nationalgrid

Robert J. Humm
Senior Counsel

October 22, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4872 - 2018 Gas Cost Recovery Filing
<u>National Grid's Rebuttal Position</u>

Dear Ms. Massaro:

In connection with the above-referenced docket, enclosed please find National Grid's[1] Rebuttal Position in response to the pre-filed direct testimony of Bruce Oliver submitted on October 16, 2018 on behalf of the Division of Public Utilities and Carriers (the Division) regarding National Grid's 2018 Gas Cost Recovery (GCR) filing.

National Grid's Rebuttal Position consists of the pre-filed joint rebuttal testimony and attachments of Nancy G. Culliford, Elizabeth D. Arangio, Ann E. Leary, Theodore E. Poe, Jr., John M. Protano, and Stephen P. Greco. The joint rebuttal testimony substantiates National Grid's request for the approval of all costs submitted with its GCR filing in this docket, effective November 1, 2018. In doing so, the joint rebuttal testimony refutes Mr. Oliver's recommendations that (1) costs associated with a supply contract with ENGIE have not been economically justified and should be excluded from recovery through the GCR; (2) costs to replace the supply lost from the decommissioning of the Cumberland liquefied natural gas tank in 2016 should be excluded from recovery through the GCR because the Division has not examined the prudency of the Company's maintenance of the facility; and (3) the Company's fixed cost commitments in the form of reservation charges are uneconomical to Rhode Island customers. The joint rebuttal testimony also addresses the remaining findings and recommendations submitted by Mr. Oliver in his testimony.

This filing also contains a Request for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain confidential gas cost pricing information provided in the joint rebuttal testimony. Accordingly, National Grid has provided the PUC with one complete unredacted copy of the confidential materials in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release,"** and has included redacted copies of the materials for the public filing.

---

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

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosures

cc: Docket 4872 Service List
Leo Wold, Esq.
Jonathan Schrag, Division
John Bell, Division
Al Mancini, Division
Bruce Oliver

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2018	)	Docket No. 4872

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential, competitively sensitive, and/or proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On August 31, 2018, National Grid submitted its 2018 Annual Gas Cost Recovery (GCR) filing in the above-captioned docket. On October 16, 2018, Bruce Oliver submitted initial testimony on behalf of the Division of Public Utilities and Carriers (Division). On October 22, 2018, the Company submitted its joint rebuttal testimony in response to Mr. Oliver's initial testimony. The Company's joint rebuttal testimony includes confidential gas cost pricing information, including competitively sensitive information relative to a Request for Proposals

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

(RFP) and pricing terms pursuant to confidential supply agreements. In accordance with Rule 1.2(g)(3), National Grid has provided a redacted public version of the GCR filing, as well as an unredacted, confidential version.

Therefore, the Company requests that, pursuant to Rule 1.2(g), the PUC afford confidential treatment to the gas cost pricing information contained the Company's joint rebuttal testimony.

II. LEGAL STANDARD

Rule 1.2(g) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal v. Convention Ctr. Auth.*, 774 A.2d 40, 47 (R.I. 2001).

The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The gas cost pricing information provided in National Grid's joint rebuttal testimony is confidential and privileged information of the type that the Company would not ordinarily make public. As such, the information should be protected from public disclosure. Public disclosure of such information could impair National Grid's ability to obtain advantageous pricing or other terms in the future, thereby causing substantial competitive harm. Accordingly, National Grid is providing the information on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,
THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

____

Robert J. Humm, Esq. (#7920)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7415
Dated: October 22, 2018

REDACTED VERSION

JOINT REBUTTAL TESTIMONY

OF

NANCY G. CULLIFORD

ELIZABETH D. ARANGIO

ANN E. LEARY

THEODORE POE, JR.

JOHN M. PROTANO

AND

STEPHEN P. GRECO

Table of Contents

I. Introduction

Q. Ms. Culliford, please state your name and business address.

A. My name is Nancy G. Culliford. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 31, 2018, I submitted pre-filed joint direct testimony in this docket with Elizabeth D. Arangio on behalf of The Narragansett Electric Company d/b/a National Grid (the Company).

Q. Ms. Arangio, please state your name and business address.

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

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 31, 2018, I submitted pre-filed joint direct testimony in this docket with Ms. Culliford on behalf of the Company.

Q. Ms. Leary, please state your name and business address.

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

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 31, 2018, I submitted pre-filed direct testimony in this docket on behalf of the Company.

Q. Mr. Poe, please state your name and business address.

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

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 31, 2018, I submitted pre-filed direct testimony in this docket on behalf of the Company.

Q. Mr. Protano, please state your name and business address.

A. My name is John M. Protano. My business address is 100 East Old Country Road, Hicksville, New York 11801.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. On August 31, 2018, I submitted pre-filed direct testimony in this docket on behalf of the Company.

Q. Mr. Greco please state your name and business address.

A. My name is Stephen P. Greco. My business address is 25 Hub Drive, Melville, New York 11747.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc. (National Grid) as Director of Pressure Regulation and Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG) Assets. In this position, I am responsible for the asset management of National Grid's pressure regulating facilities, LNG facilities, and related equipment in all jurisdictions, including Rhode Island.

Q. Please describe your educational background and professional experience.

A. I graduated from the New York Institute of Technology in 1981 with a Bachelor of Science degree in Mechanical Engineering Technology. In 1987, I graduated from the State University of New York at Stony Brook with a Master of Science degree in Engineering. I also hold a Professional Engineer license, and am licensed in the State of New York. I have worked for National Grid or one of its predecessor companies for the last 29 years. My experience at National Grid includes 16 years in various management roles related to LNG, including Plant Engineer, Plant Manager, and Project Manager. I assumed my current position August 2016.

Q. Are you a member of any professional organizations?

A. I am a member of the American Gas Association, as well as the American Society of Mechanical Engineers (ASME).

Q. Have you previously testified before the Public Utilities Commission (PUC)?

A. Yes. I submitted pre-filed direct testimony in the Company's 2017-18 Gas Cost Recovery (GCR) proceeding in Docket No. 4719 and in the Company's Fiscal Year (FY) 2019 Gas Infrastructure, Safety, and Reliability proceeding in Docket No. 4781.

Q. What is the purpose of your joint rebuttal testimony?

A. The purpose of our joint rebuttal testimony is to respond to the pre-filed direct testimony and comments submitted to the PUC in this proceeding by Bruce R. Oliver on behalf of the Division of Public Utilities and Carriers (Division). In particular, our rebuttal testimony substantiates the Company's request for the approval of all costs submitted with its 2018-19 GCR filing in this docket, effective November 1, 2018. Furthermore, our rebuttal testimony refutes Mr. Oliver's recommendations that (1) the costs associated with a supply contract with ENGIE has not been economically justified and should be excluded from recovery through the GCR; (2) costs to replace the supply lost from the decommissioning of the Cumberland LNG tank in 2016 should be excluded from recovery through the GCR because the Division has not examined the prudency of the Company's maintenance of the facility; and (3) the Company's fixed cost commitments in the form of reservation charges are uneconomical to Rhode Island customers. Our rebuttal testimony also addresses the remaining findings and recommendations submitted by Mr. Oliver.

Q. How is your testimony organized?

A. Following this introductory section, Section II of our rebuttal testimony explains why the Company's fixed costs, including supplier demand charges, were reasonable and necessary to procure even though such costs have increased. Section III explains why the PUC should not exclude from recovery any costs associated with a supply agreement with ENGIE. Section IV explains why the PUC should not exclude from recovery any costs associated with the decommissioning of the Cumberland LNG tank in 2016. Section V responds to the various other recommendations and findings made by Mr. Oliver. Section VI is the conclusion.

Q. Are you sponsoring any attachments as part of your testimony in this proceeding?

A. Yes. We are sponsoring the following rebuttal attachments that accompany our testimony:

Attachment 1-Joint Rebuttal

II. The Company's Fixed Costs, Including Supplier Demand Charges, Are Reasonable

Q. Are the Company's fixed costs higher this year than in prior years?

A. Yes, the Company's fixed costs are higher this year than in prior years. Two key factors have driven the higher level of fixed costs: (1) the significant increase in the Company's planning load requirements, and (2) market conditions.

Q. How has the significant increase in the Company's planning load requirements impacted the Company's gas costs?

A. The Company's planning load (i.e., projected design load requirements that must be procured by the Company) has increased significantly from last year.[1] In other words, the amount of gas the Company needs to meet the supply requirements for the Rhode Island customers it plans for has increased significantly. A comparison of the design day, design heating season, and design year load forecasts for 2017-18 and 2018-19 is provided in the table below.[2]

[1] This information is also explained in the pre-filed joint direct testimony of Ms. Culliford and Ms. Arangio at pages 7 through 10.

[2] This table is also provided in Ms. Culliford and Ms. Arangio's pre-filed joint direct testimony at page 9.

2017/18 and 2018/19 Design Forecast Comparison

Design Day	2017/18 Forecast	2018/19 Forecast	Delta	Delta %
Total Design Day (Sales + Transportation)	358,008	390,227	32,219	9.0%
Design Day - Sales	295,421	336,289	40,868	13.8%
Design Day - Transportation	62,587	53,938	(8,649)	-13.8%
Design Heating Season (November - March)	**2017/18 Forecast**	**2018/19 Forecast**	**Delta**	**Delta %**
Total Design Heating Season (Sales + Transportation)	26,723,437	29,676,936	2,953,499	11.1%
Design Heating Season - Sales	21,492,629	24,782,750	3,290,121	15.3%
Design Heating Season - Transportation	5,230,808	4,894,186	(336,622)	-6.4%
Design Year	**2017/18 Forecast**	**2018/19 Forecast**	**Delta**	**Delta %**
Total Design Year (Sales + Transportation)	37,754,531	41,521,561	3,767,030	10.0%
Design Year - Sales	29,325,948	33,532,200	4,206,252	14.3%
Design Year - Transportation	8,428,583	7,989,361	(439,222)	-5.2%

The forecast filed in Docket No. 4719 against this year's forecast.
Volumes include only customers utilizing Company assets.
Volumes are in decatherm (Dth).

To meet the significant increase in customer requirements, the Company had to procure additional supply resources. Specifically, the Company had to procure an additional 32,219 dekatherms (Dth) to meet the peak day requirements and 2,953,499 Dth to meet the peak season requirements. These volumes represent increases of ***9 percent*** and ***11.1 percent***, respectively. Comparatively speaking, the equivalent year over year increase in Sales and FT-2 design volumes were 1.2 percent per annum and 1.4 percent per annum over the years from 2014-15 to 2016-17. See Figure 1 below for historical annual demand, and Figure 2 below for historical peak season demand.

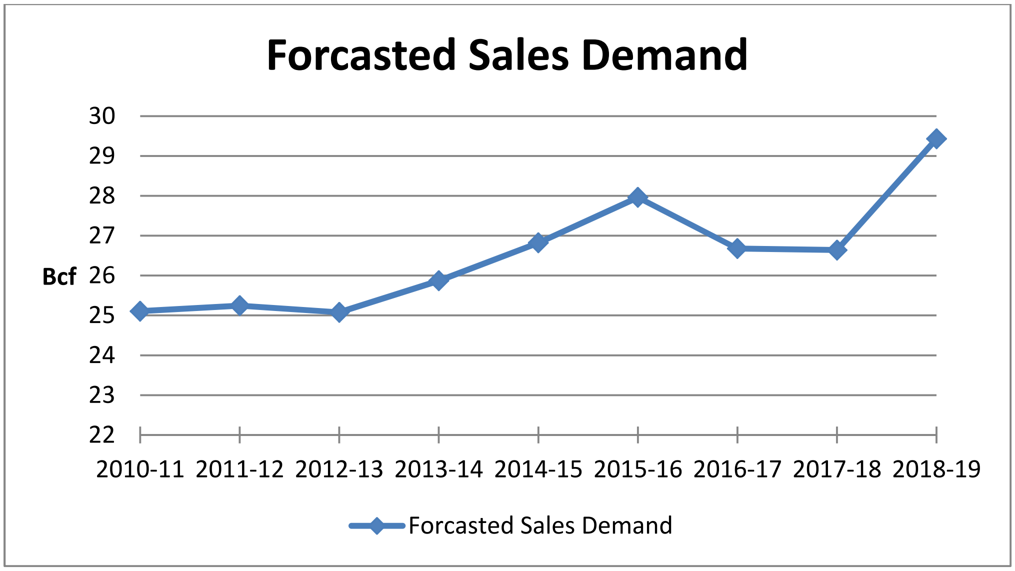


Figure 1: Annual Demand

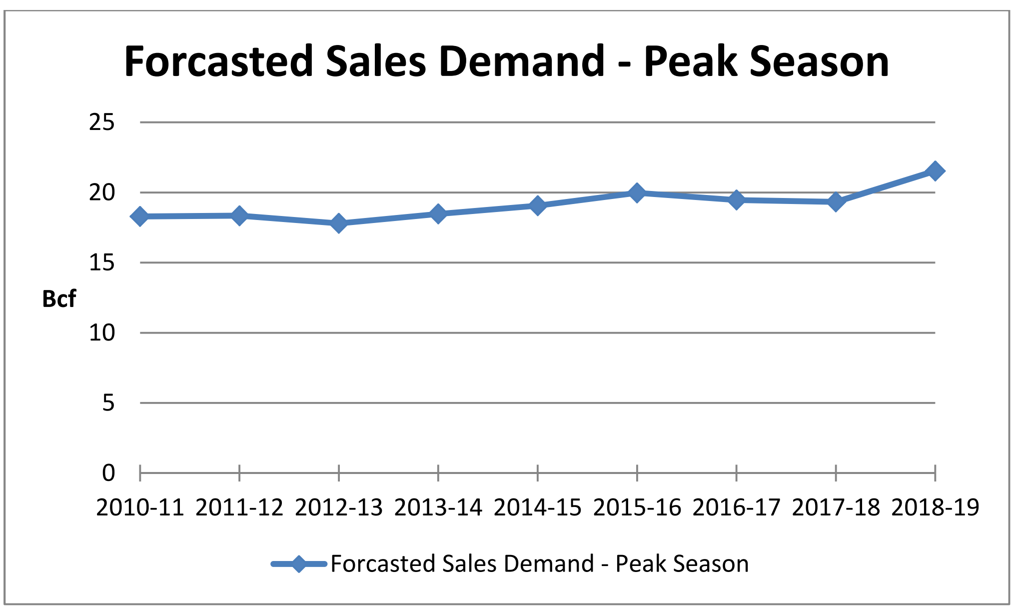


Figure 2: Peak Season Demand

Q. What is the reason for the significant increase in the Company's planning load requirements?

A. The Company's portfolio of supplies for the GCR year November 2018 through October 2019 are designed to provide firm service to the Company's customers based on its 2018 forecast. Two factors have led to an increased forecasted load for the upcoming GCR year relative to the Company's forecast in its 2017 GCR submission:

- Since the submission of the Company's Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27 (Long-Range Plan) in Docket No. 4816, the Company updated its forecast to incorporate the customer demand data from the 2017/18 heating season, where the Company had observed demand higher than its 2017 forecast had predicted; and
- In response to seeing that its forecasted allocation of demand between its capacity-eligible and its capacity-exempt customers in its 2017 forecast was not reflecting the Company's actual observations, the Company improved its forecasting methodology (*see* the Company's response to Data Request Division 2-11).

In both its 2017 and its 2018 GCR submissions, the Company continued to use its 5,458 heating degree day (HDD) normal year for ratemaking purposes.

Q. How have the changes to the market conditions impacted the Company's gas costs?

A. The Company's ability to procure the additional needed resources has been exacerbated by the fact that the two interstate pipelines feeding the Company's Rhode Island distribution system are constrained. For years, the Company has benefitted from increased gas supplies delivered to Dracut and/or Beverly in Massachusetts and has transported these volumes to Rhode Island on relatively inexpensive short-haul capacity on both Algonquin Gas Transmission Company (Algonquin) and Tennessee Gas Pipeline (Tennessee).[3] However, these sources saw a relatively quick decline in production, rendering the supply points illiquid. In response to this phenomenon, coupled with the decreased access to imported LNG, in 2013 the Company embarked upon a two pronged approach to address the near-term and long-term reliability of the gas supply portfolio, including (1) incremental pipeline capacity with access to liquid supply points, and (2) short-term and long-term LNG solutions[4].

To address the first approach, the Company pursued the following incremental pipeline projects:

1) **Algonquin's Incremental Market (AIM) Project**, which provided a one-for-one replacement of the Company's existing HubLine capacity of 18,000 Dth per day from Ramapo, New York to the Company's citygates. This project was fully in service in January 2017.

[3] "Short-haul capacity" in this instance refers to capacity that originates in the same market area that it delivers to, so no "long-haul" transportation is necessary. Fixed cost associated with short-haul capacity is far less expensive than fixed costs associated with long-haul capacity.

[4] The short-term LNG solutions include the Company's agreements for off-peak LNG refill with both Gaz Metropolitan and ENGIE. These costs have been included in the Company's annual GCR filings beginning in 2016/17. The long-term solutions, discussed in Ms. Culliford and Ms. Arangio's pre-filed joint direct GCR testimony, are not expected to be available until the 2020 and 2021 off-peak seasons, so no costs associated with these projects are included in this GCR filing.

2) **Millennium Pipeline Expansion Project**, which will provide an additional 9,000 Dth per day of incremental upstream capacity delivered into Algonquin and flow on a portion of the Company's existing AIM capacity. This project will reduce the Company's exposure at Ramapo, typically priced at the Tetco/M3 index, which can experience extreme price blow-outs on the colder days during the winter season. This project is expected to be in service for this winter season in December 2018.[5]

3) **Tennessee's Northeast Energy Direct (NED) Project**, which would have provided a one-for-one replacement of the Company's existing Dracut capacity (15,000 Dth per day) and also provided 20,000 Dth per day of incremental capacity to the citygates. This project was canceled in May 2016.

Following the cancellation of Tennessee's NED Project, the Company pursued discussions with Tennessee regarding availability of short-haul capacity (zone 6 to zone 6) to the Company's citygates now that it was no longer reserved for the NED Project. The Company also engaged in discussions with Portland Natural Gas Transmission System (Portland)/Union/TransCanada regarding the availability of capacity to access liquid supplies from Dawn, Ontario to be delivered into Tennessee at Dracut.

[5] The Company previously provided this information in Ms. Culliford and Ms. Arangio's pre-filed joint direct testimony at pages 24-25; in its Long-Range Plan submitted on March 30, 2018 in Docket No. 4816; and in the Company's GCR filing last year (Docket No. 4719) in Ms. Culliford's pre-filed direct testimony at page 14.

As a result of these discussions, the Company entered into two agreements with Tennessee and one agreement with Portland/Union/TransCanada, as described below:[6]

1) **<u>Tennessee Agreements</u>:** In aggregate, the two Tennessee Agreements will allow the Company to access up to 44,000 Dth per day, when the agreements are fully phased-in, from Dracut and Everett for delivery to the Company's firm gas customers behind its existing citygates at Lincoln and Cranston, Rhode Island.

   a) The Tennessee agreement for 24,000 Dth per day to replace output from the decommissioned Cumberland LNG tank will go into service effective November 1, 2018. This contract volume and associated cost are ***not*** incremental compared to last year. The 24,000 Dth per day has been in the Company's portfolio since the winter of 2016/17 when the Cumberland LNG was taken out of service.

   b) The Tennessee agreement for an incremental 20,000 Dth per day (when fully phased-in) was originally planned to go into service on November 1, 2018 with a maximum daily quantity (MDQ) of 5,000 Dth per day; increasing on November 1, 2019 to 10,000 Dth per day; and increasing again on November , 2023 to 20,000 Dth per day. To meet a portion of

[6] The Company previously provided this information in Ms. Culliford and Ms. Arangio's pre-filed joint direct testimony at pages 14 through 17; in its Long-Range Plan submitted on March 30, 2018 in Docket No. 4816; and in an informal filing submitted to the Division and Mr. Oliver on November 30, 2017.

the increase in customer requirements, the MDQ on this capacity was accelerated to 15,000 Dth per day effective November 1, 2018.[7]

2) **Portland/Union/TransCanada Agreement:** The Portland agreement will allow the Company to access up to 29,000 Dth per day, when the agreement is fully phased-in, from Dawn, Ontario to Dracut. For Phase I, commencing on or around November 1, 2018, the Company shall receive a MDQ of 10,757 Dth per day.[8] For Phase II, commencing on or around November 1, 2019, the Company shall receive a MDQ of 25,705 Dth per day. For Phase III, commencing on or around November 1, 2020, the Company shall receive a MDQ of 29,000 Dth per day.

Q. With the resources you have described, did the Company have sufficient resources to meet customers' needs for the 2018-19 winter season?

A. No. Despite the Company's efforts to procure additional capacity to meet current and forecasted customer requirements, the Company ***still*** needed to procure incremental resources to meet the significant increase in the Company's design day and design season requirements. As the Company has done in prior years when additional resources are needed over and above those in the Company's portfolio, on July 26, 2018, the Company

[7] This information is also explained in Ms. Culliford and Ms. Arangio's pre-filed joint direct testimony at pages 15 through 16.

[8] This is a correction to page 17, lines 12 through 14 of Ms. Culliford and Ms. Arangio's pre-filed joint direct testimony, which refers to this amount as firm capacity entitlements of 11,037 Dth per day on the Union Gas pipeline system from Dawn to Parkway and 10,910 Dth per day on TransCanada from Parkway to East Hereford. Both volume references should be 10,757 Dth per day.

issued a Request for Proposals (RFP) for citygate delivered peaking supplies. Citygate delivered peaking supplies are supplies delivered to the Company's distribution system (either on the Algonquin or Tennessee pipelines) by a third party. In the RFP, the Company requested an affidavit from the prospective bidders in order to guarantee primary delivery to the Company's citygate or an explanation of the priority of service to be used in meeting the Company's gas supply requirements if selected. The Company needed the affidavit as a result of events that occurred in Massachusetts last year during the December/January cold snap. [redacted] The risk of such default leaves the Company in the precarious position of potentially not having sufficient supplies for its customers when needed most. Thus, the Company believes it would not be prudent to ignore the risk of a future supplier default, as it is essential that such supplies be delivered to Rhode Island customers on the coldest days when they are most needed.

However, the bids the Company received in response to the July 26, 2018 RFP [redacted]. Furthermore, the [redacted] offered in response to the July 26, 2018 RFP reflected a [redacted] At this point, the Company needed to act swiftly to secure additional resources. As discussed in Ms. Culliford and Ms. Arangio's pre-filed joint direct testimony, the Company looked at the ***plausible options available*** (that were also operationally feasible) which included only (1) acceleration of the Tennessee incremental capacity, and (2) incremental peak season LNG deliveries.

Q. Mr. Oliver's testimony asserts that the reservation charges paid to gas suppliers appear to be uneconomic for Rhode Island's gas consumers. Does the Company agree with this statement?

A. No. This statement is simply not true, and Mr. Oliver provides no basis for the statement. Like every other procurement decision, the Company used the SENDOUT model to determine the mix of ***available*** resources that represented the ***total*** least-cost solution (including both fixed and variable costs). The results recommended the following combination of incremental resources:

- Citygate delivered peaking supply for 14,100 Dth per day;
- Increasing peak season LNG volume from 125,000 Dth with three trucks per day to 300,000 Dth with eight trucks per day; and
- Accelerating the incremental Tennessee contract from a MDQ of 5,000 Dth per day to 15,000 Dth per day (noting that a total of 20,000 Dth per day was available when fully phased-in).

The Company secured the additional resources so that it could ensure a reliable, least-cost portfolio of resources is available to meet forecasted peak day and peak season customer requirements this winter season. When the cold snap occurred so early in the 2017/18 winter season and reduced inventories far below what the Company needed to have on hand so as to plan for design weather going forward, to ***not*** have procured the additional resources would have been reckless and potentially uneconomic for Rhode Island's gas customers.

The Company is obligated to maintain a least-cost portfolio of resources in order to meet design day and design season customer requirements. As the interstate pipelines serving the region continue to remain constrained, and become even more constrained until incremental capacity comes on line, the Company's options will be limited when seeking additional resources to be delivered to its distribution system. It is under these very conditions that the Company must secure access to supplies throughout the winter period. This is exactly what the Company has done for the 2018-19 winter. The resources available in the market place for this winter are offered under a cost structure with high fixed costs and lower variable costs. The Company is equally concerned about the impact of the additional fixed costs included in the Company's filing, but the Company did not enter into these arrangements lightly or arbitrarily without consideration of the best interests of its customers. The Company determined the least-cost portfolio ***based on the options available***. The need to secure access to resources is paramount to maintaining reliability.

Q. Are the challenges resulting from the changing market conditions unique to Rhode Island?

A. No. National Grid is experiencing these same challenges in both Massachusetts and New York. In both territories, as in Rhode Island, customer requirements have increased in locations where interstate pipeline capacity constraints exist, resulting in incremental costs to secure the necessary resources to reliably serve customer loads.

Q. Does the Company agree with Mr. Oliver's assertion that the Company's commitments to substantial reservation charges are not beneficial to Rhode Island customers?

A. No. The Company strongly disagrees with Mr. Oliver's unsupported suggestion that the Company's commitment to substantial fixed cost payments appear more beneficial to the Company than its Rhode Island gas customers. The Company further disagrees with Mr. Oliver's comparison of the fixed cost commitments to a very expensive and uneconomic insurance policy under which the annual premiums quickly exceed the expected cost avoidance benefits. To put Mr. Oliver's insurance example into context, consider the following: a responsible individual who maintains car insurance, and is fortunate enough to avoid a traffic incident for several years, would ***not*** cancel her insurance because annual premiums may exceed the expected cost avoidance benefits. When considered in the context of portfolio planning, to not have sufficient supply to meet the needs of its customers because costs to procure the supply have increased would be reckless and irresponsible of the Company. The Company does not plan a supply portfolio hoping to break even on the arrangement, as Mr. Oliver suggests. Instead, the Company plans a supply portfolio to maintain reliability while minimizing costs. To do as Mr. Oliver suggests would undermine the premise of portfolio planning.

Q. Do you agree with Mr. Oliver's assertion that the Company's gas supply planning lacks necessary sensitivity to the uncertain weather conditions in which it must operate, and that during the winter of 2017-18 the Company basically found itself without a plan for dealing with a cold snap that occurred earlier in the winter than it had modeled?

A. No. The Company's forecast and planning process – as detailed in the Company's Long-Range Plans filed biannually, and most recently filed on March 30, 2018 in Docket No. 4816 – not only includes a normal, design and a high case, but also includes a cold snap (*see* Docket No. 4816 at Chart IV-C-1, pages 15-17). The Company has used a 14-day cold snap, occurring during the coldest 14-day period of the Company's normal year (January 8 through January 21) to test the adequacy of inventories and refill requirements. The table below shows the ***actual*** HDDs, as measured at T.F. Green Airport, compared to forecasted normal and design weather HDDs for the five week period of cold weather last winter.

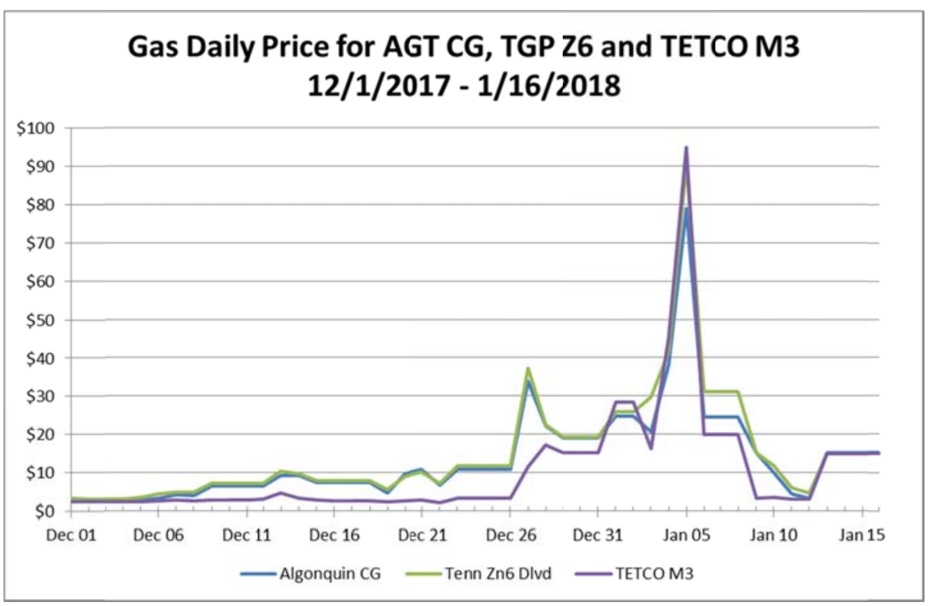
Heating Degree Day Summary (T.F. Green Aiport)					
	ACTUAL	NORMAL	DESIGN	Actual vs. Normal	Actual vs. Design
Week Ending 12/17	263	212	238	124%	111%
Week Ending 12/24	200	191	214	105%	93%
Week Ending 12/31	348	171	193	204%	180%
Week Ending 1/7	351	219	238	160%	147%
Week Ending 1/14	205	264	286	78%	72%
Total	1,367	1,057	1,169	129%	117%

Beginning December 11, 2017 through and including January 7, 2018, actual weather was colder than forecasted normal weather for all four weeks and colder than forecasted ***design*** weather in three of the four weeks.

Because of the colder than normal and design weather, from mid-December into January, the overall Northeast markets posted large increases in demand. During this period, the Company experienced 6 of the top 10 highest sendout volumes in Company history within its service territory. The table below shows the top 10 highest sendouts in Rhode Island in Company history.

Rank	Date	Sendout	HDD
1	January 6, 2018	387,584	60
2	January 5, 2018	372,048	56
3	February 14, 2016	368,126	59
4	January 1, 2018	365,370	56
5	February 13, 2016	363,535	62
6	December 31, 2017	360,872	58
7	December 28, 2017	360,058	56
8	February 15, 2015	353,402	57
9	January 15, 2004	351,459	64
10	December 29, 2017	345,152	56

This extreme weather relatively early in the season caused increased customer usage and required the Company to purchase market area-priced supplies, including supplies over and above those in the Company's existing portfolio. During this period, these supplies were largely priced at Gas Daily Indices at one of the following locations: Algonquin citygates, Tennessee Zone 6 delivered, or Texas Eastern M-3. The chart below shows the respective daily indices for December 2017 and January 2018, demonstrating the sharp price escalation as the cold stretch continued. The bulk of the Company's incremental purchases were made from late-December through mid-January. As demonstrated by the chart below, the cost of these incremental supplies during the extreme cold was as expensive as $94 per million British thermal units (MMBtu).



When pipeline supplies were exhausted, the Company had to use LNG to meet customer requirements. During a winter period, the Company maintains certain LNG inventory levels in adherence with the LNG storage rule curves developed prior to the start of the winter season. LNG storage rule curves indicate the level of inventory needed to meet design season requirements for each day remaining in the winter period. The extreme cold weather and corresponding increases in customer load stressed the Company's LNG inventory levels and put them well below the LNG storage rule curve levels. At the end of December 2017, the Company's LNG storage inventory balance was 67 percent full, or 497,909 Dth, which is below the design season rule curve level of 95 percent, or 718,000 Dth, for that point in the season.

The LNG inventory levels decreased further into January 2018. By January 8, the Company's available LNG supplies were at 36 percent, or 266,567 Dth, which is well below the rule curve of 81 percent, or 612,774 Dth, for that point in the season. Because of this significant shortage of LNG inventory, the Company had to purchase both market area gas supplies and incremental LNG supplies to replenish the LNG inventory.

In last year's Interim GCR filing in Docket No. 4719, Ms. Culliford's pre-filed direct testimony explained that to ensure the continued reliability of supplies to meet forecasted design season requirements for the remainder of the winter, the Company entered into ***two*** agreements with ENGIE (Mr. Oliver's testimony mistakenly refers to only one agreement with ENGIE). The first agreement with ENGIE was a LNG liquid supply contract that commenced on January 10, 2018 and terminated on October 1, 2018. The

Company retained the right to purchase a quantity of LNG up to the MDQ of 5,000 MMBtu per day with a total quantity during the term of up to 100,000 MMBtu. As explained above, the Company entered into this LNG liquid supply contract with ENGIE during the extended cold period to refill its LNG facilities. The second agreement with ENGIE was a Firm Combination Agreement for both vapor and liquid that also commenced on January 10, 2018 and terminated on October 1, 2018. During the term, the Company retained the right to purchase a quantity of LNG up to the MDQ of 10,000 MMBtu per day with a total quantity during the term of up to 150,000 MMBtu. Prior to April 1, 2018, the Company had the option to call on the MDQ as either vapor or LNG. The vapor component of the Firm Combination Agreement had a delivery point of Dey Street in Providence, Rhode Island. As discussed above, the Company entered into this Firm Combination Agreement with ENGIE for the following two reasons: (1) during the extreme cold period, few counterparties were able to deliver pipeline gas to the Company's citygates due to restrictions on the interstate pipelines; and (2) the addition of the 10,000 MMBtu per day supply provides for deliveries to the Company's citygates and provided an opportunity for the Company to bring its LNG supply back in line with its LNG rule curve.

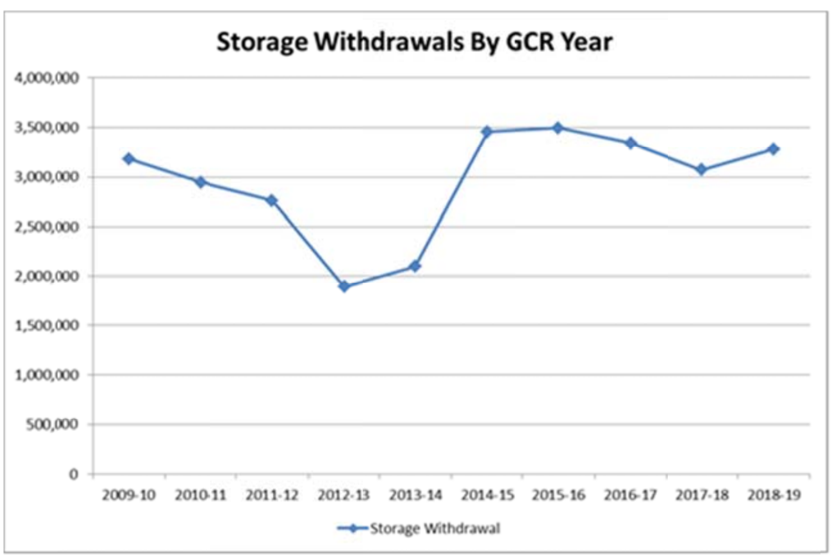
Later in our testimony (Section III), we provide further justification for the ENGIE supply agreements and explain why any costs associated with those agreements with ENGIE should not be excluded from recovery in this GCR proceeding.

Q. Do you agree with Mr. Oliver's assertions regarding the differences between the Company's commitments for physical pipeline capacity and its commitments to fixed delivery charges for the reservation of gas purchases?

A. Not entirely. The Company agrees with the fact that there are times when the Company expects to have resources, including pipeline capacity, in excess of its requirements for a period of time, and the Company has the ability to re-market the available resources, including capacity, for use by other parties during the periods the Company is not required to serve Rhode Island gas customers. This very activity is accomplished through the Company's Natural Gas Portfolio Management Plan (NGPMP). Through the NGPMP, the Company is able to generate revenues to offset the cost of its portfolio, and provide savings to Rhode Island gas customers. Although the Company is not "managing" capacity, the Company will have the opportunity to mitigate the fixed cost commitments for access to gas supplies when and if the supplies are not needed for Rhode Island gas supply requirements, just as it does when capacity under the Company's management is not needed. The opportunities will be available when the supplies are available to be called on by the Company.

Q. Mr. Oliver's testimony states that there has been "[a] shift in the Company's design day planning to place greater reliance on LNG and reduce its use of Underground Storage without a corresponding reduction in Storage Fixed Costs". Do you agree with this statement?

A. No. The Company has not modified its design day planning to place greater reliance on LNG and reduce the use of underground storage. Although Mr. Oliver includes this statement in his testimony at page 5, he offers no support for the statement anywhere else in his testimony or attachments. The chart below shows the forecasted underground withdrawals from the Company's GCR filings over the last 10 years (volumes in Dth). Please note that the forecasted underground withdrawals in this year's GCR filing exceed the forecasted underground withdrawals in last year's GCR filing.



REDACTED

III. <u>The Costs for the ENGIE Agreement Should Not Be Excluded from Recovery</u>

Q. Does the Company agree with Mr. Oliver's recommendation to remove the fixed costs associated with the ENGIE agreement from the costs it will recover through its proposed GCR charges pending further review of the economic justification for this contract?

A. No. Mr. Oliver's analysis of this issue contains several critical errors. First, as explained in detail earlier in our testimony and in Ms. Culliford's pre-filed direct testimony in the Company's Interim GCR filing in Docket No. 4719, the Company entered into ***two*** agreements with ENGIE, not one agreement as Mr. Oliver indicates. Second, Mr. Oliver's calculations showing the cost of the incremental LNG supplies are incorrect. It appears Mr. Oliver has erroneously included the cost of LNG liquid purchased to supply the portable LNG operation in Cumberland, which was discussed and included in the Company's Supplemental GCR filing in Docket No. 4719, submitted on September 29, 2017, in his total of LNG costs [redacted] Next because Mr. Oliver overlooked the fact that the Company entered into two agreements with ENGIE, he failed to account for the total volume of both deals; however, he nonetheless included the cost of both agreements in his calculations. The actual cost of the agreements totals [redacted] (not [redacted] as calculated by Mr. Oliver). The volume available under both agreements totals 250,000 Dth. Thus, the per-unit cost of gas available under the agreements is [redacted] per Dth, not [redacted] per Dth as calculated by Mr. Oliver. As we explained earlier, through January 8, 2018, only 69 days into the 151-day winter season, the Company's

LNG inventory showed the Company had a deficiency of 346,207 Dth. Thus, the two ENGIE agreements for 250,000 Dth represented a substantial portion of the volume needed to get back in line with the LNG rule curve.

Q. Has the Company economically justified the two ENGIE agreements that you describe?

A. Yes. In addition to the information we provided earlier in this rebuttal testimony, Ms. Culliford's testimony in the Interim GCR proceeding in Docket No. 4719 economically justifies the fixed cost payments associated with the two ENGIE agreements, at the time the agreements were made and under the circumstances. Mr. Oliver has provided no support to suggest otherwise. Instead, Mr. Oliver is suggesting that the PUC review in hindsight the Company's sound decision making, by using actual knowledge of what transpired last winter season after January 8 regarding actual weather, customer load, and market pricing. Through a hindsight review, Mr. Oliver suggests that the Company should have assumed that Rhode Island would not have experienced another cold snap after January 8, and not have entered into the necessary agreements to ensure a reliable portfolio of resources to meet customer requirements for the remainder of the winter season. For the Company to have made such an unfounded assumption, at the time and under the circumstances, would have been reckless, and is not recommended under any prudent planning decision process. The Company's decision to enter into the ENGIE agreements was prudent and reasonable at the time and under the circumstances, and there is no basis to exclude the recovery of such costs in the GCR. The Company respectfully requests that the PUC reject Mr. Oliver's recommendation to remove the fixed costs associated with the ENGIE agreement from the costs the Company will recover through its proposed GCR charges. Furthermore, the Company does ***not*** agree with Mr. Oliver's assertion that the PUC offered no explicit recognition or acceptance of these costs in its interim rate determinations.

Q. Are there any other reasons why the PUC should reject Mr. Oliver's recommendation to exclude from recovery the costs associated with the referenced ENGIE agreement?

A. Yes. It is the Company's opinion that Mr. Oliver has had ample time to review the ENGIE agreement, so additional time to review is not justified. As explained earlier, the Company first provided notice of the arrangement with ENGIE more than nine months ago in its Interim GCR filing in Docket No. 4719, submitted on January 29, 2018. The Company has also reflected these costs in each of the monthly GCR deferred balance report in Docket No. 4719 filed with the PUC and provided to the Division beginning in February 2018.

Moreover, the Company included these costs in its Annual GCR Reconciliation Report filing submitted to the PUC on June 29, 2018. The Company submits its Annual GCR Reconciliation Report by July 1 of each year pursuant to a Settlement Agreement in

Docket No. 4346, in which the Company agreed to change the due date of the Annual GCR Reconciliation Report filing from August 1 to July 1 to provide Mr. Oliver with additional time to review the report. As a result, there is a four-month period to review the Annual GCR Reconciliation Report filing. In this proceeding, however, Mr. Oliver is claiming again that he does not have enough time to conduct his review of the Annual GCR Reconciliation Report. Mr. Oliver's testimony indicates, at footnote 3, that he initiated his review of the Company's 2018-19 GCR filing and issued his first data requests to the Company regarding this filing within one business day of the Company's August 31, 2018 filing (i.e., on September 4, 2018). However, this assertion does not take into account that Mr. Oliver received the Annual GCR Reconciliation Report more than two months before the Company submitted the 2018-19 GCR, which provided ample time to request further information from the Company regarding this contract. To exclude from recovery the ENGIE costs, incurred to secure reliable supply during what appeared at the beginning of January to be one of the coldest winter periods on record, to provide even more time to review information that has been available since January 2018, would be unjust.

Q. Should the Division be provided with an indefinite period of time to review the Company's commodity costs?

A. No. It is important that a reasonable time period be established for annual commodity cost reviews, and decisions regarding the recovery of costs incurred should not continue indefinitely. In fact, in Docket No. 4199, Mr. Oliver testified as follows: "Reconciliation tariffs such as the GCR in this proceeding necessarily require adjustments to rates for costs after they have actually have been incurred. However, the Commission's procedures do not provide for open ended adjustment periods. Rather, a reconciliation period has been defined (i.e., in this case it is the twelve month period ended June 30th[9] of each year), and it (sic) for that period when subject to review in the Company's subsequent GCR proceeding that adjustments can and should be made without concern regarding claims of retroactive ratemaking." Therefore, Mr. Oliver's recommendation in this proceeding to remove the costs associated with the ENGIE contract, which have been reflected in the Annual GCR Reconciliation Report filing, conflicts with his prior recommendation that the annual reconciliation period is subject to review in the Company's subsequent annual GCR filing.

IV. <u>The Costs to Replace the Supply from the Cumberland LNG Tank Should Not Be Excluded from Recovery</u>

Q. Does the Company agree with Mr. Oliver's recommendation that the PUC should remove from recovery the incremental costs the Company has incurred to replace peaking supply from the Cumberland LNG tank?

A. No, the PUC should not exclude costs to replace the supply from the Cumberland LNG

[9] In Docket No. 4323 the Company changed the annual reconciliation period ending June of each year to a fiscal year basis ending March.

tank. The costs themselves are reasonable, and as we have demonstrated earlier in our rebuttal testimony, the Company needs the supply to meet its increased customer load requirements for the 2018-19 winter season. No evidence or information has been offered to demonstrate otherwise. Therefore, there is no reason to exclude those costs from recovery through this year's GCR proceeding. Excluding such reasonable and necessary costs from recovery would penalize the Company for no apparent reason.

Q. Mr. Oliver states that "to the extent the Company was not prudent in maintaining the tank, these incremental costs should be borne by shareholders". Has any information been presented in this proceeding to demonstrate that the Company "was not prudent in maintaining the tank" in Cumberland?

A. No. To date, no demonstration has been made that the Company did not prudently maintain the Cumberland LNG tank. The Company strongly believes that it operated the Cumberland LNG facility in a prudent fashion and made a reasonable and prudent decision to decommission the tank to ensure the safety of the public and the Company's personnel. The Company disagrees with any suggestion otherwise. The Company reserves its right to defend its prudent decision making if a challenge is made at some point in the future. In the meantime, costs should ***not*** be removed from rates unless a determination is made that the Company did not act prudently. Until then, the Company is entitled to a presumption that it acted prudently. The Company is not aware of any precedent that supports the exclusion of costs ***before*** a decision or action is determined to be imprudent, especially where the costs will be subject to a reconciliation filing at a later date.

Q. Are the calculations in Mr. Oliver's testimony for the amount related to the supply needed to replace the Cumberland LNG tank correct?

No. Mr. Oliver's calculation of the amount he proposes to remove from the GCR factors is based on information provided by the Company in response to Data Requests Division 3-1 and 3-2 in this proceeding. Division 3-1 requested the Company's ***estimate*** of the gas supply costs it would have incurred had the Cumberland LNG tank remained in service and was operated during the 2016-17 and 2017-18 GCR years, as well as in the upcoming 2018-19 GCR year. Division 3-2 requested the Company's ***estimate*** for the costs the Company has incurred to replace the gas supplies that would have been provided from the Cumberland LNG tank. To develop an amount, Mr. Oliver simply subtracted the Company's estimate of the gas supply costs it would have incurred had the Cumberland LNG tank remained in service from the estimate of the Company's replacement costs for volumes previously supplied from the Cumberland LNG tank. This calculation, however, is too simplistic to sufficiently establish the amount at issue. For example, consider the Tennessee capacity secured to meet the majority of the volume previously supplied by the Cumberland LNG tank. As explained earlier, the Cumberland LNG tank provided up to 30,000 Dth per day for a total of 74,000 Dth per winter season. Mr. Oliver's calculations include a fatal flaw, in that they assume the Tennessee capacity was utilized only up to the volume previously provided by the Cumberland LNG tank in a winter season. This is not the case. Since the Company added the Tennessee capacity to its portfolio, the capacity was utilized well in excess of the 74,000 Dth level. The table below shows the actual volumes transported on the Tennessee contract used to meet customer requirements over the last two winter seasons.

	Contract # 322983 Usage (MDQ=24,000 Dth)
December 2016	48,000
January 2017	72,000
February 2017	90,000
March 2017	197,000
Total	**407,000**
December 2017	168,643
January 2018	89,444
February 2018	94,333
March 2018	69,000
April 2018	39,263
Total	**460,683** [10]

Q. Are there any other reasons why the PUC should reject Mr. Oliver's recommendation to exclude from recovery the costs to replace the Cumberland LNG tank?

A. Yes. Some of the incremental costs associated with the peaking supplies from the Cumberland LNG tank that Mr. Oliver recommends removing date back to the 2016-17 period, which has already been reviewed and approved by the PUC in Docket No. 4719.

[10] Mr. Oliver notes that the derivation of this amount is documented in CONFIDENTIAL Attachment DIV-GCR-3 to his testimony. The derivation of the calculations is actually documented in Attachment DIV-GCR-6.

As explained earlier, the recommendation to remove costs that have already been approved by the PUC conflicts with a prior recommendation by Mr. Oliver. Specifically, in Docket No. 4199, Mr. Oliver stated as follows in his pre-filed testimony: "Thus, once each annual reconciliation filing has been accepted and new GCR rates are established which address demonstrated differences between estimated and actual costs, the reconciliation exemption from retroactive ratemaking claims appropriately disappears. To do otherwise would be neither reasonable nor appropriate. Allowing an open ended exemption from retroactive ratemaking claims would subject future ratepayers to never ending exposure to requests for recoveries of prior period costs regardless how far back in time the alleged costs were incurred. I don't believe that has ever been the intent of the GCR mechanism that this Commission has implemented for National Grid." Accordingly, Mr. Oliver's recommendation in this proceeding – to make a negative adjustment to the previously approved Annual GCR Reconciliation Report filings – is inconsistent with Mr. Oliver's recommendation in prior proceedings. Adopting Mr. Oliver's unprecedented approach in this proceeding would be unfair to the Company.

V. <u>Response to Mr. Oliver's Other Recommendations and Findings</u>

A. <u>Costs for Portsmouth LNG Vaporization</u>

Q. Please summarize Mr. Oliver's testimony with respect to the status of the LNG operations in Aquidneck Island.

A. Mr. Oliver states that the status of the LNG equipment on Aquidneck Island is unclear; that the Company has spent operation and maintenance (O&M) and capital costs in 2018 to re-initiate LNG vaporization activities in the Aquidneck Island area, without the use of portable LNG in the winter of 2018-19; and that it is not clear whether the Company is seeking recovery of the O&M or capital costs through the GCR.

Q. What is the status of the LNG equipment at the Newport Naval Base?

A. Although the existing LNG equipment at the Newport Naval Base is currently operational, the Company has not operated the LNG equipment at the Newport Naval Base for some time due to site access issues with the Naval Base. The Company has no plans to retire the equipment, and the equipment could be operational if necessary. To re-initiate the equipment will require testing and calibration of the instruments and controls, and test firing of the heaters. As a result, the Company is pursuing parallel paths to develop the Company-owned site at Old Mill Lane in Portsmouth in conjunction with its efforts to negotiate site lease amendments with the Naval Base to allow expedited access to the site for operation of the equipment. As there is no LNG storage tank at either site, portable LNG trailers are required for operations.

Q. Does the Company need LNG operations on Aquidneck Island beginning in winter 2018-19?

A. No, the Company is not expecting to need LNG operations on Aquidneck Island beginning in winter 2018-19. However, the Company expects that it may need LNG operations on Aquidneck Island during the spring and/or summer of 2019 to assist the transmission pipeline company's inspection of its pipe, although the date for the inspection has not been provided by the pipeline company. The Company was notified by the operator of the pipeline serving Aquidneck Island that it would be using an in-line inspection method commonly referred to as "pigging" to assess its transmission pipeline to comply with a U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) requirement to periodically inspect its transmission pipelines. Pigging refers to the practice of inserting an in-line inspection tool, commonly referred to as a "smart" pig, into the pipeline that can travel through the interior and locate any dents or areas of wall loss due to corrosion. The Company is required to provide backup gas supply during the pigging operation in case the pig becomes lodged inside the pipeline, requiring the pipeline to be cut open to extract the pig or otherwise taken out of service for repairs. Thus, the Company will need LNG gasification capability on Aquidneck Island in 2019, during the 2018-19 GCR period, to ensure reliable supply during line pigging of the transmission line serving Aquidneck Island.

Q. To accommodate the inspection of the transmission pipeline, what are the Company's plans for the operation of LNG equipment on Aquidneck Island?

A. The Company had two options for vaporization on Aquidneck Island. First, the Company could perform maintenance, testing, and calibration of its LNG equipment at the Newport Naval Base in preparation for vaporizations; however, this option would require the U.S. government to agree to revisions and improvements to the terms of the existing lease regarding site access, which would be a lengthy process. Second, the Company could set up portable LNG operations at its existing site on Old Mill Lane in Portsmouth.

The Company first investigated whether it could re-initiate operations at the Newport Naval Base to accommodate the inspection of the transmission pipeline. In March 2018, the Company met with representatives of the Naval Base to discuss its plans. However, two issues arose at the Naval Base. First, the representatives from the Naval Base informed the Company that the portable LNG operations would require a variance to the Company's existing lease at the Naval Base, which would take a minimum of six to nine months. Thus, the variance might not be awarded in time for the transmission pipeline company to commence its inspection activities. Second, the representatives from the Naval Base informed the Company that the U.S. government could require that the Company abandon its LNG operations at the Naval Base if the Company's national security clearance ever changed. Based on this meeting, the Company did not believe reinitiating its LNG operations at the Newport Naval Base was a viable option, as the Naval Base's restrictions could have resulted in the Aquidneck Island area not having sufficient gas supply in the event of any issues with the pigging operation.[11]

As a result, the Company also needed to examine the feasibility of operating portable LNG at another location. The Company determined that the most feasible location would be the Company's property at Old Mill Lane in Portsmouth. To install and operate temporary LNG equipment at the Old Mill Lane property necessary for portable LNG operations, the Company has incurred $708,490 in O&M expenses and $256,952 in capital costs in 2018. The Company anticipates that in 2019 it will incur $653,915 in O&M expenses to provide backup supply during repairs to the Aquidneck Island area transmission pipeline.

Q. Does the Company plan for any LNG deliveries to the Aquidneck Island area for the winter of 2018-19?

A. No. Any LNG supplies needed would be served by contracts the Company already has in place to secure liquid.

[11] Although the variance might not be awarded in time for the transmission pipeline operator to commence its inspection activities, the Company is pursuing the variance to the existing lease with the Naval Base for potential future use to operate without restrictions that would affect the customers on Aquidneck Island.

Q. Why would the Company have incurred O&M expenses and capital costs to operate LNG equipment on Aquidneck Island when it does not plan to have any LNG deliveries to the Aquidneck Island area during the winter of 2018-19?

A. While the Company has had to incur O&M expenses and capital costs to set up the portable LNG operations in Portsmouth in case something goes wrong with the transmission company's pigging operation and the Company has to provide backup supply, the Company does not actually plan to use portable LNG in Portsmouth during the winter of 2018-19.

Q. Does the Company seek recovery in this proceeding for the O&M expenses and capital costs for portable LNG at Old Mill Lane?

A. The Company has not reflected these specific costs in the supply related LNG O&M cost reflected in the proposed GCR factor for effect November 1, 2018, but will include the actual costs in its annual reconciliation filing. In the Company's Gas Cost Recovery Clause tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A, Sheet 4, the Company defines TC_{FC} as 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 determined annually as estimated by the Company. In addition, in the Settlement Agreement in Docket No. 4770 at Article II.C.9.vi, the parties agreed that the Company would estimate the O&M expense associated with its LNG activities as a component of fixed gas supply costs.

This estimate is subject to reconciliation to actual LNG O&M expense incurred during the term of the applicable GCR factor.

Q. Were the LNG-related O&M costs for 2019 included in the Company's rate year LNG supply-related O&M costs?

A. No, the LNG-related O&M costs for 2019 were not specifically included in the Company's rate year LNG supply-related O&M costs.

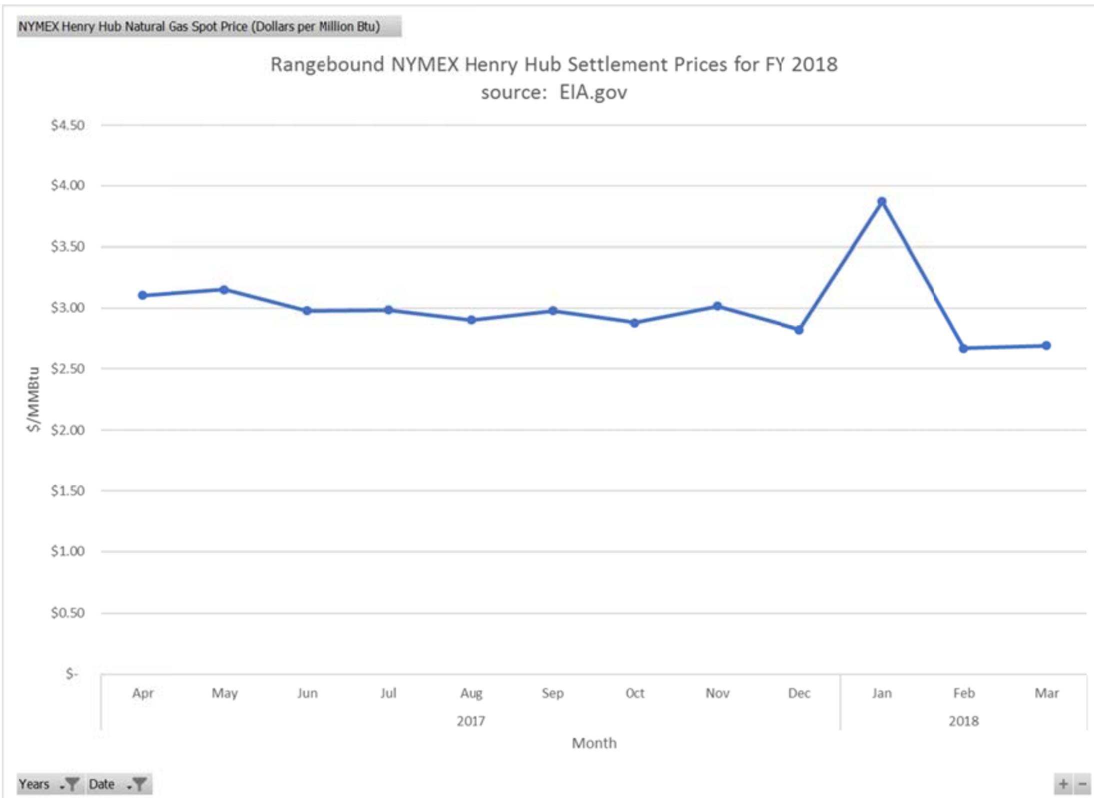
B. <u>Gas Procurement Incentive Plan, Natural Gas Portfolio Management Plan, and Market Area Hedge</u>

Q. Mr. Oliver's testimony questions the ongoing effectiveness of the Gas Procurement Incentive Plan (GPIP) structure. What is the Company's response to Mr. Oliver's comments?

A. The Company believes the GPIP will continue to be an effective program. The fact that 2018 resulted in the lowest incentives is a direct result of market conditions. For much of 2017, NYMEX Henry Hub prices remained range-bound, meaning the difference between the maximum and minimum prices was especially small. Below is a chart that illustrates exactly how narrow the difference between the maximum and minimum NYMEX Henry Hub settlement prices[12] were over the April 2017 to December 2017

[12] Daily settlement prices of the first nearby contract were provided by U.S. Energy Information Administration (EIA) (at http://tonto.eia.gov/dnav/ng/hist/rngwhhdd.htm), and an average was calculated for each month of the period.

period, when prices trended from a maximum of $3.15 per MMBtu in May, to a minimum average of $2.82 per MMBtu, which is a very small range of $0.33.[13]



The upturn in NYMEX natural gas prices occurred during the winter period, which did not create any opportunities to expand discretionary hedges. The objective of making discretionary hedges is to extract value when prices are lower than the mandatory hedges. When discretionary prices are higher than mandatory prices, a penalty is imposed. The Company attempts to maximize customer value by transacting at the lowest possible

[13] In contrast, the range in 2014 for the April to December period was much higher. Prices trended from a maximum price of $4.66 per MMBtu in April 2014 and a minimum price of $3.48 per MMBtu for December 2014, which is a wider range of $1.18, leading to more discretionary opportunities.

price. As illustrated from the chart above, NYMEX Henry Hub prices were very range bound for the April 2017 to March 2018 period, providing limited viable discretionary hedging opportunities during the January 2018 period.

Q. Mr. Oliver raises concerns regarding the manner in which National Grid's increased use of contracts that involve reservation charges will impact its gas purchasing decisions and its incentives for more cost-effective procurement of gas supplies. Does the Company agree with this opinion?

A. No. "The increased use of contracts that involve reservation charges" will ***not*** impact the purchasing decisions of the GPIP. The GPIP utilizes mandatory, ratable hedges purchased in a unified manner up to a predefined weather-normal gas purchase requirement. For example, mandatory hedges will equal 60 percent of forecasted normal weather gas purchase requirements for the April and October gas supply months and 70 percent of forecasted normal weather gas purchase requirements for the remaining 10 months. Purchases and/or hedges will be based on the forecast of requirements in place when the purchases and/or hedges are made. Additionally, the discretionary portion of the program may not exceed 95 percent of the forecasted weather-normal requirements for a given supply month. If the costs for discretionary hedges exceed the costs for mandatory hedges, then the Company will pay a penalty. Conversely, if discretionary hedging costs are lower than mandatory hedging costs, as the GPIP intends, then there is an incentive paid to the Company and a resulting benefit to the customer. Thus, the increased use of contracts that may increase reservation charges will have no impact on the GPIP.

Q. Mr. Oliver's testimony questions the benefits of the Natural Gas Portfolio Management Plan (NGPMP). What is the Company's response to Mr. Oliver's comments regarding the NGPMP?

A. The Company is willing to investigate additional ways to improve the NGPMP. For example, the Company will certainly consider any benefits of providing a forward-looking analysis, rather than a backward-looking analysis questioned by Mr. Oliver. However, there are additional, unforeseen complications – such as an unprecedented move in natural gas market prices from $18.48 per MMBtu in 2008 to a minimum price of $1.83 per MMBtu in 2009[14] – to keep in mind when attempting to forecast forward-looking statements. Also, a forward-looking analysis could only be based on reasonable assumptions, rather than on actual data.

Regarding the "plummeting" of earnings under the NGPMP, as Mr. Oliver opines, it is difficult to look at annual earnings in a vacuum, for only a single year. As Table 3 in Mr. Oliver's testimony illustrates, ratepayer benefits and incentives were lowest in the first year of the NGPMP (2010). Since then, ratepayers have received clear benefits from the NGPMP, with the highest benefit received two years ago, in 2016, after years of increasing benefits. With the changing fundamentals in the natural gas market place, each year can be very different from those before it, so although ratepayer benefits may have "plummeted" in a single year, this does not justify abandoning the benefits that the NGPMP has provided over the past nine years.

Q. Mr. Oliver suggests it is reasonable to draw comparisons between the fixed cost commitments that National Grid has negotiated and its past market area hedging activities. What is the Company's response to this opinion?

A. The Company does not understand Mr. Oliver's rationale here. The necessary increase in physical transactions will address potential reliability issues and deliverability constraints at the Tennessee Zone 6 location that occurred during the coldest days of the 2017-18 winter. Similar to the electric capacity markets, physical assets must be purchased above coincident peak, or in the case of gas, design month demand, so that any forecast error may be accounted for and there are no supply disruptions. A probability-weighted average would not protect customers, and could lead to supply disruptions and reliability constraints. Thus, there is a key difference between having increased physical transactions compared to making additional financial hedges. Physical transactions provide two important benefits, as described throughout this rebuttal testimony: (1) reliability of having natural gas physically available; and (2) a reduction of price uncertainty. Financial hedges, however, mitigate only price uncertainty, and do not

[14] EIA, at http://tonto.eia.gov/dnav/ng/hist/rngwhhdd.htm.

address physical delivery risk. Financial hedging takes place after physical supply and reliability issues are addressed. This year, additional financial hedging is not recommended because the physical supply and reliability issues have been addressed. The market area hedge is a valuable program, and each year the Company will continue to analyze whether market area hedging activity is in the best interest of its customers.

C. Relationship Between the GCR and Long-Range Plan

Q. Do you agree with Mr. Oliver's assertion that the PUC should require National Grid to strengthen the ties between its Annual GCR filings and its long-range gas supply planning, particularly as they relate to the Company's expected gas service costs?

A. The Company agrees it would be helpful to strengthen the ties between the Company's annual GCR filings and the Company's Long-Range Plan filed biannually with the PUC. The Long-Range Plan sets forth the underlying forecast methodology, supply planning process, and resource portfolio for the GCR filing. The Company disagrees, however, with the implication that the Company had not worked to advance this effort in the past. During the last several years of GCR proceedings, Mr. Oliver has raised questions about the Company's forecasting and planning process, implying that he would like to review them further and suggest changes. When Mr. Oliver has raised such questions, the Company has consistently offered to review the Long-Range Plan in greater detail, as it is a docketed filing, and address any areas of concern. As it has in the past, the Company continues to welcome the opportunity to review its Long-Range Plan filing in more detail.

Q. Has Mr. Oliver had sufficient opportunity to review the Company's current Long-Range Plan filing before the Company submitted this pending GCR filing?

A. Yes. Mr. Oliver has had ample time to review and, if necessary, critique the Company's forecast methodology, supply planning process and decisions, and resource portfolio. The Company filed its current Long-Range Plan almost seven months ago, on March 30, 2018, in Docket No. 4816. On July 17, 2018, the Division issued one set of data requests in that docket, to which the Company responded on August 9, 2018. There has been no other activity in that docket, except for the technical session presented by the Company on October 4, 2018, at the PUC's request. The Company remains willing to collaborate with Mr. Oliver to review and modify the Long-Range Plan where necessary, but it is unfair for the Company's Long-Range Plan – and, therefore, the Company's gas supply decisions in the GCR that are derived from the Long-Range Plan – to be criticized without further discussion of the Long-Range Plan.

D. Considerations of Demand Side Management Programs

Q. Mr. Oliver recommends that the PUC mandate that the Company investigate and timely report its assessment of the potential for expanded use of interruptible service offerings and gas demand side management programs to meet its peak gas supply requirements. What is the Company's response to this recommendation?

A. The Company is assessing the viability and cost effectiveness of various options that could be employed to minimize supply costs for customers. In its response to Data Request Division 2-17, the Company includes details of the current assessment, including the potential number of customers to target for expanded interruptible service, the gas demand response pilot for Commercial and Industrial customers beginning this winter, and limitations to the potential for residential gas demand response.

Specifically, the Company has explored the possibility of offering residential demand response as part of its Connected Solutions program and called three demand response events in 2017. The Company believes that due to heat loss in a home and the difference in indoor and outdoor temperatures, there is no evident path to a scalable, cost effective demand response program for Residential Heating customers using Wi-Fi thermostats.

Additionally, the Company is in the process of testing a gas demand response pilot (the Pilot) this upcoming winter for commercial customers through its Energy Efficiency Plan. Findings from this Pilot will help assess the potential for demand response to be a tool for operating natural gas system in the most efficient, reliable, and cost-effective way. This Pilot is intended to explore customer interest in gas demand response and it will focus on reducing customer usage during a three-hour period that is coincident with periods of peak usage on the gas system. While this Pilot is not specifically designed to determine how demand response could be used to manage the Company's supply portfolio, it will provide useful information regarding customer preferences, which can be combined with the Company's experience with non-firm customers that can help inform future decisions regarding the role of demand response in managing supply needs. Thus, while the Company is interested in further exploring a demand response program to manage its supply portfolio, the Company believes it is premature to mandate such a program at this stage, especially before the Company implements and understands the results of the upcoming Pilot. The Company has additional insights from an existing gas demand response pilot in downstate New York and a study of gas demand response potential in Massachusetts that is in partnership with Fraunhofer Center for Sustainable Energy. The New York pilot and ongoing research will be helpful for the Company to understand customer opt-out and variability, as well as savings, costs, and benefits. The Company will use the lessons learned from the New York pilot and the Company's research in Massachusetts to help inform innovations in Rhode Island. The Company has provided more details regarding the potential for demand response programs in its response to Data Request Division 2-17 in this docket and Division 1-15 in Docket No. 4816, and in the 2019 Annual Plan, at Attachment 8, in Docket No. 4888.

With respect to gas demand side management programs, the Company is committed to reducing gas consumption through energy efficiency. The Energy Efficiency Three Year Plan includes targets for reducing gas consumption by approximately one percent (compared to 2015 reference load) each year over the three-year period from 2018 to 2020. The actual and projected savings from energy efficiency are incorporated into the gas sales forecast. The assessment of cost-effective achievable energy efficiency savings beyond 2020 will be conducted by the Energy Efficiency Resources Management Council (EERMC) in collaboration with the Company.

E. Bill Impacts

Q. Mr. Oliver claims that the bill impacts to typical Residential Heating customers will increase by nearly 20 percent for comparable levels of usage for the first four months of the 2018-19 GCR year when compared to the charges effective November 1, 2017, and a 13.5 percent annual bill increase for the 2018-19 GCR year if the Company's proposed GCR charges are approved. Does the Company agree that Residential Heating customers will experience these bill increases?

A. No, the Company believes Mr. Oliver has overestimated the bill impacts for Residential Heating customers associated with the Company's proposed 2018-19 GCR factors. First, in the Company's experience, customers focus on their total bill and do not look at changes in individual components of their bill. Mr. Oliver reports on only one aspect of customers' bills that will change on November 1 (i.e., the beginning of the GCR period) and does not take into account all changes to bills that will occur on November 1 (i.e., the Distribution Adjustment Charge (DAC) portion of the bill). In the Company's response to Division 2-6, the Company provided bill impacts for the four month period of November through February. In this calculation, the Company compared the total bill based on all rates in effect during the period November 1, 2017 through February 28, 2018 with the proposed GCR and DAC factors effective November 1, 2018, and the peak base distribution rates approved by the PUC in Docket No. 4770. Attachment DIV 2-6 in response to Division 2-6 shows that during the four month period, an average Residential Heating customer using 456 therms would experience an 8.9 percent increase in their total bill. This increase reflects changes to base distribution rates, the GCR factor, and the DAC factor. The increase in the GCR component alone would be only a 12.8 percent increase, which is significantly less than the 20 percent bill increase on this charge on the bill as stated by Mr. Oliver.

However, it is not accurate to compute bill impacts for the four month period of November through February, since this period does not include the months in which customers were billed the higher Interim GCR factor effective March 1, 2018. A more appropriate comparison is to compare annual bills based on the proposed rates to become effective on November 1, 2018 with annual bills based on actual rates billed to customers each month during the period November 1, 2017 through October 31, 2018. This analysis results in a total annual bill decrease of 0.2 percent for an average Residential

Heating customer using 845 therms. This decrease includes not only changes proposed to the GCR and DAC factors, but also reflects the changes in the base distribution rates approved by the PUC and effective September 1, 2018. Please see Attachment 1-Joint Rebuttal for a summary of the bill impacts. Also, Residential Heating Low Income customers will continue to experience a total bill decrease as compared to their bills last year due to the new 25 percent total bill discount approved by the PUC in Docket No. 4770.

VI. <u>Conclusion</u>

Q. Does this conclude your joint rebuttal testimony?

A. Yes.

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption - Nov 2017-Oct 2018 Rates vs Proposed Nov 2018-Oct 2019 Rates

Residential Heating:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	GCR	Difference due to: DAC Base DAC	Difference due to: DAC ISR	EE	LIHEAP	GET
(1)												
(2)												
(3)												
(4)												
(5)	548	$921.77	$928.58	($6.81)	-0.7%	$49.35	$37.62	($25.53)	($67.29)	($0.76)	$0.00	($0.20)
(6)	608	$1,002.66	$1,010.82	($8.17)	-0.8%	$54.30	$41.65	($28.35)	($74.68)	($0.84)	$0.00	($0.24)
(7)	667	$1,082.20	$1,091.42	($9.22)	-0.8%	$58.99	$45.98	($31.08)	($81.90)	($0.94)	$0.00	($0.28)
(8)	726	$1,161.72	$1,170.63	($8.91)	-0.8%	$65.52	$49.84	($33.84)	($89.16)	($1.00)	$0.00	($0.27)
(9)	785	$1,241.20	$1,248.14	($6.94)	-0.6%	$73.48	$53.90	($36.59)	($96.42)	($1.10)	$0.00	($0.21)
(10)	845	$1,322.08	$1,325.02	($2.94)	-0.2%	$83.58	$57.92	($39.37)	($103.80)	($1.18)	$0.00	($0.09)
(11)	905	$1,402.98	$1,401.92	$1.06	0.1%	$93.68	$61.98	($42.18)	($111.18)	($1.27)	$0.00	$0.03
(12)	964	$1,482.44	$1,477.32	$5.11	0.3%	$103.63	$66.04	($44.93)	($118.44)	($1.34)	$0.00	$0.15
(13)	1,023	$1,561.96	$1,552.61	$9.35	0.6%	$113.98	$69.88	($47.68)	($125.70)	($1.41)	$0.00	$0.28
(14)	1,082	$1,641.50	$1,626.71	$14.79	0.9%	$124.99	$74.20	($50.41)	($132.92)	($1.51)	$0.00	$0.44
(15)	1,142	$1,722.42	$1,701.90	$20.51	1.2%	$136.75	$78.23	($53.18)	($140.31)	($1.59)	$0.00	$0.62

Residential Heating Low Income:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Base Rates	GCR	Total Bill Discount	Difference due to: DAC Base DAC	Difference due to: DAC ISR	EE	LIHEAP	GET
(16)													
(17)													
(18)													
(19)													
(20)	548	$685.39	$870.79	($185.40)	-21.3%	$88.19	$37.62	($204.72)	($32.88)	($67.29)	($0.76)	$0.00	($5.56)
(21)	608	$745.42	$949.08	($203.66)	-21.5%	$95.91	$41.65	($223.12)	($36.47)	($74.68)	($0.84)	$0.00	($6.11)
(22)	667	$804.43	$1,025.78	($221.36)	-21.6%	$103.34	$45.98	($241.19)	($40.01)	($81.90)	($0.94)	$0.00	($6.64)
(23)	726	$863.43	$1,101.27	($237.83)	-21.6%	$112.42	$49.84	($259.25)	($43.55)	($89.16)	($1.00)	$0.00	($7.14)
(24)	785	$922.40	$1,175.21	($252.81)	-21.5%	$122.79	$53.90	($277.30)	($47.09)	($96.42)	($1.10)	$0.00	($7.58)
(25)	845	$982.41	$1,248.69	($266.28)	-21.3%	$135.14	$57.92	($295.69)	($50.68)	($103.80)	($1.18)	$0.00	($7.99)
(26)	905	$1,042.45	$1,322.19	($279.74)	-21.2%	$147.49	$61.98	($314.08)	($54.29)	($111.18)	($1.27)	$0.00	($8.39)
(27)	964	$1,101.40	$1,394.23	($292.83)	-21.0%	$159.65	$66.04	($332.12)	($57.83)	($118.44)	($1.34)	$0.00	($8.78)
(28)	1,023	$1,160.41	$1,466.19	($305.78)	-20.9%	$172.17	$69.88	($350.19)	($61.36)	($125.70)	($1.41)	$0.00	($9.17)
(29)	1,082	$1,219.41	$1,537.03	($317.63)	-20.7%	$185.29	$74.20	($368.25)	($64.90)	($132.92)	($1.51)	$0.00	($9.53)
(30)	1,142	$1,279.42	$1,608.99	($329.57)	-20.5%	$199.13	$78.23	($386.64)	($68.51)	($140.31)	($1.59)	$0.00	($9.89)

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption - Nov 2017-Oct 2018 Rates vs Proposed Nov 2018-Oct 2019 Rates

Residential Non-Heating:

								Difference due to:				
(31)												
(32)	Annual	Proposed	Current					DAC				
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)												
(35)	144	$362.59	$375.75	($13.16)	-3.5%	$24.02	($1.76)	($11.84)	($22.99)	($0.19)	$0.00	($0.39)
(36)	158	$380.02	$395.50	($15.49)	-3.9%	$25.52	($1.87)	($12.98)	($25.47)	($0.22)	$0.00	($0.46)
(37)	172	$397.49	$415.14	($17.65)	-4.3%	$26.80	($1.97)	($14.13)	($27.59)	($0.23)	$0.00	($0.53)
(38)	189	$418.68	$439.29	($20.61)	-4.7%	$28.40	($2.42)	($15.53)	($30.21)	($0.24)	$0.00	($0.62)
(39)	202	$434.88	$457.53	($22.65)	-5.0%	$29.80	($2.43)	($16.57)	($32.49)	($0.28)	$0.00	($0.68)
(40)	220	$457.28	$482.92	($25.64)	-5.3%	$31.51	($2.73)	($18.08)	($35.29)	($0.28)	$0.00	($0.77)
(41)	238	$479.70	$508.32	($28.62)	-5.6%	$33.22	($3.03)	($19.55)	($38.09)	($0.31)	$0.00	($0.86)
(42)	251	$495.91	$526.54	($30.63)	-5.8%	$34.61	($3.05)	($20.59)	($40.36)	($0.32)	$0.00	($0.92)
(43)	268	$517.09	$550.71	($33.61)	-6.1%	$36.22	($3.47)	($22.02)	($42.99)	($0.34)	$0.00	($1.01)
(44)	282	$534.50	$570.35	($35.85)	-6.3%	$37.50	($3.58)	($23.18)	($45.13)	($0.38)	$0.00	($1.08)
(45)	297	$553.19	$591.55	($38.36)	-6.5%	$39.00	($3.82)	($24.39)	($47.59)	($0.41)	$0.00	($1.15)

Residential Non-Heating Low Income:

									Difference due to:				
(46)													
(47)	Annual	Proposed	Current					Total Bill	DAC				
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)													
(50)	144	$270.38	$343.97	($73.60)	-21.4%	$42.77	($1.76)	($75.51)	($13.71)	($22.99)	($0.19)	$0.00	($2.21)
(51)	158	$283.33	$363.09	($79.77)	-22.0%	$44.88	($1.87)	($79.70)	($15.00)	($25.47)	($0.22)	$0.00	($2.39)
(52)	172	$296.24	$381.44	($85.19)	-22.3%	$46.69	($1.97)	($83.18)	($16.36)	($27.59)	($0.23)	$0.00	($2.56)
(53)	189	$311.96	$404.18	($92.21)	-22.8%	$48.95	($2.42)	($87.56)	($17.97)	($30.21)	($0.24)	$0.00	($2.77)
(54)	202	$323.95	$421.83	($97.87)	-23.2%	$50.92	($2.43)	($91.44)	($19.21)	($32.49)	($0.28)	$0.00	($2.94)
(55)	220	$340.59	$445.75	($105.17)	-23.6%	$53.33	($2.73)	($96.12)	($20.92)	($35.29)	($0.28)	$0.00	($3.16)
(56)	238	$357.21	$469.69	($112.48)	-23.9%	$55.75	($3.03)	($100.81)	($22.61)	($38.09)	($0.31)	$0.00	($3.37)
(57)	251	$369.21	$487.32	($118.11)	-24.2%	$57.71	($3.05)	($104.68)	($23.86)	($40.36)	($0.32)	$0.00	($3.54)
(58)	268	$384.91	$510.06	($125.15)	-24.5%	$59.97	($3.47)	($109.07)	($25.50)	($42.99)	($0.34)	$0.00	($3.75)
(59)	282	$397.85	$528.43	($130.58)	-24.7%	$61.78	($3.58)	($112.55)	($26.80)	($45.13)	($0.38)	$0.00	($3.92)
(60)	297	$411.68	$548.63	($136.95)	-25.0%	$63.89	($3.82)	($116.68)	($28.23)	($47.59)	($0.41)	$0.00	($4.11)

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption - Nov 2017-Oct 2018 Rates vs Proposed Nov 2018-Oct 2019 Rates

C & I Small:

(61)						Difference due to:						
(62)	Annual	Proposed	Current					DAC				
(63)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Base DAC	ISR	EE	LIHEAP	GET
(64)												
(65)	830	$1,356.59	$1,465.09	($108.50)	-7.4%	$0.03	$58.77	($54.16)	($108.35)	($1.54)	$0.00	($3.26)
(66)	919	$1,467.74	$1,575.50	($107.76)	-6.8%	$12.40	$64.61	($59.97)	($119.86)	($1.71)	$0.00	($3.23)
(67)	1,010	$1,581.46	$1,688.88	($107.42)	-6.4%	$24.28	$71.05	($65.89)	($131.76)	($1.88)	$0.00	($3.22)
(68)	1,099	$1,692.70	$1,796.38	($103.68)	-5.8%	$39.35	$77.36	($71.69)	($143.53)	($2.06)	$0.00	($3.11)
(69)	1,187	$1,802.73	$1,900.71	($97.97)	-5.2%	$55.72	$83.76	($77.43)	($154.86)	($2.22)	$0.00	($2.94)
(70)	1,277	$1,915.15	$2,004.24	($89.09)	-4.4%	$75.89	$90.03	($83.33)	($166.63)	($2.38)	$0.00	($2.67)
(71)	1,367	$2,027.59	$2,107.80	($80.21)	-3.8%	$96.06	$96.29	($89.20)	($178.41)	($2.54)	$0.00	($2.41)
(72)	1,456	$2,138.84	$2,210.16	($71.32)	-3.2%	$115.82	$102.62	($95.03)	($189.89)	($2.70)	$0.00	($2.14)
(73)	1,544	$2,248.84	$2,311.02	($62.18)	-2.7%	$135.79	$108.99	($100.74)	($201.51)	($2.84)	$0.00	($1.87)
(74)	1,635	$2,362.53	$2,415.62	($53.09)	-2.2%	$156.27	$115.41	($106.66)	($213.45)	($3.07)	$0.00	($1.59)
(75)	1,725	$2,474.95	$2,519.43	($44.48)	-1.8%	$176.24	$121.46	($112.56)	($225.08)	($3.20)	$0.00	($1.33)

C & I Medium:

(76)						Difference due to:						
(77)	Annual	Proposed	Current					DAC				
(78)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Base DAC	ISR	EE	LIHEAP	GET
(79)												
(80)	6,907	$8,828.05	$8,734.47	$93.58	1.1%	$621.55	$413.24	($315.87)	($615.02)	($13.13)	$0.00	$2.81
(81)	7,650	$9,663.68	$9,576.72	$86.96	0.9%	$672.26	$457.60	($349.87)	($681.14)	($14.50)	$0.00	$2.61
(82)	8,391	$10,496.56	$10,416.03	$80.52	0.8%	$722.84	$502.05	($383.72)	($747.14)	($15.92)	$0.00	$2.42
(83)	9,136	$11,334.22	$11,260.13	$74.10	0.7%	$773.67	$546.77	($417.85)	($813.39)	($17.33)	$0.00	$2.22
(84)	9,880	$12,170.86	$12,103.51	$67.36	0.6%	$824.45	$591.09	($451.83)	($879.61)	($18.76)	$0.00	$2.02
(85)	10,623	$13,006.46	$12,945.62	$60.85	0.5%	$875.22	$635.66	($485.85)	($945.84)	($20.17)	$0.00	$1.83
(86)	11,366	$13,842.05	$13,787.63	$54.43	0.4%	$925.99	$680.23	($519.79)	($1,012.05)	($21.59)	$0.00	$1.63
(87)	12,111	$14,679.73	$14,631.96	$47.77	0.3%	$976.83	$724.71	($553.88)	($1,078.34)	($22.98)	$0.00	$1.43
(88)	12,855	$15,516.36	$15,475.13	$41.23	0.3%	$1,027.60	$769.24	($587.93)	($1,144.54)	($24.38)	$0.00	$1.24
(89)	13,596	$16,349.25	$16,314.50	$34.75	0.2%	$1,078.18	$813.72	($621.84)	($1,210.54)	($25.81)	$0.00	$1.04
(90)	14,340	$17,185.90	$17,157.62	$28.28	0.2%	$1,128.95	$858.27	($655.83)	($1,276.72)	($27.24)	$0.00	$0.85

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption - Nov 2017-Oct 2018 Rates vs Proposed Nov 2018-Oct 2019 Rates

C & I LLF Large:

(91)								Difference due to:				
(92)	Annual	Proposed	Current					DAC				
(93)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Base DAC	ISR	EE	LIHEAP	GET
(94)												
(95)	37,587	$45,725.97	$43,703.42	$2,022.55	4.6%	$3,205.97	$2,887.16	($908.75)	($3,144.24)	($78.27)	$0.00	$60.68
(96)	41,634	$50,381.50	$48,168.86	$2,212.64	4.6%	$3,524.21	$3,198.09	($1,006.57)	($3,482.78)	($86.69)	$0.00	$66.38
(97)	45,683	$55,039.73	$52,637.14	$2,402.59	4.6%	$3,842.67	$3,508.93	($1,104.45)	($3,821.51)	($95.12)	$0.00	$72.08
(98)	49,731	$59,696.93	$57,104.29	$2,592.65	4.5%	$4,160.98	$3,819.84	($1,202.35)	($4,160.06)	($103.54)	$0.00	$77.78
(99)	53,777	$64,351.37	$61,568.82	$2,782.55	4.5%	$4,479.15	$4,130.58	($1,300.19)	($4,498.52)	($111.95)	$0.00	$83.48
(100)	57,825	$69,008.58	$66,035.70	$2,972.88	4.5%	$4,797.53	$4,441.72	($1,398.03)	($4,837.15)	($120.38)	$0.00	$89.19
(101)	61,873	$73,665.78	$70,502.60	$3,163.18	4.5%	$5,115.92	$4,752.85	($1,495.89)	($5,175.78)	($128.81)	$0.00	$94.90
(102)	65,920	$78,321.26	$74,968.30	$3,352.96	4.5%	$5,434.16	$5,063.54	($1,593.74)	($5,514.34)	($137.25)	$0.00	$100.59
(103)	69,967	$82,977.39	$79,434.29	$3,543.09	4.5%	$5,752.40	$5,374.47	($1,691.61)	($5,852.79)	($145.67)	$0.00	$106.29
(104)	74,016	$87,635.63	$83,902.59	$3,733.04	4.4%	$6,070.85	$5,685.30	($1,789.47)	($6,191.54)	($154.10)	$0.00	$111.99
(105)	78,063	$92,291.13	$88,368.00	$3,923.13	4.4%	$6,389.10	$5,996.28	($1,887.32)	($6,530.08)	($162.54)	$0.00	$117.69

C & I HLF Large:

(106)								Difference due to:				
(107)	Annual	Proposed	Current					DAC				
(108)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Base DAC	ISR	EE	LIHEAP	GET
(109)												
(110)	41,956	$42,170.75	$44,039.70	($1,868.95)	-4.2%	$2,860.88	($776.19)	($804.85)	($3,019.97)	($72.75)	$0.00	($56.07)
(111)	46,471	$46,441.73	$48,539.40	($2,097.67)	-4.3%	$3,141.82	($859.66)	($891.45)	($3,344.89)	($80.56)	$0.00	($62.93)
(112)	50,991	$50,716.90	$53,043.88	($2,326.98)	-4.4%	$3,423.01	($943.47)	($978.16)	($3,670.16)	($88.39)	$0.00	($69.81)
(113)	55,507	$54,988.69	$57,544.21	($2,555.52)	-4.4%	$3,704.08	($1,026.64)	($1,064.80)	($3,995.26)	($96.23)	$0.00	($76.67)
(114)	60,028	$59,264.78	$62,049.72	($2,784.95)	-4.5%	$3,985.39	($1,110.55)	($1,151.50)	($4,320.68)	($104.06)	$0.00	($83.55)
(115)	64,545	$63,537.40	$66,551.27	($3,013.87)	-4.5%	$4,266.46	($1,194.02)	($1,238.19)	($4,645.80)	($111.90)	$0.00	($90.42)
(116)	69,062	$67,810.05	$71,052.77	($3,242.73)	-4.6%	$4,547.53	($1,277.49)	($1,324.84)	($4,970.90)	($119.74)	$0.00	($97.28)
(117)	73,583	$72,086.12	$75,558.33	($3,472.21)	-4.6%	$4,828.84	($1,361.42)	($1,411.57)	($5,296.33)	($127.56)	$0.00	($104.17)
(118)	78,099	$76,357.93	$80,058.64	($3,700.71)	-4.6%	$5,109.91	($1,444.58)	($1,498.18)	($5,621.43)	($135.40)	$0.00	($111.02)
(119)	82,619	$80,633.13	$84,563.12	($3,929.99)	-4.6%	$5,391.10	($1,528.36)	($1,584.89)	($5,946.71)	($143.23)	$0.00	($117.90)
(120)	87,137	$84,907.55	$89,066.27	($4,158.72)	-4.7%	$5,672.31	($1,611.73)	($1,671.56)	($6,271.90)	($151.08)	$0.00	($124.76)

National Grid - RI Gas
Supplemental Distribution Adjustment Charge (DAC) Filing
Bill Impact Analysis with Various Levels of Consumption - Nov 2017-Oct 2018 Rates vs Proposed Nov 2018-Oct 2019 Rates

C & I LLF Extra-Large:

(121)								Difference due to:				
(122)	Annual	Proposed	Current					DAC				
(123)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Base DAC	ISR	EE	LIHEAP	GET
(124)												
(125)	233,835	$226,060.38	$208,024.47	$18,035.91	8.7%	$5,386.91	$18,626.91	($656.27)	($5,343.25)	($519.47)	$0.00	$541.08
(126)	259,019	$249,739.55	$229,844.72	$19,894.83	8.7%	$5,886.28	$20,632.81	($726.98)	($5,918.74)	($575.39)	$0.00	$596.84
(127)	284,197	$273,413.73	$251,659.70	$21,754.03	8.6%	$6,385.61	$22,638.78	($797.59)	($6,494.06)	($631.33)	$0.00	$652.62
(128)	309,381	$297,092.87	$273,479.69	$23,613.17	8.6%	$6,884.97	$24,644.91	($868.30)	($7,069.52)	($687.28)	$0.00	$708.40
(129)	334,562	$320,769.52	$295,297.39	$25,472.12	8.6%	$7,384.31	$26,650.74	($938.96)	($7,644.91)	($743.22)	$0.00	$764.16
(130)	359,745	$344,447.83	$317,116.76	$27,331.07	8.6%	$7,883.67	$28,656.65	($1,009.68)	($8,220.35)	($799.15)	$0.00	$819.93
(131)	384,928	$368,126.19	$338,936.05	$29,190.15	8.6%	$8,383.03	$30,662.62	($1,080.30)	($8,795.81)	($855.10)	$0.00	$875.70
(132)	410,110	$391,803.68	$360,754.70	$31,048.98	8.6%	$8,882.38	$32,668.38	($1,150.99)	($9,371.23)	($911.03)	$0.00	$931.47
(133)	435,293	$415,482.00	$382,573.75	$32,908.25	8.6%	$9,381.73	$34,674.58	($1,221.67)	($9,946.67)	($966.97)	$0.00	$987.25
(134)	460,471	$439,156.15	$404,388.78	$34,767.37	8.6%	$9,881.06	$36,680.53	($1,292.33)	($10,522.00)	($1,022.91)	$0.00	$1,043.02
(135)	485,655	$462,835.27	$426,209.02	$36,626.26	8.6%	$10,380.43	$38,686.42	($1,363.03)	($11,097.48)	($1,078.87)	$0.00	$1,098.79

C & I HLF Extra-Large:

(136)								Difference due to:				
(137)	Annual	Proposed	Current					DAC				
(138)	Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	Base DAC	ISR	EE	LIHEAP	GET
(139)												
(140)	486,528	$400,976.20	$415,250.82	($14,274.61)	-3.4%	$9,149.95	($11,666.22)	($799.78)	($9,680.43)	($849.89)	$0.00	($428.24)
(141)	538,924	$443,491.89	$459,387.34	($15,895.45)	-3.5%	$10,054.58	($12,922.96)	($885.90)	($10,722.92)	($941.39)	$0.00	($476.86)
(142)	591,320	$486,006.73	$503,522.70	($17,515.97)	-3.5%	$10,959.15	($14,179.26)	($972.05)	($11,765.43)	($1,032.90)	$0.00	($525.48)
(143)	643,718	$528,523.86	$547,660.48	($19,136.62)	-3.5%	$11,863.82	($15,435.74)	($1,058.18)	($12,808.00)	($1,124.42)	$0.00	($574.10)
(144)	696,109	$571,035.04	$591,792.09	($20,757.05)	-3.5%	$12,768.34	($16,691.99)	($1,144.32)	($13,850.42)	($1,215.95)	$0.00	($622.71)
(145)	748,506	$613,551.43	$635,929.00	($22,377.57)	-3.5%	$13,673.00	($17,948.36)	($1,230.45)	($14,892.96)	($1,307.47)	$0.00	($671.33)
(146)	800,903	$656,067.82	$680,065.99	($23,998.17)	-3.5%	$14,577.66	($19,204.77)	($1,316.59)	($15,935.50)	($1,399.02)	$0.00	($719.95)
(147)	853,294	$698,578.98	$724,197.50	($25,618.53)	-3.5%	$15,482.18	($20,460.99)	($1,402.73)	($16,977.92)	($1,490.51)	$0.00	($768.56)
(148)	905,692	$741,096.10	$768,335.29	($27,239.19)	-3.5%	$16,386.85	($21,717.49)	($1,488.84)	($18,020.48)	($1,582.05)	$0.00	($817.18)
(149)	958,088	$783,610.95	$812,470.64	($28,859.69)	-3.6%	$17,291.41	($22,973.76)	($1,574.96)	($19,063.02)	($1,673.57)	$0.00	($865.79)
(150)	1,010,485	$826,127.37	$856,608.09	($30,480.72)	-3.6%	$18,196.06	($24,230.63)	($1,661.11)	($20,105.53)	($1,765.09)	$0.00	($914.42)