532	515,764	517,676	532,016	6,680,387
(15)	Total	3,125,208	4,768,426	6,037,988	6,182,765	5,398,665	4,192,466	2,727,108	1,654,359	1,183,267	1,114,668	1,187,152	1,775,267	39,347,340

Figure 15

Summarizing this data in Figure 16, below, February was 20.9 percent of the November-March period in normalized actual data for PY2014, rising to 21.3 percent in normalized actual data for PY2015. The Company's 2015 GCR filing predicted the February percentage to decline to 20.7 percent. The normalized actual data for PY2016 showed that the February percentage actually rose to 22.8 percent. Hence, the Company's 2016 GCR filing is now predicting the February percentage to trend upward to 24.5 percent.

XL Low Load-Transport (Dth)	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov-Mar	Annual	Feb/(Nov-Mar)
Actual Normalized PY2014	146,105	182,477	206,731	189,465	181,661	106,948	47,116	18,448	17,151	17,370	22,094	59,446	906,439	1,195,012	20.9%
Actual Normalized PY2015	142,527	175,765	226,398	200,528	194,155	117,473	42,710	24,195	21,506	20,814	23,760	82,954	939,373	1,272,786	21.3%
Forecasted PY2016 (2015 AEL-1_14)	116,250	179,379	208,355	171,056	151,292	100,183	69,941	37,280	26,627	19,847	24,917	84,065	826,332	1,189,192	20.7%
Actual Normalized PY2016	119,406	133,676	201,201	186,708	178,201	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	819,192	#N/A	22.8%
Forecasted PY2017 (2016 AEL-1_14)	96,935	154,436	197,958	202,172	174,405	132,458	81,479	44,044	26,644	24,028	26,857	48,070	825,906	1,209,486	24.5%

Figure 16

Thus, changes between the Company's GCR filing last year in Docket No. 4576 and in this year's filing can be explained in consideration of the additional 12 months of data used in this year's filing as compared to the 2015 GCR filing. This additional 12 months of data provides new observations of customers' current behavior in preparation for the upcoming planning year. Accordingly, the Company's estimated gas use per degree day is not irrational or inconsistent.

Q. What is the Company's response to Mr. Oliver's comment that the Company's forecasts of total throughput, total sales volumes, design winter sales, and design peak day requirements between this year's GCR filing and last year's GCR filing in Docket No. 4576 are inconsistent?

A. In support of this comment, Mr. Oliver presents a chart (Attachment BRO-7, included as Figure 17, below) and states that the Company's forecast of total annual retail Sales volumes in this year's GCR filing show a 4.0 percent decrease over the Sales volumes forecasted for 2015-16 in the Company filing in Docket No. 4576 while the projected design day wholesale sendout requirements are 4.7 percent higher.

Attachment BRO-7
Page 1 of 1

National Grid- RI Gas
Docket No. 4647 - 2016 Annual GRC Proceeding

Docket No. 4647 - 2016 Annual GRC Proceeding

Forecast	**Docket 4576** *2015-16*	**Docket 4647** *2016-17*	Change from Prior Year	% Change from Prior Year
Annual Sales	27,009,852	25,929,986	(1,079,866)	**-4.0%**
Annual Throughput	39,897,042	39,347,340	(549,702)	-1.4%
Design Winter Sales	20,338,327	20,109,626	(228,701)	-1.1%
Design Day Requirements	341,091	357,153	16,062	**4.7%**

Figure 17

The reason for this observation is, in part, that Mr. Oliver is comparing retail volumes for Sales only customers with wholesale design day volumes for combined Sales and Customer Choice customers. The comparable forecasted wholesale Sales-only design day requirement in Docket No. 4576 for the 2015-16 winter was 285,628 Dth, while the forecasted wholesale Sales-only design day requirement in this year's filing for the 2016-17 winter are 296,295 Dth, which represents a growth of 3.7 percent.

Discussing the changes from one Company forecast to the next confounds the forecasts themselves and the benefit of an additional 12 months of actual usage data. The foregoing numbers indicate a decreasing load factor for Sales customers, with peak day needs growing while seasonal or annual requirements are decreasing. This can be seen in Figure 18, below, where the Company has analyzed the normal year forecasted volumes from Docket 4576 (from Figure 13, above) and the normal year forecasted volumes from this year's docket (from Figure 15, above). In Figure 18, the Company has calculated a simple load factor by rate class using the annual retail sales and the February retail sales. The load factor presented is calculated as one-twelfth the annual retail sales divided by the February retail sales. As demonstrated in Figure 18, for 2016-17, annual retail sales are forecasted to be 25,929,986 Dth, which is lower than the Docket No. 4576 annual value of 27,009,851 Dth. For 2016-17, February retail sales are forecasted to be 4,497,542 Dth, which shows slight growth from the Docket No. 4576 value of 4,484,570 Dth. The forecasted annual load factor is forecasted to decline from 50.2 percent to 48.0 percent.

Dkt 4647
Normal Volumes (Dth)

		Nov-2016	Dec-2016	Jan-2017	Feb-2017	Mar-2017	Apr-2017	May-2017	Jun-2017	Jul-2017	Aug-2017	Sep-2017	Oct-2017	Nov-Oct	Annual Sales	Feb Sales	Load Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)			
(1)	Residential Non-Heating	61,398	89,290	110,313	112,206	98,591	78,155	53,411	35,271	25,629	24,348	25,656	35,674	749,942	749,942	112,206	55.7%
(2)	Residential Heating	1,468,822	2,422,361	3,163,979	3,252,058	2,798,847	2,097,234	1,245,874	622,889	333,615	289,355	335,174	684,134	18,714,342	18,714,342	3,252,058	48.0%
(3)	Small C&I	165,415	315,799	433,065	447,372	375,474	263,850	128,588	29,824	28	25	28	39,202	2,198,668	2,198,668	447,372	41.0%
(4)	Small Transport	8,999	14,333	18,388	18,779	16,201	12,307	7,573	4,097	2,464	2,218	2,484	4,476	112,319			
(5)	Medium C&I	254,663	399,478	510,752	522,834	453,810	348,373	219,911	125,684	81,767	75,158	82,250	135,881	3,210,561	3,210,561	522,834	51.2%
(6)	Med Transport	200,552	302,473	379,821	388,069	339,766	266,096	175,632	109,040	76,371	72,042	77,135	114,700	2,501,698			
(7)	Large Low Load	52,415	88,802	116,353	119,020	101,449	74,903	42,642	18,952	7,967	6,309	8,101	21,542	658,455	658,455	119,020	46.1%
(8)	Large Low Load Transport	161,095	268,006	349,937	357,796	305,997	227,768	132,694	63,040	30,089	25,175	30,556	70,514	2,022,667			
(9)	Large High Load	17,142	20,113	22,351	22,569	21,134	18,966	16,331	14,397	13,180	13,048	13,191	14,260	206,682	206,682	22,569	76.3%
(10)	Large High Load Transport	72,899	86,798	97,270	99,035	92,265	82,038	69,609	60,897	56,230	55,592	56,282	61,882	890,796			
(11)	XL Low Load	4,605	7,782	10,188	10,421	8,887	6,569	3,751	1,682	352	204	364	1,563	56,368	56,368	10,421	45.1%
(12)	XL Low Load-Transport	96,935	154,436	197,958	202,172	174,405	132,458	81,479	44,044	26,644	24,028	26,857	48,070	1,209,486			
(13)	XL High Load-Transport	11,250	11,153	11,069	11,062	11,109	11,179	11,264	11,327	11,399	11,404	11,398	11,354	134,968	134,968	11,062	101.7%
(14)	XL High Load	549,020	587,602	616,543	619,372	600,731	572,570	538,346	513,215	517,532	515,764	517,676	532,016	6,680,387			
(15)	Total	3,125,208	4,768,426	6,037,988	6,182,765	5,398,665	4,192,466	2,727,108	1,654,359	1,183,267	1,114,668	1,187,152	1,775,267	39,347,340	25,929,986	4,497,542	48.0%

Dkt 4576
Normal Volumes (Dth)

		Nov-2015	Dec-2015	Jan-2016	Feb-2016	Mar-2016	Apr-2016	May-2016	Jun-2016	Jul-2016	Aug-2016	Sep-2016	Oct-2016	Nov-Oct	Annual Sales	Feb Sales	Load Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)			
(1)	Residential Non-Heating	48,049	71,423	92,942	107,427	113,117	87,291	46,799	31,200	24,471	22,307	24,221	28,799	*698,046*	698,046	107,427	54.1%
(2)	Residential Heating	1,462,287	2,349,767	3,119,896	3,107,497	2,828,266	2,124,881	1,241,085	751,389	425,245	352,061	402,675	561,110	*18,726,159*	18,726,159	3,107,497	50.2%
(3)	Small C&I	150,098	412,467	502,968	445,399	395,993	275,911	177,969	95,230	57,312	44,037	46,985	68,102	*2,672,471*	2,672,471	445,399	50.0%
(4)	Small Transport	5,363	8,696	11,591	10,934	10,410	8,175	5,238	3,493	2,396	1,784	1,955	3,346	*73,381*			
(5)	Medium C&I	226,941	423,681	566,157	652,912	564,095	387,529	229,766	134,838	110,007	97,621	98,729	129,347	*3,621,623*	3,621,623	652,912	46.2%
(6)	Med Transport	193,275	303,653	384,203	409,058	350,625	258,521	165,741	108,354	92,475	80,448	81,394	117,046	*2,544,793*			
(7)	Large Low Load	52,508	109,572	132,377	117,870	103,702	71,427	44,582	22,548	12,314	8,822	12,359	21,893	*709,974*	709,974	117,870	50.2%
(8)	Large Low Load Transport	193,833	339,407	399,879	355,152	309,381	206,353	132,733	67,827	44,989	38,807	50,460	111,317	*2,250,138*			
(9)	Large High Load	14,538	19,318	23,722	22,322	14,405	15,209	13,872	14,726	14,458	19,582	13,117	14,091	*199,360*	199,360	22,322	74.4%
(10)	Large High Load Transport	78,709	105,298	118,838	117,330	111,436	91,120	73,563	66,700	62,218	57,547	61,167	68,286	*1,012,212*			
(11)	XL Low Load	4,205	14,733	20,770	14,692	13,574	9,759	7,268	3,689	2,026	608	880	4,676	*96,880*	96,880	14,692	55.0%
(12)	XL Low Load-Transport	116,250	179,379	208,355	171,056	151,292	100,183	69,941	37,280	26,627	19,847	24,917	84,065	*1,189,192*			
(13)	XL High Load-Transport	28,920	35,960	25,159	16,451	15,315	18,775	20,994	22,523	20,767	18,159	33,250	29,065	*285,338*	285,338	16,451	144.5%
(14)	XL High Load	533,656	588,830	624,359	560,165	522,493	446,653	405,972	390,417	390,118	438,007	440,474	476,331	*5,817,475*			
(15)	Total	*3,108,632*	*4,962,184*	*6,231,216*	*6,108,265*	*5,504,104*	*4,101,787*	*2,635,523*	*1,750,214*	*1,285,423*	*1,199,637*	*1,292,583*	*1,717,474*	*39,897,042*	27,009,851	4,484,570	50.2%

Figure 18

The Company summarizes these changes in Figure 19, below.

	Docket 4647		Docket 4576		Change in	Change in	Pct Change	Pct Change
	Annual Sales	Feb Sales	Annual Sales	Feb Sales	Annual Volume	Feb Volume	Annual Volume	Feb Volume
Residential Non-Heating	749,942	112,206	698,046	107,427	51,896	4,779	7.4%	4.4%
Residential Heating	18,714,342	3,252,058	18,726,159	3,107,497	-11,817	144,561	-0.1%	4.7%
Small C&I	2,198,668	447,372	2,672,471	445,399	-473,803	1,973	-17.7%	0.4%
Small Transport								
Medium C&I	3,210,561	522,834	3,621,623	652,912	-411,062	-130,078	-11.4%	-19.9%
Med Transport								
Large Low Load	658,455	119,020	709,974	117,870	-51,519	1,150	-7.3%	1.0%
Large Low Load Transport								
Large High Load	206,682	22,569	199,360	22,322	7,322	247	3.7%	1.1%
Large High Load Transport								
XL Low Load	56,368	10,421	96,880	14,692	-40,512	-4,271	-41.8%	-29.1%
XL Low Load-Transport								
XL High Load-Transport	134,968	11,062	285,338	16,451	-150,370	-5,389	-52.7%	-32.8%
XL High Load								
Total	25,929,986	4,497,542	27,009,851	4,484,570	-1,079,865	12,972	-4.0%	0.3%

Figure 19

As demonstrated in Figure 19, the Residential Heating Sales class is forecasted to have greater February retail volumes (4.7 percent increase) with minor overall change in annual retail volumes (0.1 percent decrease) decreasing its load factor from 50.2 percent to 48.0 percent and driving the overall Sales load factor.

The other factor driving the growth in the Company's wholesale Sales-only design day is the annual use of the most recent year's daily wholesale sendout data. Underlying its Docket 4576 forecast was a backcasted design day for the 2014/15 heating season of 338,928 Dth for its Sales and Customer Choice customers, growing to 341,901 Dth in 2015/16. Following the 2015/2016 heating season, its Docket 4647 forecast was a backcasted design day for the 2015/16 heating season of 356,102 Dth for its Sales and Customer Choice customers, growing to 357,153 Dth in 2016/17. Hence, the Company's Docket 4576 forecasted peak day for 2015/16 underpredicted what the Company actually observed.

The Company performs its forecast of retail volumes by rate class annually so that it can reflect in its GCR filings the most recent information on its customer's gas usage. This year's GCR filing has the benefit of an additional 12 months of actual usage data since last year's GCR filing, and the Company's forecast is reflective of the trends in gas use as well as the Rhode Island economic climate. Thus, the fluctuations in the Sales forecast between this year's GCR filing and last year's GCR filing that Mr. Oliver notes in his testimony is attributable to the Company's observations of customer behavior over an additional 12-month period and is not an error or inconsistency in the forecast. Accordingly, there is no error or inconsistency in the forecast.

Q. What is the Company's response to Mr. Oliver's comment that there are large unexplained shifts in the distribution of gas use across months in both the Company's forecasts of normal weather and design winter requirements?

A. In Attachment BRO-5 (presented as Figure 20, below) and Attachment BRO-6 (presented as Figure 21, below), Mr. Oliver points out changes in monthly forecasted retail volumes by rate class from last year's GCR filing (Docket No. 4576) to this year's GCR filing and states that these changes ". . . can impact the Company's estimation of requirements under Design Winter, and possibly Cold Snap, planning scenarios."

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Attachment BRO-5

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Changes in Forecasted Normal Weather Annual Throughput by Rate Classification

Docket 4647 vs Docket 4576

TOTAL THROUGHPUT	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov - Oct
Residential Non-Heating													
Forecasted 2016-17	61,398	89,290	110,313	112,206	98,591	78,155	53,411	35,271	25,629	24,348	25,656	35,674	**749,942**
Forecasted 2015-16	48,049	71,423	92,942	107,427	113,117	87,291	46,799	31,200	24,471	22,307	24,221	28,799	**698,046**
Difference	13,349	17,867	17,371	4,779	(14,526)	(9,136)	6,612	4,071	1,158	2,041	1,435	6,875	51,896
% Difference	27.8%	25.0%	18.7%	4.4%	-12.8%	-10.5%	14.1%	13.0%	4.7%	9.1%	5.9%	23.9%	7.4%
Residential Heating													
Forecasted 2016-17	1,468,822	2,422,361	3,163,979	3,252,058	2,798,847	2,097,234	1,245,874	622,889	333,615	289,355	335,174	684,134	18,714,342
Forecasted 2015-16	1,462,287	2,349,767	3,119,896	3,107,497	2,828,266	2,124,881	1,241,085	751,389	425,245	352,061	402,675	561,110	18,726,159
Difference	6,535	72,594	44,083	144,561	(29,419)	(27,647)	4,789	(128,500)	(91,630)	(62,706)	(67,501)	123,024	(11,817)
% Difference	**0.4%**	3.1%	1.4%	4.7%	-1.0%	-1.3%	0.4%	-17.1%	-21.5%	-17.8%	-16.8%	21.9%	-0.1%
Small C&I													
Forecasted 2016-17	174,414	330,132	451,453	466,152	391,675	276,157	136,161	33,921	2,491	2,243	2,511	43,678	2,310,988
Forecasted 2015-16	155,461	421,163	514,559	456,333	406,403	284,086	183,207	98,723	59,708	45,821	48,940	71,448	2,745,852
Difference	18,953	(91,031)	(63,106)	9,819	(14,728)	(7,929)	(47,046)	(64,802)	(57,217)	(43,578)	(46,429)	(27,770)	(434,864)
% Difference	12.2%	-21.6%	-12.3%	2.2%	-3.6%	-2.8%	-25.7%	-65.6%	-95.8%	-95.1%	-94.9%	-38.9%	-15.8%
Medium C&I													
Forecasted 2016-17	455,215	701,951	890,573	910,903	793,576	614,469	395,543	234,724	158,138	147,199	159,385	250,580	5,712,256
Forecasted 2015-16	420,216	727,334	950,360	1,061,970	914,720	646,050	395,507	243,192	202,482	178,069	180,123	246,393	6,166,416
Difference	34,999	(25,383)	(59,787)	(151,067)	(121,144)	(31,581)	36	(8,468)	(44,344)	(30,870)	(20,738)	4,187	(454,160)
% Difference	8.3%	-3.5%	-6.3%	-14.2%	-13.2%	-4.9%	0.0%	-3.5%	-21.9%	-17.3%	-11.5%	1.7%	-7.4%
Large C&I LLF													
Forecasted 2016-17	213,509	356,808	466,290	476,816	407,446	302,671	175,337	81,992	38,056	31,484	38,657	92,056	2,681,122
Forecasted 2015-16	246,341	448,979	532,256	473,022	413,083	277,780	177,315	90,375	57,303	47,629	62,819	133,210	2,960,112
Difference	(32,832)	(92,171)	(65,966)	3,794	(5,637)	24,891	(1,978)	(8,383)	(19,247)	(16,145)	(24,162)	(41,154)	(278,990)
% Difference	-13.3%	-20.5%	-12.4%	0.8%	-1.4%	9.0%	-1.1%	-9.3%	-33.6%	-33.9%	-38.5%	-30.9%	-9.4%
Large C&I HLF													
Forecasted 2016-17	90,041	106,911	119,621	121,603	113,399	101,004	85,940	75,294	69,410	68,640	69,473	76,143	1,097,479
Forecasted 2015-16	93,247	124,616	142,560	139,652	125,841	106,329	87,435	81,426	76,676	77,129	74,284	82,377	1,211,572
Difference	(3,206)	(17,705)	(22,939)	(18,049)	(12,442)	(5,325)	(1,495)	(6,132)	(7,266)	(8,489)	(4,811)	(6,234)	(114,093)
% Difference	-3.4%	-14.2%	-16.1%	-12.9%	-9.9%	-5.0%	-1.7%	-7.5%	-9.5%	-11.0%	-6.5%	-7.6%	-9.4%
Extra Large C&I LLF													
Forecasted 2016-17	101,540	162,218	208,146	212,593	183,292	139,027	85,231	45,726	26,996	24,231	27,220	49,633	1,265,853
Forecasted 2015-16	120,455	194,112	229,125	185,748	164,866	109,942	77,209	40,969	28,653	20,455	25,797	88,741	1,286,072
Difference	(18,915)	(31,894)	(20,979)	26,845	18,426	29,085	8,022	4,757	(1,657)	3,776	1,423	(39,108)	(20,219)
% Difference	-15.7%	-16.4%	-9.2%	14.5%	11.2%	26.5%	10.4%	11.6%	-5.8%	18.5%	5.5%	-44.1%	-1.6%
Extra Large C&I HLF													
Forecasted 2016-17	560,270	598,755	627,612	630,434	611,840	583,749	549,611	524,542	528,931	527,168	529,074	543,369	6,815,355
Forecasted 2015-16	562,576	624,790	649,518	576,616	537,808	465,428	426,966	412,940	410,885	456,166	473,724	505,396	6,102,813
Difference	(2,306)	(26,035)	(21,906)	53,818	74,032	118,321	122,645	111,602	118,046	71,002	55,350	37,973	712,542
% Difference	-0.4%	-4.2%	-3.4%	9.3%	13.8%	25.4%	**28.7%**	**27.0%**	28.7%	15.6%	11.7%	7.5%	11.7%
Total Throughput													
Forecasted 2016-17	3,125,209	4,768,426	6,037,987	6,182,765	5,300,075	4,114,311	2,727,108	1,654,359	1,183,266	1,114,668	1,187,150	1,775,267	39,170,591
Forecasted 2015-16	3,108,632	4,962,184	6,231,216	6,108,265	5,504,104	4,101,787	2,635,523	1,750,214	1,285,423	1,199,637	1,292,583	1,717,474	39,897,042
Difference	16,577	(193,758)	(193,229)	74,500	(204,029)	12,524	91,585	(95,855)	(102,157)	(84,969)	(105,433)	57,793	(726,451)
% Difference	**0.5%**	-3.9%	-3.1%	1.2%	-3.7%	0.3%	3.5%	-5.5%	-7.9%	-7.1%	-8.2%	3.4%	-1.8%

Figure 20

National Grid- RI Gas

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Attachment BRO-6

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Comparison of National Grid's Forecasted Design Winter Sales

Docket No. 44647 vs Docket No. 4576 by Rate Class by Month

	Forecasted Design Winter Sales					Design
	Nov	Dec	Jan	Feb	Mar	Nov - Mar
Residential Non-Heating						
Forecasted 2016-17	70,090	97,034	117,723	121,080	109,244	515,171
Forecasted 2015-16	53,941	77,188	98,971	115,968	126,115	472,183
Difference	16,149	19,846	18,752	5,112	(16,871)	42,988
% Difference	29.9%	25.7%	18.9%	4.4%	-13.4%	9.1%
Residential Heating						
Forecasted 2016-17	1,742,439	2,677,188	3,412,157	3,548,322	3,159,670	14,539,776
Forecasted 2015-16	1,717,242	2,586,711	3,357,695	3,382,220	3,182,483	14,226,351
Difference	25,197	90,477	54,462	166,102	(22,813)	313,425
% Difference	1.5%	3.5%	1.6%	4.9%	-0.7%	2.2%
Small C&I						
Forecasted 2016-17	204,548	354,125	470,892	492,298	430,187	1,952,050
Forecasted 2015-16	174,169	456,463	542,538	485,434	446,417	2,105,021
Difference	30,379	(102,338)	(71,646)	6,864	(16,230)	(152,971)
% Difference	17.4%	-22.4%	-13.2%	1.4%	-3.6%	-7.3%
Medium C&I						
Forecasted 2016-17	296,466	438,183	548,327	567,770	508,198	2,358,944
Forecasted 2015-16	257,001	462,575	606,594	708,784	631,256	2,666,210
Difference	39,465	(24,392)	(58,267)	(141,014)	(123,058)	(307,266)
% Difference	15.4%	-5.3%	-9.6%	-19.9%	-19.5%	-11.5%
Large C&I LLF						
Forecasted 2016-17	63,090	98,666	125,858	130,264	115,134	533,012
Forecasted 2015-16	62,348	121,502	142,955	128,647	117,169	572,621
Difference	742	(22,836)	(17,097)	1,617	(2,035)	(39,609)
% Difference	1.2%	-18.8%	-12.0%	1.3%	-1.7%	-6.9%
Large C&I HLF						
Forecasted 2016-17	18,157	20,943	23,143	23,587	22,278	108,108
Forecasted 2015-16	14,538	19,734	24,407	23,071	14,405	96,155
Difference	3,619	1,209	(1,264)	516	7,873	11,953
% Difference	24.9%	6.1%	-5.2%	2.2%	54.7%	12.4%
Extra Large C&I LLF						
Forecasted 2016-17	5,623	8,689	11,051	11,439	10,137	46,939
Forecasted 2015-16	4,929	16,378	22,481	16,056	15,379	75,223
Difference	694	(7,689)	(11,430)	(4,617)	(5,242)	(28,284)
% Difference	14.1%	-46.9%	-50.8%	-28.8%	-34.1%	-37.6%
Extra Large C&I HLF						
Forecasted 2016-17	11,272	11,153	11,069	11,090	11,109	55,693
Forecasted 2015-16	30,194	37,373	25,233	16,451	15,315	124,566
Difference	(18,922)	(26,220)	(14,164)	(5,361)	(4,206)	(68,873)
% Difference	-62.7%	-70.2%	-56.1%	-32.6%	-27.5%	-55.3%
Total Throughput						
Forecasted 2016-17	2,411,685	3,705,981	4,720,220	4,905,850	4,365,957	20,109,693
Forecasted 2015-16	2,314,362	3,777,924	4,820,874	4,876,631	4,548,539	20,338,330
Difference	97,323	(71,943)	(100,654)	29,219	(182,582)	(228,637)
% Difference	4.2%	-1.9%	-2.1%	0.6%	-4.0%	-1.1%

Figure 21

As stated earlier, the Company performs its forecast of retail volumes by rate class annually so that it can reflect in its GCR filings the most recent information on its customer's gas usage. The instant GCR filing has the benefit of an additional 12 months of actual usage data since its previous GCR filing and its forecast is reflective of the trends in gas use as well as the Rhode Island economic climate. Thus, the fluctuations in the monthly forecasted retail volumes between this year's GCR filing and last year's GCR filing that Mr. Oliver notes in his testimony is attributable to the Company's observations of customer behavior over an additional 12-month period and is not an error or inconsistency in the forecast.

Additionally, as documented in the Company's Long-Range Plan filings, while the retail volume forecast specifies the growth in its wholesale forecast, the Company's wholesale Design Day, Design Winter, and Cold Snap are based on its regression analysis of its daily wholesale sendout and weather observations, which are updated annually. Hence, the distribution of retail volumes has no impact on the distribution of its forecasted design volumes.

IV. <u>Gas Supply Planning Process</u>

Q. Do the Company's forecasts provide a reasonable basis for making determinations for the acquisition of gas supply resources?

A. Yes. As I discuss earlier in my rebuttal testimony and in the Company's Long-Range Plan submissions, the Company uses regression analysis to develop its retail forecast, which is based on historical data beginning in 2010, and historical and forecasted economic and fuel price data specific to its Rhode Island territory. The Company's design day and design year gas resource planning begins with its regression analysis of daily sendout versus weather from the most-recent 12-month period. It is this design day and design year forecast that underlies the Company's planning decisions to ensure the least-cost reliable service to its Rhode Island customers on the coldest day of the year.

Q. What is the Company's response to Mr. Oliver's comment that there are substantial differences in the Company's planning criteria for Rhode Island and that of other utilities?

A. On pages 43-44 of this testimony, Mr. Oliver discusses the frequency of design day conditions that the Company uses in making its planning decisions, and he compares that criteria to that of other utilities. Mr. Oliver expresses his concern that the Company's planning criteria may produce results that overstate the amount of capacity that the Company requires to provide reliable service to its Rhode Island gas customers. As I discuss earlier in my rebuttal testimony, the Company's design day and design year forecast underlies its gas resource planning decisions. The Company's method of using a frequency of one occurrence in 98.86 years to depict design day conditions is more conservative relative to other utilities. However, this method reflects what the Company believes is reasonable for ensuring that sufficient capacity will exist even on the coldest day of a year. To the extent that the Public Utilities Commission (PUC) determined that the Company should be using a lesser design day standard, the Company could implement that into its forecasting process; however there is some risk that it would be unable to serve all customers on that coldest day of a year.

Q. Is the Company's forecast of the Cumberland LNG requirements reasonable?

A. Yes. As I explained earlier, the Company's wholesale forecast provides the basis for making determinations for the acquisition of gas supply resources. The Company then models the wholesale requirements of its capacity-eligible customers for four territories in Rhode Island (Providence, Bristol/Warren, Westerly, and Valley) using its SENDOUT model to establish its portfolio requirements on a least-cost basis. By modeling each territory separately and simultaneously, the Company can best determine its pipeline requirements, as well as its LNG requirements and the interactions between the two.

Q. Why should the Public Utilities Commission accept the Company's forecasts for purposes of the upcoming GCR period and for the longer-term acquisition of gas supply resources?

A. For purposes of the upcoming GCR period and for the longer-term acquisition of gas supply resources, the Company's forecasts should be accepted to permit the Company appropriate cost recovery as well as to permit the Company to serve its customers in a safe, reliable, and least-cost fashion.

V. Conclusion

Q. Does this conclude your rebuttal testimony in this proceeding?

A. Yes.